BP Cherry Point Cogeneration Project

Volume 2 - Responses to Comments

DOE/EIS-0349

Lead Agencies:

Energy Facility Site Evaluation Council

Bonneville Power Administration

Cooperating Agency:

U.S. Army Corps of Engineers

August 2004

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<u>List of Commenters</u>

Note: Each comment letter or transcript listed below appears first, followed by the corresponding responses.

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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
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
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
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
LOS	level-of-service
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_{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 volume dry
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

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

1. INTRODUCTION TO VOLUME 2, RESPONSES TO COMMENTS

1.1 BACKGROUND

The Draft EIS for the BP Cherry Point Cogeneration Project was published on September 5, 2003. The comment period for the Draft EIS ended on October 27, 2003, which was 52 days after publication. During the comment period, a public comment meeting was held on October 1, 2003, at the Blaine Performing Arts Center in Blaine, Washington.

At the end of the comment period, the lead agencies had received a total of 315 comments made up of the following:

- 262 written comments from 25 agencies and organizations;
- 29 written comments from 11 citizens;
- 24 oral comments from 11 speakers at the public meeting (transcribed by a court reporter).

1.2 ORGANIZATION OF VOLUME 2

This volume contains the written comments received during the comment period, the transcript from the October 1, 2003, public meeting, and the corresponding responses to those comments, organized into the following three sections:

1. **Introduction**

2. **General Responses to Comments on Major Issues**. Two issues were the subject of numerous written comments from individuals and agencies. To address these comments with a minimum of repetition and to provide a response that is meaningful to decision-makers, Volume 2 contains two general responses that encompass many commenters' concerns on each issue. These general responses are:

   A. Alternatives analysis
   B. Wetland impacts and mitigation

   For each general response, we first summarized the issue and then responded to the commenters' concerns, incorporating new information from prefiled testimony, hearing testimony and examination, hearing exhibits, and Settlement Agreements.

3. **Written and Oral Comments and Detailed Responses**. For each of the letters received during the comment period and for each speaker at the public meeting, EFSEC assigned an identification number in chronological order based on the date the comment was received or presented. Within each letter and transcript, comments are marked with a line and the corresponding comment number in the right-hand margin. In many cases, individuals have numerous comments addressing a variety of topics.

   After each letter and transcript are the corresponding responses written by the EIS authors. The responses are numbered to match the comment numbers.

As described in WAC 197-11-560, possible options for responding to comments on a Draft EIS include modifying the alternatives or developing new alternatives, improving or modifying the analysis, making factual corrections, or explaining why the comments do not warrant further agency response. In this regard, for each comment within each letter or transcript, we:

- provide additional information or elaborate on a topic previously discussed in the Draft EIS;
- note how the EIS text has been revised to incorporate new information or factual corrections;
- refer the reader, when appropriate, to another comment response or one of the general responses to avoid repetition;
- explain why the comment does not warrant further response; or
- simply acknowledge the commenter when an opinion was stated.

1.3 REFERENCES CITED IN VOLUME 2

The responses in this volume reference the following types of documents:

- Documents that were submitted as exhibits by those who testified during the EFSEC Adjudicative Hearings or the Prevention of Significant Deterioration Permit Comment Meeting on the BP Cherry Point Cogeneration Project. A list of these exhibits is provided below.
- The written transcript of the Adjudicative Hearings. Flygare & Associates, Inc., a court reporter under contract to EFSEC, prepared the transcript.
- Documents contained in the appendices of the Final EIS (see Volume 1).
- Additional literature sources, which are listed below.

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.

Other Information Sources

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2. GENERAL RESPONSES TO COMMENTS ON MAJOR ISSUES

A. ALTERNATIVE ANALYSIS

Issue Summary:

Some commenters requested additional information regarding alternative locations for the project as well as different project sizes.

Response:

The 404(b) 1 Alternatives Analysis established that the basic purpose and need 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 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.

The Applicant has designed the cogeneration facility to occupy the smallest footprint area feasible, limited to 33 acres, and to affect the least amount of wetlands. There is no alternative configuration that would further reduce the wetlands impact and no other action that would satisfy all of the elements of purpose and need. The Alternatives Analysis defined the criteria for evaluating practicable alternative locations, based on cost, technology, and logistical limitations. Those criteria are size, proximity to the refinery, security, and accessibility.

Six potentially practicable sites were evaluated, including the proposed site. The six sites are described in more detail in the Alternatives Analysis included in Appendix A of this Final EIS. The proposed site is shown to be the one with the least wetland and overall environmental impact. The sites are compared in Table 1 below.

The criteria used to evaluate the six sites are described in Section 2.4.1 of the Draft EIS. Site 1 is the proposed project site.

Table 1: 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

Laydown areas (material staging areas) are required for construction of the cogeneration facility and for permanent use by the refinery for maintenance activities called turnarounds. Alternative laydown sites must meet three criteria to serve the purpose and need: size, accessibility, and security. Costs would be similar for all sites so this factor was not taken into account when comparing sites. Technology is also not relevant in comparison of sites because no alternate electrical generating 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.

In general, the same sites considered practicable for the cogeneration facility would also meet the key criteria for practicability for the laydown/turnaround areas. However, one site would be occupied by the cogeneration facility itself. The potentially practicable sites are compared in Table 2 below. Alternative A, the proposed site, is the site that has the least wetland and overall environmental impact and meets the practicability criteria and the purpose and need.

Table 2: 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

For both the cogeneration facility and the laydown areas, no combination of sites would satisfy the purpose and need and meet the practicability criteria.

The Alternatives Analysis demonstrated that no other practicable action, site, combination of sites, or site configuration would have less wetland impact or overall environmental impact 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.

Also, the project size was developed to meet the following critical criteria:

- Reliability - Steam and power reliability are critical to the operation of the BP Refinery. A plant with three gas turbines and one steam turbine (3x1) provides this reliability because if one turbine is shut down for planned maintenance, two turbines would remain running. If one of the two remaining turbines shuts down inadvertently, only one turbine would be running. One gas turbine is sufficient to supply steam and electricity to the refinery.

- Efficiency - The newest turbines, which also happen to be the largest, are the most efficient available. Efficiency lowers the cost to produce electricity, reduces air emissions, reduces greenhouse gas emissions, and reduces fuel consumption per kilowatt hour of electricity produced.
- Economy of Scale - Within certain constraints, such as infrastructure, the incremental increase in size generally lowers the cost of construction and operation of the plant. For instance, smaller plants may cost less to construct, but their cost is not necessarily proportional to the output produced. A facility half the size does not cost half as much. To recover the cost of capital invested in the project, the plant must be of a sufficient size to lower the cost per kilowatt produced into a competitive range. Because private money is being used to finance the proposed project, investors must weigh risk versus return like any other investment.

B. WETLAND IMPACTS AND MITIGATION

Issue Summary:

Several commenters stated that the Draft EIS did not adequately describe the impacts on wetlands or the proposed mitigation plan.

Response:

The Wetland Mitigation Plan was prepared to provide mitigation for the wetland impacts associated with the proposed construction of the BP Cherry Point Cogeneration Project. 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 affected wetlands have been degraded over many decades of farming, road building, and industrial activity. In addition to the resulting changes in the vegetation and habitat, ditches and roads have redirected water flow from historical paths.

The mitigation plan proposes to restore in place the temporarily disturbed wetlands upon completion of construction activities that will occur in those areas. For the permanent wetland fill, compensatory mitigation is proposed.

Areas surrounding the impact site in the Terrell Creek drainage were screened for mitigation potential. The chosen sites were shown to be among the best sites available in the watershed for mitigation potential. They are on BP-owned land just north of Grandview Road across the road from the impact sites and total 110 acres in two land parcels. Those two parcels are located on each side of Blaine Road between Grandview Road and Terrell Creek. The eastern parcel is labeled Compensatory Mitigation Area (CMA) 1, and the western parcel is labeled CMA 2.

The mitigation areas are similar in overall character to the impact areas. They are mostly fallow fields dominated by non-native pasture grasses. More than 72% of the mitigation areas qualify as jurisdictional wetlands and are either seasonally inundated or seasonally saturated, drying out by late summer.

Functional assessments were conducted on the wetlands in the impact areas and the mitigation areas, and historical information was reviewed. The mitigation plan was designed to compensate for wetland functions that have been lost by restoring conditions prevalent before settlement and farming of the area took place. The most difficult functions to demonstrate compensation are the hydrological functions, and those became the central theme of the mitigation. The ditches that have been dug to drain farmland in the mitigation areas will be plugged and the water spread back into areas it historically occupied before farming activities changed it. In addition, to compensate for water that does not reach CMA 2 as it did before Grandview Road and Blaine Road and their roadside ditches were built, treated runoff water will be piped across them from the impact area so that it can flow in approximately historical pathways.

The other major focus of the mitigation is to restore native vegetation in patterns similar to what existed before the advent of farming in the area. This will be done by eradicating invasive species, primarily reed canarygrass and blackberries, and by planting native species. Historical maps indicate some areas in the project vicinity were freshwater marshes, probably associated with shrub-dominated habitat, but the majority of the area was probably forested. Remnants of unfarmed forest suggest that the dominant forests were probably mixed deciduous/coniferous tree species on hummocky terrain. In the mitigation planting plan, about 78% of the mitigation areas will be occupied by forest and shrub habitat, and grasses and sedges will dominate the remainder in herbaceous wetland and upland. The open areas in particular will have habitat structure, such as logs, included to provide habitat for small mammals and other wildlife species. Small seasonal ponds will be distributed throughout the sites to provide breeding areas for native amphibians. These ponds, however, are designed to dry up in late summer to prevent bullfrog reproduction. The mitigation area has been designed to maintain and improve equivalent habitat available for the great blue herons that nest in a nearby colony to the west.

Performance standards, monitoring, and contingency measures have been designed and approved by the regulatory agencies to ensure that the mitigation plan will succeed and will compensate for all the wetland impacts. Monitoring, which will occur for 10 years, will include hydrology, vegetation, and invasive species.

3. WRITTEN AND ORAL COMMENTS AND DETAILED RESPONSES

Responses to Comments in Letter 1 from Verne Kucy, Manager Environmental Services Division, the Corporation of Delta

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. Figure 3.2-1 in the Final EIS has been changed to reflect the suggested revisions.

2. Thank you for your comment. Tsawwassen has been replaced with Delta on figures and in tables in the Final EIS.

3. The City of Surrey has been included in Figure 3.2-1 and other figures in the Final EIS.

4. Table 3.2-16 in the Draft EIS is correct. For eight-hour carbon monoxide (CO) readings, the maximum concentration of 4.8 micrograms per cubic meter in Canada is 7.8 miles north of the project on the U.S.-Canada border. The maximum CO concentration is projected to be at a slightly different location than that for other pollutants, which are 7.5 miles away from the project.

5. Thank you for your comment. Table 3.2-18 has been revised and the City of Delta now appears in the table.

Response to Comment in Letter 2 from Dr. Mary Lynn Derrington, Superintendent, Blaine School District 503

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Comment acknowledged.

Responses to Comments in Letter 3 from Sam Crawford, Whatcom County Council Member

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Comment acknowledged.

2. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the air quality impacts.

3. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the air quality impacts.

4. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

5. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

6. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

7. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

8. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

9. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

10. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

11. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

12. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

13. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

Responses to Comments in Letter 4 from Wyburn Bannerman, Ferndale Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. It is Bonneville's normal practice to coordinate with landowners during the siting of electrical transmission towers. If new towers are erected as part of the proposed project, the selection of lattice or monopole towers will take into consideration costs, avoidance of natural resources, and landowners' preferences. Also, please refer to Response 4(2) of the Public Meeting comments.

Responses to Comments in Letter 5 from S. Gilfillan

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment. Potential impacts on air quality, wetlands, and wildlife habitats were assessed in Sections 3.2, 3.5, and 3.7, respectively, of the Draft EIS. The results of the assessment did not identify significant impacts on these resources. Those impacts that were identified will be mitigated by the Applicant through compliance with the conditions in the Site Certification Agreement and permit conditions approved by federal regulatory agencies, if the project is approved.

Responses to Comments in Letter 6 from Doug Caldwell

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The commenter indicates that selective catalytic reduction (SCR) technology can be the source of nitrosamines and hydrogen cyanide. The commenter has attached excerpts from a 1989 report indicating that although the production of nitrosamines and hydrogen cyanide is possible if the combustion gases entering the SCR unit contain hydrocarbons, the formation of both cyanide compounds and nitrosamines is extremely unlikely. SCR technology has been in operation for 20 years at facilities all over the world with no indication of safety concerns related to cyanide compounds or nitrosamines. It is the generally accepted control technology of choice for NO_x emissions control for this type of application.

   The commenter's submittal indicates that the emissions control technology manufactured by ISCA Management Ltd. should be chosen over SCR technology because it controls sulfur oxides and heavy metals in addition to NO_x. The choice of emissions control technology is based on rigorous review according to state and federal laws and regulations. Best Available Control Technology (BACT) must be technically feasible and cost-justified. The technology being proposed by ISCA Management Ltd. has not been demonstrated as technically feasible or commercially available on any combustion turbine facility similar in nature or size to this project. The ISCA technology, therefore, would not meet BACT under the requirements of the Prevention of Significant Deterioration program.

Responses to Comments in Letter 7 from H. J. Schneider, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. The project would incorporate into the design the Best Available Control Technology (BACT) for criteria pollutant emissions.

2. Please refer to General Response A.

3. New transmission lines from the cogeneration facility will connect to Bonneville's existing powerline grid system approximately 0.8 mile east of the facility. No new lines connecting to Vancouver, Canada, will be constructed.

4. Tables 3.2-32 and 3.2-33 in the Final EIS show the worst-case cumulative effect of emissions from the Sumas 2 Project and the proposed BP Cherry Point Cogeneration Project.

5. Thank you for your comment. The proposed project does not include adding transmission lines or "links" between Canada and Anacortes.

Response to Comment in Letter 8 from Todd L. Harrison, WSDOT, Northwest Region/Mount Baker Area

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The Draft EIS has been revised to reflect that no signal is proposed at the Blaine/Grandview intersection. The Applicant has reached an agreement with WSDOT that a signal will be installed at the intersection of Grandview Road and Portal Way and a left-turn lane will be established from westbound Grandview Road to Blaine Road.

Responses to Comments in Letter 9 from Senator Dale E. Brandland, 42nd District

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment.

3. Thank you for your comment.

Responses to Comments in Letter 10 from State Representative Kelli Linville, 42nd District

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment.

3. Thank you for your comment.

Response to Comment in Letter 11 from Gary Russell, Gerald Metzger, Michael Murphy, and Al Saab, Whatcom County Fire District No. 7

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

Responses to Comments in Letter 12 from Arne R. Cleveland, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. You are correct. Analyses performed to evaluate impacts on ambient $PM_{2.5}$ concentrations resulting from project emissions have conservatively assumed that all particulate matter emitted is 2.5 microns or less in diameter.

2. The U.S. Environmental Protection Agency has established National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$. These standards, which are codified in Chapter 40, Section 50.7 of the Code of Federal Regulations (CFR), were established to protect human and environmental health against impacts associated with this pollutant. However, other than the NAAQS for Significant Impact Levels, incremental consumption standards have not yet been established in federal regulation (40 CFR 52.21).

   To assess the impacts of the $PM_{2.5}$ emissions on the NAAQS, the U.S. EPA allows PM_{10} to be used as a surrogate because there is no incremental standard for $PM_{2.5}$ established in 40 CFR 52.21. The Applicant has demonstrated that the project's PM_{10} emissions would be below the Significant Impact Level thresholds and would therefore not cause or contribute to a violation of the NAAQS for PM_{10}. Maximum ambient air concentrations of $PM_{2.5}$ that would result from the project are below the NAAQS established for $PM_{2.5}$, as shown in Table 3.2-11 of the Final EIS

3. As required by state and federal regulations under the Prevention of Significant Deterioration (PSD) review, the Applicant modeled project emissions to determine whether or not impacts on ambient air quality concentrations would exceed the Significant Impact Levels established by EPA. Under PSD regulations, only facilities with impacts that exceed Significant Impact Levels are required to include the impacts of other facilities within the modeling zone. The modeling demonstrated that the impacts of the project would be less than EPA's Significant Impact Levels. In fact, the Draft EIS determined that the project would not have any adverse impacts on ambient air quality in the project vicinity and would comply with all Washington State and national ambient air quality standards.

   The Applicant has, however, assessed the sum of the project emissions with existing ambient background levels for criteria pollutants regulated under the PSD program. These data were presented in the Draft EIS in Table 3.2-11 for U.S. locations, and Tables 3.2-15 and 3.2-16 for Canadian locations.

   In addition to the analyses performed under the PSD program, the combined impacts of the BP Cherry Point Cogeneration Project and the Sumas Energy 2 Generation Facility were conservatively evaluated. This analysis is included in Section 3.2 of the Final EIS.

4. As described in Section 3.9 Noise, of the Draft EIS, there would be no perceptible increase in noise at any of the studied receptor locations surrounding the facility.

5. As noted in Section 3.2 Air Quality in the Final EIS, the combined background and predicted concentrations for all criteria pollutants analyzed in the local area are less than the most stringent air quality standards. Section 3.9 Noise in the Draft EIS indicates there would be no perceptible increase in noise at any of the receptor locations surrounding the facility, including Birch Bay State Park. Also, please refer to General Response A for a description of alternative site analysis and an evaluation of the size of the proposed cogeneration facility.

Responses to Comments in Letter 13 from Bill Henshaw, Bellingham Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. The employment benefits noted are correct. Under minimal water demand conditions and with Alcoa Intalco Works in operation, the cogeneration plant would reduce withdrawals from the Nooksack River by more than 700,000 gallons per day.

Responses to Comments in Letter 14 from James Randles, Director, Northwest Air Pollution Authority

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The cited reference of BP 2002 is provided in Chapter 4 on page 4-2 of the Draft EIS. The reference is as follows: BP West Coast Products, LLC. June 2002 (including April 2003 revisions). *BP Cherry Point Cogeneration Project, Application for Site Certification*. Application No. 2002-01. Part I, Compliance Summary; Part II, Environmental Report; and Part III, Technical Appendices. Prepared by Golder Associates, Inc. for the Energy Facility Site Evaluation Council. Olympia, Wash.

2. The annual emission rates for toxic VOCs were identified in Table 3.2-13 of the Final EIS. These total 6,416.8 lbs/year and represent 7.6% of total facility VOC emissions.

3. Nitric oxide emissions, NO, were included in the evaluation of all nitrogen oxide (NO_x) emissions. The maximum modeled concentration of NO_x from the facility as a whole is 2 $\mu g/m^3$ on a 24-hour average, which is much lower than the 100 $\mu g/m^3$ Acceptable Source Impact Level.

Responses to Comments in Letter 15 from Rob Pochert, Executive Director, Bellingham Whatcom, Economic Development Council

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

Response to Comment in Letter 16 from Preston Sleeger, Regional Environmental Officer, United States Department of the Interior

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Comment acknowledged.

Responses to Comments in Letter 17 from Gerald Steel, Attorney-at-Law, Seattle

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The design of the Applicant's project avoids many potentially adverse environmental impacts. Potential impacts that could not be avoided were evaluated and, with proposed mitigation, the resulting impacts are not considered significant. Assuming the project is approved, the Applicant will carry out stipulated mitigation measures contained in the Site Certification Agreement as well as conditions (general and specific) in the federal permits to be obtained by the Applicant. EFSEC and federal regulatory agencies will monitor the success of the mitigation designed and carried out by the Applicant.

2. Thank you for your comment. Recent research and analyses into the effects of global warming have identified global and regional impacts that may occur. There is uncertainty as to the time when such effects will be measurable and the magnitude of the impacts that may occur. Because of the nature of the models used to predict the effects of greenhouse gas (GHG) emissions on global warming and the global nature of the effects, there is insufficient information to predict the actual impacts resulting from the project's emissions alone. Additional information regarding GHG and global warming has been added to Sections 1.8.1 and 3.2.5 of the Final EIS.

3. As noted in Section 3.6 of the Draft EIS, the cogeneration facility (and in fact the entire project) is located on land zoned for industrial land uses; it therefore does not meet the federal definition for prime agricultural land. While the soils present on the site are those identified in Whatcom County Code 20.38 as "Agriculture Protection Overlay Soils," the code further states the provisions apply only to rural, not industrial, zoning designations.

4. Please refer to Response 3 of this letter. The project will burn a clean fuel, natural gas, and the resulting emissions will be dispersed over a wide area. Only a small fraction of the pollutants would remain in the project vicinity. When compared to coal and diesel fuel, natural gas combustion emits much lower quantities of criteria and toxic pollutants and is not a significant source of acid rain. Project emissions will be minimized through the use of Best Available Control Technology as explained in Section 3.2 of the Final EIS.

5. Water removed from the Nooksack River for use at Alcoa Intalco Works is discharged to the Strait of Georgia. If Alcoa Intalco Works is not in operation, the water that would have been transferred to the cogeneration facility for reuse would instead be delivered directly to the BP Cherry Point Refinery. There would be no increase in water withdrawn from the Nooksack River. All water used by the cogeneration facility would either evaporate in the cooling tower or be treated at the refinery's wastewater treatment facility and discharged to the Strait of Georgia. The water will not be distributed to the local microsystem or agricultural lands.

6. In accordance with the requirements of the Prevention of Significant Deterioration (PSD) program, the Applicant used the CALPUFF model to determine visibility in Class I areas in the U.S. PM_{10}, NO_X, and SO_2 were modeled with chemical transformations of secondary pollutants such as ammonia nitrate and ammonia sulfate, and the results were combined to calculate a visibility coefficient. The results were then compared with background data to calculate the percentage of visibility change.

   Table 3.2-12 of the Final EIS shows that the project emissions (excluding any emission reductions from removal of refinery boilers) predict a 5% visibility change for one day at one Class I area (Olympic National Park). Federal guidelines for determining the criteria used to define a significant impact on regional visibility from emissions at new air pollutant sources were recently published by the Federal Land Managers' Air Quality Related Values Workgroup in its Phase One Report, published by the U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service in December 2001. According to the federal land mangers responsible for protecting air quality in Class I areas, a 5% change in extinction (a coefficient used to quantify how pollutants in the atmosphere reduce visual range) indicates a "just perceptible" change to a landscape and a 10% change is considered a significant incremental impact. The National Park land managers were consulted about the perceptible change caused by the project, and they consider it acceptable (Morse 2003).

   The Draft EIS assesses the cumulative impact on visibility from construction of the BP Cherry Point Cogeneration Project and other proposed power plants in the Pacific Northwest. Phase II of Bonneville's regional impact analysis addressed the visibility impacts of the BP Cherry Point Cogeneration Project in a "most likely" scenario of the Phase II baseline group. In other words, if all projects included in that baseline group were built, some impacts on visibility would most likely occur, as explained in detail in the Draft EIS, but visibility would not be permanently cut off.

<u>Exhibit 1</u>

1(1) The energy market in the Pacific Northwest has changed in the last 18 to 24 months; however, long-term regional energy needs require that additional facilities be constructed to meet regional demand within the next 10 years. Market forces will control which of the proposed facilities actually move forward to construction and operation once they have received environmental and other approvals.

   The Northwest Power Pool comprises all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of Northern California; and the Canadian provinces of British Columbia and Alberta. From 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6% and 1.7%, respectively. With a large percentage of hydro-generation in the region, the ability to meet peak demand is expected to be adequate for the next 10 years. Capacity margins for this winter peaking area range between 23.4% and 29.6% for the next 10 years.

As shown in the following table, a recent survey of large combustion turbine facility projects in the Pacific Northwest indicates that over 11,000 MW of large natural gas turbine proposals have been cancelled, denied permit, or delayed indefinitely, approximately 4,750 MW have been approved but have not started construction, and approximately 5,500 MW are undergoing review. In its most recent 10-year coordinated plan summary, the Western Electricity Coordinating Council projects that reserves will be adequate throughout the region through 2012, but only if 32,300 MW of new generation are brought on line when needed. Droughts in the Pacific Northwest may substantially reduce the availability of electricity for export from the region, and capacity becomes highly dependent on northwest hydroelectric conditions after 2008. The net power increase is projected to be 12,300 MW of committed resources and 20,000 MW of uncommitted resources.

The 546 MW for the Hermiston Power Project reflect the numbers presented in the 2001 Phase II study completed by Bonneville.

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest

Facility	County	Location	Technology	Output (MW)	Est. Online 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	Williamette
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

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
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
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

1 A facility that operates during peak power demands.

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
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
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		Weyerhaeuser
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		

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
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.

1(2) As indicated in the alternatives analysis (see Section 2.4 and Appendix A of the Draft EIS), the Applicant considered the construction of a smaller facility. However, a smaller facility would not meet the requirements of reliability for steam delivery to the refinery and cost-effective power productions. Please refer to General Response A for additional information regarding an evaluation of facility size.

1(3) SCONOx control technology has been demonstrated on smaller combustion turbines (approximately 1 to 40 MW) in California and Massachusetts. To date, however, there have not been any SCONOx systems installed on large combustion turbine applications such as that proposed for this project. Additional technical uncertainties regarding the applicability of SCONOx technology to “F” class turbines have recently been raised by other permitting agencies. On May 30, 2001, the U.S. EPA Environmental Appeals Board and the California Energy Commission issued simultaneous rulings on another project; both refused to overturn a Best Available Control Technology (BACT) decision by the Shasta County Department of Resource Management Air Quality Management District that the SCONOx technology is not technically feasible for turbines of the size being considered for the proposed BP Cherry Point Cogeneration Project. In its BACT decision, the District said that several operational requirements associated with the SCONOx technology make it impractical for use as an emission control technology for “F” class turbines. It stated that all routine operating conditions were not covered in the SCONOx technology guarantee and that the guarantee would be void if water came into contact with the catalyst. Selective catalytic reduction (SCR) was the alternative BACT technology that was selected.

While it is true that the SCR system can use aqueous ammonia to control NO_x, anhydrous ammonia is proposed for economic reasons. Aqueous ammonia is approximately 20% ammonia, which would require additional quantities of ammonia to be delivered to the cogeneration facility, requiring more or larger storage tanks and additional internal piping. Because the BP Refinery currently transports, uses, stores, and internally transfers anhydrous ammonia—all within local, state, and federal guidelines—the Applicant chooses to use anhydrous ammonia in the SCR.

1(4) A discussion of the handling and storage of ammonia is presented in Sections 2.2.2 and 3.16.2 of the Draft EIS. As described in Section 3.15.2 of the Draft EIS, 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 SCR would be supplied by local suppliers and delivery trucks would use the same routes as used today. All ammonia delivery trucks would have to follow appropriate federal, state, and local permitting requirements. In addition, the revised Risk Management Plan required by the EPA 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 in which ammonia is released into the environment.

1(5) The models used for estimating the amount of secondary particulate formed did not cap the amount of ammonia available for reaction. It is assumed that sufficient ammonia was present in the airshed for the maximum amount of secondary particulate to be formed from NO_x and SO_2 emissions. The source of ammonia in the airshed (i.e., ammonia from existing industrial or agricultural sources, or ammonia from the project) did not influence the amount of secondary particulate formed.

Ammonia is recognized as a hazardous air pollutant as defined under WAC 173-460-150, and the impacts of ammonia emissions were analyzed in accordance with the requirements of Chapter 173-460 WAC. The maximum predicted concentrations were modeled and compared against the corresponding Acceptable Source Impact Level (ASIL). The ASILs are health-protective thresholds well below concentrations that are known to cause harm to human health and the environment. If concentrations are below the ASILs, no additional study is required by state or federal law. If concentrations exceed the ASILs, a “second tier” health assessment must be performed to determine if the emissions and resulting ambient concentrations will threaten human health or increase human health risks. The second tier analysis may be required to consider the impact of other existing sources of the compound on potential health risks. Because no ASILs were exceeded, additional analysis of other ammonia sources is not necessary.

1(6) Please refer to Response 1(3) of this letter for a discussion of SCONOx technology. This comment refers to a new generation of low NO_x burners appropriate for power plants that can reportedly lower NO_x emissions to below 5 ppm without causing ammonia emissions. The authors of the Final EIS assume that this improved technology is being proposed instead of the dry low NO_x burners proposed by the Applicant. Without more specific detail regarding the manufacturer and usage specifications of the <5 ppm burners, it is not possible to assess whether such technology could be applied to this size and type of generation facility. The dry low NO_x technology being proposed has been commercially available and proven effective for GE 7FA turbines. BACT for this type of project also requires NO_x emission reductions to be 2.5 ppm or lower.

1(7) Atmospheric reactions that convert ammonia, NO_x, and SO_x to secondary particulate (ammonium nitrate and ammonium sulfate) take place outside of the exhaust stacks hours to days after the NO_x and SO_x have been emitted from the facility. The reactions are controlled by time, temperature, humidity, sunlight, concentration of the reactants, and atmospheric mixing. Secondary particulate is therefore formed at great distances from the source of the pollutants.

Impacts of nitrate and sulfate deposition on soils must be evaluated in Class I areas. This evaluation was performed and results were within acceptable criteria, according to the federal land managers (see Section 3.2.3 in the Final EIS).

Neither guidelines nor thresholds for impacts from deposition to soils have been established for Class II areas. Nevertheless, the Applicant modeled the deposition rates near the project site and determined that maximum rates occur on the northern side of the facility boundary. The maximum deposition rates modeled were 167 and 187 grams/hectare/year for ammonium sulfate and ammonium nitrate, respectively. In the absence of any guidelines or regulatory criteria for the assessment of impacts, this deposition rate was compared to typical nitrogen fertilizer rates in agricultural soils. Agricultural spreading of fertilizer can vary widely depending on soil or crop type. Nitrogen is typically spread on agricultural lands at a rate of 250 pounds/acre/year. The maximum deposition rate for the project represents 0.17 pound/acre/year, which is a small amount compared to that added by agricultural soil amendment.

1(8) Please refer to Response 1(4) of this letter.

1(9) Please refer to Responses 1(3) and 1(4) of this letter.

1(10) Please refer to Response 1(4) and Section 3.16.2 of the Draft EIS regarding the transportation, handling, storage, and potential impacts resulting from a release of ammonia.

1(11) Section 3.2.1 of the Draft EIS has been revised to reflect that the proposed cogeneration facility would be subject to Title III requirements. Pertinent regulations addressing this issue include: Accidental Release Prevention and Risk Management Plan, 40 CFR 68, Chapter 90.56 RCW and Hazardous Substances/Worker Community Right to Know Act, Chapters 70.105, 70.136, and 49.70 RCW.

1(12) Section 2.4.3 of the Final EIS has been updated to include additional information about the Applicant's choice of a wet cooling system versus a dry cooling system.

In choosing wet cooling for the project, the Applicant considered the following factors: (1) availability of water supply; (2) footprint required for the cooling system; (3) impacts on project power generation efficiency; (4) impacts on visual resources; (5) noise emissions from the facility; and (6) capital cost of the cooling system.

As explained in Section 2.4.3 of the Final EIS, dry cooling was originally considered because of the restricted availability of local certificated water resources. Instead, an agreement was established among the Applicant, Alcoa Intalco Works, and the Whatcom PUD allowing once-through water used for cooling at Alcoa Intalco Works to be used as inlet water in the wet cooling system for the project. At times when Alcoa Intalco Works is not in operation, the PUD will supply the water directly to the project. It should be noted that if Alcoa Intalco Works is not in operation, the average amount of water supplied to the project would be less than the water consumed by Alcoa Intalco Works and reused by the project.

The Applicant is choosing the wet cooling system because it would require a smaller footprint for the equipment, would have less visual impact, would produce less ambient noise, would not incur a 1.6% loss in power generation efficiency, and would cost less (one-third that of a dry cooling system).

The commenter presents an extensive list of facilities that use cooling systems other than wet cooling. The commenter, however, does not explain the particular circumstances of the facilities that lead to these choices. For example, in the case of the Chehalis Generation Facility, the choice to use air cooling was made partially to avoid the cost of constructing a pipeline to withdraw and carry the water from the Chehalis River and to discharge wastewater to the City of Chehalis' water treatment system rather than to the Chehalis River.

1(13) There is no economic justification for evaluating a zero liquid discharge facility. The BP Refinery has an operating wastewater treatment facility that is capable of treating and disposing of the wastewater from the cogeneration facility. A new and separate treatment plant would not be warranted. Solid waste material from the refinery's treatment system would include small quantities of chemicals in the waste stream from the cogeneration facility; the quantity of solids attributed to the cogeneration facility would be small compared to the material currently disposed of by the refinery.

1(14) The Draft EIS states that the cogeneration facility would generate 190 gpm on average (assuming 15 cycles of concentration in the cooling tower) of non-recyclable process wastewater that would be sent to the BP Refinery's wastewater treatment system. As presented in Table 3.4-4 of the Draft EIS, the estimated concentration of trace metals and other constituents in the cogeneration facility wastewater discharge represents what is anticipated to be present after up to 15 cycles. The Draft EIS includes detailed notes for Table 3.4-4, including the source of the data used to make the concentration calculations. Many of the trace metals presented in the table were not detected. This indicates that if those metals are present in the water from the Nooksack River, they are at concentrations below the values used to derive the concentrated values presented in Table 3.4-4. Therefore, it is not anticipated that concentrating trace metals present in cogeneration facility feedwater (i.e., raw water from the Nooksack River) would produce significant concentrations of potentially toxic materials in the discharge water. Additionally, no radioactive materials will be used at the cogeneration facility, and therefore there is no reason to anticipate the presence of radioactive materials at toxic concentrations in the feedwater or discharge water.

1(15) The ISOM unit (gasoline isomerization or Clean Fuels Project). is being constructed on existing laydown areas within the refinery, not in wetlands; therefore, it is not subject to the jurisdiction of the U.S. Army Corps of Engineers (Corps) under the Clean Water Act.

BP Refinery is proposing to use the Brown Road Materials Storage Area to replace those laydown areas used for the ISOM unit. That area does have wetlands under the jurisdiction of the Corps, and the Corps is reviewing the proposal. The Brown Road Materials Storage Area is located between Alternative Cogeneration Sites 2 and 3 or Alternative Laydown Sites C and D as presented in the revised alternatives analysis (Appendix A) in the Final EIS.

It is correct that the wetland mitigation area for the Brown Road Materials Storage Area is adjacent to CMA 2, one of the wetland mitigation areas for the cogeneration facility.

1(16) Consideration of the impacts of the ISOM project has been incorporated into the analysis of cumulative impacts resulting from the proposed project. The ISOM project would cumulatively, but not significantly, add to air emissions and wetland impacts. The ISOM project is being constructed within the refinery grounds and has no wetland impacts. The Brown Road Materials Storage Area would include wetland mitigation north of Grandview Road and west of the proposed cogeneration facility mitigation areas. Discharge from the Brown Road Materials Storage Area to the wetland mitigation area would be through existing ditches within the proposed cogeneration facility laydown areas. These ditches would not be eliminated by construction of the laydown areas.

The appropriate sections of Chapter 3 have been revised to incorporate this information.

1(17) The Draft EIS states that effluent from the cogeneration facility's oil-water separator would be discharged to a final treatment and detention pond properly sized in accordance with Whatcom County and Ecology requirements, not to ponds in CMA 1. Once treated, stormwater would be routed to the wetland mitigation area.

1(18) Please refer to Response 1(16) of this letter.

1(19) Thank you for your comment. The Applicant proposes to tap into the Ferndale Natural Gas Pipeline that runs between the refinery and the proposed location of the cogeneration facility. The Ferndale Pipeline, owned and operated by BP Pipeline, Inc., originates in Sumas, Washington, near the Canadian border. The pipeline extends 30.7 miles to Ferndale. The pipeline is not dedicated or devoted to any public use but is used exclusively to transport natural gas for consumption as fuel at BP's Cherry Point Refinery and Alcoa Intalco Works. The maximum allowable operating pressure of 550 pounds per square inch gauge (psig) was authorized by the Washington Utilities and Transportation Commission (WUTC) in a waiver at the time the Ferndale Pipeline was commissioned in 1990. The pipeline was designed for Class 4 locations (a location where buildings with four or more stories aboveground are prevalent) per CFR 192 (DOT regulations) and to operate at a maximum allowable operating pressure of 1,105 psig. The pipeline operates at 550 psig.

There have been no leaks or operational failures on the Ferndale Pipeline (Walsh, pers. comm., 2004). The WUTC pipeline safety inspection staff have performed annual inspections on the pipeline since it was put in use. In March of 2000, BP inspected the pipeline using what is known as a “smart pig.” One metal failure was found and repaired; two others were investigated, but no repairs were required.

BP Pipeline, Inc. is required to operate the pipeline according to applicable state and federal safety standards and regulations. Since the pipeline was installed, the regulatory agency with oversight (WUTC) has not raised questions about the pipeline’s structural integrity or safety record.

1(20) Please refer to Response 1(19) of this letter.

1(21) If a pipeline incident were to occur inside the refinery boundary, the refinery’s emergency response personnel would respond to the emergency. The Applicant has agreed to work with Fire District No. 7 to develop an emergency response protocol, which would be incorporated into mutual aid agreements between the two entities.

1(22) Hydrogen will be stored in pressurized cylinders near the gas turbines as shown in Table 3.16-5 of the Draft EIS. The hydrogen will be used for cooling combustion turbine blades during normal operation. An estimated 605,000 standard cubic feet of hydrogen storage is required. As mentioned in Response 1(21), specific protocols would be followed in using, storing, and transporting hydrogen and other potentially flammable materials.

1(23) State and federal laws require certain hazardous materials to be identified and quantified for local emergency response organizations. The proposed project will continue to comply with all state and federal laws concerning hazardous material transport, use, and storage.

1(24) Regardless of the current supply, demand, and future predicted market characteristics, the use of gas, its cost, and the potential for new gas reserve development or alternatives to gas as an energy source are determined by market forces and not evaluated in this EIS. An attempt to identify potential impacts resulting from further gas development in Canada would be, at best, speculative in nature, and such development would be subject to Canadian environmental review and mitigation by the appropriate Canadian regulatory agencies.

Section 3.8.4 of the Final EIS have been updated to include an analysis of cumulative impacts on regional natural gas supplies.

1(25) Thank you for your comment. Section 3.2.3 of the Final EIS has been revised to include a discussion of secondary formation of particulate matter.

1(26) PM_{10} emissions from the cooling towers will be limited to 7.2 tons per year on a rolling annual average, estimated monthly. Therefore, even though the cogeneration project may be larger than the Goldendale Energy Plant, its annual cooling tower emissions will be similar. The PM_{10} emissions from the cooling tower were included in the consideration of the project’s impacts on ambient air quality and other regulated air quality values. It was determined that the project as a whole, including the cooling tower, would not violate ambient air quality standards.

Emissions from the cooling tower are expected to consist of only PM_{10}. These emissions originate from the dissolved solids contained in droplets of cooling water called “drift” that escape in the air stream exiting the cooling tower. Drift eliminators have been incorporated into the tower design to remove as many droplets as practical before the air exits the tower. A high efficiency drift eliminator with a drift rate of 0.001% is proposed for the project. Droplets that exit the tower are expected to land close to this source.

1(27) Section 3.2 of the Draft EIS addressed the formation of secondary particulate. The discussion has, however, been expanded in the Final EIS. Table 3.2-23 of the Final EIS estimates the secondary particulate that could be formed by the project and decreases in secondary particulate emissions as a result of removing the refinery boilers.

The CALPUFF model was used to assess the visibility impacts in Class I areas, as required by the PSD program. CALPUFF takes into account the formation of secondary particulate and the contribution of that particulate on visibility impacts. The federal land managers have indicated that the visibility impacts on Class I areas (see Section 3.2 3 of the Final EIS) are acceptable (Morse 2003).

Section 3.2.3 of the Final EIS has been updated to include a discussion of health impacts of fine particulate, PM_{10}, and $PM_{2.5}$ in particular. The project will not violate PM_{10} and $PM_{2.5}$ National Ambient Air Quality Standards. These standards conservatively protect human health.

1(28) The Department of Ecology, as a contractor to EFSEC, reviewed the Applicant’s process wastewater characteristics and proposed treatment protocol. The primary purpose of this technical review was to identify conditions, mitigation measures, and/or wastewater treatment methods needed to meet the state water quality standards that protect marine biota in the receiving water around the refinery discharge. If the project is approved, final project-specific State Waste Discharge and National Pollutant Discharge Elimination System (NPDES) permits would specify the discharge limits of treated process wastewater (including inhibitors) and stormwater from the project. Such limits protect human health and aquatic species.

1(29) The Applicant estimates 0.7 cubic yards per day of spent cellulose filter material will be sent from the cogeneration project to the refinery’s non-hazardous waste land farm. The refinery’s land farm disposes of 10 to 30 cubic yards per day. Based on the maximum potential rate of generation of spent cellulose waste, the cogeneration project would increase the current land farm disposal rate at the refinery by 2.3% to 7.0%. Hazardous materials would be treated and disposed of at an approved facility.

1(30) The stormwater treatment system will be designed to meet the requirements of Whatcom County and the design standards presented in Ecology’s Stormwater Management Manual for Western Washington (2000). Additionally, discharge from the oil-water separator and stormwater treatment pond will be required to meet the conditions of a NPDES and State Waste Discharge permits, which cover all discharge from the cogeneration facility to surface waters. These measures should sufficiently minimize potential impacts of stormwater runoff from the cogeneration facility and would protect all applicable state water quality standards.

1(31) The stormwater collection and treatment system is described in detail in Section 3.4 Water Quality on page 3.4-12 of the Draft EIS. As described, all stormwater runoff from the cogeneration facility, with the exception of stormwater captured in secondary containment structures for outside tanks and chemical storage areas, would be routed to the oil-water separator by the stormwater collection system. Stormwater captured in the secondary containment structures would be analyzed for the presence of fuel and chemical contaminants. If contaminants are detected, this stormwater would be routed to the refinery's treatment system. If contaminants are not detected, this stormwater would be routed to the cogeneration facility's stormwater treatment system, including the oil-water separator. It should be noted that some stormwater in the switchyard area will infiltrate directly into the underlying soil. Additionally, discharge from the oil-water separator and stormwater treatment pond will be required to meet the conditions of a NPDES permit, which covers all discharge from the cogeneration facility to surface waters. These measures should sufficiently minimize impacts of stormwater runoff from the cogeneration facility.

1(32) Biocides will be added to control bacteria in the cooling towers, and thereby prevent the formation of *Legionella* bacteria. A mixture of bleach (15% aqueous solution of sodium hypochlorite) and sodium bromide (40% aqueous solution) will be added to the circulating water in a ratio 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, which have caused 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. This information has been incorporated into Section 3.16 of the Final EIS.

1(33) Because the comment mentions proposed transmission lines "about 3000 feet long" we assume it refers to the 230-kV double circuit line (approximately 0.8 mile long or 4,224 feet) needed to connect with Bonneville's Custer-Intalco Transmission Line No. 2 for integration with the transmission grid. Underground construction of high voltage transmission lines tends to be much more expensive than overhead construction. It is unusual for any utility to use underground construction for 230-kV lines—the few examples cited are exceptions. Reasonable circumstances for constructing transmission lines underground would be marine crossings or dense urban areas. The additional equipment required, such as insulating fluids, high-pressure pumps, and temperature-monitoring equipment, would greatly increase costs. Also, the relative difficulty of maintaining and repairing underground transmission lines makes an underground line less reliable. Regarding the point that the new line would create an avian collision hazard, studies have found that such problems occur only in specific, localized situations where birds in flight must frequently cross a power line within their daily use area (Edison Electric Institute 1994). Although the proposed transmission line would pass through an emergent wetland, a narrow band of black cottonwood, and mixed coniferous/deciduous forest habitat used by some of the birds listed in Table 3.7-1, there is no evidence to indicate the line would intersect a major local flyway. It was also suggested the line would cause significant visual impact and increase human exposure to electromagnetic fields; however, the line would be located on unpopulated land zoned for industrial use and near industrial facilities. Finally, underground construction would cause substantially more ground disturbance than overhead construction. Underground construction is not a reasonable alternative because it offers no environmental advantages to overhead construction in this situation, would be significantly more expensive, and would be less reliable.

1(34) The estimate of pollutant emission reductions from removal of refinery boilers focused only on criteria pollutants. The ammonia emissions from operation of the project were identified in Table 3.2-13 of the Draft EIS. Secondary particulate formed by ammonia, NO_x, and SO_2 emissions was also discussed in Section 3.2 of the Draft EIS. Long range modeling of project emissions, including conversion to secondary particulate (and excluding any reductions from removal of refinery boilers), has shown that the project will not violate any U.S. or Canadian ambient air quality standards or objectives.

We assume that the commenter's statement that the project will emit as much as 1,400 tpy of secondary particulate is based on the analysis performed in the Wallula Power Project Final EIS. The Wallula Final EIS states that, theoretically, 1 ton of ammonia emissions could yield 4.6 tons of secondary particulate as ammonium nitrate. However, the Wallula Final EIS also states that the chemical fate of ammonia emissions from the plant is not well understood, and it is uncertain what fraction of the ammonia would actually react to form ammonium nitrate. As noted in Response 1(5), the Whatcom County/Lower Fraser Valley airshed is already ammonia rich because of existing industrial and agricultural activities; therefore, additional emission of ammonia from the project may not be the controlling factor in secondary particulate formation and the emissions of NO_x and SO_2 would be. Other commenters have also noted that the conversion rates used by the Applicant (much less than the theoretical stated above) could be overestimating the actual conversions.

1(35) To meet the 2005 federal standard for sulfur in gasoline, the Applicant proposes to implement a clean gasoline project at its Cherry Point Refinery in Whatcom County. The project will process light naphtha feedstocks to produce a gasoline blend that has essentially no benzene, olefins, or sulfur, and is higher in octane than its feed. The project will have a naphtha dehexanizer unit; an ISOM Hydrotreater (IHT) that includes a process heater, a naphtha hydroheater, and a BenSat unit; a Penex (isomerization) unit; connections to existing processes and changes in tank services within the refinery; and a new #2 boiler. The cumulative impacts of the ISOM project (gasoline isomerization or Clean Fuels Project) have been included in the appropriate sections of the Final EIS, with air emissions from the ISOM project identified in Section 3.2.

Please refer to Letter 12, Response 3 and Response 1(5) of this letter for an explanation of why cumulative impacts on ambient air quality from both criteria and toxic pollutants are not expected.

1(36) Regarding NO_x reductions mandated by the consent decree (*United States v BP Exploration and Oil Co.*, 2:96 CV 095 RL)[1], BP West Coast Products, LLC maintains a list of emissions sources at the refinery that are targeted for removal to comply with the emissions reductions mandated by the consent decree. According to the requirements of the decree, the list is updated annually; however, equipment may be added or removed as long as the emission reduction targets are met. At the time of Final EIS preparation, the refinery boilers were on the list of equipment targeted to be removed at the refinery to comply with the decree. Emission reduction credits (ERCs) are not being sought for the removal of the boilers. Therefore, if the boilers are still on the mandated equipment removal list when the proposed project is constructed, their removal can partially fulfill the requirements of the consent decree.

Consideration of the contribution of the BP Refinery emissions to the past non-attainment status of the Seattle area or to ambient air quality in British Columbia is outside the scope of this Final EIS.

1(37) The emission of toxic air pollutants was summarized in Table 3.2-13 of the Draft EIS. Table 3.2-13 showed all toxics for which emission increases are expected. The Applicant does not seek credits for decreases in toxic air pollutants or criteria emissions resulting from removal of the boilers at the refinery. The Applicant is not seeking to trade emissions of toxic air pollutants from the project, which underwent the full review required by WAC 173-460 without any credits for refinery reductions being taken into account. The commenter is correct that removal of the refinery boilers can also lead to a reduction in toxic air pollutant emissions. This would represent an environmental benefit. Because the primary environmental benefit for the regional airshed is associated with reductions in criteria pollutants, the benefit of reducing toxic air pollutants was not quantified.

No ERCs are being sought for the proposed project. The analysis of the environmental and health impact of emissions from the project was performed without taking into account reductions resulting from the removal of the refinery boilers. These reductions were considered only in a semi-quantitative manner regarding the regional impact of the project as a whole. All impact analyses required by state and federal regulation were performed without including the refinery reductions.

[1] See http://www.nwair.org/regulated/aop/BP/BP%20-%20Consent%20Decree%201-01.pdf

Responses to Comments in Letter 18 from Karen Kloempken, Fish and Wildlife Biologist, Department of Fish and Wildlife

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. In Section 3.7.2 of the Final EIS under the heading Wildlife and Habitat, Custer-Intalco Transmission Line No. 2, the following text will be added, “Bonneville will consult with WDFW during design of the transmission line to develop the Hydraulic Project Approval.”

2. In Section 3.7.1 of the Final EIS under the heading Threatened and Endangered Species, Federally Listed Threatened Species, the following text will be added, “The WDFW Priority Habitat and Species database identifies a bald eagle nesting site within about 400 feet of the Custer-Intalco Transmission Line No. 2.”

   In Section 3.7.5, Mitigation Measures, the following text will be added to the Final EIS: “Bonneville will avoid transmission line construction and maintenance activities near the known bald eagle nesting site from mid-March to mid-June.”

3. Thank you for your comment. Seed mixes in disturbed areas will be determined based on coordination with federal, state, and local agencies.

Responses to Comments in Letter 19 from Trina Blake, NW Energy Coalition

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. According to a Settlement Agreement between the Applicant and Counsel for the Environment, and should the project be approved by the Governor, the Applicant shall decommission the BP Refinery's No. 1, No. 2, and No. 3 boilers within six months of the project's entry into commercial operation. Upon completion of the decommissioning, the Applicant would provide EFSEC with written notification and proof that the boilers have been decommissioned at the BP Refinery. Other stipulations of the agreement have been included in the Final EIS, Section 3.2, Mitigation Measures.

2. Without an applicable state or federal regulation requiring mitigation or reduction of CO_2 emissions[2], the EFSEC must consider proposals for CO_2 mitigation on a case-by-case basis. According to the Settlement Agreement between the Applicant and the Counsel for the Environment, BP West Coast Products, LLC will go beyond the mitigation proposal presented in the Draft EIS. Regarding the potential for facility ownership to change, the Settlement Agreement requires that the Applicant continue to offset its ownership (equity) share of the CO_2 emissions according to BP's existing, voluntary policy, and that the third party certificate holder mitigate its share according to the requirements of the Settlement Agreement described in Section 3.2.7 of the Final EIS.

3. Capacity factor is no longer a consideration in determining the amount of CO_2 emissions that have to be mitigated. If the Applicant holds an equity (ownership) interest in the project, the Applicant will offset its share in the project's emissions by reducing greenhouse gas emissions elsewhere in the Applicant's worldwide operations, consistent with its voluntary corporate policy. If a portion of the project is sold, 23% of actual emissions would be mitigated.

4. The Settlement Agreement between Applicant and the Counsel for the Environment is independent of the Oregon standard. Depending on the ownership of the project, from 23% to 100% of actual emissions must be mitigated at a cost of $0.87 per metric ton of CO_2.

5. Through the Settlement Agreement between the Applicant and the Counsel for the Environment, the payment would be increased to $0.87 per metric ton. Although the Settlement Agreement continues to endorse annual payment, the cost per metric ton is now linked to the Producer Price Index and would be adjusted annually.

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[2] House Bill 3141, signed into law on March 30, 2004, applies to proposals that submit Applications for Site Certification to EFSEC after July 1, 2004.

6. Thank you for your comment. The Settlement Agreement between the Applicant and the Counsel for the Environment does not require additional payment for administrative costs.

7. The Settlement Agreement between the Counsel for the Environment and the Applicant allows a third party (should project ownership change in the future) to choose the method of mitigation only on the share of emissions not owned by the Applicant.

8. Thank you for your comment. The Settlement Agreement between the Applicant and the Counsel for the Environment goes beyond the original proposal made by the Applicant in its Application for Site Certification and ensures substantial mitigation of CO_2 emissions.

Responses to Comments in Letter 20 from Mike Torpey, Environmental Team Lead, BP Cherry Point Cogeneration Project

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment. The description of the No Action Alternative has been revised in the Final EIS. The No Action Alternative indicates that in order to meet long term regional power needs additional generation would need to be brought on line. Baseload generation would most likely be augmented by increasing the size of existing facilities or constructing new ones. It is correct that the siting of other cogeneration facilities is less likely, because in addition to access to transmission and natural gas supply services, a cogeneration developer would have to find a receptive host for produced steam. Because non-cogeneration combustion turbine projects are less fuel efficient, they would likely produce more emissions (air and water) per kilowatt hour. The impacts of this type of inefficiency have been assigned to the No Action Alternative in the respective sections of Chapter 3.

   Appropriate changes/corrections have been incorporated into the Final EIS. The project description in the Draft EIS was consistent with the Application for Site Certification and its Appendix D; therefore, the "typographical errors or correcting statements" usually reflect changes in the design of the project since the Draft EIS was prepared.

3. See specific responses below.

3(1) Thank you for your comment. The Draft EIS has been revised to reflect an 83% boiler efficiency.

3(2) Thank you for your comment. The Draft EIS has been revised to note the Bonneville right-of-way occupies 71 acres.

3(3) Thank you for your comment. A 265-horsepower, diesel-driven emergency water pump for fire suppression has been added to the list of project elements.

3(4) Thank you for your comment. Treatment facilities for boiler water have been added to the list of project elements.

3(5) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description.

3(6) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description.

3(7) Please refer to Response 2 of this letter.

3(8) Thank you for your comment. This and the following six comments relate to “issues to be resolved.” Section 1.6.1 of the Draft EIS has been revised to reflect the resolution of this issue.

3(9) Thank you for your comment. The Draft EIS has been revised to reflect the resolution of this issue and change in the project description.

3(10) Thank you for you comment. Table 2-1 of the Draft EIS has been revised to reflect this change in the project description.

3(11) Thank you for you comment. Table 2-1 of the Draft EIS has been revised to reflect this change in the project description.

3(12) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description. The new substation within the refinery near the existing substation MS3 will have a kilovolt capacity of 115, not 230 kV.

3(13) Thank you for you comment. The Draft EIS has been revised to reflect this refinement of the project description. Wetland impacts from the construction of the pipeline support structure are addressed in the Section 3.5, Wetlands, of the Final EIS.

3(14) Thank you for your comment. The commenter notes the expansion or modification to the Custer-Intalco electrical transmission system will be built, owned, and operated by Bonneville. The types of transmission structures to be erected are identified in Figure 1-2 and described in Section 2.2.2 of the Draft EIS. The following sentence has been inserted in the Final EIS under the heading Option 2b - New Transmission Line with Monopole Towers, “Under either Option 2a or 2b, the specific number of structures and their locations, as well as specific access road needs, will not be known until further design is completed.”

3(15) The bullet has been revised to reflect mitigation measures presented in the revised Application for Site Certification.

3(16) Thank you for your comment.

3(17) Table 1-2 of the Draft EIS has been revised to reflect this addition.

3(18) Thank you for your comment.

3(19) Thank you for your comment. According to the Stormwater Management Manual for Western Washington (Ecology 2000), Best Management Practice (BMP) C106 recommends the use of wheel washers for construction sites when a stabilized construction entrance is not preventing sediment from being tracked onto pavement.

3(20) Thank you for your comment.

3(21) Table 1-2 of the Draft EIS as been revised to reflect this addition.

3(22) Thank you for your comment.

3(23) Thank you for your comment. The recommended mitigation measure has been incorporated into list of the Applicant's proposed mitigation measures.

3(24) The EIS has been revised to reflect this correction.

3(25) For information on the agreed upon traffic mitigation after the start of construction, please refer to Letter 8, Response 1.

3(26) The existence of the 71-acre Bonneville right-of-way as part of the project has been noted in the Final EIS.

3(27) Thank you for your comment. The pump has been added to the equipment list for the cogeneration facility in the Final EIS.

3(28) Thank you for your comment. Water treatment facilities have been added to the referenced list.

3(29) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(30) Thank you for your comment. The Draft EIS has been revised to reflect this change in the list of proposed equipment.

3(31) Thank you for your comment. Table 2-1 of the Draft EIS has been revised to reflect uninterruptible power supply.

3(32) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(33) Thank you for your comment.

3(34) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(35) The Draft EIS has been revised to reflect this clarification. Conditions set through the National Pollutant Discharge Elimination System (NPDES) permit, BMPs, and other permit requirements are expected to protect state water quality standards by limiting potential contamination of stormwater and protecting groundwater quality during construction and operations.

3(36) Thank you for your comment. According to the draft NPDES permit, “stormwater that has the potential to collect process chemicals and lube oils will be routed to the process wastewater system.”

3(37) Section 2.2.2, Project Description, and Section 3.3.2 of the Draft EIS have been revised to reflect this additional information.

3(38) The Draft EIS has been revised to reflect that Compensatory Mitigation Area (CMA) 2 will receive stormwater discharge from the cogeneration facility.

3(39) BP’s application indicates that Access Road 3 would meet Washington State Department of Transportation (WSDOT) and emergency vehicle requirements. According to Section 2.11 of Appendix D in the application, roadwork outside the plant boundary would be constructed in accordance with the WSDOT and emergency vehicle requirements. The Applicant did not support the suggested change in Access Road 3 construction standards with a revision to the application or a commitment during the adjudicative hearings.

3(40) Thank you for your comment. The text in the Draft EIS has been revised to reflect that all major equipment and buildings, including the steam generator, will be on piles.

3(41) Section 2.2.3 of the Draft EIS has been revised to reflect this new information.

3(42) Section 2.2.3 of the Draft EIS has been revised to reflect this new information.

3(43) Section 2.2.3 of the Draft EIS has been revised to reflect that the right-of-way will not exceed 150 feet in width.

3(44) Section 2.2.4 of the Draft EIS has been revised to reflect this clarification.

3(45) Thank you for your comment. The EIS has been revised to reflect this information.

3(46) The Draft EIS has been revised to more accurately reflect the Application for Site Certification’s mitigation requirements if contaminated soils are found during construction.

3(47) Table 3.2-1 of the Draft EIS has been revised to reflect this clarification.

3(48) Table 3.2-1 of the Draft EIS has been revised to reflect this clarification.

3(49) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(50) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(51) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(52) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(53) Section 3.2 of the Draft EIS has been updated to reflect that no criteria pollutant emission concentrations exceed the Class II Significant Impact Levels (SILs).

3(54) Section 3.2 in the Final EIS has been updated to reflect that no criteria pollutant emission concentrations exceed the Class I SILs.

3(55) The discussion of estimated emissions from the project, including emission reductions resulting from refinery boiler removal and other adjustments, has been revised for more clarity. The correction has been made.

3(56) Secondary particulate conversions based on molecular weights have been incorporated into Section 3.2.

3(57) The Final EIS reflects the statement in the Application for Site Certification (Volume 1, Section 3.2.3.2) that, "icing is not expected to occur."

3(58) The Draft EIS has been revised to state that, excluding those projects that have received certification from EFSEC, no currently permitted facilities are subject to greenhouse gas mitigation requirements in Washington State.

3(59) The No Action Alternative in Section 3.2 of the Draft EIS has been revised to reflect that if other natural gas–fired plants are built to meet regional electric demand, they would not likely be cogeneration facilities and would likely produce energy less efficiently than the proposed project. This would result in higher criteria pollutant and greenhouse gas emissions per kilowatt hour produced.

3(60) Please refer to Response 3(59) of this letter. The tonnage of CO_2 emission reductions was corrected in the Final EIS.

3(61) The Department of Energy (DOE) recognizes that natural gas leaks occur in natural gas transmission systems. The Final EIS estimates the resulting greenhouse gas emissions that could occur based on the DOE emission factors.

3(62) The Phase I study (Bonneville 2001a) went as far as identifying where impacts might occur in the northwest region assuming all the facilities considered became operational. The Phase I study did not attempt to identify which facilities caused the potential impacts identified. The purpose of the Phase II study for each specific project being proposed (i.e., the BP Cherry Point Cogeneration Project) was to refine the analysis of regional impacts and determine to what degree the impacts could be attributable to that specific facility. As indicated in the Final EIS, the Phase II study conducted for the proposed cogeneration project concluded that the project would not significantly contribute to regional haze at any of the Class I areas within the Bonneville service area, the Columbia River Gorge National Scenic Area, or the Mt. Baker Wilderness when the facilities considered in this analysis are fired by natural gas. During periods of oil firing during a winter simulation by other facilities in the study group, the project's contributions are not significant on any of the six days when the baseline group's combined change in extinction is greater than 10% in Mt. Rainier National Park. (Extinction is a coefficient used to quantify how pollutants in the atmosphere reduce visual range.)

3(63) Thank you for your comment. The correction has been made in Section 3.2 of the Final EIS.

3(64) Please refer to Response 3(62) of this letter.

3(65) The statement has been revised to reflect that the production of greenhouse gases could be reduced if operation of the BP Cogeneration Facility displaces the operation of other less efficient facilities that emit more greenhouse gases per kilowatt-hour.

3(66) Table 3.2-28 has been revised to reflect this clarification.

3(67) Table 3.2-29 has been revised to reflect this clarification.

3(68) Table 3.2-29 has been revised to reflect this clarification.

3(69) The mitigation measure has been revised in the Final EIS.

3(70) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(71) Section 3.2.8 of the Draft EIS has been revised to reflect that the proposed cogeneration facility would have a minimal impact on air quality and would not violate any ambient air quality standards or objectives, or other regulatory air quality values.

3(72) Thank you for your comment. According to the Stormwater Management Manual for Western Washington (Ecology 2000), Best Management Practice C162 specifically recommends avoiding land disturbance activities during rainy periods.

3(73) Please refer to Response 3(72) of this letter.

3(74) Based on the contour information available at this time, it appears the project will intercept the low spot in the wetland. Using the 1-foot contours to fine tune the ditch design is a good first step. It is the opinion of the Corps of Engineers that there should be no perimeter ditch within the wetland or buffer to minimize the potential for draining Wetland C (Romano, pers. comm., 2004).

3(75) The text of the Draft EIS has been revised to reflect this correction.

3(76) The application indicates sanitary waste discharge from the cogeneration project would be routed to the PUD's wastewater treatment plant for treatment and discharge to the Strait of Georgia. The Applicant did not support this suggested change with a revision to the application or a commitment during the adjudicative hearings.

3(77) Thank you for your comment. The Draft EIS has been revised to reflect this clarification. Please refer also to Response 3(35) of this letter.

3(78) The text of the Draft EIS has been revised to reflect this correction.

3(79) A map provided by Whatcom County (Olson, pers. comm., 2004) depicts most of the western half of Section 8 (east of Blaine Road between Grandview and Aldergrove) as “open space agriculture.” This would include the refinery interface area. This is not a zoning designation, but rather a Department of Revenue designation for current use taxation valuation.

3(80) The text of the Draft EIS has been revised to reflect this correction.

3(81) The text of the Draft EIS has been revised to reflect this correction.

3(82) Comment acknowledged. As noted in Section 3.4.4.2 of the revised Application for Site Certification, “all equipment should be cleaned before leaving the site.” The Draft EIS text was revised to read, “to minimize and control the spread of noxious weed species, all-wheeled vehicles would be cleaned if they cross disturbed or exposed soil areas during construction of the proposed project.”

3(83) The Draft EIS has been revised to reflect that a person’s perception of a 3- to 5-dBA change in noise levels may vary with the environmental context.

3(84) The commenter is correct, and the statement in Section 3.9-6 of the Draft EIS has been removed.

3(85) The commenter is correct, and Table 3.9-5 of the Draft EIS has been revised.

3(86) The construction mitigation measure list has been revised.

3(87) The construction mitigation measure list has been revised.

3(88) Thank you for your comment. The correction has been made in the Final EIS.

3(89) The text of the Draft EIS has been revised to reflect this correction.

3(90) The Corps of Engineers and the State Historic Preservation Office (SHPO) concur with the results of the archaeological survey conducted near detention pond 2, the interconnecting pipeway, and Access Road 3. In a letter to the Corps, SHPO agreed with the definition of the Area of Potential Effect (APE) and concurred with the Corps’ recommendation of Finding of No Historic Properties.

In conformance with Section 106 of the National Historic Preservation Act, the Corps identified and listed conditions in its 404 permit. SHPO also concurred with these conditions, which the Applicant would be required to comply with during construction of the proposed project.

3(91) The commenter is correct. Note 2 has been corrected in the Final EIS.

3(92) The text of the Draft EIS has been revised to reflect this correction.

3(93) The text of the Draft EIS has been revised to reflect this correction.

3(94) The text of the Draft EIS has been revised to reflect this correction

3(95) The text of the Draft EIS has been revised to reflect this correction.

3(96) Thank you for your comment. Although the use of waterborne transportation (barge) to bring heavy equipment to the site was identified in the Application for Site Certification, correspondence dated May 30, 2003, from the Applicant specifically states a barge would not be used. Therefore, the Applicant does not address potential landing impacts in the nearshore, road impacts from heavy equipment, road conflicts on public roads, or other issues. According to the Applicant, barge landings would require a number of authorizations for which analyses have not been produced. At this time, barge transport of equipment is not considered viable.

3(97) The text of the Draft EIS has been revised to reflect this correction.

3(98) The text of the Draft EIS has been revised to reflect this correction. Please refer to Response 3(25) of this letter.

3(99) Reference to the Health and Safety Plan and the Emergency and Security Plan has been revised.

3(100) The text of the Draft EIS has been revised to reflect this correction.

Responses to Comments in Letter 21 from Susan Meyer, Wetland Specialist, Department of Ecology

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. Section 3.5.2, Custer-Intalco Transmission Line No. 2, of the Draft EIS acknowledges that if the new transmission line cannot avoid wetlands, wetland delineations would need to be performed before wetland impacts can be quantified and wetland permits can be issued. The Bonneville Record of Decision would include conditions if towers need to be constructed in the right-of-way. These conditions would be that detailed wetland delineations, impact assessments, and mitigation design and monitoring plans will be completed concurrent with the proposed project.

2. Thank you for your comment. As noted in Section 3.4.5 of the Draft EIS, EFSEC has developed appropriate process wastewater and stormwater permits that include both effluent standards and a monitoring schedule for stormwater discharge from the cogeneration facility. Table 3.4-7 of the Draft EIS identifies the effluent limitations.

3. Thank you for your comment. If a recommendation for approval is made to the governor, EFSEC would develop a Section 401 water quality certification that would require submittal of a final Wetland Mitigation Plan for review by EFSEC and its Ecology contractors. In addition to detailed grading and planting plans, the final mitigation plan would include monitoring and contingency plans and all other elements recommended by existing, applicable Ecology guidance.

4. Figure 3.5-2 in Section 3.5, Wetlands, of the Draft EIS is not intended to depict wetlands. It is a map of vegetation types. Reference to wetlands has been removed from this figure. Wetland communities are accurately displayed in Figure 3.5-1 of the Draft EIS.

Responses to Comments in Letter 22 from M. D. Nassichuk, Manager, Pollution Prevention and Assessment, Environment Canada

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Section 3.2.3 of the Draft EIS has been updated to include a discussion of the potential health impacts of $PM_{2.5}$.

2. Section 3.2 of the Draft EIS has been updated to include a more thorough analysis of potential ambient concentrations of particulate matter and $PM_{2.5}$. As noted in Letter 12, Response 1, it was conservatively assumed that all particulate matter emissions were less than 2.5 microns in size.

3. Section 3.2 of the Draft EIS has been updated to include modeling of long range impacts of particulate emissions that include secondary particulate. Long range ambient air quality concentrations were assessed using the CALPUFF model.

4. Section 3.2 of the Draft EIS has been updated to include the impacts of start-up scenarios.

5. In a Settlement Agreement with the Counsel for the Environment, the Applicant has committed to remove the refinery boilers if the cogeneration project is constructed and begins operation.

6. For the review of air emissions in the scope of a permitting decision, state and federal regulations require an assessment of impacts on ambient air quality and rely only on tonnage increases as thresholds for levels of review detail. The annual mass emissions were relied on to determine that Prevention of Significant Deterioration review was applicable, and these emissions were input as applicable into the dispersion models.

   In response to this comment, the percentage increase in the Whatcom County and Lower Fraser Valley airsheds, for which the project would be responsible, was calculated based on the data in the Greater Vancouver Regional District's 2003 Forecast and Backcast of the 200 Emissions Inventory for the Lower Fraser Valley Airshed 1985-2000. The results are shown in the table below.

Annual Mass Emissions

Emissions Source	Pollutant						
	CO	NO_x	VOC	SO_x	PM_{10}	$PM_{2.5}$	NH_3
Whatcom County							
Total metric tons	114,654	17,396	40,283	10,063	1,542	2,536	3,490
Lower Fraser Valley							
Total metric tons	481,933	99,897	111,196	18,769	15,364	8,964	18,003
Sum of both airsheds, metric tons	596,587	117,293	151,479	28,832	16,906	11,500	21,493
BP Cogen/Refinery							
Max emissions, metric tons[1]	143.2	211.8	38.4	46.3	237.5	237.5	157.2
Expected emissions, metric tons[2]	73.7	164.4	25.0	45.0	85.3	85.3	157.2
Refinery reductions, metric tons	-49.0	-453.1	-2.7	-6.4	-9.1	-9.1	0.0
% of Whatcom County Emissions							
Maximum BP Cogen emissions	0.1	1.2	0.1	0.5	15.4	9.4	4.5
Expected BP Cogen Emissions	0.1	0.9	0.1	0.4	5.5	3.4	4.5
BP Refinery reductions	0.0	-2.6	0.0	-0.1	-0.6	-0.4	0
% of Whatcom County and Lower Fraser Valley Airshed Emissions							
Maximum BP Cogen emissions	0.02	0.18	0.03	0.16	1.41	2.07	0.73
Expected BP Cogen emissions	0.01	0.14	0.02	0.16	0.50	0.74	0.73
BP Refinery reductions	-0.01	-0.39	0.00	-0.02	-0.05	-0.08	0.00

1. Maximum emissions used for regulatory purposes.
2. Expected emissions include refinery boiler reductions.

7. See specific responses below.

7(1) The cogeneration project and the refinery boilers are two technologically different processes, constructed and operated for different reasons. The refinery boilers produce steam only for the refinery and are not designed or operated to produce electricity. The technology for heat production in the boilers is notably different the from combustion turbine technology being proposed for the cogeneration project, and it is therefore normal for the two processes to have different levels of emissions. It is beyond the scope of this EIS to evaluate why refinery boiler emissions are different from those of the project.

7(2) The Draft EIS has been updated to indicate that the conversion rates used by the Applicant for the long range impact of fine particulate in the airshed represent the higher end of supportable data. The quoted conversion rates (20% for SO_2 and 33% for NO_x) could be achieved under low dispersion conditions, when the maximum impacts could be expected to occur. In general, low dispersion conditions (i.e., lower wind speeds) are usually associated with higher relative humidities when water is present, resulting in the higher conversion rates.

7(3) The per-ton conversion analysis has been corrected. Mass of converted particulate is calculated based on stochiometry.

7(4) Table 3.2-8 of the Draft EIS has the correct data. Table 3.2-9 has been updated accordingly.

7(5) The footnote in Table 3.2-15 has been revised to indicate the maximum $PM_{2.5}$ emissions.

7(6) Thank you for your comment. The net regional change in PM_{10} emissions has been corrected.

7(7) Thank you for your comment. Table 3.2-23 has been simplified.

7(8) Thank you for your comment. The most recent air quality report (Greater Vancouver Regional District 2003) indicates that recent air quality trends in the Lower Fraser Valley have not changed significantly from data collected in the previous year.

Responses to Comments in Letter 23 from Mary C. Barrett, Senior Assistant Attorney General

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. At this time, the Applicant would be the sole owner and operator of the project. If the project does change ownership, EFSEC would be responsible for reviewing and approving this change. The Applicant is working with TransCanada to develop the project, but there is no official commercial agreement between the two entities. Any new owner of the facility, TransCanada or any another developer, would be required to comply with the Site Certification Agreement.

2. Please refer to Response 1 of this letter.

3. Bonneville does not now intend to purchase power from the BP Cherry Point Cogeneration Project. The power would be available to customers that are connected to the Bonneville system.

4. Please refer to Response 1 of this letter.

5. Regarding the supply of electrical energy, the Western Electricity Coordinating Council (WECC) has concluded that projected reserves are expected to be adequate through 2012, assuming that approximately 32,300 MW of planned new generation will be constructed and sufficient energy will be available for peak demands. The WECC has determined that capacity adequacy may become dependent on Pacific Northwest hydroelectric conditions after 2008.

   Both the WECC and the Northwest Air Pollution Authority (NWPCC) include existing generation, renewables, and conservation in their forecasts.

   The NWPCC's long-term forecast reflects, "estimates of future demand unreduced for conservation savings beyond what would be induced by consumer responses to price changes." (NWPCC 2003, p. 4).

   The Northwest Power Pool comprises all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of Northern California; and the Canadian provinces of British Columbia and Alberta. From 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6% and 1.7%, respectively. With a large percentage of hydro-generation in the region, the ability to meet peak demand is expected to be adequate for the next 10 years. Capacity margins for this winter peaking area range between 23.4% and 29.6% for the next 10 years.

   WECC's 2002-2012 10-year Coordinated Plan Summary updates the load growth forecast for the Northwest Power Pool Area. It states, "for the period from 2003 through

2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6 percent and 1.7 percent, respectively." (WECC 2002, p. 10). Section 1.2.2 of the Draft EIS has been revised to include the more recent estimates. The WECC report projects generation additions in the Northwest Power Pool Area totaling 11,863 MW from 2003 through 2012, including 8,753 MW combined-cycle combustion turbine, 971 MW hydro, 105 MW geothermal, and 87 MW "other." The WECC report does not identify conservation resources.

The U.S. Department of Energy (2004) in its Annual Energy Outlook 2004 with Projections to 2025, referred to as the *AEO2004* report, projects, "continued saturation of electric appliances, installation of more efficient equipment, and the promulgation of efficiency standards are expected to hold growth in electricity sales to an average of 1.8 percent per year between 2002 and 2025." Section 1.2.2 of the Draft EIS has been revised to include the more recent estimate.

The report continues, "changing consumer markets could mitigate the slowing of electricity demand growth seen in the *AEO2004* projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than expected, they could offset some or all of the projected efficiency gains."

AEO2004 also projects generation capacity additions: "With growing demand after 2010, 356 gigawatts of new generating capacity (including end-use combined heat and power) will be needed by 2025, with about half coming on line between 2016 and 2025. Of the new capacity, nearly 62 percent is projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technology." Regarding renewable generation, *AEO2004* projects, "renewable technologies account for just over 5 percent of expected capacity expansion by 2025—primarily wind and biomass units."

Regarding renewable generation technologies, "*AEO2004* projects significant increases in electricity generation from both wind and geothermal power. From 4.8 gigawatts in 2002, total wind capacity is projected to increase to 8.0 gigawatts in 2010 and 16.0 gigawatts in 2025. Generation from wind capacity is projected to increase from about 11 billion kilowatt-hours in 2002 (0.3 percent of generation) to 53 billion in 2025 (0.9 percent). Nevertheless, the mid-term prospects for wind power are uncertain, depending on future cost and performance, transmission availability, extension of the federal production tax credit after 2003, other incentives, energy security, public interest, and environmental preferences. Geothermal output, all located in the West, is projected to increase from 13 billion kilowatt-hours in 2002 (0.3 percent of generation) to 47 billion in 2025 (0.8 percent).

"Generation from municipal solid waste and landfill gas is projected to increase by nearly 9 billion kilowatt-hours, to about 31 billion kilowatt-hours (0.5 percent of generation) in 2025. No new waste-burning capacity is expected to be added in the forecast. Solar technologies are not expected to make significant contributions to U.S. grid-connected electricity supply through 2025. In total, grid-connected photovoltaic and solar thermal generators together provided about 0.6 billion kilowatt-hours of electricity generation in

2002 (0.02 percent of generation), and they are projected to supply nearly 5 billion kilowatt-hours (0.08 percent) in 2025."

6. The description of the No Action Alternative in Section 1.4 of the Draft EIS indicates that none of the environmental impacts resulting from construction or operation of the project would occur, and this includes no incremental increase in greenhouse gas emissions. Section 3.2.4 of the Draft EIS has been revised to better describe the continued impacts on air quality associated with no action.

7. While Ecology does address water quality impacts through its regulation of the National Pollutant Discharge Elimination System (NPDES) permit for the refinery, EFSEC must also address impacts as part of the NPDES permit for the cogeneration facility. Water quality impacts are discussed in the Draft EIS in Section 3.4, Water Quality, and the effects of those impacts are discussed in Section 3.7, Vegetation, Wildlife, and Fisheries. The cogeneration facility will represent an estimated 8% increase in discharge from the refinery outfall, which is within the variability of existing discharge rates from the refinery. It should also be noted, as discussed in Section 3.4.1 of the Draft EIS, "the refinery uses approximately 50% of the organic and hydraulic capacity of the wastewater treatment system."

   Increases in temperature and salinity have been modeled as insignificant (BP 2002). Kyte (Prefiled Testimony, Exhibits 27.0 and 27R.0) testified that while the dilutions at the Zone of Initial Dilution and the chronic dilution zone required by the refinery's existing NPDES permit were 28:1 and 157:1, respectively, in actuality they have been shown to be 144:1 and 1709:1. Given the low level of biological effect reported at the outfall under present conditions, it is unlikely the cogeneration facility will have any measurable effect on marine life.

   The impact of wastewater discharge from the cogeneration project on state water quality standards was reviewed as part of the State Waste Discharge and NPDES permits developed for the cogeneration project. This review concluded that the discharge would not violate state water quality standards.

8. The Application under review is, and always has been, submitted solely by BP West Coast Products, LLC. If the project is approved, all permits and certifications would be issued to BP West Coast Products, LLC. If BP West Coast Products, LLC decides to sell part or all of the project, that transaction would be subject to review requirements established in EFSEC laws and rules. The Settlement Agreement with the Counsel for the Environment addresses how new ownership of the project would be addressed for mitigation conditions associated with greenhouse gas emissions. The new owner would have to comply with the requirements of the Site Certification Agreement issued to the project.

9. Section 1.8.1 of the Draft EIS has been revised to reflect the impacts of the proposal. The discussion of impacts from global warming in the Pacific Northwest has also been augmented in Section 3.2 of the Final EIS.

10. Section 1.8.2 of the Draft EIS has been revised to reflect that the Applicant is committed to shutting down three refinery boilers if the cogeneration facility is constructed and operated.

11. Ammonia emissions were analyzed per the requirements of Chapter 173-460 WAC. Ammonia emissions are regulated as a toxic air pollutant in Washington State. Ammonia emissions as a result of "slip" were modeled and compared against the appropriate Acceptable Source Impact Level (see Table 3.2-14 of the Final EIS). The ASIL is a level of concern that conservatively protects human health and the environment. Best Available Control Technology for ammonia slip is to control emissions below a specified target level, in this case 5 ppm.

12. The Applicant used the EPA test method for PM_{10} only in estimating the actual emissions that might occur from the project. This estimate of actual emissions was used to assess the likely long range impact on the airshed. The test method was not used for regulatory review of the air emissions or for determining compliance with U.S. or Canadian ambient air quality standards.

13. The discussion in Section 3.2.5 of the Draft EIS has been revised to include specific impacts from global warming that might occur in the Pacific Northwest.

14. As noted in Response 12 of this letter, the corrections to the EPA test method for primary PM_{10} emissions were not used to determine the compliance of the project with the Prevention of Significant Deterioration (PSD) and new source review requirements. The analysis of secondary particulate formation is required to assess the impacts on visibility and haze in federally protected Class I areas. The analysis was based on maximum potential emissions from the cogeneration project and did not include any adjustments for primary particulate test method. Additional modeling (not required by the PSD and new source review programs) was performed to determine the long range impact of particulate emissions; results are shown in Appendix B of this Final EIS. Exhibit 22.2, Page 2 in Appendix B shows the predicted PM_{10} concentrations for potential maximum annual emissions excluding any refinery reductions or test method adjustments. Table 3.2-23 of the Draft EIS has been revised to reflect the impacts on regional particulate matter emissions with and without the test method adjustment.

15. Please refer to Response 7 of this letter. The diffuser was inspected in August 2003. A diffuser inspection was a requirement of the refinery NPDES permit. A video was taken and a report was written and sent to the Department of Ecology.

Responses to Comments in Letter 24 from Ken Cameron, Manager, Policy and Planning, Greater Vancouver Regional District, Canada

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Additional information regarding the health effects of $PM_{2.5}$ has been added to Section 3.2 of the Final EIS.

2. Modeling of long range emissions without refinery reductions or "adjustments" for test methods to assess potential actual emissions has been included in the Final EIS (see Section 3.2). For regulatory purposes, test method and other adjustments were not considered.

3. Please refer to Letter 22, Response 7(2).

4. Section 3.2 of the Final EIS describes additional long range modeling data, which include the Canadian airshed. The modeling includes conversion to secondary particulate. The data presented in the Draft EIS were based on estimates performed with the Industrial Source Complex (ISC) Prime model; it included primary and secondary particulate by adding 20% of the sulfur emissions to the particulate matter emissions. This represented the worst-case scenario. Primary and secondary particulate were also modeled with the CALPUFF model for the annual averaging time (see isopleths in Appendix B of this Final EIS).

5. A discussion of the relationship between ammonia and secondary particulate has been included in Section 3.2 of the Final EIS. Regarding the reporting of maximum predicted ammonia concentrations in Canada, ammonia emissions from the project were reviewed under the requirements of Chapter 173-460 WAC, which considers ammonia to be a toxic air pollutant. The Applicant used a Gaussian dispersion model (ISC Prime) to determine the maximum concentration of this pollutant (reported in Table 3.2-14 of the Final EIS) and found that the resulting concentration was well below the applicable Acceptable Source Impact Level (ASIL). The ISC Prime model is used to assess impacts within a 50-km range of the source. Therefore, maximum modeled ambient concentrations in Canada would also be less than the maximum value reported (2.8 $\mu g/m^3$, 24-hour average).

6. Maximum ambient concentrations resulting from various modes of facility startup are described in Section 3.2 of the Final EIS.

7. Please refer to Letter 22, Response 6.

8. Please refer to Letter 22, Response 5. The Applicant is not seeking credit for refinery emissions reductions for regulatory purposes. Therefore, even though the removal of the refinery boilers will benefit ambient air quality concentrations, that benefit cannot be taken into account; for regulatory purposes, the analysis of environmental impact is based on maximum emissions from the cogeneration project. However, the Applicant has made

certain assumptions regarding what the expected benefit might be and has evaluated the long range impact on resulting ambient air quality. Appendix A in this Final EIS shows isopleths for criteria pollutants, which take into account refinery reductions.

9. The Applicant has demonstrated that particulate matter (PM) emissions, including particulate matter less than 2.5 microns, meet both U.S. and Canadian regulatory standards. The Applicant is using Best Available Control Technology (BACT) to control PM emissions, represented by the combustion of natural gas only in the combustion turbines. Under state and federal laws and regulations, compliance with ambient air quality standards in an attainment area and application of BACT for emission control are considered appropriate mitigation of impacts.

10. Pursuant to an Agreement with the Counsel for the Environment, the Applicant's proposal for greenhouse gas mitigation has been modified and now requires additional measures. As described in Section 3.2 of the Final EIS, the mitigation plan requires formal reporting of offsets that have been achieved and encourages projects in the Whatcom County area.

11. Thank you for your analysis and comment. It should be noted that the adjustments to maximum potential emissions were not considered for regulatory purposes. The intent was to estimate the impacts of actual emissions on the airshed. Please refer also to Letter 23, Responses 12 and 14.

12. Thank you for your comment. It has been conservatively assumed that all PM is emitted as $PM_{2.5}$. Letter 22, Response 6 addresses the percentage of BP's Cherry Point Refinery contribution of emission to the Whatcom County and Fraser Valley airsheds.

13. The particulate matter adjustments were not taken into account for regulatory purposes. The intent was to estimate the impacts of actual emissions on the airshed. Through a Settlement Agreement with the Counsel for the Environment, the Applicant has committed to remove the refinery boilers if the cogeneration project is constructed and operated.

14. Please refer to Letter 22, Response 7(2).

15. Thank you for your comment.

16. Isopleths depicting the impact on ambient air concentrations of particulate matter, averaged over 24 hours, have been added to Appendix B of this Final EIS. These isopleths include a 20% conversion to secondary particulate and do not take into account refinery emissions reductions.

17. The evaluation of impacts on ambient concentrations of ozone are only required when the proposed facility is in an area designated as non-attainment for ozone. In such a case, state and federal regulations consider nitrogen oxides (NO_x) and volatile organic

compound (VOC) emissions as ozone precursors. Whatcom County is in an attainment area for all criteria pollutants, including ozone.

18. Impacts on ambient air quality from startup of the facility have been added to Section 3.2 of the Final EIS.

19. A discussion of the impacts of particulate matter on human health has been added to Section 3.2 of the Final EIS.

20. Please refer to Letter 24, Response 9.

21. Selective catalytic reduction (SCR) has been the technology of choice for controlling NO_x emissions for this type of power generation facility. SCR meets the three BACT criteria that are required under the Prevention of Significant Deterioration (PSD) program: (1) the most stringent form of emissions reduction technology possible will be used; (2) the technology is technically feasible, and (3) the technology is economically justifiable. Although other non-ammonia-based technologies exist (XONON and SCONOx for example), neither of these has been demonstrated as technologically possible for the size of combustion turbine project being proposed. To reduce collateral effects, ammonia emissions will be limited to no more than 5 ppm.

    Regarding the toxic effects of ammonia emissions, EFSEC requires an ambient air quality analysis of toxic air pollutant emissions in accordance with WAC 173-460 Controls for New Sources of Toxic Air Pollutants. The toxic air pollutants are evaluated for both acute (24-hour) and chronic (annual) effects as required by the regulation. The quantities of all toxic air pollutants known to be emitted from the turbines and duct burners, including ammonia, were estimated and screened against the small quantity emission rates in WAC 173-460. Ammonia did not exceed the applicable Ambient Screening Impact Level (ASIL), and therefore no adverse health impacts are expected to occur from the emissions of this pollutant. The maximum ammonia concentration in Canada was determined to be 1.1 $\mu g/m^3$.

22. Please refer to Letter 22, Response 5.

23. Please refer to Letter 24, Response 9. There is no regulatory basis for requiring an offset of emissions in an area that is designated “attainment.” The proponent of the Sumas Energy 2 Project offered to voluntarily offset PM emissions, and EFSEC included this as a requirement in that project’s Site Certification Agreement.

24. Please refer to Letter 24, Response 10.

25. Regarding the emission of particulate matter, although the tons per year emitted represents a large number, the impact on ambient air quality and the environment is not deemed significantly adverse. Emissions of all air pollutants meet both U.S. and Canadian regulatory standards and guidelines. Regarding greenhouse gas emissions, the Applicant has proposed a plan that would mitigate 23% of CO_2 emissions.

26. Thank you for your comment. The table has been revised in the Final EIS.

27. Air Quality Index (AQI) hours data for 2001 have been added to Table 3.2-5 in the Final EIS. In 2002, the Greater Vancouver Regional District discontinued the practice of providing the data in the form presented in Table 3.2-5. In 2001, air quality in the district was measured as “good” 98.4% of the time, with “fair” and “poor” readings occurring 1.6% and less than 0.1% of the time, respectively. These readings are equivalent to or better than conditions recorded during the past few years. During 2001, one air quality advisory was issued. During 2002, air quality was reported as “good” 97.4% of the time, with “fair” and “poor” readings occurring 2.6% and less than 0.1% of the time, respectively. These readings are equivalent to or slightly worse than conditions recorded during the past few years. No air quality advisories were issued in 2002.

28. Table 3.2-8 of the Draft EIS had the correct data. Table 3.2-9 has been updated accordingly.

29. The footnote to Table 3.2-15 has been revised to indicate that the maximum concentrations of $PM_{2.5}$ are equal to the maximum concentrations of PM_{10}. The concentrations for $PM_{2.5}$ in Table 3.2-16 are the maximum concentrations, and the table heading has been revised to reflect this. Table 3.2-20 of the Final EIS has been corrected and reorganized for clarity.

30. Table 3.2-23 of the Final EIS has been revised for clarity. The data have been corrected to reflect molecular weights of compounds.

**Responses to Comments in Letter 25 from David M. Grant,
Deputy Prosecuting Attorney, Whatcom County**

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Dave Enger, a traffic engineer with Traffic Planning and Engineering Inc., analyzed the intersection of Grandview Road and Vista Road with the proposed Delta Tech Industrial Park, including the proposed closure of the southern segment of Delta Line Road. Based on Mr. Enger's results, if the proposed Delta Tech Industrial Park is open prior to the start of construction of the cogeneration facility and the southern portion of Delta Line Road is closed, the level-of-service (LOS) at the intersection of Grandview Road and Vista Drive would change from C to D. LOS D is acceptable to Whatcom County, and therefore traffic flow through the intersection is considered adequate. For further explanation, refer to Enger, Prefiled Testimony, Exhibit 34R.0.

   Construction traffic will not use Brown Road during construction of the cogeneration facility. With little or no increase in traffic on Brown Road, no impact mitigation is proposed.

2. See specific responses below.

2(1) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "identification and acknowledgement of a new fault must meet the rigorous 'standard of care' followed in the USGS process. Review of USGS' most recently published PSHA studies (Reference: USGS Open-File Report 02-467; also, visit http://geohazards.cr.usgs.gov/eq/2002faults/flt-spreadsheet-2002.html for the list of recognized faults and their parameters) shows that Sumas and Vedder Mt. faults have not been recognized by USGS. This is despite the fact that the USGS has been conducting focused research in the Pacific Northwest region; yet, the USGS' current research plans (http://geology.wr.usgs.gov/wgmt/pp02.html and http://www.usgs.gov/contracts/nehrp/attach-a.doc) do not include the hypothetical Sumas and Vedder Mt. faults as potential faults that warrant studies."

2(2) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "detailed site-specific geotechnical analyses have already been performed for the Cogeneration site. Other soil information from somewhere in the 'area' will not supersede the data developed in these specific geotechnical investigations because geotechnical properties can vary significantly within a distance of mere few hundred feet, let alone miles. If there is any belief that such data may have some significance in terms of regional seismic activity. I would reiterate that the USGS is the most recognized and accepted source for seismic sources (i.e., faults) and hazards. It is unlikely that information for the petroleum exploration studies will provide any relevant and reliable data to improve the design safety of the BP Cogeneration facility."

2(3) The commenter is correct. The findings of the BP Cherry Point Cogen Project, Report of Subsurface Investigation/Laboratory Testing, URS Corporation, July 3, 2003, will assist in the detailed design of foundations and structures.

2(4) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, “the USGS has already performed a detailed PSHA. The most recent PSHA for the USGS was just published a few weeks ago, October 29, 2003. It shows that the BP Cogeneration facility site has significantly less seismic hazard potential than the default design ground motion prescribed in UBC-97.…Design per UBC-97 will be completely appropriate and will provide a conservative design for the cogeneration facility.”

2(5) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, “the two sites are approximately 23 miles apart. Soil and seismic hazard conditions can vary significantly over such distances….The likelihood of commonalties of any significance between geology of these sites is thus minimal. Reference to analyses related to an entirely separate and distant site, like Sumas Energy 2 location, would provide no useful information for the Cogeneration plant and is more likely to confuse than clarify understanding of conditions at the BP Cogeneration site.”

2(6) The report referenced (URS 2003c) is strictly the raw data from geotechnical field investigations to be used by Bechtel Power Corporation during final design of the project components. In his prefiled testimony, Dr. Sanjeev R. Malushte notes that these data were used in a subsurface investigation and foundation report. He also notes that the site has significantly less seismic hazard potential than the default design in the Uniform Building Code. Finally, he noted that a site-specific PSHA would not be appropriate.

2(7) As stated in Moore, Prefiled Testimony, Exhibit 20.0, “what the Applicant said it is willing to do is conduct a periodic monitoring program similar to the one currently in use at the refinery would be appropriate. Under such a program, various aspects of the facility’s structural integrity are checked on a regular basis, and after significant seismic events. Inspections include:

- Inspect major foundation seams for differential movement,
- Inspect major foundation grout pads for cracking,
- Check for proper alignment of major piping shoe supports,
- Check piping spring hangers for proper position,
- Check for piping and cable tray misalignment at building penetrations,
- Review equipment vibration monitoring logs for unusual vibration patterns.

“If problems or discrepancies are identified during the inspections, appropriate repairs will be made. These inspections ensure that structural components would continue to serve their intend function.

“The facility will also have vibration monitors on major pieces of rotating equipment. Were a significant seismic event to occur, the cogeneration facility would likely shut down because vibration monitors would see the tremors as high vibrations and would trip the equipment.”

3. Thank you for your comment. See Responses 3(1) through 3(44) that address comments provided by Dr. Stenberg in the attached report.

4. See specific responses below.

4(1) Both noise studies used accepted and approved methods for assessing noise impacts. Noise impacts at 15 receptors, both industrial and residential, within an approximate 1.5-mile radius of the cogeneration facility were monitored during the day and night. Modeling was based on existing noise in the area and anticipated noise from the facility. Perceptible noise increases (3 dBA or greater) were not identified at a single site, including immediately adjacent to the proposed facility. Anne Eissinger reports that the herons in the nearby colony showed no evidence of disturbance either by the existing refinery or the recent construction of a bridge over Terrell Creek within 1,000 feet of the colony.

4(2) Roadside measurements were taken to assess the impact of predicted changes in vehicular traffic patterns, primarily during the construction phase of the project, but also to a lesser extent operational truck noise. The 15-minute time frame is typical of traffic noise measurements taken in accordance with FHWA/WSDOT noise measurement protocols (FHWA 1996, WSDOT 2003).

The time of day these measurements were taken is not important because the purpose of the measurement is to calibrate the traffic noise model by comparing actual noise measurements to modeled results.

The roadside measurements were not intended to provide background noise information. Suitable background levels are available from the Hessler study, the results of which are presented in Table 3.9-5 of the Draft EIS.

4(3) Washington State and most other state and federal agencies that deal with noise issues require the use of A-weighted noise level measurement to assess environmental noise impacts. A-weighting estimates the response of the human ear under conditions that would reasonably be judged normal. C-weighting is most often used for extremely highnoise levels and short-term noise sources, such as pile-driving, but not for industrial facilities similar to the cogeneration facility being considered by the EIS. At Fort Lewis, Washington, the U.S. Army uses C-weighting in artillery-related noise control.

4(4) Washington State environmental noise regulations (WAC 173-60) were observed for this study. The WAC rules apply throughout the state and are considered reasonable and appropriate for this EIS.

The suggested approach would be a “relative” approach to noise limitation, as used by most Departments of Transportation in defining noise levels for new construction that would “substantially exceed” existing levels. Such levels are typically in the 10 to 15 dB range. The WAC 173-60-040 uses an “absolute” approach in defining impacts that is invoked for all projects throughout the state. In any case, as noted in Table 3-9.4 of the

Draft EIS, 3 dB is greater than the noise impact modeled at any receptor. Most noise-related literature regards 3 dB to be at the threshold of perceptible change. The perception of a noise increase is not automatically considered a noise impact.

4(5) Greater sensitivity to nighttime environmental noise is compensated by the noise limitations in WAC 173-60-040, which reduce allowable nighttime noise by 10 dB for all categories of noise receptors, including residential. Eliminating the daytime sound levels from the average would artificially weight the data to a degree not intended by the regulation.

4(6) Sound propagates spherically from a point (stationary) source, dispersing geometrically at a minimum rate of roughly 6 dB for each doubling of distance from the source (without taking into account ground absorption or meteorological interference, which is not consistent throughout the seasons or from one year to the next). A sound measured at 80 dB (very noisy) at a distance of 15 meters would therefore attenuate by more than 36 dB at 1,440 meters to 44 dB, below even nighttime noise limits per the WAC. Noise impacts were modeled for sites much closer to the proposed cogeneration facility than 1,400 meters (see Figure3.9-1 of the Draft EIS), and no perceptible noise impacts were identified (Table 3.9-4 of the Draft EIS).

4(7) A change of 1 dB can be perceived under specific conditions, but most authorities consider that under non-laboratory conditions in a heterogeneous noise environment typical of most residential situations where midrange frequency sounds are dominant 3 to 5 dB is the minimum perceptible change in noise level for people with average hearing ability.

4(8) Please refer to Response 4(3) of this letter. Table 3.9-5 of the Draft EIS shows that low frequency noise would be well below the American National Standards Institute (ANSI) recommended limit of 75 to 80 dBC at all but one location—an industrial site. Evaluation of low frequency noise in the Draft EIS exceeds the requirements of applicable regulation and indicates a level of diligence above the norm.

4(9) Eissinger (Prefiled Testimony, Exhibit 31R.0) notes that there is no apparent impact from existing noise at the refinery on the nearby heron colony and that it is reasonable to use standards for noise impacts on human beings to assess impacts on wildlife.

4(10) Please refer to Response 3(2) of this letter. Also, Ann Eissinger testified that the herons "exhibited no observable response" to a bridge construction site (within 1,000 feet of the colony) or the concurrent construction activity at the refinery. Based on these observations, further analysis is not warranted.

5. The project, as proposed, includes only a compressor station constructed within the fenceline of the refinery. The Applicant separately evaluated the feasibility of constructing a compressor at or near Sumas but determined it would not be economically practical and therefore is not part of the proposed project.

6. Please refer to Response 5 of this letter.

7. The project includes "end-of-line" compression inside the refinery fenceline. This compressor would also be within the Heavy Impact Industrial zone of Whatcom County. Please refer to Response 5 of this letter.

8. Thank you for your comment.

<u>Attached Report</u>

3(1) Thank you for your comment. USFWS does not identify great blue heron as a species of concern, candidate, or proposed species for listing. Whatcom County, however, identifies it as a species of local concern. The term "critical habitat" is applied in reference to Endangered Species Act–related species. Critical habitat has not been scientifically defined for great blue heron. Quality habitat associated with great blue heron staging and foraging activities, such as Drayton Harbor, Birch Bay, and Lummi Bay, is located within a 4-mile radius of the Birch Bay great blue heron colony. As described in Section 3.7.1 of the Draft EIS, however, the dominant presence of non-native, invasive plant species associated with the project site (reed canarygrass), including wetland mitigation sites, do not provide habitat conditions typically identified as quality habitat for great blue heron. Reed canarygrass is not generally considered to be a quality foraging habitat for great blue herons because of its height during the growing season and thick matted nature when down in the winter. In addition, long term monitoring of the Birch Bay great blue heron colony has not documented great blue heron staging or foraging activity at the project site or project wetland mitigation areas. Great blue heron habitat and potential project-related impacts on great blue heron are thoroughly addressed in Eissinger, Prefiled Testimony, Exhibit 31R.0.

Mitigation sites located west of the project wetland mitigation sites, as described in the Brown Road Materials Storage Area Final Mitigation Plan (URS 2003a) and Habitat Management Plan (URS 2003b), do not provide habitat conditions typically identified as quality foraging and staging habitat for great blue heron.

As described in Section 3.7.2 of the Draft EIS, treated wastewater associated with the BP refinery's National Pollutant Discharge Elimination System (NPDES) permitted outfall is not likely to significantly affect Puget Sound habitat that supports a variety of aquatic species such as salmon, other fish, shellfish, and other marine wildlife. Great blue heron foraging habitat associated with the marine environment of Drayton Harbor, Birch Bay, and Lummi Bay is located more than 2.5 miles from the project outfall. Michael Kyte, in Prefiled Testimony Exhibits 27.0 and 27R.0, addresses impacts on marine water quality issues, including toxin bioaccumulation and/or heavy metals.

3(2) Potential impacts on wildlife associated with noise are discussed in Section 3.7.2 of the Draft EIS. As discussed in Section 3.9, Noise, the project meets state standards for noise, and modeling shows that noise associated with the project would result in a 1 dBA increase over existing background noise at most receptor locations. It should also be noted the refinery has been in operation for over 30 years and the herons have continued to occupy the rookery. Whatcom County has approved two residential developments within 1 mile of the Birch Bay great blue heron rookery: a 66-lot residential development located less than a mile northeast of the rookery and a 125-lot residential development located about a half mile northeast of the rookery. Ann M. Eissinger, in Prefiled Testimony Exhibit 31R.0, addresses potential noise impacts on great blue heron.

Under Section 3.7.2 Impacts of the Proposed Action, Construction, Wildlife and Habitat, the following text will be added to the Final EIS: "The Birch Bay great blue heron rookery is located about 1.5 miles from the project site. WDFW management recommendations (2004a) for great blue heron include a 3,280-foot buffer between heron colonies and construction activities." A cooperative agreement between the Applicant and Whatcom County has been completed that addresses noise impacts associated with wildlife.

3(3) Please refer to Response 3(2) of this letter. In addition, as discussed in Eissinger, Prefiled Testimony, Exhibit 31R.0, scientific literature lacks sound-tolerance levels or guidelines to accurately asses impacts on wildlife from noise. Reliance on human levels of tolerance and perceptibility is generally accepted as the best available measure. Potential levels of noise reaching the heron colony and areas of primary use are so low that impact on the herons is unlikely.

3(4) Please refer to Responses 3(2) and 3(3) of this letter. As discussed in Section 3.9, Noise, noise associated with the proposed project would not result in a perceptible increase over ambient background noise. Because maximum noise levels were evaluated, any variation in noise from the project would be a decrease and would not be audibly perceptible.

3(5) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(6) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(7) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(8) As noted in Response 3(2) of this letter, the heron colony is about 1.5 miles from the proposed cogeneration facility. Two of the three noise receptors in the vicinity (south and east of the colony) showed no increase in modeled noise, whereas a third (to the west) showed measurable but not perceptible noise increases. Please refer also to Responses 3(3) and 3(4) of this letter.

3(9) Please refer to Response 3(1) of this letter.

3(10) Construction noise impacts on wildlife are addressed in Section 3.9.2 of the Draft EIS, where it is acknowledged some wildlife may be disturbed during the two-year construction period. In addition, please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(11) The Draft EIS notes an imperceptible change in noise (0 to 1 dBA at all but one of 15 receptors) relative to existing conditions. In addition, please refer to Responses 3(1), 3(2), 3(3), and 3(4) of this letter.

3(12) Outdoor lighting would generally provide operator access and safety. Lighting off the ground on outdoor equipment would only be required at monitoring platforms. As noted in Section 3.7 of the Draft EIS, exhaust stacks would not be lighted. Because of its location adjacent to the much larger refinery, the cogeneration facility's incremental increase in lighting is expected to be insignificant.

3(13) The commenter is correct that navigation lights will not be necessary on the cogeneration exhaust stacks. Lighting that would be included in the design of the cogeneration facility would enhance safe working conditions. In addition, structures would be painted gray to decrease glare from lights at night and sunlight during the day. Proposed landscaping with trees to the east and north of the cogeneration facility would further reduce the effect of light and glare.

3(14) Please refer to Response 3(13) of this letter.

3(15) Please refer to Letter 23, Response 7, and Response 9 of this letter. Kyte (Prefiled Testimony, Exhibits 27.0 and 27R.0) in his prefiled testimony states, "the Refinery has had no measurable adverse impact on marine water quality during its 30-year history. It is unlikely that the addition of wastewater from the Cogeneration plant, including trace metals, will have an adverse effect during its 30-year projected life." Kyte further states that he has seen no evidence for, "any negative impact to fish or their food sources from the Refinery outfall. The addition of the wastewater effluent from the Cogeneration project should have no additional impact."

3(16) Table 3.4-5 of the Draft EIS shows that refinery wastewater after addition of the cogeneration facility water would be 82.7°F. As presented in the Fact Sheet for the State Waste Discharge Permit, a temperature analysis was conducted of the combined (refinery and cogeneration facility) discharge. The results of the analysis indicated the temperature loading from the cogeneration facility was negligible and in fact the cogeneration wastewater would probably be lower than the refinery process wastewater and the combined discharge would be within water quality standards. The State Water Quality Standards are designed to protect biota in the receiving waters around the refinery outfall.

3(17) Please refer to Letter 23, Response 7.

3(18) Thank you for your comment.

3(19) Please refer to Response 3(15) of this letter.

3(20) Please refer to Response 3(15) of this letter.

3(21) Please refer to Responses 3(15) and 3(16) of this letter.

3(22) Please refer to Letter 17, Response 23. The stormwater collection and treatment system for the cogeneration facility is described in detail in Section 3.4.2 of the Draft EIS. Stormwater would be treated at the cogeneration facility site prior to being discharged to the wetland areas north of Grandview Road. All stormwater discharged to the wetland mitigation areas is expected to meet water quality standards.

3(23) Section 2.2.2 of the Draft EIS states that the stormwater facilities would be designed consistent with Whatcom County and Department of Ecology requirements, including the Stormwater Management Manual for Western Washington (Ecology 2000).

3(24) Section 2.2.2 of the Draft EIS states the cogeneration facility would occupy approximately 33 acres. This would be mostly impervious surface and would be subject to stormwater design constraints. Please refer to Response 3(23) of this letter.

3(25) Thank you for your comment. As stated in David Every's prefiled testimony, Exhibit 28R.0, "it is true that bullfrogs are known to find and reproduce in stormwater ponds. However, that can be prevented by making sure that the ponds go dry during the dry summer or fall months. Salamanders and other amphibians in the area have shorter life cycles and can complete metamorphosis to the land stage in a few months. If the ponds are designed to allow both entry and exit by the amphibians, then they need not become mortality sinks. However, only species that find the other conditions suitable for reproduction are likely to be present. Some species require certain structural features, such as redds, to deposit their eggs. If those features are not present, the species will not breed there. The ponds will be designed and managed to avoid the problems noted."

3(26) The Draft EIS notes the net benefit is a result of 110 acres of habitat creation and restoration that would occur as compensation for the loss of 30.5 acres of generally low quality wetland habitat.

3(27) Thank you for your comment. Grading will be minimized purposely to limit impacts resulting from earth disturbances. Permanent ponds will be avoided to prevent creating bullfrog habitat.

3(28) The revised mitigation plan addresses herons. According to David Every (pers. comm., 2004), no permanent pond was created. The ponds that were created go dry by late summer and do not support bullfrog reproduction. The cogeneration project mitigation will be governed by a 10-year monitoring requirement with the initial as-built report and each annual report delivered to the Corps of Engineers, the Department of Ecology, and Whatcom County for review.

3(29) According to David Every (pers. comm., 2004), the pond created for waterfowl habitat was unfortunately created with steep slopes on the islands. The banks did not erode to their current configuration but have been stable. While water level fluctuation does occur, it does not cause erosion in the ponds, and the level of the ponds does not fluctuate excessively. The driving principle for the hydrologic restoration for this project was to plug ditches and spread water out over broad areas. Water will be directed to CMA2 to get it back to historical pathways that have been disrupted by roads and ditches, but that water will also be spread widely. Detailed hydrologic monitoring is being required as part of mitigation, and it will allow and guide adaptive management as necessary.

3(30) Monitoring heron use of the habitat is being conducted for a year. The results will provide data on both areas and patterns of usage as well as timing. The information will be used to establish the timing of mitigation actions as needed to be sensitive to established heron needs. Please refer also to Response 3(1) of this letter.

3(31) The results of the monitoring mentioned above will be used to adjust activities to the appropriate season. Any tilling will be started early enough to displace nesting activities of ground-nesting birds rather than disrupt established nests.

3(32) The mitigation plan will establish additional forest that could become attractive to herons in the future. The mitigation plan specifically states what measures are included to make remaining habitats more attractive to herons. Please refer also to Response 3(1) of this letter.

3(33) The intent is to use materials available at the site as much as possible. The initial benefit of the habitat features is likely to be most important. As the plantings develop, structural diversity of habitat will improve. In addition, even decomposing woody debris provides some additional habitat value (Every, pers. comm., 2004).

3(34) As noted in the mitigation plan, the artificial snags with cross beams are intended for perching; herons perch on higher vegetation but hunt from the ground. Again, the intent is to provide habitat structure in the short term before the planted trees grow large enough to provide the structure (Every, pers. comm., 2004).

3(35) The intent is to use rooted vegetation, such as rushes, sedges, and grasses, to provide amphibian egg deposition sites. Some experiments in King County, Washington, demonstrated that the function could be provided by artificial structure, but that is not what is proposed here (Every, pers. comm., 2004).

3(36) The brush shelters are proposed for open areas where additional vole production would help herons, not for areas where woody plantings might be affected by voles.

3(37) Thermal benefits, while likely, are probably of minor consequence in coastal Whatcom County where there are few mountains to influence temperature or limit dispersal of wildlife (Every, pers. comm., 2004).

3(38) Benefits come from structural diversity increases, forested connections to the Terrell Creek corridor, and reduction of invasive species, in addition to increases in plant diversity. The proximity of the restoration and compensatory mitigation areas to the active refinery places them in a noise and light impact situation similar to what will result after the cogeneration facility is built; the incremental impact on wildlife use will be small. The functions of the impact areas as wildlife habitat are already degraded because of past activity, including agricultural activity and the building of roads and ditches. The temporal loss will therefore be small and will be compensated by the mitigation measures (Every, pers. comm., 2004).

3(39) Thank you for your comment. Species lists are not a good indicator of impacts. Discussion of effects on habitat is much more important (Every, pers. comm., 2004).

3(40) Thank you for your comment. As described in Section 3.7.1 of the Draft EIS and in Response 3(1) of this letter, the project site and wetland mitigation sites do not provide habitat conditions typically identified as quality foraging or staging habitat for great blue heron. In addition, monitoring of the Birch Bay great blue heron colony has not documented great blue heron staging or foraging activity at the project site or wetland mitigation areas (Eissinger, Prefiled Testimony, Exhibit 31R.0).

3(41) Species of local importance are now addressed in the mitigation plan. Increasing the shrub and forest cover in the Compensatory Mitigation Areas (CMAs) will benefit neotropical migrants in general by providing more suitable habitat. According to the Washington Department of Fish and Wildlife (WDFW) Priority Habitat and Species database, four eagles' nests are located within 2 to 4 miles of the proposed project. Loons have been reported at Lake Terrell about 2 miles away. Pileated woodpeckers could be found along Terrell Creek. Although they could fly over the project site, none of these species or others on Whatcom County's list of species of local significance is likely to use habitats present on the site.

3(42) According to WDFW (2004b), coho salmon, cutthroat trout, and largemouth bass have been documented in Terrell Creek, as noted in Section 3.7.1 of the Draft EIS. WDFW, however, have not documented Puget Sound chinook salmon use of Terrell Creek. NOAA Fisheries and the USFWS have issued their concurrence that the project is not likely to adversely affect any threatened or endangered wildlife or fish species. Concurrence letters from NOAA Fisheries and the USFWS have been added to the Final EIS in Appendix B of this Final EIS.

3(43) As discussed in Response 3(1) of this letter and by Eissinger, Prefiled Testimony, Exhibit 31R.0, the project site and wetland mitigation sites do not provide habitat conditions typically identified as quality foraging or staging habitat for great blue heron. Mitigation sites located west of the project wetland mitigation sites, as described in the Brown Road Materials Storage Area Final Mitigation Plan (URS 2003a) and Habitat Management Plan (URS 2003b), do not provide habitat conditions typically identified as quality habitat for native wildlife species (great blue heron). Proposed wetland mitigation designs for these projects, including planting native tree and shrub vegetation, would improve overall habitat conditions for native wildlife species.

BP has agreed to fund the development of a comprehensive management plan for its land holdings north of Grandview Road. The plan, which will be developed by Western Washington University, will guide and coordinate future actions in the area.

3(44) Thank you for your comment. Please refer to the biological evaluation and the wetland mitigation plan. The mitigation plan and its supporting documents describe how the mitigation sequence has been followed (Every, pers. comm., 2004).

Response to Comment in Letter 26 from Steve and Helene Irving, Ferndale Residents

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The project would meet all state and federal standards for air quality. In addition, there would be a reduction in air emissions due to shutting down older utility boilers. The water reuse project being developed jointly with Alcoa Intalco Works, Whatcom PUD, and the Applicant, on average, would provide more “reuse” water than the cogeneration facility would use thereby reducing the amount of water normally withdrawn from the Nooksack River.

   Regarding constructing a smaller facility and/or purchasing power from Sumas Energy 1 and Sumas Energy 2 generation facilities, please refer to General Response A.

Response to Comment in Letter 27 from Judith Leckrone Lee, Manager, Geographic Implementation Unit, US EPA

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The revised Alternatives Analysis (see Appendix A in the Final EIS) provides more detail on the siting of the proposed cogeneration facility to limit wetland impacts.

2. The proposed wetland mitigation plan has been developed in consultation with the Corps of Engineers, Washington Department of Ecology, Washington Department of Fish and Wildlife, and Whatcom County. Wetland functions for both the project site and the wetland mitigation areas were rated using the Methods for Assessing Wetland Functions (Ecology 1999), which is based on the Hydrogeomorphic Approach for Assessing Wetland Functions. Based on this functional assessment, the wetland mitigation area provides an increase in functions and values to fully mitigate wetland impacts of the proposed project.

3. Please refer to Response 2 of this letter.

4. Bonneville has asked officials with the Lummi Tribe whether they have any remaining concerns about the project; they expressed no need for further consultation with Bonneville.

Responses to Comments in Letter 28 from Cathy Cleveland, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Existing water quality and potential impacts are discussed in Section 3.4 Water Quality rather than Section 3.3 Water Resources of the Draft and Final EISs. Table 3.4-5 of the Draft EIS indicates that the existing flow of wastewater to the Strait of Georgia is 2,338 gallons per minute (gpm) and that the cogeneration facility would add an additional 190 gpm. Assuming the facility operates 24 hours a day, the daily discharge added to what is currently being discharged by the refinery would be 273,600 gallons. As discussed in Letter 25, Response 3(15), there would be no discernable difference between the quality of the discharge water and that of the background water quality when measured at the boundary of the permitted mixing zone. This would include salinity and temperature, as well as other characteristics.

2. Thank you for your comment. The decline in the herring population off Cherry Point has been added to the Final EIS. Kyte (Prefiled Testimony, Exhibits 27 and 27R.0) notes no evidence of adverse effect on the fish populations off Cherry Point from the existing wastewater discharge. He also anticipates no adverse effect from the additional discharge from the cogeneration facility. Please refer also to Letter 25, Response 3(15).

3. Thank you for your comment. The great blue heron rookery located about a mile from the project site is discussed in Section 3.7.1, Existing Conditions, State Priority Species, of the Draft EIS.

   As described in Section 3.7.2, Impacts of the Proposed Action, in the Draft EIS, treated wastewater associated with the National Pollutant Discharge Elimination System (NPDES) permitted outfall is not likely to significantly affect Puget Sound habitat that supports a variety of aquatic species such as salmon, other fish, shellfish, and other marine wildlife. NOAA Fisheries and the USFWS have issued their concurrence that the project is not likely to adversely affect any threatened or endangered wildlife or fish species. Concurrence letters from NOAA Fisheries and the USFWS have been added to the Final EIS in Appendix D of this Final EIS.

4. Please refer to Response 2 of this letter.

5. Thank you for your comment. Washington Department of Natural Resources (DNR) is developing a master plan for the Cherry Point Aquatic Reserve; when it is completed, DNR will prepare an EIS.

6. Thank you for your comment.

7. The project has been designed to minimize the emissions of particulate, both as criteria pollutants and as toxic air pollutants. The U.S. Environmental Protection Agency has identified five types of atmospheric pollutants that can contribute to marine deposition:

nitrogen compounds, mercury, other metals, pesticides, and emissions (excluding nitrogen compounds) associated with the incineration of wastes. Emissions of nitrogen compounds will be minimized through the use of Best Available Control Technology (BACT) for both nitrogen oxides (NO_x) and ammonia emissions. The deposition of mercury and other metals from combustion processes are associated with the combustion of dirtier fuels such as coal and fuel oil. The natural gas fuel used for the project is very clean and will not contribute significant amounts of mercury or other metals to the airshed. The project air emissions will not be a source of any types of pesticide. Finally, the project will not combust wastes and will not be a significant source of polycyclic aromatic hydrocarbons (PAHs) or other persistent biocumulative toxins. Because of the clean type of fuel being used by the project and the additional emission controls, the project is not expected to contribute pollutants to local marine waters.

8. Please refer to Response 7 of this letter.

9. Please refer to Response 7 of this letter.

10. Please refer to all responses to Letter 12 for concerns raised by Mr. Cleveland.

11. Thank you for your comment. Section 3.2 of the Final EIS includes a discussion on the health impacts of $PM_{2.5}$.

12. Through the Prevention of Significant Deterioration (PSD) program, emission controls proposed by the Applicant undergo strict scrutiny. Only BACT technology is ultimately permitted. BACT technology must meet three important criteria: technical and commercial feasibility, cost efficiency per ton of pollutant removed, and most efficient removal rate of the pollutant of concern. The commenter suggests the use of the following emission control technologies: gravitational settling, centrifugal separators, wet scrubbers, baghouse filters, and electrostatic precipitators (ESPs). The large volume and dilute nature of the emissions from the combustion turbines render all of these techniques inappropriate for cost and pollutant removal efficiency reasons. Gravitational settling and centrifugal separators are only applicable to large particulate matter such as fly ash, which would not be generated by a combustion turbine facility burning natural gas. These technologies would not be appropriate for high volumes of exhaust that contain a low concentration of particulate, such as the emission from the project. Wet scrubbers, baghouse filters, and ESPs are not cost efficient for the treatment of large volume and dilute emissions of fine particulate. The nature of the particulate also does not lend itself to ESP control. For ESPs, which operate on the principle of charge migration, the low particulate concentration would prevent significant charge buildup on particles, resulting in low migration of particles to the collecting plates. For these turbines, the peak particulate emission concentration is 0.001 to 0.003 grains per standard cubic foot (gr/scf) during natural gas firing, which approaches concentrations that ESP and baghouse vendors are striving to achieve for particulate control in other applications (such as oil-fired or other fossil-fuel fired boilers). The use of an ESP and/or baghouse filter is considered technically infeasible and not representative of BACT. The most stringent “front-end” particulate control method demonstrated for combustion turbines is the use of

low-ash fuel and/or low-sulfur fuel such as natural gas and controlled combustion to minimize particulate formation.

13. Thank you for your comment. The referenced sentence in Section 3.10.1 (Existing Land Use, Project Site and Surrounding Area) of the Draft EIS has been revised as follows: “Northwest of the refinery, residential properties occur in the bayfront community of Birch Bay. According to U.S. Census data in 2000, the Birch Bay Census Designated Place supported a total of 5,105 total housing units 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).”

14. Through state law, the Legislature mandates that EFSEC review the impacts of large energy facilities under its jurisdiction, such as this project. State law also requires that EFSEC be the lead agency under the State Environmental Policy Act (SEPA). EFSEC prepares the Environmental Impact Statement pursuant to SEPA law and regulations, which apply equally to all state and local governments in Washington State. EFSEC law also requires that a third party independent consultant be retained to prepare the EIS. Finally, EFSEC contracts with other state agencies to review other permits that may be required by state law or regulation. In formulating its recommendation to the governor, EFSEC must balance the increasing demands for energy facility location and operation in conjunction with the broad interests of the public, which include public health and welfare, and protection of the environment. The governor will make the final decision.

    The Bonneville Power Administration proposes to interconnect the project with the federal transmission system and is the lead federal agency for purposes of the National Environmental Policy Act of 1969 (NEPA). Bonneville’s administrator is officially responsible for the EIS as specifically required by NEPA and implementing regulations.

15. Thank you for your comments regarding the odor emissions from the refinery reported by local property owners. The cogeneration project will not be powered by crude or refined petroleum products. Clean natural gas will be burned in the combustion turbines. Sulfur concentrations in the natural gas fuel are extremely low compared with concentrations in oil received from Alaska. Furthermore, combustion of natural gas in the turbines does not emit odors comparable to oil refining processes at the existing refinery. The cogeneration project would therefore not contribute to existing odor problems experienced by local residents.

16. Please refer to Response 15 of this letter.

17. The commenter is correct that the U.S. EPA has established ambient air quality standards for $PM_{2.5}$. However, thresholds to measure impacts of $PM_{2.5}$ under the PSD program have not been established yet. Furthermore, Washington State and the U.S EPA have only recently begun to designate attainment, nonattainment, and unclassifiable areas for $PM_{2.5}$. Table 3.2-11 of the Final EIS indicates ambient concentrations of $PM_{2.5}$ resulting from the project, when added to background levels, do not violate the standards adopted by EPA. Please refer to Letter 12, Response 2 for an analysis of $PM_{2.5}$ emissions compliance

under PSD. Finally, as stated in both the Draft and Final EISs, $PM_{2.5}$ emissions were conservatively estimated as equal to PM_{10} emissions.

18. The cogeneration facility is considered a major source and is therefore required to undergo PSD review because emissions of one or more criteria pollutants exceed 100 tons per year (tpy). The annual emissions from the cogeneration project are shown in Table 3.2-7 of the Final EIS. The 100 tpy threshold for PSD review was exceeded for the following pollutants: NO_x by 133.3 tpy; CO by 57.7 tpy; PM_{10} and $PM_{2.5}$ by 161.6 tpy. It should be noted, however, that to require further analysis under the PSD program, source emissions must only exceed the 100 tpy thresholds, no matter by how much.

    The statement regarding the regulation of $PM_{2.5}$ under the PSD program has been corrected in the Final EIS. It has been determined that $PM_{2.5}$ emissions do not violate state or national ambient air quality standards.

    The mitigation measures proposed by the Applicant (i.e., the emissions control technologies) have been selected based on their compliance with Best Available Control Technology, as mandated by the PSD program. The selected control technologies all represent the highest level of emissions control commercially available for the pollutants in question. These technologies are: selective catalytic reduction for NO_x, an oxidation catalyst for volatile organic compounds and carbon monoxide, and the use of clean natural gas fuel and best combustion practices for particulate matter and sulfur oxide emissions. Regulatory compliance for air emission will be established through a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) permit that would be issued if the governor approves the project. Permit noncompliance for any and all regulated pollutants would be addressed through appropriate enforcement mechanisms and financial penalties as required by state and federal law and regulations.

19. The Applicant has demonstrated that all regulated air pollutant emissions including both criteria and toxic pollutants from the cogeneration facility will not violate ambient air quality standards. Ambient air quality standards have been established to conservatively protect the health of the population. State and federal regulations do not require baseline monitoring of people's health if a project has demonstrated compliance with applicable standards and thresholds.

20. Both the state and national ambient air quality standards (for criteria pollutants) and the Acceptable Source Impact Levels (ASILs) (for toxic pollutants regulated under state law) conservatively protect human health. The ASILs do not represent a threat to human health, but a level of concern that requires additional modeling to assess whether a threat to human health could exist. Emissions that do not exceed the ASILs are considered below the level of regulatory concern and do not require additional analyses, including the evaluation of synergistic effects. The clean natural gas fuel that will be used by this project would further limit the emissions of toxic pollutants.

21. Please refer to Response 20 of this letter.

22. Please refer to Response 20 of this letter.

23. The proposed project must be located adjacent to the steam host, the BP Cherry Point Refinery. The proposed project would deliver about 510,000 lbs/hr, 750°F, 600 psig steam to the refinery. This steam line must necessarily be as short as possible to minimize heat loss. For a discussion regarding alternative siting of the proposed project and project size, please refer to General Response A.

Responses to Comments in Letter 29 from Kathy Berg, Birch Bay Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The Applicant has performed extensive modeling of the impacts of air emissions from the proposed project. The modeling was performed to satisfy the requirements of the Federal Prevention of Significant Deterioration (PSD) program and the State of Washington's new source review program. In addition, federal land managers (Forest Service and National Park Service) were consulted regarding impacts on Class I areas that are federally protected. All of the modeling was reviewed for EFSEC by the Department of Ecology and had to meet strict regulatory requirements and guidelines. Emissions of all regulated pollutants, including particulate matter, have been shown to be well below any applicable protective thresholds, and they do not violate national or state ambient air quality standards. Ambient air quality standards conservatively protect the environment and human health.

   As indicated in Section 3.2 of the Final EIS, the Applicant went beyond federal requirements to also analyze the impacts of the emissions in Canada, including impacts on the Fraser Valley. If considered alone, the particulate emissions from the project are well within any Canadian regulatory standards and objectives. In addition, the Applicant has committed to remove three existing boilers at the BP Cherry Point Refinery should the cogeneration project proceed to construction. Removal of these boilers will decrease the overall impact of the project's particulate emissions in both Whatcom County and Canada.

   If approved by the governor, the project would be subject to the conditions of a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) air emissions permit, which would require monitoring of all emissions and reporting of results to EFSEC and Environmental Protection Agency. If permit conditions are exceeded and it is deemed that an immediate risk to public health may be involved, EFSEC has the authority to stop project operations until the problems are resolved.

2. The project would meet the state and county noise standards. In addition, noise modeling shows that the cogeneration facility is not likely to be heard above existing background (refinery) noise. Three background noise surveys have been conducted around the project site, including the Birch Bay area and Birch Bay Village. One of these surveys was conducted along with a representative of the Whatcom County Planning and Development Services, Jim Thompson. The engineering and construction contractor has guaranteed the Applicant that noise levels would be consistent with the Application for Site Certification. Pre- and post-construction monitoring would be conducted as part of performance testing.

Responses to Comments in Letter 30 from Tom Pratum, Bellingham Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. A shutdown of the Alcoa Intalco Works would have no practical effect on PUD water diversions from the Nooksack River. If operations at the Intalco facility were suspended or shut down, water would be transmitted directly to the cogeneration facility instead of being transmitted through the Alcoa Intalco Works cooling system. In fact, because the average amount of water required for the cogeneration facility is less than the approximately 4 million gallons per day historically used by Intalco and the extra, reused water would be used by the refinery, the amount of water taken from Nooksack River would be reduced (Anderson, Prefiled Testimony, Exhibit 25.0).

2. Potential temperature increases are addressed in Letter 25, Response 3(16). The final, combined effluent from the refinery and cogeneration facility will be well below permitted limitations as discussed in Letter 23, Response 7.

3. Please refer to Letter 25, Response 3(2).

Responses to Comments in Letter 31 from Doralee Booth, Birch Bay Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1 The commenter is correct that removal of the refinery boilers will not reduce all emissions generated by the cogeneration project. As indicated in Table 3.2-20 of the Final EIS, however, removal of the refinery boilers will reduce emissions for each criteria pollutant from the refinery. Section 3.2 of the Draft EIS has been updated and revised to explain more clearly how emissions for each criteria pollutant will increase or decrease if removal of the refinery boilers is considered. It should be noted, however, that for purposes of regulatory review and assessment of impacts on ambient air quality standards, refinery reductions were not taken into account.

2. Regarding the explanation of health risks, the standards and thresholds used for regulatory review conservatively protect human health. Criteria pollutant emissions are evaluated for their potential to violate state and ambient air quality standards (see Table 3.2-11 of the Final EIS). The Environmental Protection Agency established ambient air quality standards to protect public health, including the health of “sensitive” populations such as asthmatics, children, and the elderly.

Should the governor approve this project, a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) permit would be issued to place conditions on air emissions from the project. Air emissions would be monitored on a regular basis and reported to EFSEC. Background monitoring would continue throughout Whatcom County and the Fraser Valley at existing monitor locations managed by the Department of Ecology.

The refinery’s Risk Management Plan (RMP) will be updated to include planned activities and responsibilities in case of an accidental catastrophic event or major release of ammonia. Refer to Section 3.16 of the Final EIS for additional information regarding the RPM.

3. Thank for your comment. Every effort has been made to prepare a readable and concise environmental review document for the proposed cogeneration project.

Responses to Comments in Letter 32 from John Williams, Williams Research, Portland, Oregon

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comments. Responses to your comments can be found in Letter 17, Response 1(1).

2. Please refer to Letter 17, Response 1(2).

3. Please refer to Letter 17, Response 1(3).

4. Please refer to Letter 17, Response 1(4).

5. Please refer to Letter 17, Response 1(5)

6. Please refer to Letter 17, Response 1(6).

7. Please refer to Letter 17, Response 1(7).

8. Please refer to Letter 17, Response 1(7).

9. Please refer to Letter 17, Response 1(27).

10. Please refer to Letter 17, Response 1(8).

11. As described in Section 2.4.4 in the Draft EIS, alternative air emission control technologies were evaluated. Both SCONOx and XONON technologies were not selected for technological and economic reasons. The emission control technology that was selected is the selective catalytic reduction or SCR system. Anhydrous ammonia will be used in the SCR system to control of nitrogen oxide (NO_X) emissions. This projected amount of ammonia from the exhaust stacks indicates that the public exposure to ammonia (approximately 5.8 $\mu g/m^3$ or 0.008 ppm) will be below the accepted range where an ammonia odor could be detected (5 to 53 ppm). Relative to the public health exposure of ammonia, the maximum projected ground-level impact of the ammonia emissions is about 6% of the 100 $\mu g/m^3$ 24-hour health-based standard identified in WAC 173-460.

12. Please refer to Letter 17, Response 1(10).

13. Please refer to Letter 17, Response 1(11).

14. Please refer to Letter 17, Response 1(12).

15 Please refer to Letter 17, Response 1(13).

16. Please refer to Letter 17, Response 1(14).

17. Please refer to Letter 17, Response 1(15).

18. Please refer to Letter 17, Response 1(16).

19. Please refer to Letter 17, Response 1(17).

20. Please refer to Letter 17, Response 1(18).

21. Please refer to Letter 17, Response 1(19).

22. Please refer to Letter 17, Response 1(20).

23. Please refer to Letter 17, Response 1(21).

24. Please refer to Letter 17, Response 1(22).

25. Please refer to Letter 17, Response 1(23)

26. Please refer to Letter 17, Response 1(24).

27. Please refer to Letter 17, Response 1(25).

28. Please refer to Letter 17, Response 1(26).

29. Please refer to Letter 17, Response 1(28).

30. Please refer to Letter 17, Response 1(29).

31. Please refer to Letter 17, Response 1(30).

32. Please refer to Letter 17, Response 1(31).

33. Please refer to Letter 17, Response 1(32).

34. Please refer to Letter 17, Response 1(33).

35. Please refer to Letter 17, Response 1(34).

36. Please refer to Letter 17, Response 1(35).

37. Please refer to Letter 17, Response 1(36).

38. Please refer to Letter 17, Response 1(37).

Responses to Comments in Letter 33 from Cathy Cleveland, Birch Bay Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Three noise monitoring surveys have been conducted. The last survey was coordinated with: Sharon Roy, Whatcom County Council; David Grant, assistant prosecuting attorney; and Jim Thompson, Whatcom County Planning and Development. This group chose three locations for additional monitoring. Monitoring results from these locations were used to model potential noise impacts resulting from operation of the proposed project. No additional noise monitoring is necessary.

2. Baseline noise monitoring collected data for 60 consecutive hours over three days and two nights.

3. This EIS evaluates the impact of noise associated with the cogeneration facility relative to ambient noise. Because the cogeneration facility would be quieter than the refinery, if monitoring were done when the refinery is exceptionally noisy the cogeneration facility would have even less of a relative impact.

4. Potential noise impacts resulting from operation of the proposed cogeneration project have been addressed in Section 3.9 of the Final EIS.

5. In Table 3.9-5 of the Draft EIS, the baseline noise levels are identified as "existing conditions."

6. As noted on Page 3.9-6 of the Draft EIS, the primary difference between daytime and nighttime noises is "transient" noise. This is noise generated by traffic, which is typically heavier during the day than at night.

Responses to Comments Presented at Public Meeting
Held October 1, 2003 in Blaine, Washington

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding public meeting transcript.

1. **Mark Lawrence**

1(1) Thank you for your comment.

2. **Rob Pochert**

2(1) Thank you for your comment.

2(2) Thank you for your comment.

3. **Dan Newell**

3(1) Thank you for your comment.

4. **Wyman Bannerman**

4(1) Thank you for your comment.

4(2) The only modification made to the original photo was to add a typical monopole transmission tower. As is typical with photos of snow covered mountains in the distance, the mountains tend to blend with the background. Views with the naked eye reveal much greater contrast.

4(3) If Bonneville, the Applicant, and Alcoa Intalco Works are able to agree on a local remedial action scheme (RAS), generation output at the cogeneration facility would be reduced to the thermal rating of any line between Bonneville's Custer 230-kV station, its Intalco station, and the cogeneration facility. The existing lines are capable of 570 million volt amps, which loosely equates to 570 megawatts. During an outage (planned or unplanned) of any line section, power from the cogeneration project would be reduced to produce a net export of 570 MW. The cogeneration facility could continue to generate enough energy to serve the BP Cherry Point Refinery, supplying from 80 to 90 MW. The cogeneration generators would then produce 650 MW, or 70 MW less than their capacity. During other seasons, Bonneville does not anticipate that the RAS would be required because the ambient temperatures would allow for the additional transfers.

If the cogeneration facility were constructed and in operation, the BP Cherry Point Refinery would no longer be served by Puget Sound Energy (PSE) and its 115-kV system because of the difference in voltage (230 kV and 115 kV). It will no longer be practical for PSE to service the refinery. In Whatcom County, the PSE and Bonneville systems, however, will continue to be interconnected at Bonneville's Custer and Bellingham stations to provide service to the Whatcom County area.

5. **Fred Schuhmacher**

5(1) As noted in Section 2.4.1 of the Draft EIS, air cooling was initially selected to minimize water use. When recycled water became available from Alcoa Intalco Works, water cooling was selected. The benefits of water cooling include a smaller footprint, less visual impact, less total water consumption, and lower cost. The adverse impacts include discharge of blowdown wastewater. These differences are outlined below:

- Plant Footprint: A water cooled plant is more compact than an air cooled plant. The stormwater detention pond can now fit inside the facility footprint after air cooling was replaced with water cooling.
- Visual: The water cooling tower is shorter than air cooled equipment. However, there is likely to be a visible water droplet plume from the water cooling tower, which is not present with an air cooling system.
- Water Reuse: A water reuse project requires less water withdrawal from the Nooksack River. The cost of the water reuse project is about $2 million.
- Cost: Water cooling costs $6 million and air cooling costs $18 million, a difference of $12 million.
- Plant Efficiency: A water cooled plant (consuming 4.5 MW) is 1.6% more efficient than an air cooled plant (which consumes 2.5 MW).

Wastewater discharge from the cogeneration facility is expected to increase discharge from the refinery by about 8% but with the treatment efficiencies of the refinery and dilution within the discharge zone. No adverse impact on the marine environment is anticipated (Kyte, pers. comm., 2004).

In Section 3.2 of the Final EIS under the heading Cooling Tower Steam Plume Fogging and Icing, potential impacts from the cooling tower vapor plume are described. The results of the modeling indicate that there would be a visible vapor plume emanating from the tower with the potential for fogging a couple of hours per year. This vapor plume is not expected to be seen beyond Grandview Road adjacent to the cogeneration facility.

5(2) Thank you for your comment. TransCanada will not be identified as the owner/operator of the cogeneration facility. If there is a change in the ownership of the facility, the current and new owners must get authorization from EFSEC pursuant to applicable laws and rules.

6. **Sam Crawford**

6(1) Thank you for your comment. Please refer to Letter 3, Responses 1 through 13.

6(2) Thank you for your comment. The Applicant will continue its community outreach program during the permitting, construction, and operation of the cogeneration facility.

7. **Frank Eventoff**

7(1) Impacts on the Fraser Valley are analyzed in Section 3.2 of the Final EIS. It was determined that the project emissions would not violate Canadian air quality standards or objectives.

8. **Sandra Abernathy**

8(1) The noise impacts from the project are described in detail in Section 3.9 of the Final EIS. It was demonstrated that noise emissions from the project would meet all regulatory thresholds, and that local residents would not be able to discern any increase above ambient levels.

The impact of air emissions from the project is analyzed in Section 3.2 of the Final EIS. The emissions from the project would meet all U.S. and Canadian regulatory standards and objectives. In addition, the Applicant has committed to removing three refinery boilers, which would greatly reduce NO_x emissions to the airshed.

9. **Wendy Steffensen**

9(1) The project site and laydown areas would be designed with stormwater detention ponds to control the quantity and quality of the stormwater runoff from these areas. These ponds would be designed to reduce peak flows and allow solids to settle out before the water is discharged into the Terrell Creek drainage basin. Most of the water from the project site would flow to a wetland mitigation area, which would further slow the water entering the creek. These modifications will improve the quality and runoff rate of water entering Terrell Creek.

The project will not be a source of acid rain. Nitrogen oxide (NO_x) emissions from the project would be limited to low levels through the use of clean natural gas and Best Available Control Technology (selective catalytic reduction technology). Sulfur dioxide (SO_2) emissions would be low because the natural gas fuel contains minimal sulfur compounds. Unlike coal or fuel oil, natural gas is the lowest sulfur containing fuel available, and it is generally not considered a source of acid rain. Refer to Letter 17, Response 1(27) for additional discussion of air quality impacts.

Disruptions to local freshwater ecosystems from the proposed project emissions are highly unlikely and not anticipated. However, through the site certification process, EFSEC has jurisdiction to stop operations and mitigation of impacts should a *direct* impact on nearby freshwater ecosystems be identified in the future.

9(2) The source of the information in the Draft EIS (Golder 2003) was incorrect. While Washington Department of Fish and Wildlife has identified most of the project site as wetland, no priority habitat has been identified in any portion of the project. The Final EIS has been revised to reflect this information.

9(3) The project will burn a clean fuel, natural gas, and the resulting emissions will be dispersed over a wide area. Only a small fraction of the pollutants would remain in the vicinity of the project. Compared to coal and diesel fuel, natural gas combustion emits significantly lower quantities of criteria and toxic pollutants and, as stated in Response 9(1), is not a significant source of acid rain. Project emissions will be minimized through the use of Best Available Control Technology as explained in Section 3.2 of the Final EIS.

9(4) As stated in note 2a of Table 3.4-4 in the Draft EIS, several trace metals were not detected in the source water (Nooksack River) for the cogeneration facility. To calculate a discharge, the detection limit concentration was used. Those values were then multiplied by the concentration that would result from the cogeneration process (four times the concentration for regeneration water and 15 times the concentration for blowdown water). Note 3 in Table 3.4-5 of the Draft EIS states the treatment efficiency study shows the wastewater treatment plant reduces heavy metals. Thus, the actual discharge concentrations for these trace metals listed in Table 3.4-4 are expected to be much lower than those shown in the table and actually may not be present. Once cogeneration operations begin, the discharge concentrations would be measured and actual concentrations can be determined.

The project would not emit large quantities of heavy metals or persistent biocumulative toxins (PBTs) to the air because the fuel being burned (natural gas) is very clean. These heavy metals and PBTs would be emitted; however, the analysis in Section 3.2 of the Final EIS concludes that toxic air pollutants emissions are below regulatory levels of concern and are not expected to harm the environment.

9(5) As stated in the Sumas Energy 2 Final EIS, “market is expected to encourage the development of efficient power facilities to satisfy increasing power demands and to discourage the development of inefficient and unnecessary facilities. In this market, project developers are expected to move forward with construction of projects only when convinced demand exists for the power the facilities would produce. Project financing, likewise, depends on a demonstration of demand and economic benefit.” In short, power generated by the Sumas generation facility is intended to be sold to customers in the Bonneville grid, thereby meeting the customers’ needs for power. For purposes of evaluating impacts resulting from both Sumas and the proposed project, the Draft EIS included a cumulative air emissions evaluation on Page 3.2-44 in Table 3.2-28.

The Georgia Strait Crossing (GSX) pipeline is intended to supply natural gas to Vancouver Island, where it may be used for a Canadian generation project. If this pipeline project and a power facility are approved by the Canadian government and constructed, the power produced from these projects would primarily be available to purchasers on Vancouver Island. Cumulative impacts from construction and operation of the GSX pipeline have been addressed the Final EIS. Please refer to Letter 25, Response 3(15).

10. **Alan Van Hook**

10(1) The project would emit only a small quantity of heavy metals because the fuel being burned (natural gas) is very clean. The project would not emit petroleum products but would emit volatile organic compounds (VOCs). The expected emissions of VOCs and heavy metals were modeled, and it was concluded that all air emissions from the project will protect ambient air quality standards and human health.

10(2) If the Alcoa Intalco Works stopped operations, Whatcom County as a whole would experience a reduction of air and water pollutants that are currently emitted by Intalco.

10(3) Thank you for your comment. The alternative analysis completed by the Applicant and described in the Application for Site Certification evaluated the following: (1) potential environmental effects of siting the proposed cogeneration facility elsewhere, and (2) potential water and air quality impacts if the proposed project were not built and power were generated by other means such as the burning of coal or from wind turbines. This analysis concluded that power generated by means other than burning natural gas would most likely result in more environmental impacts than those identified in the Draft EIS.

11. **Cathy Cleveland**

11(1) Modeling the deposition of particulate matter in local watersheds is not warranted because natural gas, a clean fuel, is being burned, and the emissions resulting from natural gas combustion are not considered a significant deposition source of PM_{10}. The particulate matter emissions from the cogeneration project, although modeled as PM_{10} for regulatory purposes, are less than $PM_{2.5}$. This type of fine particulate behaves more like a gas and will disperse to a wider area; it will not deposit close to the site and in Terrell Creek as much as larger particles would.

11(2) Noise monitoring has been addressed in Letter 33, Responses 1 and 2. Prior to the Applicant's most recent noise monitoring, the Applicant met with County officials to discuss the collection of additional noise monitoring data. Mike Torpey and David Hessler met with Whatcom County Council Member Sharon Roy, Whatcom County Attorney David Grant, and Whatcom County Planning and Development Services Noise Specialist Jim Thompson. In light of the County's concern about noise, the Applicant asked the County to select the locations for additional monitoring. The County selected four locations: 8026 Birch Bay Drive, 4825 Alderson Road, Arnie Road east of Blaine Road, and Jackson Road across from the Puget Sound Energy gas metering station. The County did not select a location in the Cottonwood Beach neighborhood. However, the 8026 Birch Bay Drive location is nearby, approximately 3,000 feet south and slightly east of the Cottonwood neighborhood.

BP Cherry Point Cogen
DEIS Comment - 1

THE CORPORATION OF DELTA
ENVIRONMENTAL SERVICES DIVISION

September 23, 2003

RECEIVED
SEP 26 2003
ENERGY FACILITY SITE EVALUATION COUNCIL

Energy Facility Site Evaluation Council
P. O. Box 43172
Olympia, Washington 98504-3172

Attention: Ms. Irina Makarow, Siting Manager

Dear Madam:

We are currently reviewing the Draft Environmental Impact Statement for the BP Cherry Point Cogeneration Project and I would like to bring to your attention some minor errors or incorrect references we have noticed so far during our review. I have contacted Mr. Jack Gouge at Shapiro & Associates Inc. and discussed the following items with him:

Figure 3.2-1 Airsheds of Interest Within 125 Miles of Project Site

- The layer of text and the international boundary line are incorrectly placed on the map layer. As a result, the text and boundary line are located too far north, at least from a Canadian perspective. 1
- Tsawwassen is misspelled on the map. However, Tsawwassen is one of three urban areas within the municipality of Delta and is not a municipality on its own. To be consistent with the naming of other municipalities on the map, the proponents may wish to refer to the area as Delta, rather than Tsawwassen. 2
- The proponents may wish to include the City of Surrey in their labeling of municipalities as it is also adjacent to the U.S. border and is the most populous municipality in the area. 3

Table 3.2-16: Highest Concentrations in Canada

- The location for the 8-HR CO concentration is listed as 7.8 miles north of the project on the US/Canada border while all other parameters in this table are listed as being located 7.5 miles from the border. Is this correct or is it a typo? 4

...../2

4500 Clarence Taylor Crescent, Delta, British Columbia, Canada V4K 3E2 Tel (604) 946-4141

Page 2

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

- Tsawwassen is misspelled in this table. The proponents may wish to refer to Delta instead of Tsawwassen. 5

For your reference, I have enclosed copies of the map and tables referred to above.

Yours truly,

Verne Kucy
Manager
Environmental Services Division

cc: J. Gouge, Shapiro & Associates Inc.

Attachment

F:ES/Terry/BP Cherry Point.Sept23

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 Time	Maximum Concentration in Canada (µg/m³) Modeled	Background	Total	Most Stringent Canadian Objective or Standard (µg/m³)
SO_2	annual	0.03	3	3	25
	24-hour	0.7	16	17	150
	three-hour	3.3	27	30	374
	one-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	eight-hour	4.8	2,668	2,673	5,500
	one-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
	one-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.
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: Highest Concentrations in Canada

Pollutant	Averaging Time	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
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

IS THIS CORRECT?

BP Cherry Point Cogeneration Project
Draft EIS

3.2-25

3.2 Air Quality
September 2003

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	Tsawassen	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

TSAWWASSEN IS CORRECT SPELLING, OR SIMPLY REFER TO DELTA

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;


AIRSHEDS OF INTEREST WITHIN 125 MILES OF PROJECT SITE
SHAPIRO
PASAYTEN WILDERNESS AREA
MOUNT BAKER/ SNOQUALMIE WILDERNESS AREA
NORTH CASCADES NATIONAL PARK
GLACIER PEAK WILDERNESS AREA
ALPINE LAKES WILDERNESS AREA
OLYMPIC NATIONAL PARK
PROJECT SITE
North Shore Mountains (The Lions)
North Shore Mountains (Golden Ears)
Vancouver
White Rock
Tsawwassen
Victoria
Langley
Abbotsford
Chilliwack
Mount Cheam
Mount Baker
CANADA
UNITED STATES
100 mi
line of sight
sensitive viewshed
Class I airshed
COGENERATION EIS
SHIFT SOUTH
SURREY
TSAWWASSEN OR DELTA
SHIFT BORDER SOUTH
* NOTE : ALL TEXT + US/CANADA BORDER APPEAR TOO FAR NORTH.

BP Cherry Point Cogen
DEIS Comment - 2

BLAINE SCHOOL DISTRICT 503

MEMORANDUM

September 25, 2003

RECEIVED

OCT 01 2003

ENERGY FACILITY SITE
EVALUATION COUNCIL

MEMO TO: To Whom It May Concern

FROM: Dr. Mary Lynn Derrington, Superintendent

SUBJECT: Proposed BP CoGen Plant

With the addition of a CoGen plant at the BP – Cherry Point Refinery it would add a number of additional benefits to the citizens and students of the Blaine School District.

Currently, the Blaine School District's assessed valuation is $2,158,983,939. The majority of this high assessment is due to B.P. and because of this high assessed value the citizens of the Blaine School District benefit from a very low levy assessment. With the addition of the CoGen plant the assessed valuation would increase by $500,000,000 bringing our total assessed value to $2,658,983,939. Such an increase would result in the taxpayers of the Blaine School District paying approximately $1.23 per one thousand dollars of assessed valuation. Currently our taxpayers are being assessed $1.73 per thousand. As you can see, with the additional assessed value our citizens would be saving $.50 per thousand on our current levy. This equates to a savings of $75.00 per year on a $150,000 home. 1

Due to these low levy rates the Blaine School District has always been able to pass our levies. Our levy rate in comparison with other districts whose rates are upwards of $3.00 per thousand enables Blaine a distinct advantage. We not only pass our levies but we are able to run a levy to the maximum the State will allow. Not all districts are able to do this because it would be cost prohibitive to the taxpayers. Currently the Blaine School District's maintenance and operation levy is approximately 21% of our current budget. It is with the passage of the levy that Blaine School District has been able to offer an exemplary program which draws people from across the State and sometimes the nation.

This low dollar per thousand levy rate also provides the district great opportunities for the passage of our General Obligation Bonds.. It is with these bonds the district builds our schools – your children's classrooms, gymnasiums, cafeterias, playgrounds, etc. The district has recently remodeled and built a number of structures with a $19,600,000 bond. We have one remaining project to complete, our administration service center. Our estimated completion time will be Summer of 2004.

Along with a substantial savings to our taxpayers comes a number of jobs. This would enable a number of people in the Blaine area the opportunity to apply for 900 or more available positions. Our students would benefit from this as they complete high school and college enabling them to move on to a wonderful career with B.P. Currently, our students are given an indepth tour of B.P. during the beginning of each school year and by maintaining a working relationship with this company our students have been exposed to an industry which has been constant in the Blaine area. A number of students do complete college and stay in the Whatcom County area so providing more career opportunities keeps our families together.

COUNTY COURTHOUSE
311 Grand Avenue, Suite #105
Bellingham, WA 98225-4038

COUNCILMEMBER
Sam Crawford

BP Cherry Point Cogen
DEIS Comment - 3

WHATCOM COUNTY COUNCIL

FROM THE DESK OF COUNCILMEMBER SAM CRAWFORD

October 1, 2003

RECEIVED
OCT 01 2003
ENERGY FACILITY SITE
EVALUATION COUNCIL

Irina Makarow
Siting Manager
Energy Facility Site Evaluation Council
925 Plum Street SE, Building 4
PO Box 43172
Olympia, WA 98504-3172

Dear Council Members, and Ms. Makarow:

I am writing this letter regarding the application you are considering for the BP Cherry Point Cogeneration Project. I will read this letter into the record at the Open House to be held in Blaine on October 1.

I should note that as a member of the Whatcom County Council, I speak from my own perspective. The County Council has not formally taken a position on this application. However, I can assure you I have spoken to many of my constituents throughout Whatcom County whom I represent, and I am honored to informally speak for them.

As I review the Draft Environmental Impact Statement for this project (dated September 5, 2003), I see the applicant is required to compare the "Impacts of the Proposal" to the "Impacts of No Action". In most cases, the "No Action" impacts are generally described correspondingly as "No Impact".

In light of the proponent's prepared materials describing the positive aspects of this project, one could view "No Action" (that is, no construction of this facility) as detrimental in a number of ways:

- No new steam source would be provided to the existing facility, thus necessitating the continued use of older, less efficient, and more polluting boilers 1
- Greenhouse Gas offsets would not occur in other facilities 2
- 30 years of proposed Greenhouse Gas mitigation would not occur 3
- Recycling of Alcoa Intalco Works cooling water would not occur 4
- Post-use treatment of this recycled water with updated treatment before discharge into Puget Sound would not occur 5
- Wetland enhancements to the CMA 1 and CMA 2 sites, creating hydraulic residence time that enhances existing wetlands and restores drained wetlands, would not occur 6
- A wetland enhancement ratio of nearly 3.6 to 1, affecting the enhancement of 110 acres of wetlands, would not occur 7

Phone: (360) 676-6690 County: (360) 384-6637 TTY: (360) 738-4555 FAX: (360) 738-2550

-2-

- Wildlife habitat quality improvements associated with wetland enhancement, along with planting, cultivating and monitoring of native trees, plants, and grasses, would not occur 8
- An aggressive noxious weed control program overseen by the Noxious Weed Control Board would not occur 9
- 635 MegaWatts of needed additional electrical power would not be supplied to the Northwest power grid 10
- Further industrial development of land zoned and set aside specifically for this type of use under Whatcom County Zoning rules, and the Whatcom County Comprehensive Plan, would not occur at this time 11
- The opportunity for 30 additional living-wage jobs in Whatcom County would be lost 12
- The revenue generation of approximately 6 million dollars in annual property taxes to be paid by this facility would not occur. There is no doubt that the County portion of this revenue is badly needed during this time of budget shortfalls 13

When one considers these attributes of the proposed project, it is an oversimplification to say the "No Action" alternative has "no impact" on Whatcom County. Much of my time on the County Council is spent working on, discussing, and implementing planning for the future. This planning practice involves a myriad of potential impacts and results, in an attempt to envision a future that is vibrant, attractive, and provides the highest qualities of life for succeeding generations of Whatcom County citizens. This proposal does have the potential to fit in well to that vision in many perspectives. "No Action", in and of itself, would speak volumes about the future of our county.

Based on my reading of the Draft Environmental Impact Statement, I see this project as an important component of our designated and zoned "Heavy Impact Industrial" portion of Whatcom County. I urge you to work cooperatively with the applicant, to carefully consider the concerns of the community along with any negative impacts that may be associated with the project, and permit the construction of this facility in a manner that benefits the people of Whatcom County as well as the applicant.

I appreciate your time, and the opportunity to comment.

Sincerely,

Sam Crawford

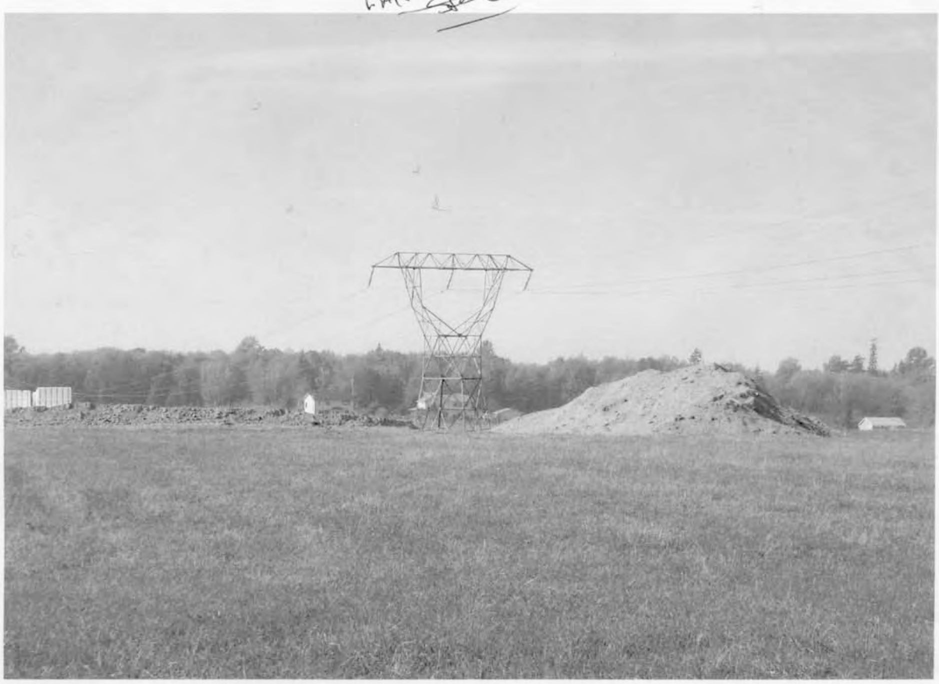
Sam Crawford
Whatcom County Councilmember

C: Dana Brown-Davis, Clerk of the Council
Correspondence File

SC/tak
I:\SHARED\COUNCIL\SC\2003\EFSEC re BP 10.1.doc

BP Cherry Point Cogen
DEIS Comment - 4

Lattice Steel



10/1/03
Bannerman testimony
See center tower, top fots

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ENERGY FACILITY SITE
EVALUATION COUNCIL

BP Cherry Point Cogen
DEIS Comment - 5

Makarow, Irina (OCD)

From: S.G. [sgg1234@yahoo.com]
Sent: Wednesday, October 01, 2003 12:37 PM
To: efsec@ep.cted.wa.gov
Subject: re: Cherry Point Co-Gen. Plant

Sir:
I strongly believe that its time you folks said "NO" to all the new polluting power generating plants being proposed for this area. 1

The Cherry Point Co-Gen. will further destroy the air quality,natural bird/animal habitat and wet lands. It was a disgrace to your whole committee to give a yes to the Se-2 plant in Sumas. 2

S.Gilfillan

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ENERGY FACILITY SITE
EVALUATION COUNCIL

10/2/2003

BP Cherry Point Cogen
DEIS Comment - 6

Makarow, Irina (OCD)

From: doug caldwell [dougcaldwell@compuserve.com]
Sent: Friday, October 03, 2003 7:42 AM
To: Makarow, Irina (OCD)
Subject: BP Cogen DEIS: New Comment Deadline

BUSINESS.PDF (20 KB)

Control technology of the future
Re: Copy of: Copy of: scr is very dangerous by the way
nitrosamine precursors and hydrogen cyanide in catalytic
reactions, such as SCR
Nitrosamine will give you cancer and hydrogen cyanide will kill you in 10
seconds
doug
Environmental Residuals
The primary environmental effect of the project will be a
slight reduction of NO, emissions and a slight increase
in emissions of ammonia m-w I sulfur trioxide (SO,), and
ammonium bisulfate (NH,HSO,). A literature review
revealed concerns about the potential for the production of trace
quan- tities of nitrosamine precursors and
hydrogen cyanide in catalytic reactions, such as SCR. However, an 1
analysis conducted for this report indicates
that for SCR applications on coal-fired power plants the potential
for generating measurable quantities of these
substances is extremely remote. The likelihood of these
occurrences is discussed in Section 4.1. This is the text
version of the PDF file
http://www.lanl.gov/projects/cctc/resources/pdfs/scr/00000158.pdf G o o g l
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text versions of PDF documents as we crawl the web.
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76720-1088 DCN 89-218-073-06
(512)454-4797

ENVIRONMENTAL INFORMATION VOLUME
SOUTHERN COMPANY SERVICES
SELECTIVE CATALYTIC REDUCTION
PROJECT AT
PLANT CRIST
PENSACOIA. FLORIDA
Prepared for:
Southern Company Services
800 Shades Creek Parkway
Birmingham, Alabama 35209
Prepared by:
Radian Corporation
8501 MO-Pat Boulevard
Post Office Box 201088
Austin, Texas 78720-1088
31 August 1989

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EVALUATION COUNCIL

1

The Business Journal of Milwaukee - July 7, 2003
http://milwaukee.bizjournals.com/milwaukee/stories/2003/07/07/story1.html

The Business Journal
SERVING GREATER MILWAUKEE

EXCLUSIVE REPORTS

Pollution control of the Future

Pete Millard

A promising air-pollution control technology from Canada could be incorporated by Wisconsin Energy Corp. into its Power the Future expansion program.

Adding more effective pollution-control technology to Wisconsin Energy's three proposed Power the Future coal plants could sway the statewide debate on whether coal is an acceptable power-plant fuel.

Executives at Wisconsin Energy, the Milwaukee-based parent company of We Energies, have reviewed the air-pollution control system. It promises to improve air quality from fossil fuel power plants by capturing 99 percent of the nitrogen and sulfur oxides and heavy metals, including mercury.

Current air-pollution technologies used in utility power plants capture between 40 percent and 60 percent of the pollutants.

Isca Management Ltd., Vancouver, British Columbia, is marketing its control technology to more than a dozen energy utilities in the United States and hopes to have a large-scale demonstration project underway before the end of 2003.

Wisconsin Energy executives believe the technology may work in the future, but aren't convinced the process is ready to be applied in a large-scale plant.

"It is a technology we're interested in but can't commit to until it's been commercially tested," said Kris McKinney, manager of environmental policy at We Energies.

So far, the technology has been successfully tested in the chemical engineering department laboratory at the University of British Columbia in Vancouver. Basic research for the Isca technology was completed at the university with funding from the National Research Council of Canada.

"If there is a technology out there that can capture virtually 100 percent of the mercury, sulfur dioxide and nitrogen oxides, it behooves We Energies to include it as part of its Power the Future project," said Marc Looze, a spokesman for Clean Wisconsin.

Clean Wisconsin is one of 30 organizations in a coalition called Reset Wisconsin that opposes the construction of new coal plants. Power the Future is We Energies' $7 billion building project that includes adding three 600-megawatt coal plants in southeastern Wisconsin.

Mercury mitigation

A recent decision by the Wisconsin Natural Resources Board to further restrict mercury emissions may force state utilities to look more closely at Isca.

"We've got the answer to the mercury problem in your waters," said Doug Caldwell, president of Isca.

By January 2010, mercury emissions under the new DNR rule would be reduced by 40 percent and by 80 percent by January 2015. The action aims to limit mercury emissions into the atmosphere.

Less mercury entering the air means less of the pollutant will be deposited into Wisconsin's waters where it builds up in fish and wildlife. Atmospheric mercury deposits have contaminated all of the state's water bodies and have resulted in a statewide fish consumption advisory in effect since 2001 for people who eat sport fish.

Caldwell said Wisconsin Energy is reluctant to buy into his company's technology because the company is testing its own in-house technology to improve the removal rates of mercury from power plant emissions.

McKinney disagrees with Caldwell's assessment of why Wisconsin Energy has not offered to invest in Isca. McKinney said Wisconsin Energy does not have the resources like some larger utilities to spend on speculative technologies. Wisconsin Energy is working through Electric Power Research Institute, Palo Alto, Calif., to conduct its pollution-control tests.

The Wisconsin Energy $6.8 million mercury project, done in collaboration with the U.S. Department of Energy's National Energy Technology Laboratory and EPRI, has been tested at the company's Pleasant Prairie Power Plant near Kenosha.

The Isca pollution-control technology injects chlorine gas into a power plant's flue-gas stream to oxidize harmful components, which are then easier to remove through conventional processes.

EPA review

The Isca process effectively removes sulfur dioxide, nitrogen oxides and mercury, according to an analysis by EPRI. The U.S. Environmental Protection Agency has reviewed the Isca technology and considers it one of several multi-pollutant control technologies under development that could gain widespread application.

One of the possible drawbacks of the Isca technology is storing large volumes of chlorine gas at power plant sites, said an EPA engineer. Possible leaks could pose a hazard to power plant employees and the public.

Isca estimates the total capital required to install this system is about $160 per kilowatt hour. A 600-megawatt plant could be retrofitted with the Isca technology for about $30 million, which is about one-third to one-half the cost of conventional pollution control devices, said Caldwell. A spokesman for the Electric Power Research Institute claims the installation cost might be optimistic given the number of process steps.

More than half a dozen utilities have offered financial support for a demonstration and full-scale designs have been completed by Research-Cottrell and Du Pont.

Isca is seeking an architectural and engineering firm, as well as a chemical firm, to fund and complete a 10-megawatt commercial demonstration.

"The problem we've encountered is there are not a lot of engineering design firms willing to take on projects and offer a warranty to utilities for the add-on equipment," said Caldwell.

Isca claims the technology could be ready within a year for full-scale application. All the equipment required for installation of the process is already available on an industrial scale, said Caldwell.

BP Cherry Point Cogen
DEIS Comment - 7

1 of 2
10.03

allen fiksdal
Em fac site Ev Con
PO Box 43172
Olympia WA 985043172

Dear Sir.

I would Hope that when the Equipment for CO-GEN is purchased It will Be the latest-design to REDUCE noxious fumes. (carbon monoxide) 1

Considering BP OILS maxium need FOR 300MW the REQUEST FOR 720MW is extra pollution (OVER-KILL) 2

Being that the trans-mission line will eventually link up with Canadas, Vancouver Island. The Real reason for this Boondoggle 3

(over)

2 of 2

we should be given
the best Equipt.
@ BP'S site. | 3 cont.

CITIZEN USA

H. J. SCHNEIDER
7520 LEESIDE
Blaine Wa 98230
360 371-0568

*w/ SUMAS II and
NOW BP Cherry
PT. We have
Become over Burd-
ened w/ fumes
One project would
have Been too
much.. | 4

We can anticipate
more LINKS on this
Transmission Line
from Canada to
Anacortes.". DO your
JOB." | 5

BP Cherry Point Cogen
DEIS Comment - 8

Washington State
Department of Transportation
Douglas B. MacDonald
Secretary of Transportation

Northwest Region / Mount Baker Area
Skagit, Island, San Juan & Whatcom Counties
1043 Goldenrod Road, Suite 101
Burlington, WA 98233-3415
360-757-5999
TTY: 1-800-833-6388
www.wsdot.wa.gov

September 25, 2003

Mr. Allen J. Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

SUBJECT: SR-548 MP 5.93 Vic. CS 3750 **JA 4746**
BP Cherry Point Cogeneration Project
Draft Environmental Impact Statement Review

Dear Mr. Fiksdal:

Thank you for giving us the opportunity to comment on the Draft Environmental Impact Statement for the subject project dated September 5, 2003.

We concur with the findings of section 3.15, Traffic and Transportation, as presented. Of particular importance to WSDOT is the need for installation of a traffic signal with railroad pre-emption at the intersection of Grandview Road/Portal Way, and left turn channelization at the intersection of SR 548 and Blaine Road. 1

In the past, WSDOT has found that interconnection of Railroad crossings with traffic signals can be a lengthy process to plan and implement with BNSF. In an effort to facilitate BP's construction of the signal at the intersection of SR 548 and Portal way in a timely manner, WSDOT has taken the liberty of entering into discussions with BNSF. During these discussions, it has been determined that the cost to BP for interconnection of the proposed signal to the Railroad crossing by BNSF will be $60,233.00. In an act of good faith, WSDOT has advanced this cost to BNSF in expectation of eventual reimbursement by BP as discussed in WSDOT's meeting with BP personnel on June 12, 2003.

If you have any further questions, please contact Mr. Roland Storme of our Development Services section at (360) 757-5961.

Sincerely,

for:

Todd L. Harrison, P.E.
Assistant Regional Administrator
Northwest Region/Mount Baker Area

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OCT 08 2003
ENERGY FACILITY SITE
EVALUATION COUNCIL

RS:rs

cc: Mike Torpey, BP
Todd Carlson, WSDOT

BP Cherry Point Cogen
DEIS Comment - 9

Olympia Address
106-B Irv Newhouse Bldg.
PO Box 40442
Olympia, WA 98504-0442
(360) 786-7682
brandlan_da@leg.wa.gov

Washington State Senate

Senator Dale Brandland
42nd Legislative District

District Address:
P.O. Box 974
Bellingham, WA 98227
(360) 966-4803

October 7, 2003

EFSEC
925 Plum Street SE Building 4
PO Box 43172
Olympia, WA 98504-3172

Dear members of EFSEC Council:

I am pleased to have this opportunity to express my support for the proposed cogeneration power plant project at BP's Cherry Point refinery. The Cherry Point facility has had a long tradition of proven environmental sensitivity and operational excellence. For over 30 years, they have been providers of family-wage employment and have contributed their time and money to support this community. 1

The proposed cogeneration plant project has many desirable features. Cogeneration is in itself an inherently superior way of producing electricity; it allows the refinery to remove older equipment and thereby reduce overall criteria pollutants from the entire complex. This also means that the project will produce less CO2 emissions and be more efficient than stand-alone facilities. Water issues are of particular concern to me; they have chosen to employ a water re-use strategy with ALCOA and the Whatcom PUD that will reduce the amount of water taken from the Nooksack River. 2

Lastly, this project will provide much-needed jobs in Whatcom County. Over 370 construction jobs will be created, and 30 full-time positions will be needed for the ongoing operations of the plant. The plant will provide $10 million / year in state and local taxes as well. Our state needs this type of project to be able to provide services to our citizens. 3

For all of these reasons, I add my support to this important project.

Sincerely,

Dale E Brandland

Senator Dale E. Brandland, 42nd District

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EVALUATION COUNCIL

Recycled   Committees: Judiciary • Health and Long-Term Care • Agriculture

STATE REPRESENTATIVE
42nd DISTRICT
KELLI LINVILLE

State of
Washington
House of
Representatives

AGRICULTURE &
NATURAL RESOURCES
CHAIR
APPROPRIATIONS

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BP Cherry Point Cogen
DEIS Comment - 10

October 1, 2003

EFSEC
925 Plum Street SE, Building 4
PO Box 43172
Olympia, WA 98504-3172

Dear Members of the EFSEC Council,

Please allow me this opportunity to express my support for the proposed cogeneration power plant project at BP's Cherry Point refinery. The Cherry Point facility has had a long tradition of proven environmental sensitivity and operational excellence. For over 30 years, they have been providers of family wage employment and have contributed their time and money to support this community. 1

The proposed cogeneration plant project has many desirable features. Cogeneration is in itself an inherently superior way of producing electricity; it allows the refinery to remove older equipment and thereby reduce overall criteria pollutants from the entire complex. This also means that the project will produce less CO2 emissions and be more efficient than stand alone facilities. Water issues are of particular concern to me; they have chosen to employ a water re-use strategy with ALCOA and the Whatcom PUD that will reduce the amount of water taken from the Nooksack River. 2

Lastly, this project will provide much-needed jobs in Whatcom County. Over 370 construction jobs will be created, and 30 full time positions will be needed for the ongoing operations of the plant. The plant will provide $10 million per year in state and local taxes as well. Out state needs this type of project to be able to provide services to our citizens. 3

For all of these reasons, I am glad to add my support to this important project. Thank you for your time.

Sincerely,

Kelli Linville
RB for Kelli Linville
Representative Kelli Linville
State Representative, 42nd District

kl\rb

LEGISLATIVE OFFICE: 328 JOHN L. O'BRIEN BUILDING, PO BOX 40600, OLYMPIA, WA 98504-0600 • 360-786-7854
DISTRICT OFFICE: 104 W. MAGNOLIA, #306, BELLINGHAM, WA 98225 • 360-738-6177
E-MAIL: linville_ke@leg.wa.gov • FAX: 360-738-6178
TOLL-FREE LEGISLATIVE HOTLINE: 1-800-562-6000 • TDD: 1-800-635-9993
PRINTED ON RECYCLED PAPER

Whatcom County Fire District No. 7

P.O. Box 1599
Ferndale, WA 98248
(360) 384-0303
FAX (360) 384-4509
E-Mail WCFD7@nas.com

October 8, 2003

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Dear Mr. Fiksdal:

Please accept this letter into the record for the BP Cherry Point Co Generation Project. At the regular October Board of Commissioner's meeting the issue was reviewed. By motion of the board, Whatcom County Fire Protection District No.7 is in full support of the project. This decision was made after careful review of staff concerning a number of issues, which are directly related to the fire department. 1

Our staff was involved early on in the process of the Co Generation Project at the Cherry Point Refinery. We have teamed up with project leaders to have a clear understanding of all aspects of the design, construction and operation of the facility when completed.

Whatcom County Fire District No.7 has been the AHJ for the refinery since it began operation in the early 70's. During that time our department has had a fine relationship with the management and operational division onsite. This close relationship has allowed our two organizations public and private to provide for a high level of emergency response to the facility and the surrounding area.

Our staff has recognized a number of benefits to the Cherry Point Refinery from the completion of the Co Generation Project. The area is zoned for this type of occupancy and will have little to no impact on the public in general. The economic benefit to the local area and the State of Washington will be substantial also.

The impact statement prepared by the project team is very comprehensive and detailed, which has involved the fire department fully. A stable supply of power to the facility, which will not be interrupted due to weather, mechanical failure or regional issues outside the site is paramount. This is very important due to the fact that a loss of power can cause a failure of the process, which could be detrimental to the safety of the facility, the employees and an economic disaster to the area.

The Co Generation of power and steam will replace the need for the current steam producing heater units, which pose a greater fire hazard within the facility. The reduction of the heater unit reduces the amount of emission released into the atmosphere, which is in the best interest of the general public.

For these reasons the Board of Fire Commissioners of Whatcom County Fire Protection District No.7 requests that EFSEC recommend approval of the BP Cherry Point Refinery Co Generation Project.

Respectfully,

Gary E. Russell, Chief

Gerald Metzger, Chairman

Michael Murphy, Commissioner

Al Saab, Commissioner

Arne R. Cleveland
7373 Birch Bay Drive
Blaine, WA 98230
360-371-2709

BP Cherry Point Cogen
DEIS Comment - 12

October 22, 2003

Mr. Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Dear Mr. Fiksdal,

I submit that Natural gas-fired power plants are a potent source of extremely hazardous health risk with tiny particles 2.5 microns or less in diameter (PM2.5). All of the particulate matter produced by the gas-fired turbines of power plants will be less than 2.5 microns in diameter. In fact, all of it will be less than 1 micron in diameter, and consist largely of organic compounds referred to as products of incomplete combustion. Hazardous trace metals plus SO4, NH4 and NO3 will also be released. The EPA has been studying PM2.5 for some time, which lead the agency to propose new standards for exposure and emissions. I am enclosing a copy of Particulate Matter Research Program Strategy, which describes the EPA's work in the areas of health and exposure. 1

Many medical studies link PM2.5 or particulate matter to heart attacks and deaths. There will be severe health implications for us at Birch Bay as this natural gas-fired power plant commences spewing hundreds of tons of PM2.5 and ammonium sulfate annually. 2 In addition, have you added what the existing cogeneration plant pollutes to what the proposed new one will add? 3

Noise is an additional concern. The BP plant is very noisy today, keeping me awake at night. Sometimes it is quite and I can sleep. This new cogeneration plant will make noise 24 hours a day. That is not acceptable for the residents of Birch Bay. Also, have you considered what the new plant noise will be along with the noise of the proposed pipeline to go under Georgia Strait from Cherry Point? 4

If you approve the site, it should be as far in the southeast corner of the BP facility as possible, away from the Birch Bay population. You should however, not approve such a huge monster and only give BP a cogeneration plant for their refinery requirements. Power plants of this large magnitude should not be located around population centers. There is plenty of space in this county to locate the plant away from people! Plus you would be contributing to ruining one of the great recreation areas of our state. 5

I strongly urge you not to approve the proposed plant. As you can read in the EPA study, you will be causing health problems and will be signing the death warrant of many seniors and children.

Sincerely,

Arne R. Cleveland

RECEIVED

OCT 23 2003

ENERGY FACILITY SITE
EVALUATION COUNCIL

NHEERL MS-97-019

PARTICULATE MATTER RESEARCH PROGRAM STRATEGY

NOTICE

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External Review Draft

OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

October 1996 DRAFT-DO NOT CITE OR QUOTE

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1. INTRODUCTION

National Ambient Air Quality Standards (NAAQS) are established by the U.S. Environmental Protection Agency (EPA) to protect public health and welfare, based on scientific criteria. Currently, NAAQS exist for ozone, lead, carbon monoxide, nitrogen oxides, sulfur dioxide, and particulate matter (PM). Periodic reviews of the standards are required by law to ensure their adequacy.

Recent studies of several metropolitan areas in the United States and elsewhere report excess mortality and morbidity in urban populations associated with airborne PM concentrations below the current PM NAAQS. These studies suggest PM exposures may shorten the human life span of susceptible subpopulations (e.g., the elderly) and cause increased morbidity in these and other susceptible groups such as children. There are, however, several aspects of these epidemiologic observations that require further consideration; in particular, a clear biologic explanation for a cause-and-effect relationship has not yet emerged, and the nature of the concentration-response relationship across a wide range of concentrations and conditions is uncertain. These provocative epidemiologic findings underscore EPA's statutory mandate to review and potentially revise the NAAQS for PM. It is imperative to reduce key uncertainties to provide for the most effective and efficient health protection through the NAAQS.

The latest available scientific information on PM is evaluated in an ambient air quality criteria document (AQCD) (U.S. Environmental Protection Agency, 1996a) prepared by EPA's Office of Research and Development (ORD) and peer reviewed by the Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board (Wolff, 1996a). Key scientific findings from the AQCD have been drawn on and summarized in a Staff Paper for PM prepared by EPA's Office of Air Quality Planning and Standards (U.S. Environmental Protection Agency, 1996b), which also was peer reviewed by CASAC (Wolff, 1996b). The Staff Paper makes recommendations that will form the basis for upcoming EPA decisions regarding proposed actions on the PM NAAQS.

In the course of assessing the latest scientific information on PM, various data gaps and uncertainties have been identified, which, if addressed by research, could lead to improvements in the databases later available to support NAAQS review. To this end, EPA has developed a document entitled Particulate Matter Research Needs for Human Health Risk Assessment (U.S. Environmental Protection Agency, 1996c). The PM research needs document is designed to serve as the basis for development of health research plans by EPA and other organizations. The intersection of the PM research needs document with the Strategic Plan for the Office of Research and Development (U.S. Environmental Protection Agency, 1996d) provides the context for the present document, which describes the research strategy for EPA's research on PM.

The EPA has a dual responsibility to review the adequacy of the NAAQS every 5 years and to ensure attainment of the NAAQS to protect public health and welfare. The EPA health effects and exposure research supports NAAQS review by providing scientific methods, models, and data needed for assessment of health risks from PM exposures. The EPA research to support implementation of PM standards is focused similarly on improving the methods, models, and data for attainment decisions. In this area, the research program is designed to ensure that federal, state, and local regulatory officials have the information and tools necessary to make objective and informed judgments about the viability of alternative attainment strategies. The direct linkage of risk management research to the risk assessment process provides the unique opportunity for EPA researchers to focus the national research agenda on the most critical uncertainties that could significantly impede future attainment of the PM standard.

This document describes ORD's PM research strategy in the areas of health, exposure, risk assessment, and risk management research and will be used to guide ORD's future PM research. It also will provide the scientific community and the public the opportunity to review and comment on the ORD PM research strategy.

The ORD approach to planning and implementing research on PM is multidisciplinary. The EPA staff from the ORD National Health and Environmental Effects Research Laboratory (NHEERL), the ORD National Exposure Research Laboratory (NERL), the ORD National Risk Management Research Laboratory (NRMRL), the ORD National Center for Environmental Assessment (NCEA), the ORD National Center for Environmental Research and Quality Assurance (NCERQA), the ORD Office of Research and Science Integration (ORSI), and the Office of Air and Radiation (OAR) have developed this strategy cognizant of the need for integrated planning across various disciplines. Implementation of the EPA research program is also coordinated by a multidisciplinary committee composed of staff from the laboratories and offices identified above. The primary clients for this PM research program include OAR, EPA's Regional Offices, and state and local air pollution control agencies. It also will be of interest to the public, congress, the international scientific community, industry, and environmental groups.

This introduction (Section 1) describes the environmental problem of concern (see above), the research program mission, and the research program goals and scope. Section 2, the research planning framework, includes an assessment of current knowledge and identification of key questions. Section 3, the strategy, includes formulation of the strategy, criteria for ranking research, and research priorities. Section 4 is the summary.

1.1 Program Mission

The mission of ORD's PM research program is to provide an improved scientific basis for future regulatory decisions concerning public health risks posed by airborne particles. The strategy has been designed to balance research to support the future Clean Air Act-mandated reviews of the NAAQS for PM with research aimed at supporting implementation of PM standards, including improved understanding of sources, exposures, atmospheric and biological processes, and risk management technologies.

1.2 Program Goals

The fundamental goals of the PM research program are (1) to address key scientific questions relating particulate matter sources, exposures, and human health effects; (2) to assess the health risks; and (3) to provide EPA and other stakeholders with technical information needed to understand the costs and performance of risk management options. Acquisition of this knowledge is needed to address policy questions related to the risks posed by PM.

It is important to plan how research will be utilized in risk assessment and regulatory activities because these considerations can influence the timing of research. A long-term research program is required to address critical PM issues fully and will be important for future PM NAAQS reviews. As an intermediate step in achieving the long-term goals, the program described here also will produce important information in the near term that can have dramatic impact on EPA's ongoing regulatory development strategy and its implementation (e.g., Federal Reference Method development).

1.3 Program Scope

The EPA's PM research strategy addresses several key issues to support NAAQS decisions and implementation. These issues are (1) the need for further interpretation of the epidemiologic data; (2) the limited understanding about biological mechanisms that could (a) explain the observed effects, (b) provide insight with respect to physico-chemical composition of the particles causing effects, and (c) explain the nature of the concentration-response function, in particular with respect to the possibility of a threshold for effects (i.e., every exposure concentration may cause an effect in some individuals in the population); (3) the uncertainties about the composition, size, physical properties, and sources of PM that may cause health effects; (4) the incomplete understanding of the aerosol transport and exposure processes (where, when, and how people are exposed to ambient PM); and (5) what existing and new risk management technologies can be cost-effectively used to control emissions of $PM_{2.5}$ and PM_{10}.

Air pollutants exist as a complex mixture, and exposure to this mixture of PM and copollutants has been associated with increased health risks. Although EPA's PM research program is focused on PM issues, it is complemented by other ongoing and planned EPA research programs focused on, for example, important copollutants such as ozone. In addition, research regarding any potential ecological effects of PM constituents, such as from acidic deposition, or regarding development of control options for well-known PM precursor source categories, such as utility boilers that emit sulfur and nitrogen oxides, are not addressed in this research strategy. If identified as a priority for EPA research, such associated effects, exposure and management research issues are addressed in ongoing and planned research activities and strategies that are complementary to this PM strategy.

2. RESEARCH PLANNING FRAMEWORK

Two steps were undertaken as part of the strategic process to develop this plan: (1) assessment of current knowledge and (2) identification of major knowledge gaps and key scientific questions. The results of these two steps are described in abbreviated fashion in this section. The AQCD and research needs documents discussed in the introduction were used as a resource in designing this strategy.

2.1 Assessment of Current Knowledge

Health Effects of Particulate Matter

Health effects reported to be associated with PM are summarized in the AQCD (see U.S. Environmental Protection Agency, 1996a; Table 12-2 and Tables 12-8 through 12-13). Effects can be grouped into two categories: (1) increased daily and annual mortality rates in adults, including those from cardiopulmonary disease, and (2) increased morbidity from cardiopulmonary disorders, including symptoms of respiratory dysfunction (e.g., wheeze, cough), asthma attacks, pneumonia, bronchitis, and chronic obstructive pulmonary disease. Other measures of morbidity, such as restricted activity due to illness, increased emergency room visits, and increased rates of hospitalization, also have been associated with ambient PM exposures. Table 1 summarizes reported effects.

Preexisting respiratory or cardiopulmonary disease and age appear to be important factors in PM susceptibility (U.S. Environmental Protection Agency, 1996a; Tables 13-6 and 13-7). According to recent epidemiologic studies, risks of PM-associated mortality appear to rise after age 40, particularly in individuals over 65 who have preexisting disease but who are not necessarily hospitalized. The average life shortening of affected individuals cannot be quantified with confidence but could conceivably be on the order of years (U.S. Environmental Protection Agency, 1996a).

Younger individuals also may be at increased risk relative to the general population. Increases in morbidity associated with increased PM exposures are reported in children in the United States, The Netherlands, and Austria. Acute pulmonary function studies are suggestive of a short term effect resulting from PM pollution, with effects larger in groups such as asthmatics (U.S. Environmental Protection Agency, 1996a; Table 12-13).

Animal toxicology studies have been conducted with various types of model particles (e.g., titanium dioxide, latex, iron oxide). In general, these studies suggest relatively low toxicity for these types of PM. Few studies have been conducted with ambient urban air particles (U.S. Environmental Protection Agency, 1995). Studies comparing the in vivo and in vitro toxicity of a range of particles demonstrated that particles collected from the ambient urban air are more toxic than a number of model particles (Hatch et al., 1985; Becker et al., 1996).

TABLE 1. SUMMARY OF REPORTED HEALTH EFFECTS ASSOCIATED WITH PARTICULATE MATTER EXPOSURES

Mortality
- Total deaths
- Respiratory deaths
- Cardiovascular deaths
- Cancer deaths

Increased Hospital Use
- Admissions
- Emergency room visits

Increased Pneumonia and Exacerbation of Chronic Obstructive Pulmonary Disease
- Hospital admissions
- Emergency room visits

Exacerbation of Asthma
- Attacks
- Bronchodilator use
- Emergency room visits
- Hospital admissions

Increased Respiratory symptoms
- Cough
- Upper respiratory tract
- Lower respiratory tract

Decreased Lung Function
- Forced expiratory flow
- Peak flow

Modified from Dockery and Pope (1994), Schwartz (1994a,b,c).

More recent animal studies suggest that higher toxicity is associated with the use of animal models of cardiopulmonary disease, smaller size (higher collective surface area) particles, and particles with higher content of soluble metals or organic matter. A possible mechanism underlying mortality and morbidity may be the induction of oxidant production, lung inflammation, and hyperactivity by these surface-associated components of PM (Oberdörster et al., 1992; Costa et al., 1994; Cohen et al., 1996; Gutteridge et al., 1996; Pierce et al., 1996; Samet et al., 1996). It is also likely that differences in air flow in the diseased lung versus the normal lung alter dosimetry and result in greater regional or localized PM deposition in diseased lungs. This is likely to contribute to the effects of PM (Kim et al., 1988; Bennett et al., 1996a,b).

In addition to cardiopulmonary effects, genotoxic and carcinogenic effects are of concern. Particulate matter collected from the ambient air contains condensed organic matter that is carcinogenic in animals and mutagenic in short-term bioassays (Lewtas, 1993; Cupitt et al., 1994).

Exposure to Particulate Matter

Figure 1 summarizes current knowledge of the mass distribution by size and categories of sources of PM. This figure shows that ambient PM is a complex mixture of sizes and types of particles that are emitted into, or formed in, the atmosphere with contributions from many sources. The size, chemical composition, and source of particles all may play a role in health effects resulting from PM exposures. This figure also indicates that particles generally are distributed bimodally by size in the atmosphere, with the minimum of the distribution between 1 and 3 μm aerodynamic particle diameter. Fine particles, including acid aerosols, appear generally to be distributed evenly across metropolitan areas, although city-center concentrations of acid aerosols tend to be lower due to ammonia neutralization (Burton et al., 1994; Suh and Burton, 1994). Little detailed information is available on the specific structure and chemical makeup of particles, especially the metal speciation and semivolatile organic components of fine particles. Even less is known about particle surface composition.

Few personal monitoring studies, where exposure is determined from monitors attached to individuals as they conduct their daily activities, have been conducted. Personal exposures to PM_{10}, while subjects are spending time indoors and outdoors are, however, invariably higher than simultaneously measured ambient and indoor PM_{10}. For example, Clayton et al. (1993) showed during the daytime, while people are active, that personal exposures to PM_{10} averaged 150 $\mu g/m^3$, whereas simultaneously both the indoor and outdoor PM_{10} averaged 95 $\mu g/m^3$. The enhancement of personal exposure relative to the PM_{10} concentrations within occupied indoor and outdoor microenvironments is believed to arise from personal activities that generate PM_{10} close to the subject but at a distance from the stationary indoor and outdoor PM_{10} monitors. This may possibly explain why human exposures to PM do not always correlate well with

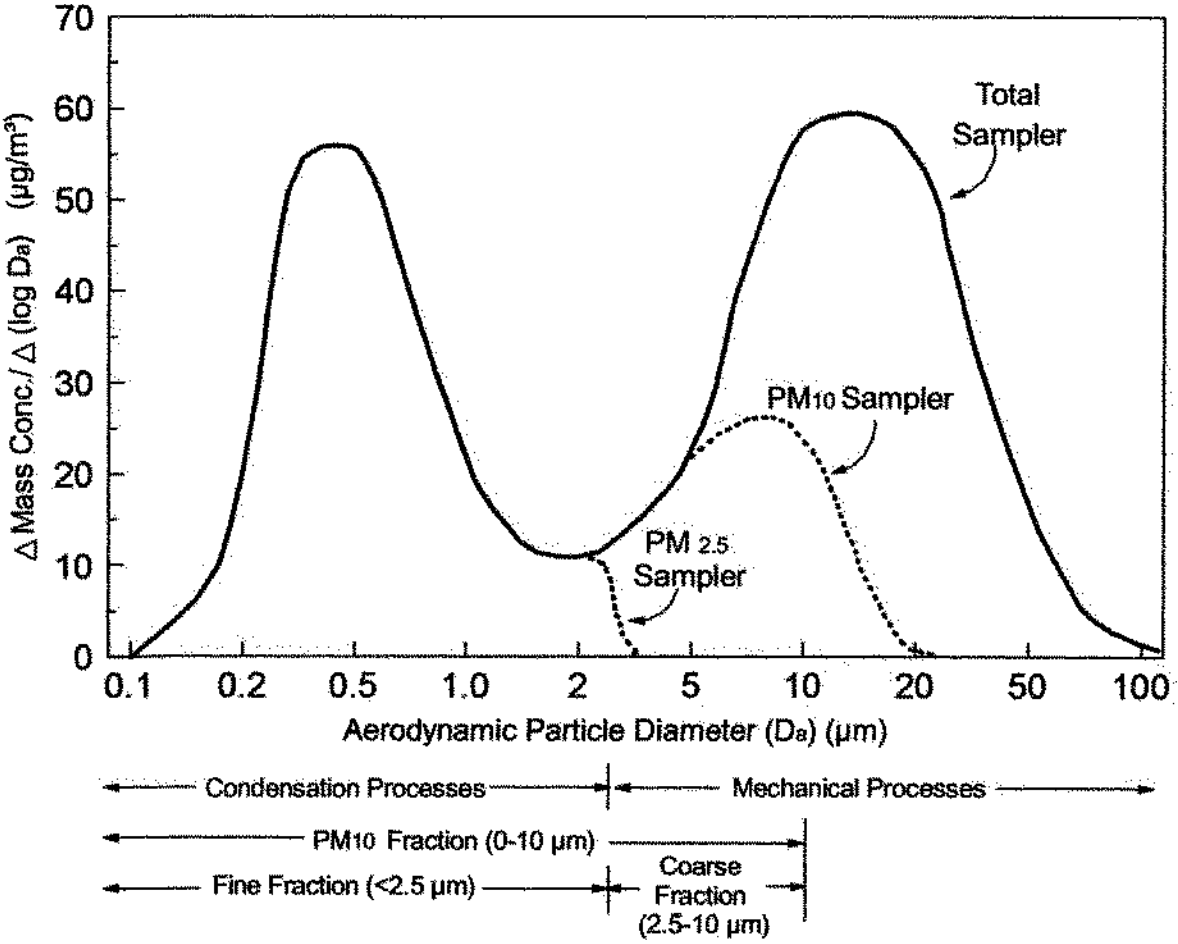

Figure 1. Sampling fractions related to a typical ambient particulate mass distribution. A typical bimodal distribution is shown. Particles in the finer mode include primary particles from high-temperature metallurgical and combustion processes, secondary particles from atmospheric reactions, and fine particles that have been deposited and resuspended by wind or human activities. Particles in the coarser mode include coarse windblown and road dust, pollens and spores, and some industrial particles.

ambient PM measurements. In homes with significant indoor sources of PM (e.g., cigarette smokers), outdoor measurements do not correlate well with indoor measurements. In studies that control for homes with significant indoor sources, indoor levels of fine particles are highly correlated with outdoor levels (Lewis, 1991). Because of the epidemiologic associations of mortality with ambient PM that have been reported (Schwartz et al., 1996), it is important to understand how community ambient PM concentrations and personal exposures to PM of ambient origin relate, particularly in reference to time and activity patterns and to residential and other indoor microenvironmental concentrations of PM.

The most commonly used ambient air sampling devices collect particles on filters. Continuous monitors, which are based on direct measurement of mass, beta-ray attenuation, light scattering, particle mobility, or other physical properties of particles, also have been developed but are used infrequently. Characteristics and uses of various ambient, indoor, and personal sampler types are summarized in Table 2. Along with the rulemaking for a revised PM NAAQS, EPA has developed and is proposing a new Federal Reference Method based on these methods to be used in determining compliance with any new ambient standard. However, the new method will not supply sufficiently detailed information needed for full assessments of public health risks. Needed are integrated (averaged over a long sampling period) and real-time methods. Integrated PM measurement accuracy is limited substantially by factors that include performance variations in sampler inlets and size discriminators, internal losses, variations in particle composition and chemical changes, loss of volatile and semivolatile components, and variable moisture content.

The myriad of exposure possibilities makes actual measurement of all cases impossible, thereby producing a need for atmospheric and exposure models. Modeling is critical for a complete assessment of both personal and environmental exposures. More useful models help define the nature of PM exposures and include consideration of emissions characterization, aerosol chemistry and dynamics, and human exposure. Information that serves as input to these models and the models themselves currently are underdeveloped. In particular, research is needed in the areas of urban-to-regional scale model development, aerosol chemistry and dynamics, emissions characterization, indoor-outdoor relationships, and human exposure model development. Validation of newly developed models is essential if they are to be used to support advanced risk assessment and regulatory decisions.

Assessment of Risk from Particulate Matter

The current state of knowledge on the health risks of particulate matter is summarized in the AQCD for PM, which recently has been updated (U.S. Environmental Protection Agency,

TABLE 2. INTEGRATED AEROSOL SAMPLERS AND CONTINUOUS PARTICLE MONITORS

Integrated Aerosol Sampler	Operating Principle	Particle Size Range (µm)	Flow Rate (Lpm)	Use/Comments
TSP Hi-Volume	Sheltered filter	0-45	1,400	Ambient monitoring
PM_{10} Hi-Vol	Impactor/cyclone	0-10	1,130	Ambient monitoring
Dichotomous	Virtual impactor	0-2.5 2.5-10	16.7	Ambient monitoring, source apportionment
Dichotomous	Virtual impactor	0-2.5 2.5-10	1,130	Ambient monitoring, source apportionment
PEM/MEM[a]	Impactor	0-2.5 2.5-10	2-10	Indoor monitoring, personal exposure
MOUDI[b]	Impactor	0.05-10	30	Particle size, 10 stages
Berner	Impactor	0.063-16.7	30	Particle size, 9 stages

[a]PEM = personal exposure monitor; MEM = micro environmental monitor.
[b]MOUDI = micro orifice uniform deposit impactor.

Continuous Particle Monitor	Operating Principle	Particle Size Range (µm)	Flow Rate (Lpm)	Use/Comments
Beta-Gauge	Beta-ray attenuation	--	16.7	TSP, PM_{10} monitoring
TEOM[c]	Direct mass sensor	--	16.7	TSP, PM_{10}, $PM_{2.5}$ monitoring
Integrating Nephelometer	Light scattering	0-3	75	Visibility monitoring
OPC[d]	Light scattering	0.3-10	Variable	Particle size, number
APS[e]	Time of flight	0.5-10	5	Particle size, number
DMPS[f]	Electrical mobility	0.003-1	4	Particle size, number

[c]TEOM = tapered element oscillating microbalance.
[d]OPC = optical particle counter.
[e]APS = aerodynamic particle sizer.
[f]DMPS = differential mobility particle sizer.
-- = not applicable.

1996a). Additional assessment methods should be developed to facilitate the future AQCD; these include the following: (1) analyses of lung function as a predictor of mortality and time of life lost; (2) determining effects of altitude on the risk of health effects from particles; (3) developing statistical models for identification of air pollution episodes and estimation of short-term temporal displacement of mortality and morbidity; (4) developing statistical models for evaluating interactions of PM, copollutants, and weather in regression models for mortality and morbidity; and (5) understanding the relative effects of $PM_{2.5}$ versus coarse particles on asthmatics as a sensitive population.

Management of Risk from Particulate Matter

Managing the health risks of exposures to particles requires knowledge of the sources and types of particles that are most likely to cause health risks and knowledge of the performance and costs of risk reduction technologies. Both direct emissions of PM and secondary particle formation caused by the oxidation of SO_2, NO_2, and aerosol organic carbon species contribute to overall levels of airborne particles. The major constituents of coarse particles across the United States are minerals, and the major constituents of fine particles vary by region, with sulfates as the major component in the eastern United States and elemental and organic carbon species dominant in the western United States (see Figures 2 and 3; U.S. Environmental Protection Agency, 1996a). The most recent data on the PM effects described in the AQCD indicate that the association between fine particles and adverse health effects tends to be stronger than the association with coarse particles. Such a finding has implications for risk management activities which must begin to consider how PM attainment strategies would have to be modified to reduce atmospheric levels of fine particles. For example, in the eastern United States, additional reductions of sulfur oxides associated with fossil fuel combustion and motor vehicle emissions may be necessary, whereas, in the West, additional reductions of inorganic and elemental carbon species emitted from wood-burning activities and mobile sources could be required.

The availability of tools to assess attainment strategies and approaches to manage PM risks varies widely depending on the size fraction and constituent of concern. Available atmospheric models and emission estimation techniques used by states to devise attainment strategies were

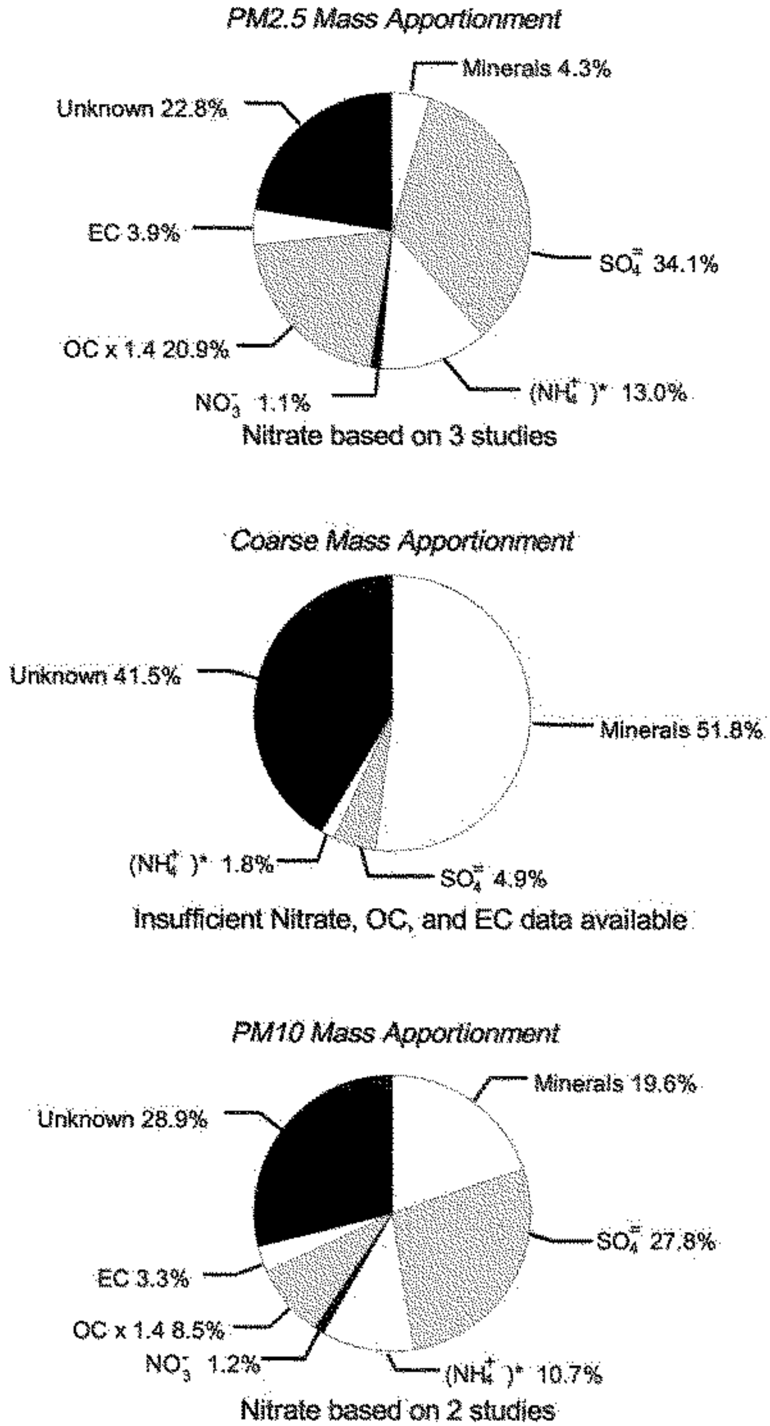

Figure 2. Major constituents of particles measured at sites in the eastern United States. $(NH_4^+)^*$ represents the concentration of NH_4^+ that would be required if all $SO_4^=$ were present as $(NH_4)_2SO_4$ and all NO_3^- as NH_4NO_3. Therefore, $(NH_4^+)^*$ represents an upper limit to the true concentration of NH_4^+.

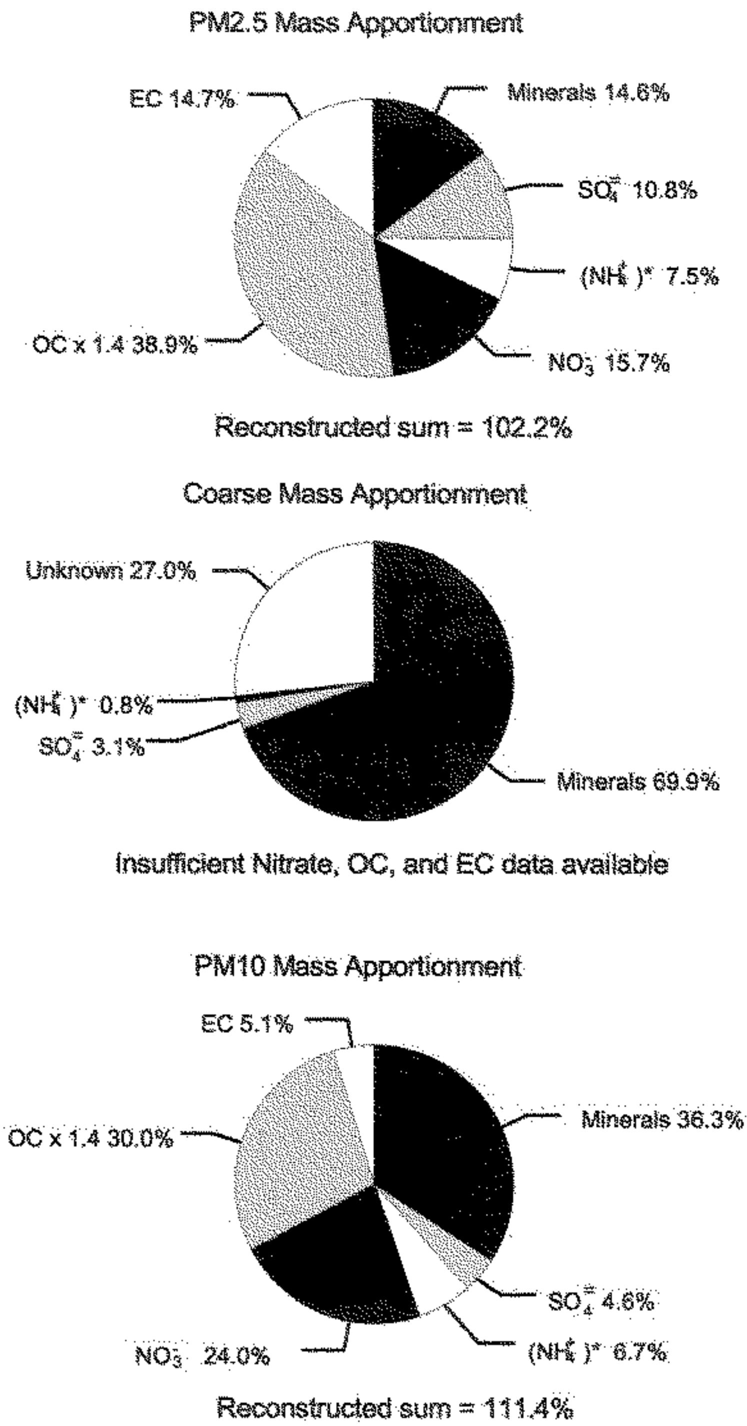

Figure 3. Major constituents of particles measured at sites in the western United States. $(NH_4^+)^*$ represents the concentration of NH_4^+ that would be required if all $SO_4^=$ were present as $(NH_4)_2SO_4$ and all NO_3^- as NH_4NO_3. Therefore, $(NH_4^+)^*$ represents an upper limit to the true concentration of NH_4^+.

designed to support implementation of the existing PM_{10} standards and have not been refined to address smaller size fractions or adequately taken into account all the atmospheric transformation processes that lead to secondary particle formation. Although much is known about emission levels of the precursors that lead to secondary particle formation, most of the estimates of primary $PM_{2.5}$ emissions are derived from data on PM_{10}, resulting in some uncertainties in the fine particle emissions inventory. This is especially true for fugitive sources. In addition, there is a general lack of data on the chemical composition of fine particle emissions. The need for emission characterization is greatest for those sources with constituents (such as metals, acidic components) that are candidates for causal mechanism studies of respiratory health effects. The availability of approaches to control both primary and secondary particles also varies widely with existing technologies available to reduce SO_x and NO_x from most large fossil fuel combustion sources and improvements or upgrades needed to limit emissions of primary particles from some source categories, particularly in cases where space limitations make existing approaches infeasible. Appendix 1 provides details on the current state of knowledge concerning management of fine particle emissions.

Appendix 1 includes data on the effectiveness and costs of emissions prevention, emissions reduction, or exposure reduction technologies to reduce fine particle levels indoors and outdoors. Approaches to reduce indoor fine-particle exposures are not well understood, with only limited data available on the efficiency and cost of air cleaning to remove particles from indoor air and virtually no data on the effectiveness of air cleaning in reducing exposures to fine particles. Because indoor concentrations of particles are generally about the same as outdoor concentrations when outdoor concentrations are high, or about twice outdoor concentrations when outdoor concentrations are low (e.g., Spengler et al., 1981; Sheldon et al., 1989), and because people spend roughly an order of magnitude more time indoors than outdoors, the effectiveness of indoor exposure controls is also a major uncertainty.

2.2 Identification of Key Questions

The thrust of this research plan is to address key scientific and technological questions regarding those aspects of airborne PM that may affect human health adversely. The key questions are drawn mostly from the PM research needs document (U.S. Environmental

Protection Agency, 1996c) and, ordered consistently with the health risk assessment paradigm, are listed below.

A. What are the causal, biologic mechanisms of effects and the implications for (1) initiation and progression of pulmonary injury, inflammation, hyperreactivity; (2) exposure-dose-responses; and (3) impacts on subpopulations? What are the mechanisms and rates of repair for the tissues and cells of the different respiratory tract regions across age, sex, and health status in humans and across species? Do host factors such as age, sex, and health status influence the number or types of target cells and their relationship to toxicity/detoxication of PM? Can laboratory animal models be developed that are homologous to the human population at risk in terms of host factors and mechanisms of action?

B. What is the spectrum of acute and chronic health effects of particulate matter? Does ambient PM exposure lead to

1. Exacerbation or initiation of pulmonary injury, inflammation, hyperreactivity;
2. Extrapulmonary effects, such as cardiovascular system effects; or
3. Cancer of the lung or other organs?

C. Can ambient PM impacts on population morbidity and mortality be better characterized in relation to potential effects modifiers and confounders such as meteorology and exposure to other pollutants? Can epidemiological and biostatistical methods further differentiate the effects of individual PM components? Similarly, can these methods help differentiate specific sources of PM from the entire ambient PM complex or the entire air pollution complex (including gases and particles)?

D. Who is being affected by ambient PM exposures, and what are important factors putting them at risk? What sensitive subpopulations are most affected by PM exposures? Are there differences with regard to sensitive groups at risk because of acute versus chronic exposure effects? Can critical host risk factors be delineated, for example, with regard to

1. Health status (preexisting cardiopulmonary disease, acute respiratory infection, COPD, asthma, etc.),

2. Age (children and the elderly),
3. Genetic factors (predisposition to emphysema, deficient lung defense mechanisms, cancer, etc.),
4. Life style (smoking, nutrition, access to health care, activity patterns/levels, etc.),
5. Differential respiratory tract dosimetry (regional deposition, and retention) as influenced by one or more of the above other factors, or
6. Prior occupational or other nonambient PM exposures (hobbies, indoor cooking/cleaning, etc.)?

E. How can dosimetry models be improved to contribute to evaluation of responses in epidemiological, controlled human exposure studies, and laboratory animal studies and to improve insight on potential mechanisms of action? What data are needed to enhance the ability of dosimetry models to describe the various factors, including both the physicochemical attributes of ambient PM, as well as host factors that influence inhaled dose, clearance, retention, and response? What data are required to construct the different internal dose metrics that may correspond to various plausible mechanisms of action? Can the variability in different dose metrics, both within humans and across species, be better characterized?

F. What are the shapes of the acute and chronic exposure-dose-response curves for ambient PM?

G. Are the apparent ambient PM effects on morbidity and mortality determined by

1. Physical properties of ambient particles (particle diameter, particle number, particle mass, and particle surface area);
2. The inorganic content of ambient particles, especially the presence of transition metals;
3. The organic content of ambient particles, especially the polar fraction;
4. The concentration in ambient particles of biologically derived material such as endotoxins;
5. The acidity of the ambient aerosol;
6. Other components of the atmosphere for which PM is a surrogate; or

7. Personal exposures, particularly indoor exposures, including the exposure patterns of susceptible populations and the so-called "personal cloud"?

H. What are the characteristics of ambient particulate matter in terms of

1. Chemical composition,
2. Size distribution,
3. Variability (spatial variation across a given city on a day-to-day basis and from city to city on a longer term, regional basis; temporal variability over diurnal cycles), and
4. Characterization of poorly understood specific PM components that depend on improved methods being developed and deployed (e.g., "live aerosol" versus "dead particles", insoluble core, material soluble in aqueous layer, and outer skin); primary biological components (fragments of insects, molds, and plants); bacteria, viruses, etc.; semivolatile organic compounds; and ammonium nitrate?

I. What portions of the population are exposed to effect-causing PM, and, based on monitoring and modeling projections, in what ambient environments and indoor microenvironments are they exposed?

J. How can standardized, widespread research-grade ambient PM monitoring best be achieved to provide improved air quality data for PM exposure (e.g., by

1. Augmentation of existing local compliance monitoring networks in selected cities,
2. De novo establishment of a research-grade national ambient monitoring network, or
3. Use of expanded measurements of specific physical and chemical parameters and appropriate sampling frequency to better reflect continuous, daily, and seasonal variations in PM)?

K. What are exposure estimates for unmonitored areas, and what is the linkage of health effects to sources, based on improved models that

1. Relate source emissions to ambient concentrations;
2. Relate central site, indoor, and personal exposures;
3. Link air quality and exposure models; or

4. Describe evolution of aerosol size distributions?

L. What are the sources of ambient and indoor particles to which the general population and susceptible subpopulations are exposed, and what are the relative contributions from mobile, stationary, and fugitive sources, including gasoline and diesel fueled vehicles, stationary combustion, paved roads, construction sites, residential wood combustion, and animal wastes?

M. What are the costs and effectiveness of technologies to prevent and control exposures to (and ultimately, risks from) fine particles, and what low-cost approaches are available to ensure that emission reductions are achieved and verify that technologies are performing as designed?

3. STRATEGY

In the formulation of this strategy, critical gaps in scientific knowledge and the resulting scientific questions (identified above) were considered in the context of their impact on EPA's regulatory efforts and relative to corresponding research being conducted by other federal agencies and the private sector. The EPA's regulatory needs include an improved scientific basis for NAAQS determinations and improved scientific and technical information for standards implementation. To address EPA's regulatory needs, two approaches are necessary. One approach supports fundamental science that ultimately, but not immediately, will impact regulatory decisions, whereas the other provides methods and data that will support directly the assessment/regulatory effort in the near future. Both the short- and long-term needs of EPA were considered in setting the objectives of the program.

Next, criteria for setting priorities for EPA's PM research program were developed. Research efforts needed to address the key scientific questions then were ranked. Identification of priorities facilitates orderly development of a complex, integrated research program and focuses available resources. The pace at which research progresses will depend on the complexity of the scientific question and on available resources.

3.1 Criteria for Ranking Research

The criteria for ranking research within the PM program are listed below.

Risk-Based Planning. The focus is on research that reduces the greatest uncertainties in the assessment of health risk from exposure to airborne PM, and the cost-effectiveness of technologies for reducing emissions; exposures; and, ultimately, risks.

Scientific Excellence. The quality of the science is critical to development and testing of hypotheses, data collection and evaluation, and, ultimately, support of credible regulatory standards by EPA.

Policy Relevance. Importance is placed on the expected utility of the research products for addressing both short- and long-term regulatory issues.

Other Sources of Data/Information. The research currently being conducted by other organizations will be considered in setting priorities and allocating resources. Through venues such as the EPA PM Research Needs Workshop (held in September 1996) and the Committee on Environment and Natural Resources, which coordinates federal research activities, EPA is fully aware of research activities by other organizations, such as the Health Effects Institute and the Electric Power Research Institute, and among federal research organizations. This allows for more efficient allocation and leveraging of resources at EPA.

Capabilities and Capacities. This criterion focuses on research implementation issues; that is, ensuring that EPA has the facilities and expertise to conduct or oversee the needed research. In-house expertise is necessary to oversee research, even if it is conducted by cooperative agreement or contract. Capabilities of the extramural scientific community are tapped through EPA's investigator-initiated, competitive, peer-reviewed Request for Applications-driven Science to Achieve Results (STAR) grants program.

Sequence of Research. The conduct of some research, no matter how important, is dependent on the execution of previous studies. Research that depends on studies that have not yet begun or are only partially complete will at this time receive lower priority, independent of its overall importance.

3.2 Research Priorities

When the ranking criteria were applied to the potential research efforts, research priorities emerged. Only the most important of the resulting research priorities are noted; current or future research in each of these areas is anticipated by EPA and collaborators or via the EPA's STAR program. Sequencing of research (i.e., the order in which research must be conducted) was an important factor in the ranking, as was the recognition that some research is needed in the near term to support standards implementation, whereas other research is needed in the longer term to support future NAAQS reviews. The priorities are discussed below (but not necessarily in priority order within the "Highest Priority" and "High Priority" groupings).

HIGHEST PRIORITY

Investigate Causal Mechanisms and Particle Characteristics. Identification of causal mechanisms is crucial because it could (1) provide a basis for understanding the associations observed in epidemiologic studies between adverse health outcomes and PM exposures; (2) clarify which particle types, sizes, and chemical and biological characteristics are associated with the effects; (3) provide information on source-exposure-response relationships, including the low-exposure range; and (4) help identify and characterize susceptible subpopulations.

There are a number of hypotheses concerning potential causative agents and related mechanisms and little information to identify the correct hypothesis. Two hypotheses are currently the focus of NHEERL's efforts to understand particle-associated causative agents: (1) transition metals and (2) potentially toxic components of organic matter, including allergenic proteinaceous material and endotoxins. Animal models of human disease will be used to understand the mechanisms underlying PM effects. Additionally, in vitro evaluation of potential mechanisms and evaluation of dosimetry in animals and humans will be used in testing key hypotheses. Clinical studies also will play an important role as appropriate, safe protocols for human studies are developed.

Another hypothesis being investigated is that polycyclic organic components of urban air PM are rapidly released from the particles and either react with deoxyribonucleic acid (DNA) at the site of deposition in the lung or after transport to other target sites where toxicity is induced via genotoxic mechanisms. This research will focus on the development and application of biomarkers in human studies to better characterize the dose-response relationships between PM exposure and DNA dose in the cardiopulmonary system, blood, and excretion of metabolites in urine. Research is also in progress to investigate whether those electrophilic components of PM that may induce cancer or other effects also could be the most toxic components in inducing acute responses in vitro and in vivo in animals and humans.

Additional hypotheses are being identified and evaluated through the investigator-initiated grants (STAR) program, to ensure a broad-based scientific effort is targeted to address this important research need.

This research directly addresses Key Question A (biologic mechanisms) and provides a basis for addressing Key Questions B (acute effects), D (susceptibility factors), and G (particle composition). This research will be coordinated with and benefit from dosimetry research described below (Question E) and will provide a basis for addressing Key Question F (shape of the dose response).

Develop and Evaluate Particle Measurement Methods. The development and evaluation of methods to identify and measure atmospheric particles by size and type are critical to understanding the relationship of particles and human health effects and to the development and implementation of PM NAAQS. Research will focus initially on developments to improve methods supporting the emerging NAAQS requirements. An ongoing methodology research and development improvement program will be maintained to address uncertainties in existing PM methods and to develop new, cost effective approaches for emerging needs such as automated techniques to support every-day, hourly determinations of PM mass, methodology supplying chemical speciation, and application of real-time, portable counting and classifying techniques for particle size distribution.

This research addresses Key Questions G (particle composition), H (particle characteristics), I (human exposure), and J (ambient monitoring).

Characterize Ambient Particle Exposures. Identification of fine particles to which people experiencing adverse health effects are exposed is important to researchers trying to establish a biological mechanism leading to those effects. With these particles characterized, effects researchers will be better able to focus their investigative research; the converse is also true. If the responsible particle characteristics causing adverse effects and the corresponding biological mechanism were known, exposure researchers would know what data to collect. The current absence of either of these crucial pieces of information points to the need to work on both simultaneously until the answer to each is found. Mechanistic research needs are discussed above. New field measurements will be undertaken, using newly developed and evaluated methods to size and speciate particle composition over the range of concentrations and conditions typical of ambient air in different regions of the country. Profiles will be developed for regions dominated by secondary sulfate- and nitrate-based particulate formation, wood smoke, semivolatile organics, crustal materials, and fugitive dust. Hourly to diurnal temporal scales and local to regional spatial scales will be part of these profiles, as will a determination of the effects that meteorology has on the spatial and temporal distribution of ambient particle concentrations. This research and the information it provides will be designed expressly to serve the epidemiological and atmospheric modeling communities attempting to draw direct correlations between atmospheric concentrations and observed adverse effects in portions of the country's populace. This information will be supplied in the near term through intensive field campaigns and potentially supplied over the long term through a nationwide particulate monitoring network now being considered by OAR.

This research addresses Key Questions A (biologic mechanisms), G (particle composition), H (particle characteristics), I (human exposures), J (ambient monitoring), and K (exposure modeling).

Develop Atmospheric Models Supporting Regulatory Implementation

To support regulatory implementation, states need atmospheric modeling tools relating changes in source emissions to changes in ambient PM levels. Currently available models require substantial additional development and evaluation before they will be sufficiently useful in planning to achieve any new PM NAAQS. Research will develop and evaluate diagnostically emissions-based, regional-to-urban scale models that focus on interactions of urban and point-source plumes with the surrounding regional atmosphere in the transport and fate of fine particles, using the EPA Models-3 framework. These models will be capable of addressing atmospheric loading of PM of varying size distributions and chemistry (toxicity and acidity) across varying spatial and temporal scales. Included is research that describes the interaction of boundary layer turbulence, vertical mixing, and cloud processes with atmospheric chemistry.

This research addresses Key Questions I (human exposure) and K (exposure modeling).

Characterize Source Emissions. Uncertainties in the quality of data in the current particle emissions inventory support the need for research to further clarify which sources are significant contributors of ambient fine particles (e.g., inventories for precursors that lead to secondary particle formation, except ammonia, are much stronger than those for sources of primary particles). In a recent emissions inventory (Knopes, 1994), the dominant sources of primary fine particle emissions were fugitive dusts from a variety of paved and unpaved roads, agricultural operations, and geologic sources. However, the aerodynamic impactors that were used to determine particle sizes from these sources are thought to have experienced "particle bounce", which may have skewed the data to show a higher fraction of fine particles than actually exists. Recent field studies to test this hypothesis compared these impactors to standard ambient $PM_{10/2.5}$ samplers. Results showed wide variability, even among the ambient samplers. A short-term, high-priority need is to determine the reliability of existing data that was collected with impactors. Once the cause and extent of the variability seen in the recent tests are determined, the validity of existing data can be assessed, and corrective measurements made as needed.

Additional measurements also are needed to fill data gaps in the inventory for potentially significant sources such as on-road, heavy-duty, diesel-powered vehicles, fugitive emissions from construction sites, road surface silt loadings, ammonia from animal wastes, transition metals from point and area sources, and construction activities. Work also needs to be done to quantify emissions from homes with current-generation wood stoves. The current database suggests that substantial increases in emissions can occur after only a few years use, but more data are needed to develop specific guidance for wood stove users and state implementation planners.

In addition, research is needed to characterize sources on the basis of potential toxicity. By associating toxic PM with a source type, research to produce effective mitigation strategies can be prioritized. Combustion emissions from a variety of stationary and mobile sources will be of primary interest. For example, particles generated by the combustion of No. 5 and No. 6 fuel oils in NRMRL's combustion laboratory will be used in animal studies by NHEERL to evaluate mechanisms for tissue damage caused by short-term exposures to the particles. The particles also will be characterized for size distribution and composition, particularly with respect to metals.

This research directly addresses Key Question L (source emissions) and supports Key Question A (biological mechanism) by providing fly ash samples for toxicological testing. This work also will be closely coordinated with the programs described above to characterize ambient fine particle exposures (Question H) and to develop regional and urban-scale PM models (Question K).

HIGH PRIORITY

Evaluate and Test Epidemiologic Observations. Epidemiologic observations are the current source for concern regarding effects associated with PM. New analytical efforts have been initiated to reevaluate several of the major published epidemiological studies. Multidisciplinary field studies will include more intensive daily PM measurements of exposure and better characterization of PM and of individual human and population exposures and more extensive characterization of potential effects. Biomarkers of exposure to PM, personal exposure monitoring, and other approaches to improving human exposure assessment in selected subsets of the population will be considered in the design of future studies. Other measurements of morbidity, cellular inflammation, and early markers of adverse human effects from PM will be incorporated in study designs. Efforts to initiate and coordinate new epidemiologic studies, funded by federal, state, and other institutions, are underway. Specific hypotheses will be developed and tested through these efforts.

This research directly addresses Key Question C (epidemiology) and will provide further information on acute effects of PM exposures (Question B), identification of factors affecting susceptibility (Question D) and constituents of particles associated with toxicity (Question G).

Elaborate on Dosimetry. Particle deposition in humans may be a critical factor in susceptibility and varies significantly in different segments of the population. Little is known about dosimetry in children and individuals with preexisting disease or about particle deposition of realistic urban aerosols. Research will be conducted to determine (1) the dose delivered to sensitive subpopulations (e.g., asthmatics, chronic obstructive pulmonary disease patients) and (2) the distribution and retention of PM as a function of particle size. Refining dosimetric models may be critical to explaining the impact of particles on sensitive subpopulations. Also, these models will be important in extrapolation from animals to humans and across exposure scenarios. As animal and human clinical studies progress, the initially developed theoretical models can be validated and improved.

This research directly addresses Key Question E (dosimetry) and will provide information useful for understanding potential mechanisms of toxicity (Question A), identifying factors affecting susceptibility (Question D), and determining constituents of particles associated with toxicity (Question G). Improved understanding of dosimetry also will reduce uncertainty in characterizing the exposure-dose-response relationships (Question F).

Improve Understanding of Exposure-Dose-Response Relationships. To determine the appropriate level (concentration) and form (exposure duration and frequency) of the PM standard, laboratory and clinical studies will be conducted to understand exposure-dose-response relationships. Research to characterize the shape of the dose-response relationship, at low concentrations in particular, will be conducted to more confidently develop and apply threshold or nonthreshold models. Exposure duration and frequency issues will be explored in detail. The current lack of understanding limits the ability to study at-risk human subjects in a clinical setting. Consequently, evaluation of the responses of laboratory animals and then low-risk, normal populations to ambient and "inert" test particle exposures, with and without exercise, must be the first steps in the analyses of PM-related effects. Various endpoints, such as pulmonary function, particle clearance, inflammation, and airway reactivity, will be assessed. These studies can provide insight into population responses and allow further development of techniques to evaluate effects. These studies also could form the foundation for exploration of exposure-response issues in at-risk susceptible subpopulations.

This research directly addresses Key Question F (exposure-dose-response realtionships) and will provide further information on acute effects of PM exposures (Question B), identification of factors affecting susceptibility (Question D), and determination of constituents of particles associated with toxicity (Question G).

Improve Personal Exposure Assessment. Several research studies will be undertaken to improve personal exposure information: (1) measurement of personal exposures to airborne particles of nonhospitalized elderly persons, particularly those with respiratory or cardiopulmonary disease; (2) determination of the relationship between personal and microenvironmental exposures for these and other susceptible individuals; (3) determination of the relationships between the outside ambient environment and indoor microenvironments for airborne particle exchange and between indoor environments and a person's immediate microenvironment (the "personal cloud"); (4) measurement and definition of the characteristics of the personal cloud, and (5) determination of the utility of ambient air measurements to predict human exposures to particles of ambient origin.

This research addresses Key Questions G (particle composition) and I (human exposure).

Refine and Develop New Human Exposure Modeling. To get a reasonable estimate of individuals' exposure to particles, it is necessary to employ exposure modeling techniques to fill in data gaps where measurements do not exist or are not affordable. Further development of particle exposure models and thorough validation of these models are needed. A model is needed for evaluation of policy decisions linking effects to exposures and alternative air quality standards for particles. Important research studies in human exposure model development that are needed include (1) developing improved methods (e.g., dispersion modeling, mass balance modeling) for elucidating the relationship between indoor air quality and the composition of outdoor air, including microenvironments contributing to health effects from particles; (2) modeling short-term exposures (i.e., peak exposures) and gradients for dispersion, deposition, and ventilation in indoor microenvironments; and (3) integrating current activity pattern data with exposure model development and collection of additional information on activity (including data on physiological parameters such as respiration rates) as it relates to personal exposure to particles.

This research addresses Key Question I (human exposure).

Conduct Scientific Assessments. Periodic scientific assessments that draw together effects and exposure research results are required by the Clean Air Act. They will be performed by NCEA by critically evaluating published research results from ORD laboratories and other (federal, academic, and industry) research groups on the health and environmental effects of PM. These assessments will be used in preparing revised air quality criteria for particulate matter to support NAAQS decision making and as inputs to Clean Air Act cost-benefit analyses.

Develop Tools To Support New Market-Based Regulatory Approaches. The EPA is transforming its regulatory approach from command and control to a more flexible market-based system that provides regulated industries with the opportunity to achieve required air emission reductions in the most cost-effective manner. Air pollutant trading programs will be more widely used and will likely include PM. In order to have confidence that the market-based approach is achieving the needed emission reductions, low-cost techniques are required to determine if the source controls implemented are adequate. One of the problems that could impede successful implementation of this new approach is the current way facilities test and report emissions. The practice of reporting emissions only during carefully controlled operating periods has been estimated to underreport PM emissions for some categories by a factor of two or three (McIlvaine, 1994). Currently available continuous PM monitors require extensive calibration to the specific source and are usually affordable only to larger sources. A universal system of emission estimating, (i.e., parametric or predictive emission monitoring) may be developed through integration of state-of-the-art mathematical models for current control technologies and process control hardware. This effort will provide the operator precise process controls and diagnostic tools, while also producing continuous operations data that may be accurately correlated to mass emissions data.

This research directly addresses Key Question M (ensure emission reductions are achieved).

Improve Particulate Matter Control Technology. Significant reductions in emissions from existing sources may be required to reduce exposure to ambient PM to meet future NAAQS. Efforts to reduce PM levels, particularly those of fine particles, will require reductions from a combination of source categories that emit both primary particles and precursors that lead to secondary particle formation. Technologies are available for many sources; however, in some cases, there are questions about the feasibility of applying these existing controls to particular source categories, particularly those comprised primarily of smaller sources. One approach to reduce emissions from these difficult to control sources is to improve the operation and maintenance of available particle control technology. Given the long lead times involved, research in the near term is needed to determine the level of emission reductions that can be cost-effectively achieved through improved operation and maintenance practices. The most promising approaches can be evaluated at pilot scale and demonstrated at full scale in cooperation with an industry partner. In situations where improved operation and maintenance do not provide sufficient emission reduction, proper application and optimization of existing retrofit technology should be considered. Such technology can be evaluated at small pilot scale. Examples of retrofit technology that readily can be piloted and offered to users include improved charging of electrostatic precipitators (ESPs; prechargers) and electrostatically augmented fabric filtration. The former technology improves the ESPs ability to handle various dust characteristics, whereas the latter enables bag houses to operate at considerably lower bag pressures, reducing leaks and wear. If existing retrofit technology cannot be modified, adequately hybrid technologies such as wet scrubbers-ESPs also will be investigated to determine their capability for more efficient cost-effective PM control. The results of such evaluations can be used by regulatory officials to compare the effectiveness of technologies for fine PM control and by the private sector to design and operate full-scale systems with confidence. In addition, ORD will prepare a guidance document for small sources of PM that do not use adequate PM control technology because the owners or managers of the source do not have adequate knowledge of the options available. The guidance document will provide cost and performance information needed to select, operate, and maintain PM control systems.

This research directly addresses Key Question M (cost and effectiveness of PM technologies).

4. SUMMARY

This document describes the process used to develop EPA's PM research strategy and presents a PM research program for addressing health, exposure, risk assessment, and risk management issues. The strategy is focused on the resolution of issues resulting from the new epidemiology observations suggesting serious health effects due to PM. The primary mission of this research program is to improve the scientific and technological basis for decisions concerning public health risks posed by PM. In particular, key issues are (1) further interpretation of epidemiologic findings; (2) the limited understanding of biological mechanisms that could explain the observed effects, provide insight with respect to physico-chemical composition of the particles causing effects, and explain the nature of the concentration-response function, in particular with respect to the possibility of a lack of a threshold for effects; (3) uncertainty about the composition, size, physical properties, sources, and controllability of PM that may cause health effects; and (4) the incomplete understanding of the aerosol transport and exposure process.

Table 3 summarizes and links the key scientific questions and research priorities for the period FY97 through FY99. The mechanisms by which the research will be done, including via EPA intramural principal investigators and the extramural STAR program, will be determined as the program is implemented and with due consideration of the capabilities and capacity of EPA and others to conduct the needed research.

TABLE 3. PARTICULATE MATTER RESEARCH STRATEGY SUMMARY

Risk Paradigm	Science Questions	FY97	FY98	FY99
Effects	What are the biological mechanisms of effect?	Investigate causal mechanisms and particle characteristics →	→	→
	Can improved methods address confounding and improve interpretation of epidemiologic observations?	Evaluate and test epidemiology observations →	→	→
	What affects the dosimetry of PM?	Elaborate on dosimetry →	→	→
	What are the shapes of the exposure-dose-response curves?		Improve understanding of exposure-dose-response relationships →	→
Exposure	What types and concentrations of particles are people exposed to? Where are they exposed?	Develop and evaluate particle measurement methods → Develop atmospheric models → Characterize ambient PM exposures → Improve personal exposure assessment →	→	→
Risk Assessment	What is the state of knowledge of PM exposure and effects?			Conduct scientific assessments →
Risk Reduction	What sources of particles need the most control to reduce risk?	Characterize source emissions →	→	→
	What are the most cost-effective approaches to reducing fine particle exposure and risk?		Tools to support new market-based regulatory approaches →	→
		Improve PM control technology →	→	→

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APPENDIX 1: Overview of Current Knowledge of Risk Management of Fine Particles

[Numbers in regular type are typical values, selected from the referenced literature; entries in italics are estimates or judgments by ORD staff.]

Source Type [References]	Constituents of Concern	Total U.S. Emission Rate (10^3 tons/year) $PM_{2.5}$	PM_{10}	Approximate U.S. Population in Close Proximity	Primary Control Options, Efficiencies for PM_{10}	Approximate Costs of Current Particle Controls
Roads [1,2,3]	Fine silica and other crustal elements plus industrial reentrainment of carbon, asbestos, and metal compounds	3,300[a]	18,000	*Essentially the entire population*	*Vacuum sweeping (0-50%)* *Water flushing and sweeping (0-96%)* *Paving and roadside improvements* *Covering trucks* *Speed and traffic reduction*	*Dependent on type of control, time of event, frequency of events/year, and volume of traffic; very limited published data*
Agricultural Production (including erosion) [1,2,3]	Fine silica and other crustal elements	2,000[a]	11,100	*Mostly in rural areas*	*Low tillage, punch planting, crop strips, vegetative cover, windbreaks* *Chemical stabilizers, irrigation*	*Dependent on crop type and regional weather conditions; little data*
Construction Activities [1,2,3]	Fine silica and other crustal elements, plus industrial reentrainment of carbon, asbestos, and metal compounds	1,700[a]	8,500	*Mostly in urban areas*	*Wet suppression of unpaved areas, material storage, handling and transfer operations* *Wind fences for windblown dust*	*Dependent on type of control, time of event, land area of event, and activity level of equipment; very limited published data*
Open Burning (including wildfires, agricultural burning, etc.) [1,2,3]	Products of uncontrolled combustion	1,130[a]	1,320	*Mostly in rural areas*	*Low wind speed and appropriate wind direction*	*Unknown*
Residential Wood Combustion [1,2,3]	POM	550	≈550	*Mostly in urban areas*	*Replace with cleaner burning stoves*	*≈$500 per replaced stove*

APPENDIX 1 (con't). Overview of Current Knowledge of Risk Management of Fine Particles

[Numbers in regular type are typical values, selected from the referenced literature; entries in italics are estimates or judgments by ORD staff.]

Source Type [References]	Constituents of Concern	Total U.S. Emission Rate (10^3 tons/year) $PM_{2.5}$	PM_{10}	Approximate U.S. Population in Close Proximity	Primary Control Options, Efficiencies for PM_{10}	Approximate Costs of Current Particle Controls
Diesel Engine Combustion [1,2,3]	Products of incomplete combustion, PM precursors (No_x)	450	500	*Mostly in urban areas*	*Combustion modification* *Improved fuel characteristics* *Particle traps*	*Very limited published data*
Mineral Products Production [1,2,3]	Fine silica and other crustal elements	100	200	*Near urban areas*	*Enclosing crushing, transfer areas* *Water spray suppression* *Chemical stabilization of unpaved traffic areas*	*Dependent on type of control and activity level of equipment; little data*
Pulverized Coal Boilers [1,4]	Ar, Cr, Hg, Mn, Ni, Pb, Sb, Se, V, Cl, and PM precursors (SO_x, NO_x)	*Unknown*	160	*Utility, mostly in rural areas* *Industrial, mostly near urban areas*	*ESPs, fabric filters*	*Capital cost, $50-110/kW; annual cost, 2-5 mils/kWh; total installed cost, $15-30/acfm*
Heavy Fuel Oil Combustion [1,5]	Cr, Fe, Ni, Pb, V, POM, Cl, PM precursors (SO_x, NO_x)	*≈30*	30	*Mostly in urban areas*	*Cyclones, ESPs*	*Unknown*
Residential Fuel Oil Combustion [1]	POM, PM precursors (NO_x)	*≈20*	20	*Mostly in urban areas*	*Proper maintenance, modern furnaces*	*Unknown*
Waste Incineration [1,6,7,8]	As, Be, Cr, Cd, Hg, Ni, Pb, PCDD/F, PCBs	*Unknown*	≈45	*Mostly near urban areas*	*Fabric filters, ESPs, venturi scrubbers*	*Total installed cost, $15-30/acfm*
Metal Smelting and Refining [1,9]	Cd, Cr, Pb, Zn, SO_x	*Unknown*	400	*Mostly in rural areas*	*ESPs, cyclones*	*Total installed cost, $15-30/acfm.*

APPENDIX 1 (con't). Overview of Current Knowledge of Risk Management of Fine Particles
[Numbers in regular type are typical values, selected from the referenced literature; entries in italics are estimates or judgments by ORD staff)]

Source Type [References]	Constituents of Concern	Total U.S. Emission Rate (10^3 tons/yr) $PM_{2.5}$ PM_{10}	Approximate U.S. Population in Close Proximity	Primary Control Options, Efficiencies for PM_{10}	Approximate Costs of Current Particle Controls
Outdoor Air Introduced into the Indoor Environment	Fine and coarse particles	Unknown	*≈250 million*	*Air cleaners for ventilation air (30-98%)*[b] *Whole-building air cleaners (30-98%)*[b] *In-room air cleaners (30-98%)*[b]	*Capital cost \$3-\$10/m³/h of outdoor Air treated; capital cost \$1 to \$10/m³/h of indoor air treated; \$200-\$800 per room*
Tracked-in dust	Lead, other heavy metals, pesticides	Unknown	*≈250 million*	*Cleaning (e.g., vacuuming) Whole-building air cleaners (30-98%)*[b] *In-room air cleaners (30-98%)*[b]	*No published data; capital cost \$1-\$10/m³/h of indoor air treated; \$200-\$800 per room*
Indoor Activities (that generate or resuspend particles)	Metals, microbials, pesticides	Unknown	*≈250 million*	*Source control, including maintenance Whole-building air cleaners (30-98%)*[b] *In-room air cleaners (30-98%)*[b]	*Highly variable; no data; Capital cost \$1-\$10/m³/h of indoor air treated; \$200-\$800 per room*

[a]Estimates of fine particle emissions from these "fugitive" sources, although large compared to other sources in this table, are very uncertain and need to be confirmed.
[b]Although the single-pass efficiency of air cleaners is generally known, their effectiveness in reducing exposures to indoor particles is not known.

REFERENCES

1. "The National Particulates Inventory - Phase II Emission Estimates," EPA Office of Air Quality Planning and Standards, June 1995, revised January 1996.
2. "Control of Open Fugitive Dust Sources". EPA 450/3-88-008.
3. "Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures." EPA 450/2-92-004.
4. Davison (1974), Kaakinen (1975), Klein (1975), White (1984), Markowski (1985), Kauppinen (1990), Andren (1975), Billing (1972).
5. Bulewicz (1974), Haynes (1978), Feldman (1982), Chung (1992).
6. Mumford (1986), Trichon (1989, 1991).
7. Lisk (1988), Greenberg (1978).
8. Shen (1979), Bennett (1982), Dewling (1980).
9. Harrison (1983).

BP Cherry Point Cogen
DEIS Comment - 13

October 24, 2003

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Dear Mr. Fiksdal,

I would like to go on record as being supportive of the BP Cherry Point Cogeneration Project. The project as outlined in the information I have received would provide for a net reducion in criteria pollutants and a net reduction in particulates within the airshed. In addition it would provide for a 700,000 gallon per day reduction in Nooksack water withdrawal and would provide 372 construction jobs and 30 permanent jobs. 1

It appears that BP has done an outstanding job in meeting all of the environmental criteria and it will provide a significant economic benefit for the community.

Your favorable response would be appreciated.

Sincerely,

Bill Henshaw
2653 North Park Drive
Bellingham, WA 98225

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ENERGY FACILITY SITE
EVALUATION COUNCIL

BP Cherry Point Cogen
DEIS Comment - 14

NORTHWEST
AIR POLLUTION AUTHORITY

1600 South Second Street
Mount Vernon, WA 98273-5202
Tel: (360) 428-1617 / Fax: (360) 428-1620

Serving Island, Skagit and Whatcom Counties

October 24, 2003

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA. 98504-3172

Re: BP Cherry Point Cogeneration Project
Draft Environmental Impact Statement Comments

Dear Mr. Fiksdal:

The Northwest Air Pollution Authority (NWAPA) is pleased to submit comments on the Draft Environmental Impact Statement dated September 5, 2003 on the BP Cherry Point Cogeneration Project. The NWAPA is a local regulatory authority with responsibility for enforcing the air quality rules and regulations in Whatcom, Skagit and Island Counties within the State of Washington

The NWAPA has a few concerns about the completeness of the Draft Environmental Impact Statement (DEIS) in regard to Section 3.2 Air Quality. Our comments are as follows:

1. Table 3.2-7 shows the annual potential criteria pollutant emissions. The total for volatile organic carbon (VOC) for the project is listed as 42.3 tons/year. This table references BP 2002 as the source. This source is not listed in the references. 1

2. It is unclear what percentage of the VOC's are hazardous air pollutants (HAPs). The document states that the project is not subject to any Maximum Available Control Technology (MACT) regulations for hazardous air pollutants. We would like to see an expanded discussion with additional pollutant information addressing whether the MACT for combustion turbines (40 CFR 63 Subpart YYYY) is applicable to this project. 2

3. Toxics Air Pollutant Analysis (Chapter 173-460 WAC) – The discussion and table did not include nitric oxide. This pollutant could be fairly large for this project and has an acceptable source impact level of 100 micrograms per cubic meter twenty-four hour average. This toxic air pollutant should be evaluated in the DEIS. 3

We appreciate the opportunity to comment on the Draft Environmental Impact Statement. Please contact Lynn Billington, Manager of Technical Services, PE at (360) 428-1617 ex. 213 if you need further information or a more detailed explanation of these comments.

Sincerely,

James Randles

James Randles
Director
Northwest Air Pollution Authority

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E-mail: info@nwair.org Website: http://www.nwair.org Printed on 100% post-consumer recycled paper

BP Cherry Point Cogen
DEIS Comment - 15

EDC

BELLINGHAM WHATCOM
Economic Development Council

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October 29, 2003

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, Washington 98504-3172

Dear Mr. Fiksdal:

The Bellingham Whatcom Economic Development Council was asked by its membership to review and comment on the economic impacts of the BP Cherry Point Cogeneration Project. To assist us with our review, we asked the Western Washington University's Center for Economic and Business Research (CEBR) to look at the economic impact assumptions that BP identified in their initial application documents.

Attached to this letter is a memorandum from CEBR that basically states that in their opinion, BP's initial economic impact are conservative and of a very positive nature. It is also our opinion that the BP Cherry Point Cogeneration Project will be good for the overall economic base in Whatcom County. This project will create hundreds of short term construction jobs and dozens of long term permanent jobs. The project will provide millions of dollars of revenue to both the public sector local governments and to private sector businesses. We also have had serious conversations with out of the area companies that are interested in locating to Whatcom County specifically to take advantage of the potential surplus electricity and to use the steam the Co-Gen would produce. 1

In summary, the project will be good for the Whatcom County economy. The Bellingham Whatcom Economic Development Council encourages your approval of this project.

Thank you for your consideration.

Sincerely,

Rob Pochert, CEcD, EDFP
Executive Director

P.O. Box 2803, Bellingham, WA 98227 • 360-676-4255 • 1-800-810-4255 • Fax 360-647-9413 • e-mail: bwedc@bwedc.org

WESTERN
WASHINGTON UNIVERSITY

An equal opportunity university

Center for Economic and Business Research
College of Business and Economics

516 High Street
Bellingham, Washington 98225-9074
(360) 650-3909 ☐ Fax (360) 650-7688

Memorandum

To: Rob Pochert

From: Hart Hodges

Date: October 27, 2003

RE: Potential Economic Impacts of BP Cogeneration Facility

I reviewed the document you sent that contained information on population, housing, and economics prepared by BP. That document describes the potential employment and wage impacts of the construction of the cogeneration facility, as well as the ongoing operation and maintenance of the facility.

Construction is estimated to create the equivalent of 714 one year jobs and operations and maintenance is estimated to require 30 full-time staff. Both estimates are for direct impacts. For indirect employment impacts, BP used a multiplier of 1.3 during the construction phase and 1.7 during the operating and maintenance phase. (A multiplier of 1.3 during the construction phase suggests there will be 0.3 indirect jobs created for each 1 direct job created – for a total of 210 one-year jobs created during the construction phase, above and beyond the 714 on site construction jobs.) BP provides a reference to "Weber and Howell, 1982" when they introduce the multipliers.

The reference may be to the book, <u>Coping with Rapid Growth in Rural Communities</u>, written by Weber and Howell in 1982. Unfortunately, we do not have that book in the Western Washington University library. I will try to get a copy through the interlibrary loan service so I can review the methodology used by Weber and Howell.

In the meantime, I checked the IMPLAN model to see what employment multipliers might be valid for this sort of project. Not surprisingly, there is no category in IMLAN for the construction of or operation of a cogeneration facility. Still, there are categories in utilities structures and power generation. Concerns about a mismatch in categories not withstanding, it seems to me that the multipliers in the BP report are conservative. According to the IMPLAN model, the construction of utilities structures should have an employment multiplier of 1.5 to 1.7 – which is higher than what is used in the BP report.

In addition, the operation and maintenance of other utilities facilities should have a multiplier closer to 2.0.

I conclude that the estimates of employment impacts in the BP study are conservative. (Which I commend, since it is very common to see people try to overstate the likely employment benefits of a given project.)

I also note that BP has done a good job of pointing out that a large percentage of the expenditures that would be made for the project would go to firms outside of the county or immediate region.

BP does not offer an estimate of indirect income or expenditure effects, they only focus on indirect employment effects. This approach may be wise since it is very difficult to know what indirect jobs might be added and at way wage. With that said, it is safe to assume that the actual income or wage effects will be higher than what is shown in the report. (For example, table 3.12-8; the table shows direct wages only – there is no entry for indirect wages.)

BP Cherry Point Cogen
DEIS Comment - 16

United States Department of the Interior

OFFICE OF THE SECRETARY
Office of Environmental Policy and Compliance
500 NE Multnomah Street, Suite 356
Portland, Oregon 97232-2036

IN REPLY REFER TO:

October 28, 2003

ER 03/829

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Dear Mr. Fiksdal:

The Department of the Interior has reviewed the Draft Environmental Impact Statement (DEIS) for the BP Cherry Point Cogeneration Project, Whatcom County, Washington. The Department does not have any comments to offer. 1

We appreciate the opportunity to comment.

Sincerely,

Preston A. Sleeger
Regional Environmental Officer

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ENERGY FACILITY SITE
EVALUATION COUNCIL

BP Cherry Point Cogen
DEIS Comment - 17

GERALD STEEL, PE
ATTORNEY-AT-LAW
2545 NE 95th STREET
SEATTLE, WA 98115
Tel/fax (206) 529-8373

October 30, 2003

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OCT 31 20[illegible]
ENERGY FACILITY SITE
EVALUATION COUNCIL

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Re: BP Cherry Point DEIS Comments

Dear Mr. Fiksdal:

On behalf of the Washington State Association of Plumbers & Steamfitters (WSAPS), I write this letter to comment on the BP Cherry Point Cogeneration Project DEIS. This power generation facility is not required to meet the region's reasonable need for additional electricity generation. Exhibit 1 at 1-2. Therefore the FEIS should indicate that the project should not be approved if there are probable significant adverse environmental direct, indirect or cumulative impacts. The DEIS fails to meet the requirements of WAC 197-11-440 in that it fails to summarize significant impacts that can not or will not be mitigated. This should be corrected in the FEIS. 1

WSAPS hereby submits 23 pages of comments (Exhibit 1 hereto) made by their environmental expert consultant, John Williams. Mr. Williams Statement of Qualifications is provided as Exhibit 2. Exhibit 1 raises issues that must be addressed in the FEIS. WSAPS incorporates by reference in this letter any additional DEIS comments timely-submitted by Mr. Williams after the date of this letter.

One troubling feature of the DEIS is the statement in many places that impacts from the project cannot be determined from the information available. For example, in Section 1.8.1, the DEIS states, "it is not possible to determine their actual impact on global warming." As another example, in Section 3.6.1, the DEIS indicates that inadequate information exists to determine the full extent of Category I and Category II prime agricultural soils that will be impacted by this project. Under SEPA if the agency proceeds in the face of uncertainty, the environmental documents need to provide a worst case analysis to the extent that this information can reasonably be developed. WAC 197-11-080. The author of the DEIS should review the DEIS for each place where there is uncertainty about impacts and seek to provide a worst-case analysis. 2 3

Allen Fiksdal, Manager
October 30, 2003
Page 2

Regarding impacts on prime agricultural soils in the Agricultural Protection Overlay, the EIS should include, as an alternative, a site with less impact to prime agricultural soils. The impacted soils are not only those soils on the project site, but also soils that are in the vicinity that will be impacted by increased levels of pollution and reduced water availability. The impact of the proposed project on prime agricultural lands in the local microclimate area should be found to be a significant impact with the project as proposed. 4

Regarding water use, the amount of water proposed to be used by this project should be considered a significant impact. It is inappropriate to consider the impact to be negligible because of the potential shutdown of the Alcoa Intalco Works which is unrelated to this project. The Alcoa Intalco Works does not consume the water that it uses while this project coverts nearly all of its water to steam that is lost to the local microsystem. The impact of water from the facility with elevated salt concentrations being discharged in agricultural areas has not been adequately addressed in the DEIS 5

The impact on visibility in the Olympic National Forest should be considered significant. This is a single project that is reducing visibility for hours each year. This is a very significant impact on visibility to be caused by just one project. Four to five thousand projects of this nature could fully and permanently cut off visibility for large areas of the National Forest. 6

Very truly yours,

Gerald Steel

PIPE10h30.03

COMMENTS ON THE DEIS FOR THE BP POWER PLANT
PURPOSE AND NEED

One of the purposes and needs for this project is the need to provide the predicted additional electrical generation capacity for the future needs of the region. This projected need, according to the Northwest Power Planning Council's power forecasts for the region, predicted that by 2015, the needed regional increase in power would range from an additional 2035 megawatts (MW) under the medium prediction, to 4120 MW under medium-high, and 7507 under the high prediction.

However, those predictions are already almost two years old. Since those predictions were made, the following plants have gone on-line:

Chehalis	520 MW
Hermiston	650 MW
Frederickson	250 MW
Coyote #2 Springs	280 MW
Klamath Cogen	484 MW
expansion	100
Combine Hills	41
SP Newsprint	96
small projects	100

TOTAL 2521 MW 1(1)

In other words, enough facilities with "firm" power generation have <u>already</u> been constructed to provide far more energy what would be needed for the next ten years under the "medium" prediction. In addition, another 519 MW of non-firm wind generating capacity have also been constructed.

(WIND)

Stateline	119 MW
Stateline II	37
Klondike	24
Condon	50
Transalta	200
Nine Canyon	48
Vancycle	41
TOTAL	519 MW

Exhibit 1

The following plants are partly constructed:
Goldendale 250
Mint Farm 300
Satsop 650
TOTAL 1200 MW

At this point, the region has enough new energy facilities already running, and under construction, to meet the medium-high prediction for needed energy capacity for the next twelve years, and for the next 22 years under the medium energy needs prediction.

ALREADY PERMITTED
Sumas II 660
Wallula 1300
Umatilla 600
PGE 560
Port Westward 600
Plymouth 300
Col. River En. 44
Ore. Eng. 93
Boise/StH 141
West Linn 94
TOTAL 4400 MW

TOTAL RECENTLY COMMISSIONED, RUNNING, UNDER CONSTRUCTION, AND ALREADY PERMITTED: 8100 MW. 1(1) cont.

In summary there is already enough new energy generation built, under construction, and fully permitted, to supply even the highest prediction of new energy need for the next twelve years, and the medium-high prediction for the next 22 years, **without the BP project**.[1] These figures do not even take into consideration the thousands of megawatts of additional projects that are even now seeking permits, including but not limited to the Wanapa project, Calpine/Turner, Peoples Energy/Klamath Falls, and Coburg, which collectively add to another 3500 MW in capacity.

CONCLUSION

The DEIS fails to demonstrate a need for a 720 MW plant at BP to meet regional energy needs.

---

[1]The DEIS at Table 3-26 features a partial list of newly commissioned thermal plants, plants under construction, and plants fully permitted which totals 6504 MW. The DEIS list considerably underestimates the amount of current, under-construction and fully permitted generation, for instance by misstating the production of HPP, which is 649 MW, not 546 as claimed in the DEIS.

for the next 22 years.

ALTERNATIVE SIZE

One alternative that was rejected without an adequate discussion would be sizing the power plant to supply only the amount of electricity and stream that the refinery can consume.
The DEIS claims that a smaller plant would not provide economic energy, and would be an uncertain steam supplier. But not enough details were supplied to verify this dismissal of an important alternative.

Only an 85 MW plant was considered when this alternative was rejected. A slightly larger plant, for instance 100 or 200 Mw, which would provide more than enough energy for BP, and would also provide considerable excess stream generating capacity, was apparently not studied.
If the plant were smaller, it could still supply its contractual obligations, but there would be less significant impacts, especially air emissions.

For instance, here is a list of several other cogeneration facilities which would supply an extrapolated 510,000 lb/hour of steam that BP needs, without producing the immense amount of air pollution and water use generated by the proposed 720 MW power plant 1(2)

NAME OF FACILITY	MW	LB/STEAM/HOUR	Extrapolated* MW/510k lb/STEAM
Sun Mill, Okeelanta, Fla	75	1,300,000	29
UW-Madison	45	600,000	37
G-P, Camas, Wash.	11	140,000	39
Petro Canada Macay River	165	1,584,000	52
Hershey's, Oakdale, CA	5.6	50,000	56
Scott Paper, Everett, Wa	47	435,000	56
NIH	23	180,000	64
Coca-Cola Leesburg	3.6	22,000	82
Auburndale	7.2	44,000	82
UC Berkeley	24	100,000	120
Grays Ferry/Trigen	170	800,000	106
Aries	45	187,000	120
ExxonMobil, Baytown, TX	160	560,000	143
United Cogen, SF, CA	30	100,000	150
Carseland Cogen	80	264,000	152
Solvay/Jemeppe-Sambre	90	286,000	158
UW-Madison	150	400,000	188
Oxychem, Ingleside, TX	440	1,100,000	210
Bear Creek	80	165,000	242

*This figure is a scaled-up estimate of what megawatt plant would also generate 510,000 lb/hour of steam, given the figures presented for each particular facility. All plants except G-P/Camas and Scott Paper are natural gas fired.

Based on the median generating capacity figure for these cogeneration plants, it can be extrapolated that a 100-200 MW facility is fully capable of generating 510,000 lb/hour of process steam for use at BP. In practice, this approximately sized plant appears to be in common use for steam geneating hosts of this magnitude. At least six plants on the list generate over 510,000 lb/hour of steam and their energy capacity ranges from 45 to 440 Mw. For instance, the Petro Canada, ExxonMobil, and the Gray's Ferry cogeneration plants generate over 1.5 million lb/hour, 560,000 lb/hour, and 800,000 lb/hour of steam while generating 160-170 MW of electricity. 1(2) cont.

This data shows that a far smaller cogeneration plant of only about 20% of the proposed size of the BP plant, would be fully capable of meeting the purpose and need stated in the DEIS, while producing only about 20% of the projected air and water pollution, and water use.

ALTERNATIVE POLLUTION CONTROL–ELIMINATE AMMONIA THREAT

The power plant will store anhydrous ammonia, and emit ammonia for use in their SCR air pollution scrubbing system. This present dangers to public health and to air quality. The DEIS should have discussed several alternatives to use of anhydrous ammonia that present far less risk to human health and safety. These alternatives include a non-ammonia scrubber system, use of aqueous ammonia, or use of urea. 1(3)

AMMONIA STORAGE AND TRANSPORT

The proposed power plant will use, handle, store and transport large amounts of ammonia. Ammonia is listed on the EPA's list of extremely hazardous chemicals. The State of Louisiana has recently tightened regulations governing handling of ammonia.
It is prudent to minimize the use and storage of any hazardous chemicals such as ammonia. Nonetheless, BP proposes to transport, use and store large quantities of ammonia on site.

The DEIS is deficient in failing to describe and address the possible consequences of transporting, piping, storing and emitting hundreds of thousands of pounds of ammonia at this facility every year. There are two issues regarding ammonia. The first issue is the constant release of ammonia from this facility under normal operating conditions. The second issue is the risk of ammonia releases from the storage and transportation of this hazardous chemical. 1(4)

AMMONIA EMISSIONS UNDER NORMAL OPERATING CONDITIONS

Ammonia may be emitted from the project at 5 parts per million (ppm) which is one/half of the odor threshold. There are other ammonia sources in this area, including other power plants, whose emissions could contribute to an ambient ammonia level. These other ammonia sources were not evaluated in the DEIS. In this case it is possible that the ammonia odor threshold could be exceeded under adverse air quality mixing conditions, such as inversions. These nearby ammonia sources should have been inventoried, because those sources may cumulatively contribute to formation of secondary particulate. 1(5)

But no controls for ammonia are discussed, nor is there any modeling that accounts for potential ambient levels of ammonia that would cumulatively join with the proposed facility's emissions. The impacts of ammonia emissions on PM formation were discussed earlier. 1(5) cont.

NON AMMONIA SCRUBBER SYSTEM--BENEFITS OF SCONOx WERE NOT ADEQUATELY CONSIDERED

SCONOX is an alternative pollution scrubbing system that does not use ammonia. SCONOX should have been comprehensively discussed as an alternative to the proposed project. The SCR system proposed for use by the Applicants results in a number of environmental problems that are reduced or eliminated with the use of SCONOx. These problems include: (1) hazards from accidental releases of the ammonia used in the SCR system during its transportation and handling; (2) the formation of particulate matter from the oxidation of SO_2 in the SCR catalyst; (3) the formation of particulate matter from reactions between ammonia and SO_2; (4) generation and disposal of the hazardous SCR catalyst at the end of its useful life; (5) inability to control NOx and CO emissions during startups and shutdowns; (6) increase in NO_2 from the use of dry low NOx combustor.

SCONOX would produce greater control of NOX and other pollutants, and eliminate ammonia emissions, and the threat of releases from storage and transport of ammonia. The EPA has recently ruled that SCONOX is considered technically "Available" for NOX control on natural gas fired turbine power plants. The SCONOX controls on two UC-San Diego Solar 130S turbines, control NOx to 1.0 ppm or below, and also control CO to below .04 ppm, according to San Diego Air pollution Control District Source tests. 1(6)

Although the DEIS rejected SCONOX based on cost, the California Air Resources Board BACT evaluation comparison reports for combustion turbines, rated SCONOX as only slightly more expensive than SCR.

LOW NOX BURNERS

The newest generation of low-NOx burners appropriate for power plants can reportedly lower NOx emissions to below 5 ppm, without using ammonia and producing ammonia emissions and crating the hazards of ammonia storage and transport. The DEIS should have discussed these devices.

PM_{10} FORMATION CAUSES VISIBILITY REDUCTION

The fact that ammonia/PM reactions actually occur and cause visibility impacts is well documented in the technical literature. A noted atmospheric textbook, for example, contains this vivid description of the problem (Pitts and Pitts, 1999,[2] p. 284):

"The formation of ammonium nitrate has some interesting implications for visibility

[2] Barbara J. Finlayson-Pitts and James N. Pitts, Jr., Chemistry of the Upper and Lower Atmosphere. Theory, Experiments, and Applications, Academic Press, San Diego, 1999.

reduction. In the Los Angeles air basin, for example, the major NOx sources are at the western, upwind end of the air basin. Approximately 40 miles east in the vicinity of Chino, there is a large agricultural areas that has significant emissions of ammonia...under typical meteorological conditions, air is carried inland during the day, with NOx being oxidized to HNO3 as the air mass moves downwind. When it reaches the agricultural area, the HNO3 reacts with gaseous NH3 to form ammonium nitrate..the particles formed by such gas-to-particle conversion processes are in the size range where they scatter light efficiently, giving the appearance of a very hazy or smoggy atmosphere even though other manifestations of smog such as ozone levels may not be highly elevated."

AMMONIA RELATED PM_{10} FORMATION ENDANGERS BIOTA

The majority of the ammonia slip reacts with NOx to form ammonium nitrate, which is a form of PM10. This PM10 can be deposited on surrounding hills, located immediately adjacent to the site. This is an especially significant impact, especially if there is already a high level of ammonia compounds emitted in the vicinity of the project. There are many other large ammonia sources in the vicinity of the project, including the Encogen, Tenaska, and March Point projects, and other power plants and large refigeration facilities.

The Federal Land Managers conducts the IMPROVE air monitoring project in the Columbia Gorge area. IMPROVE's results show than almost 40% of fine particulate in the Gorge vicinity is made up of ammonia compounds; ammonium sulfate and ammonium nitrate. These same ammonia compounds could form additional concentrations of PM in the vicinity of the BP plant.

This additional PM10 would increase the Project's reported contribution to soil nitrogen. The impact of this additional ammonium nitrate has not been evaluated and must be to fully evaluate the environmental impacts of SCR. Ammonia emissions are discussed further in the following comments. These types of reactions, as described above, are a potentially significant impact that should have been discussed in the DEIS 1(7)

RISKS OF AMMONIA RELEASES

The plant will store hundreds of thousand of pounds of ammonia on site, and millions of pounds of ammonia will be transported to this site every year. But the DEIS does not describe the likelihood of a transportation accident, the numbers of truck trips bearing ammonia, the possible size of any ammonia releases from a truck accident, the inability of this rural area's emergency response system to react to a large release, the neighborhoods and businesses that would be threatened by a release, or the risk and effects of a release from the ammonia tanks at the power plant, including the risk and effect of a tank failure. 1(8)

In fact, the DEIS is virtually silent on this troubling subject, of large scale ammonia releases from transport and storage of large amounts of ammonia on the site, and how, or whether, emergency responses will be conducted. Ammonia releases are fairly common. A study submitted to the Congress revealed there have been over 1000 ammonia releases over one nine year period, which caused 801 injuries, 9 deaths, and 61 evacuations of over 22,000 people. [3]

For instance, there was a release of ammonia in August, 2001 from the Pratt & Whitney power plant in East Hartford, Conn., that caused the shutdown of nearby streets for five hours and led to the evacuation of 20 people. For this reason the commentors urge that the DEIS should have discuss ammonia hazards, and the ability to respond, from storage and transport releases, and any requirements to comply with the CAA amendments governing storage and transport of ammonia and other hazardous materials.

The facility will use anhydrous ammonia which is the most hazardous form of ammonia, and the type of ammonia most often implicated in releases causing injuries, deaths, and evacuations of thousands of people. The DEIS evaluation should have studied alternatives types of ammonia to be stored and used, for instance the use of urea instead of ammonia, or the use of aqueous ammonia, and alternative transport methods for ammonia. Anhydrous ammonia should be specifically banned from use because of the increased dangers from its releases. 1(9)

The DEIS' evaluation should also study the potential impacts of large scale ammonia releases from different site locations, and the release impacts from different types of transport accidents. 1(10)

SOME RECENT RELEASES OF AMMONIA (not a complete list)

evacuations	injuries	location	gallons released
1000	65	Quebec	" "
1500	0	Morro Bay, CA	300
100-300	n/a	Wauwatosa, Wi	n/a
125	n/a	Columbus Jct, IA	200
36	1300	Minot, ND	about 140,000
280	4	Washington, IND	Not provided
not known	15	St. Paul, MN	not provided
not known	9	Lorain, Ohio	10 pounds
230	5	Old Monroe, MO	not known
200	1	New Plymouth, NZ	not known

The Project may be subject to the Title III requirements regarding storage of hazardous materials, but those requirements, including a hazard assessment and risk management program, have not yet been developed and reviewed by the public and the relevant agencies. These requirements should have been fulfilled in time for these proceedings, so that the public can evaluate this project's risks in a single round of reviews and meetings. 1(11)

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[3]Report to Congress Section 112(r) (10) Clean Air Act as Amended. EPA 550-r-93-002. December, 1993.

ALTERNATIVE DESIGNS TO FURTHER REDUCE WATER USE AND DISCHARGE
The proposed plant will use water cooling. It will consume an average of over 2200 gallons per minute of water; or more than 3 million gallons per day. It will also discharge about 190-260 gpm. (About 300,000 gallons/day)

Over 2200 gallons/minute (Over 3 million gallons per day) is a very high rate of water use for this size of power plant. Many power plants are designed to generate far more energy, while at the same time using far less water than is proposed for this plant. For instance, the proposed natural gas fired Chehalis power generates almost as much energy (520 vs 720 MW) as the BP proposal, but will use only about 7% as much water. The Chehalis plant is solely air cooled.

Many power plants are also able to function without discharging 200 gpm or more of waste water, also, including the Sumas I plant. The DEIS should have more comprehensively discussed alternative designs of the facility that would reduce water use and discharge, as follows. While the DEIS rejected these alternatives as too costly, the widespread use of htese water conservation methods indicates that any increased costs are relatively insignificant. 1(12)

For instance, the BP facility will use far more water to generate 700 MW, than will the Lakefield Junction plant in Minnesota, to generate over 600 MW. Diamond Energy's Nevada plant will use only 20-50 af/year (about 40,000 gallons/day) to generate 500 MW, according to published accounts. Colorado Springs/Fountain will use only 80 gpm to generate 480 MW, compared to BP water use of over 2000 gpm, (well over 3000 af) according to published accounts.

If many other power producers can bear these slightly increased costs, and in the process conserve billions of gallons of water, than the DEIS should conduct a more stringent review of the purported reasons for rejecting water conservation measures out of hand.

AIR COOLING
This alternative would include complete air cooling, rather than partial water cooling for the facility. The commentors are aware of many existing and proposed power plants that are solely air cooled, including the two Neil Simpson plants and the Wyodak plant in Wyoming, the permitted Chehalis Power facility in the State of Washington, the Doswell facility in Virginia, the Matimba and Kendal powerhouses in South Africa, the Rosebud plant in Montana, the Linden and Sayreville plants in New Jersey, Colorado Springs near Fountain, Colorado, Diamond Generating, near Goodsprings, Nevada, Duke, and Miriant, both near Las Vegas, Reliant's Choctaw County projects near French Camp, Mississippi, and its Hunterstown, Pennsylvania, project, Taiyuan #2 in China, Trakya in Turkey, Uran III in India, Tousa in Iran, and the Camarillo facility in Ventura County, California.

In addition, most large power plants permitted recently in California have been exclusively air cooled, including Sutter Power, and Otay Mesa. Total Air cooling of the BP plant could reduce water use by 70% or more, and would save about 2 million gallons/day.

HYBRID COOLING SYSTEMS

These plant designs use a combination of both air and water cooling, and are in use at the West Cogeneration plant in Germany, and the Exeter Energy plant in Conn., USA. Three Mountain Power is California is another hybrid cooled plant, as is Mass Power's Indian Orchard plant. Water use is cut approximately in half.

ZERO DISCHARGE PLANTS

These types of facilities extensively re-treat and re-use their waste water, often with the reverse osmosis membrane process. Public Service in New Mexico has employed this technology for over 20 years, as does the Massena, New York plant, Ocean State in Burrillville, Rhode Island, and FJ Gannon in Florida. There are several variations on this process, including brine concentration. We understand that HPD plant, in Naperville, Illinois, uses this process. Staged cooling, used at Pasco in Dade County, Florida employs this alternative. The nearby Sumas I plant is zero discharge.

The DEIS rejected zero discharge after a truncated discussion that concluded the costs of trucking out waste water solids was too high. The treatment plant for this effluent is going to have solids that will need trucking and disposal, in any event. This was not an adequate discussed of an alternative that would not require the commitment of this massive amount of water for the power plant, and which is in active use at many other competitive power plants. **1(13)**

WATER QUALITY AND QUANTITY IMPACTS

The DEIS at 2-27 states that the waste water will have to be concentrated at a ratio of 15-1 before it will be discharged. The water tests in the DEIS did not present an analysis of the trace metals and radioactive materials that may be finally present in the cooling water. Even if these types of materials area present in very small amounts, they will be concentrated by 1500% by the cooling cycles, and this activity could produce a significant concentration of potentially toxic materials in the discharge water. **1(14)**

WETLANDS

The DEIS claims that about 30 acres of wetlands will be destroyed by the project, and about 100 acres will be rehabilitated. Again, however, the DEIS fails to inform the reviewers that the degrading of these and directly adjacent wetlands, and the ultimate rehabilitation of other wetlands, is actually the product of two contemperaneous projects; the cogen plant and the isomerization (Isom) unit.

In fact, the Isom unit is currently undergoing its own review by the Army Corps of Engineers, whom admits that the construction lay down area, and the resulting lost wetlands, for the Isom unit (the Brown Road Materials Storage Area)is next to the lay down area, and lost wetlands, for the cogen unit. The wetlands areas proposed for rehabilitation for both the Isom and Cogen units are also contiguous, north of Grandview Road. **1(15)**

But the DEIS fails to discuss the cumulative impacts of the Isom and the Cogen projects on any **1(16)** resources, including but not limited to wetlands. For instance, the proposed cogen laydown area west of Blaine Road would appear to conflict with the proposed plans for wetlands water conveyance that are part of the Isom project wetlands mitigation plans. 1(16) cont.

SOME REHABILITATED AREAS ARE EFFLUENT TREATMENT PONDS, NOT WETLANDS

The DEIS admits that effluent from the cogen's oil-water separator will be discharged to the ponds in CMA-1. The DEIS claims these and other areas provide rehabilitated wetlands which mitigate for the losses of over 30 acres of natural wetlands. But if an industrial uses a ponded area to receive effluent, the recipient area is part of a wastewater treatment plant, not a "wetland."

For this reason, Ecology publications state that "wetlands" created for stormwater treatment are "high risk" because they may receive high sediment and debris loading, or may accumulate toxic materials and become dangerous to wildlife. For this reason much higher replacement ratios are justified. (DOE Publication 92-8, p.14) The DEIS should describe what acreage of rehabilitated areas are being used for receipt of stormwater, so that commentors can determine if an appropriate replacement ratio of wetlands is actually being provided. 1(17)

DEIS FAILED TO CONSIDER CUMULATIVE IMPACTS WITH THE ISOM CONSTRUCTION AND OTHER RAPIDLY UPCOMING CLEAN FUEL PROJECTS

The DEIS' failure to discuss the closely related and physically adjacent Isom construction job and its impacts, which will be cumulative with the BP Cogen, violated NEPA and SEPA, which require a study of cumulative impacts of nearby projects taking place at the same time. 1(18)

PIPELINE IMPACTS

The proposed power plant and its support facilities include a natural gas pipeline lateral. There are many other natural gas pipelines around the country, and in the Northwest, that were constructed according to federal standards. But in the Northwest alone, pipelines have blown up three times within the last few years.

A pipeline near Bonneville Dam exploded and burned on February 27, 1999. The roar from the explosion was heard for two miles. The 300 foot high fireball was so huge it was visible for miles. Route 14 in Washington was closed to protect the public. Press accounts state that earth movement from recent heavy rains may have been responsible for the pipeline break. The fire destroyed a resort hotel that was under construction and a nearby dwelling.

Near Kalama, Washington, a natural gas pipeline broke in February, 1997. Again, a 300 foot high fireball blazed into the sky. And just one day earlier, the same pipeline exploded and burned near the BP site, Bellingham, Washington.

In March of 1995, that same pipeline had raptured and blew up near Castle Rock, Washington. After that 1995 explosion, the company removed soil from 300 feet of the pipeline, to relieve any stress. But less than two years later, it blew up again. Again, soil movement was the cause of the pipeline breakage, according to published accounts.

There have been a total of at least ten large natural gas pipeline explosions, since 1978 in the Northwest, including other ruptures in Stevenson, Washington, La Grande, Oregon, and Montpelier, Idaho. All of these explosions have been on the Williams Pipeline system that may supply this proposed power plant.

A few years ago, a construction backhoe caused a leak in a Northwest Natural Gas pipeline recently in Rainier. Seventy five people were evacuated. There is other evidence regarding the potential impact on public health and safety from natural gas pipelines.

Earlier this year, at least six people were killed in a natural gas pipeline explosion near Carlsbad, New Mexico, and another six were injured. Landslides in Ventura county, California ruptured several natural gas pipelines in February, 1998, again after heavy rain. Between 1965 and 1986, there have been 250 pipeline failures in the United States as a result of stress corrosion cracking, caused by a combination of water, soil types, and gas temperature within the pipelines.

Twenty-one people were killed during 1995 from natural gas pipeline accidents.[4] A Transwestern Pipeline natural gas pipeline exploded on August 20, 1994 in New Mexico, near the Rio Grande River, damaging a bridge. An October, 1994 explosion of a pipeline in Torrance, California, injured 30. A December, 1989 pipeline rupture caused by a farmer's plow, triggered the evacuation of 600 people in Butler, Illinois.

In March, 1994, a natural gas pipeline exploded in New Jersey, killing and injuring scores of people and creating a 30 foot deep crater and a fire that destroyed eight buildings and severely damaged six more buildings.

All of these pipelines were constructed to federal standards, and monitored by federal agencies. The DEIS should explain, how with all the mitigation measures and careful engineering, pipelines, including facilities in Washington State, on the very pipeline that will service this power plant, can still blow up. When these events occurred in a populated areas, there may be heavy loss of life and property. These pipeline explosions are significant impacts. Additional protective measures should be discussed and implemented, and the problems that caused this explosion should be carefully explained at length in an revised DEIS. 1(19)

But the DEIS did not discuss pipeline accidents, also known as "service incidents."
A service incident is reportable if there is a gas leak causing a death or serious injury, gas ignition, over $5000 in property damage, if it occurred during a test, if it required immediate repair, or if a portion of the line was taken out of service because of the incident.

[4]New York Times, 4/9/97, p. 1.

An revised DEIS should be prepared to describe the likely scenario of service incidents on the pipeline serving the power plant, perhaps by describing several of the recent explosions on this pipeline and at similar pipelines. 1(20)

Descriptions of a range of several recent incidents should be provided, so that readers and commentors can be appraised of the possible impacts of service incidents. This is appropriate because service incidents can be expected over a 50 year life span for these pipelines. The DEIS should also have discussed whether, and how local agencies in this area would respond to a pipeline explosion and fire. 1(21)

POWER PLANT ACCIDENTS

The DEIS failed to discuss the potential for accidents and explosions at this proposed facility. On occasion, similar power plants have experienced fires and explosions that have damaged property and killed people.

On October 8th, 2002, a massive explosion at the Florida Power & Light natural gas fired Palm Beach plant rocked two counties, followed by a hydrogen-fed fire. The explosion shook houses and rattled windows, and was as loud as a sonic boom. In January, 2002, there was a hydrogen explosion and a resulting fire at the natural gas fired BC Hydro plant in Port Moody, BC.

Less than two weeks ago, on October 1, 2002, there was a nine-alarm fire at the Sithe power plant in Boston, that began in a hydrogen generator. The fire and explosion caused $10 million in property damage.

The BP DEIS does not apparently even mention the use of hydrogen at that plant, or list it as being stored on site. We understand that hydrogen is routinely used and stored at natural gas fired and other power plants similar to BP, including but not limited to these three plants, that have blown up recently. But this potential impact from explosives and fires from caused or fed by hydrogen, and the impact on emergency services to respond, was not adequately discussed in the DEIS. 1(22)

At the Sithe blaze, 180 firefighters had to respond. The natural gas fired turbine at the Doswell power plant in Virginia recently suffered an catastrophic fire and explosion. It took 75 fire fighters to quell the resulting fire The DEIS should have discussed what will happen if hundreds of fire fighters are needed to respond to a problem at BP.

There were other explosions and fires at power plants recently. An explosion and fire rocked the Black Hills Power and Light power plant in Wyoming, in June, 2002. A back-up generator blew up and caused a "major" fire at the Allegheny Energy plant in Pennsylvania, in July, 2002. Firefighters from at least five communities had to respond to the blaze. A pressure relief valve activation at the Mirant plan in Zeeland, Michigan in August, 2002 caused diversion of traffic, to avoid released gasses.. Three workers were killed at a fire in the O'Brien Newark, New Jersey Cogeneration power plant fire recently. At least 20 other fires have been recorded over the last

10 years at power plants, causing another death and $417 million in property damage. The most severe fires often involved the release of lube oil, which ignited. Thousands of gallons of lube oil will be stored at BP.[5]

There were 272 to 557 equipment failures and accidents per year at power boilers and pressure vessels since 1992, causing almost 200 injuries and 29 deaths, and another 145 to 387 failures, and another 270 injuries and 54 deaths, from unfired pressure vessels, according to Power Magazine, Jan-Feb., 2001, p 53.

Because Power plants typically store and use many materials that present a danger of fire and explosion, such as hydrogen and lube oil, some of these hundreds of annual accidents at power plants cause injuries, and losses of life and property beyond the power plant boundaries, and require a large response of emergency personnel, as previously described. The dangers from the use and storage of these materials, and even the types of materials to be stored at BP, and the ability or lack thereof of local fire departments to respond, was not discussed in the DEIS. These kinds of serious accidents are significant impacts that should be discussed in an EIS. 1(23)

CUMULATIVE EFFECTS OF INCREASED USAGE OF NATURAL GAS

The EIS did not discuss the adverse impacts from the increased exploration and processing of gas in Canada, in part sparked by the development of these this project.

Discussions of Canadian impacts is mandated by Presidential findings during the Carter Administration regarding the scope of NEPA-covered projects. A description of Cross-border impacts are also appropriate, considering that the Canada Energy Board requires assessments of impacts in the United States, when evaluating proposals for Canadian pipelines. 1(24)

Nor did the DEIS adequately discuss the cumulative impacts of this project and the many other power projects in the Northwest, on the natural gas supplies. Although this very topic was the subject of a chapter in the Wallula Power EIS, it received inadequate discussion in this document, even though the cumulative impact of some of the recently proposed power plants in the Northwest, was the additional consumption of over 6% of domestic natural gas reserves.

PM-10

ADDITIONAL PM SOURCES

. The DEIS also lacks adequate information to assure commentors that its calculations included the impact from formation of secondary PM by conversion of ammonia. While the DEIS did discuss secondary formation of PM from conversion of nitrogen and sulfur compounds, the DEIS did not discuss secondary formation of PM by conversion from airborne ammonia compounds. 1(25)

This plant will emit hundreds of tons per year (TPY) of PM-10 from its turbines alone PM-10 is fine particulate that is capable of being drawn deep into the lungs. PM-10 is highly damaging to

[5]Most of these narratives are from the Chemical Safety Board's web site.

human health. But in addition to the power plant exhaust, there are other sources of PM-10 and total suspended particulate (TSP) from this project, including the cooling tower.

COOLING TOWER DRIFT

The cooling towers are PM-10 and TSP sources, to the degree which the cooling water contain solids, which are emitted from the cooling tower exhaust as particulate. A large power plant using water high in solids content can emit many tons per year of PM-10 and TSP. For instance the Goldendale Energy plant was predicted to emit 6.6 TPY of PM, and BP is 300% larger. The PM emissions from the cooling tower will contribute significantly to the ambient air concentrations of PM_{10} concentrations. The effluents have low exit temperatures, low exit velocities and correspondingly are low in momentum and buoyancy. Switching to full air cooling would also reduce PM and TSP emissions, since a cooling tower will no longer be needed. 1(26)

Cooling tower emissions also contain salts, metals, water treatment chemicals, and other contaminants, which could degrade the quality of soils, and affect human health, wherever the cooling tower drift is deposited. .

THE DEIS FAILED TO CONSIDER HOW AMMONIA SLIP WILL ADD TO PM10 EMISSIONS

The DEIS failed to describe the reactions between SO3, NH3, and NO2, which form salts, some of which are emitted to the atmosphere and some of which deposit within the HRSG. Equations can be used to estimate a portion of the secondary PM_{10} that is formed from ammonia slip. Secondary PM_{10} can be formed by reaction of ammonia with SO_3 and NO_2 emitted by the gas turbines and present in the stack gases and plume as well as additional SO_3 and NO_2 that are present downwind in the atmosphere.

Additional ammonium nitrate could form from the reaction of NO_2 in the atmosphere with any emitted ammonia. This additional PM_{10} may not have been included in the Project's emissions estimates. Apparently the formation of secondary PM10, ammonia nitrate, from the proposed project, was not done in the DEIS, so the combined PM10 emissions will be more than what was estimated. BPA's own EIS on the Wallula Power project admitted ammonia emissions could produce as much as 460% of their own weight as secondary particulate.

1(27)

In summary, the DEIS appears to have underestimated the resulting concentrations of PM 10 from the project. These underestimations need to be considered in light of the Federal Land Managers certifications that significance degradation of air quality in nearby Class I areas are already being exceeded. This certification by federal agencies of an already occurring significant impact, that will be increased by the proposed project, was not mentioned in the DEIS

For these reasons, the subject of the health and environmental effects of PM-10 and the plant's contribution individually and cumulatively, should have been presented in depth. Many recently published studies demonstrate that PM-10 and TSP are far more harmful that previously considered. In one study of the Seattle area, days of high particulate concentrations in the air were correlated with increased hospital visits for asthma. In another series of similar studies, days of high particulate concentrations were correlated with days of high death rates in Santa Clara, California, Steubenville, Ohio, Birmingham, Alabama, and Philadelphia, Pennsylvania, among seven separate studies on this topic. Particulate have been recently, convincingly implicated in harm to pulmonary function.

Some important conclusions from these studies is that harmful health effects occur even when particulate concentrations are far, far below the legal limits, there is no apparent particulate threshold for adverse health effects, and that harmful health effects are apparently caused by very minor increase in particulate concentrations. This means that even though the Project will not cause violations of the PM legal limits it could still cause significant health impacts. Construction will also create about 1 ton of TSP per acre of disturbance per month. Construction equipment, truck and car traffic related to this project, both in the construction and operation stage, will be an additional PM-10 and TSP source.

It appears from these studies that <u>any</u> increase in PM-10 and TSP levels will cause an adverse health impact. This is a significant health impact that should have been discussed in an EIS. There are important environmental impacts from PM-10 emissions, also.

<u>IMPACTS FROM WATER DISCHARGES</u>

The DEIS does not list water treatment chemicals to be used at the plant, and does not list any details of the toxicity of inhibitors or algicides that would be discharged. Lacking a complete discussion of the possibly pollutants in these sources's discharge, it is not possible to conclude that the this source's waste water will not contribute to water treatment problems. These chemicals could also be discharged in the cooling tower discharges. **1(28)**

<u>SOLID WASTES</u>

Water treatment for a large power plant can generate as much as 10 tons per month of wastes, as backwash, or filter cake. There are other waste streams, including spent catalyst, which is a hazardous waste. Catalyst wastes could be avoided by used of the SCONOX scrubber system. This generation of wastes was never described adequately in the DEIS. The materials contained in this wastes, the amount to be produced, its destiny, and its impacts on landfill capacity should all have been discussed. **1(29)**

<u>STORMWATER RUNOFF AND SPILLS</u>

The project will include the creation of impervious surfaces. This will cause the generation of millions of gallons of storm water runoff. This water will be tainted with oil, grease, and other contaminants present on the site and its parking lot and roof. The DEIS did not describe adequately the quality of this runoff, its destiny, and its potential impacts on nearby wetlands and surface waters. While there would be unlined detention ponds the DEIS did not describe to what degree these ponds will treat the storm water to remove pollutants before it is allowed to infiltrate into the ground water. **1(30)**

While an oil/water separator will be present, the DEIS did not assure commentors about the degree to which stormwater will be channelized through the separator. Nor did the DEIS describe the fate of wastes that are separated from the storm water. The DEIS did not describe the project's compliance with the DOE Stormwater Management rules. For instance, use of oil/water separators is actually criticized as having limited application, in DOE guidance manuals. The DEIS did not describe why a separator was appropriate for this location, or why alternative methods of storm water pollution control were not used. [6] 1(31)

LEGIONNAIRES DISEASE

The DEIS did not provide a table of materials stored on site that listed biocides known to be effective against Legionnaires Disease. This disease breeds in moist, warm climates, including cooling towers such as those to be used by BP. It has been spread through the discharge of steam from cooling towers. In March, 2001, for instance, two Ford employees died in Ohio after exposure to Legionnaires' Disease, spread by the facility's industrial cooling towers. Legionnaires Disease organisms have also bee found in the CEGB power plant's cooling tower water, near Stafford, England. Since it is not apparent that BP plans to use appropriate chemical treatment of its cooling tower system to stifle development of the relevant bacteria, there is a threat of Legionnaires Disease from this facility. This should be discussed in a revised DEIS. 1(32)

POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)

The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure. EMF exposure is another potentially significant impact that was not discussed in the DEIS.

POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)

This project will include a new power line. The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure, and the impacts to avian species which collide with above ground power lines.. Bird Mortality from the new power lines and EMF exposure are other potentially significant impacts that should have been discussed in the DEIS, and power line burial should be discussed as a mitigating factor, and a method of avoiding impacts on the nearby sensitive areas. 1(33)

The power lines associated with this project, as currently proposed, are a potentially significant factor. The DEIS should have addressed to what degree power line burial would address this concern,.

There are many examples of burial of high voltage power lines of considerable length. Since the proposed lines are about 3000 feet long, burial of this line would reduce the visual impact of the project would protect avian species, would reduce the project's above ground "footprint," and

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[6]Department of Ecology. Stormwater Management Manual. Chapter III-7. #91-75.

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would add only about 1/10% of one percent to the project costs; about $500,000.

Some example of actual and proposed burials of large pipeline include the 345 kV line that would be buried for 1700 feet to go under the Namekagon River near Trego, Wisconsin.

Sierra Pacific is burying a 14,000 volt line for about 2000 feet near downtown (Lake) Tahoe City, according to the company's June 9, 1999 press release.

Sierra Pacific is also burying a 120,000 volt (120kV) line for about 1700 feet near Carson City, Nevada, according to the company's April 19, 1999 press release.

Sierra Pacific's longest underground line is 2.6 miles, according to their Media Relations department.

The California Public Utility Commission's consultants, Aspen Environmental, prepared a study of an all-underground route for a 230 kV line near Pleasanton, California (Pleasanton Weekly. "Objectors, Proponents speak out on PG&E Power Line Plan." 2/16/01) 1(33) cont.

The Sumas II Power Plant has proposed a buried 230 kV line for 1.4 miles, in Abbotsford, Canada, as part of its trans-border proposal. (Canada Newswire. "NSB Receives a Revised DEIS from Sumas Energy II to Construct an International Power Line." October 2000)

The Sargent & Lundy engineering firm's advertising materials list several underground transmission lines for which they provided engineering, including a 115/138-kV line, a 230 kV line in Washington Dc, a 1800 foot 115-kV line in Baltimore, five 230-kV lines in China, two 69 kV lines in Iowa, a 1300 foot 138-kV line in Tennessee, and a one-mile, 138-kV line in Salt Lake City.

This litany of buried transmission lines indicates that this is a practicable, feasible and economic alternative design for this portion of the project. It would reduce the visual and land use impact of the project. For this reason a burial alternative, should have been presented in the DEIS.

QUESTIONS ABOUT THE EMISSIONS OFFSETS

The power plant will be permitted to emit the following annual tonnages.

NOx	239
CO	158
VOC	41
PM10	251
SO2	51

BP will purportedly shut down existing boilers, creating the following offsets:

NOx	499
CO	54

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VOC 28
PM 94
SO2 7

The DEIS claimed this would have the following net impacts
NOx -249
CO 104
VOC 13
PM 156
SO2 43

This list does not include the increased NH3 emissions of another 346 TPY. While the NH3 emissions are not a criteria pollution, it is still a toxic air emission, and an important source of secondary particulate matter, which is a criteria pollutant. Indeed, there is some evidence that BP's new power plant NH3 emissions will be responsible for an increase of as much as 1400 TPY of secondary PM. 1(34)

DEIS DID NOT INCLUDE THE EMISSIONS INCREASES FROM THE CONTEMPORANEOUS ISOMERIZATION PROJECT

This data also does not include the contemporaneous isomerization project at BP. The isomerization project will be constructed at the same time as the Cogen project, it will share the same construction lay-down yard, and in fact will share the same wetlands mitigation plan with the Cogen. The isomerization project will cause the following increases in air pollution, according to an on-line description of the project by EPA Region 10: 1(35)

POLLUTANT	TONS/YR	DEIS CLAIMED CHANGES	NET INCREASE W/ ISOM
NOX	166	-249	-76
PM	11	156	167
SO2	84	43	127
VOC	31	13	44
CO	47	31	78
H2SO4	2		38*
NH3			173*

*Includes totals from Table 3.2-13

DEIS DID NOT ADEQUATELY DISCLOSE INFORMATION ABOUT THE PURPORTED EMISSIONS REDUCTIONS FROM THE SHUTDOWN OF THE REFINERY BOILERS

ERCs must be surplus, permanent, and verifiable. The boilers that will be shut down are old, and may be shut down after the Clean Fuels project provides new boilers, so these sources would permanently emit at the levels which the DEIS claims as credits. RACT (Reasonable Available Control Technology) of BACT determinations should be made to determine realistic Emission

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offsets credits. Another indication that the emissions credits are not permanent is the requirement of the BP Consent Decree which mandates NOx reductions at the Cherry Point refinery. These sources may not be permitted to function at the current levels, anyway.

The DEIS also admits that new boilers will be constructed during the upcoming Clean Fuels Project. (p. 3.2-28) For this reason, the DEIS inappropriately deducted the old boilers' emissions from new cogen emissions during its discussion of the net project impacts. In other words, the old boilers' emissions are going away very soon, cogen or no cogen. The DEIS needed to discuss the emissions from the new Clean Fuel boilers, as the only proper, legitimate offsetting emissions reductions that could be deducted from the new Cogen emissions. Since the DEIS failed to consider the permitted emissions from the boilers that are about to be constructed, the DEIS's claims of new air quality benefits are misleading and untrue.

Emission reduction credit guidance from the EPA (cited later in this document) generally suggests that the low value of actual emissions, vs. permitted emissions should be employed to determine the appropriate ERC. But the DEIS does not say if the figures given for the boiler emissions were permitted or actual emissions.

DEIS DID NOT DISCUSS THE NOX REDUCTIONS MANDATED UNDER THE BP CONSENT DECREE

Furthermore, BP is under the strictures of a Consent Decree with the Federal EPA, under which BP is required to reduce its NOx emissions at the majority of its heaters and other equipment at the Cherry Point Refinery. The Consent Decree also set limits on how BP can characterize NOx emissions reductions from equipment subject to the Consent Decree. The DEIS did not discuss the relationship between the NOx reductions required under the consent decree, and the NOx reductions from shutdown of the utility boilers, that is discussed in the DEIS. 1(36)

This discussion should be required in the DEIS because ERCs must be surplus, quantifiable and permanent. If the old boilers were not shut down, it is doubtful that the old boiler emissions would have continued permanently at their current rate, because at some point RACT would have been mandated. Thus the boilers' emissions above RACT levels are not surplus, because some reductions will soon be required by law.

Permanent ERCs should not be based on past, high, emission rates, since those rates will not continue indefinitely, due to imposition of RACT, and the requirements of the Consent Decree, among other factors.

Federal register discussions state that VOC sources can be considered to impact ozone non-attainment areas within 36 hours wind travel time, because precursor emissions that occur within 36 hours traveltime of each other interact to form oxidant.[1]

Based on these discussions, The commentors ask that the old boilers at BP can be considered to contribute to the recent non-attainment status of the Seattle and Vancouver BC areas. EPA policy discussions suggest that RACT emission rates should be considered, rather than actual emission rates, or whichever is lower, for sources that are in non-attainment areas.[2] 1(36) cont.

The commentors are also concerned that several other criteria be followed in determining an acceptable amount of ERCs from the old boiler shutdown. The DEIS should establish that the Washington SIP does not already include, as part of its attainment plans, emissions reductions from shutdowns and the phasing out of aged emission units.

Some SIPs assume a quantity of reductions from new plant openings and existing plant shutdowns. These SIPs incorporate into their attainment strategy a net "turnover" reduction in emissions because new plants will be cleaner than the old shutdown plants.

If the Washington SIP includes this sort of "turnover" emissions reduction as part of an implementation strategy, then ERCs from the shutdown of the old BP boilers should not be granted, otherwise those emissions reductions would be double counted. (Federal Register 4/7/82, p. 15081)

In addition, if the Washington SIP contains emissions limits for the BP old boilers that are lower than BP's computation of its ERCs, then the SIP limits should be used to compute ERCs instead. (Federal Register, 1/16/79, p. 3284)

In summary, the old boiler actual emission rates should be compared with RACT/BACT emission rates from similar units, and the lower of those two rates should be used in the DEIS discussion of emissions reductions from the old boilers' shutdown.

AIR TOXICS

The new cogen project will emit several highly hazardous air toxics, including benzene and formaldehyde, and others, which are listed at Table 3.2-13. Toxics such as Acrolien, (and several metals), are emitted at amounts exceeding the Small Quantity Emissions Rate for both the hourly and annual emissions rate. But the DEIS fails to describe whether the project will result in greater or lesser emissions of these and other air toxics. The DEIS does not compare the emissions of air toxics from the cogen project, with the purported "reductions" caused by the shut down of the older utility boilers. 1(37)

The DEIS should have performed this comparison. It is not wise or legal to trade increases in comparatively hazardous air pollutants for decreases in relatively less harmful pollutants. Such a trade should be fully disclosed and discussed on an DEIS. As one treatise on this topic stated:

> "Certainly no one should be allowed to trade an increase in a more harmful pollutant for a decrease in a more benign one simply because it is cheaper to do so...if an increase in a hazardous pollutant were to be traded for a decrease in a more benign one the net effect would be a greater threat to public health despite the equivalence in pollutant quantities" [3]

But the trade-off of some decreases in NOx emissions from the old boilers, for increased emissions in formaldehyde and benzene emissions and other VOCs and air toxics from the BP Cogen, is a trade of comparatively benign pollutants for more harmful pollutants. In particular, benzene increases as a trade for reduction of generic emissions are explicitly prohibited.

EPA guidance documents regarding pollution trades and reductions clearly and plainly state:

> "(E)ven within a category (such as VOCs), pollutants that pose significant health hazards cannot be traded against less harmful pollutants ... The emissions of ...benzene which (is) listed under section 112, may be increased at one emission point ... only as long as there is a compensating decrease in the emission of the same pollutants at another emission point at the same location or a contiguous location ... Sources may equally trade hazardous pollutants with nonhazardous pollutants in the same criteria pollutant category only in the cases where the source decreases the emission of the hazardous pollutant.(emphasis and parentheses comment added) [4]

A later update of this guidance document continued to maintain the ban on trades of hazardous for non-hazardous pollutants, and specifically proscribed trades involving increases in benzene emissions:

> "Emissions Trades Should Not Increase Hazardous Pollutants. Where pollutants have been listed under Section 112, but are not yet subject to specific regulations...states may allow trades consisting of equivalent increases and decreases of the same listed pollutant ... the State may also approve trades in which reductions of hazardous pollutants compensate for increases in non-hazardous pollutants....a source may trade benzene for any non-hazardous VOC, if the benzene emissions are decreased." [5]

This coverage of this quotation would also apply both to formaldehyde, which was listed under Section 112 as part of the Clean Air act amendments of 1990, and to benzene, which was listed at an earlier time under Section 112. Language in the amended Section 112 also addresses trades of hazardous pollutants as follows;

> "A physical change in ... a major source which results in a greater than de minimis increase in actual emissions of a hazardous air pollutant ... will be offset by an equal or greater decrease in ... emissions of another hazardous air pollutant ... which is deemed more hazardous." [6]

CONCLUSIONS

ERCs from the old boilers shutdown should be limited to the RACT emissions from these boilers, or the actual boiler emissions, or the emissions of the Clean Fuel Project replacement boiler, whichever is lower. If these boilers are supposed to be shut down or controlled under the Consent Decree, those reductions should not be considered credits at all. Reductions in non-toxic air emissions should not be described as offsetting increased emissions of air toxics. If air toxic emissions will actually rise, the DEIS should say so and provide details.

ENDNOTES

1.Federal Register, Vol. 44, No. 11, January 16, 1969. P. 3278- 9.

2. Federal Register, 4/7/82, p. 15080.

3. Landau, Jack. "Economic Dream or Environmental Nightmare? The Legality of the "Bubble Concept" in Air and Water Pollution Control." Environmental Affairs. Vol. 8:705, pp. 770 and 780.)

4. Federal Register Vol. 44, No. 239, December 11, 1979, page 71784.

5. Federal Register, Vol. 47, No. 67, April 7, 1982, pp. 15082-3.

6.Public Law 101-548, Nov. 15, 1990, 104 Stat.2544.,Section 112, (g)(1)(A).

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QUALIFICATIONS

I have been involved in the permitting and reviews of federal and state environmental impact statements, environmental reviews, and permitting and reviews of air permit applications of industrial facilities, including cogeneration facilities, power plants, and a variety of industrial facilities, for sixteen years, throughout the West and Northwest. I have a BA degree in history from the University of California at Berkeley, and I am a member of the Northwest Chapter of the Air and Waste Management Association.

Over the last 16 years, on behalf of law firms, environmental and public interest groups, companies, and individuals, I have reviewed many environmental assessments for a variety of industrial facilities, including power plants, throughout the Midwest and West.

My recent participation on behalf of private parties in review of the Chehalis Power natural gas fired facility helped lead to a 70%, or 520 ton/year reduction, in that power plant's permitted nitrogen oxides emissions. My participation also caused the developer to switch to a more-efficient water conservation measure, thus reducing its water use by about 2 million gallons per day.

My participation in the air permit review of the Amax Hayden Hill Gold Mine in California was a factor in an enforcement action and consent decree by the Federal EPA, and a resulting fine in the $300,000 range, and additional air quality mitigation provided to local agencies. My assistance in preparing a critique of the Sierra Pacific Aberdeen, Washington air permit application led to a stop work order and a $10,000 fine against Sierra Pacific, in August, 2002.

When I was a paralegal for the Adams & Broadwell law firm in Northern California in the late 1980s, I participated in the review of scores of environmental reviews of power plants, refineries, and other types of industrial facilities throughout California. I participated in the review of the air permit for one of the largest wood fired power plants in the country in the late 1980s, what was then the Signal Energy facility near Redding, California. This was the first-ever installation of an added-on pollution control system, that of Selective Non-Catalytic Reduction (SNCR), onto a wood fired power plant.

I have attached a partial list of recent environmental assessment and permit reviews in which I have participated on behalf of a variety of private clients and environmental groups.

Exhibit 2

POWER PLANTS
Cogentrix power plant, Oregon
Cogentrix power plant, Rathdrum, Idaho
Kootenai Power, Idaho
Avista power plant, Longview, Washington
Sumas II power plant, Washington
Chehalis Power, Washington
Goldendale Power, Washington
Tenaska I power plant, Whatcom County, Washington
Tenaska II power plant, Tacoma, Wash.
Sierra Pacific cogeneration power plant, Greys Harbor, Wash.
Mission Energy/Weyerhaeuser power plant, Longview
Tollhouse power plant, Sedro Wolley, Wash.
power turbine, Willamette Industries, Albany, Ore.

INDUSTRIAL FACILITIES
Cascade Grain ethanol plant, Oregon
Morton Chemical, Elma Washington
PGT Pipeline expansion, Washington, Idaho, Oregon
Olympic Pipeline, Washington
Tuscarora Pipeline, Oregon, California, Nevada
Skagit and Nooksack River Basin Hydroelectric plants, Washington
Weyerhaeuser pulp mill expansion, Longview, Washington
James River Paper, Wauna, Oregon
General Chemical, Washington
Frito-Lay, Washington
Steel Dynamics Mill, Whitley County, Indiana

GRAVEL AND SAND MINES, CALIFORNIA
Western Aggregates, Marysville, California
Gilt Edge Tract, Yuba County, Ca.
Calaveras Materials, Fresno, California
Silica Resources, Marysville, California
Kaweah River Rock, Tulare County
Desert Aggregates, Tulare County
Garcia Gravel, Timbuctoo
Bud Plant, Yuba Goldfields
River City Aggregates, Sacramento County
Granite Rock, Santa Cruz County
Vulcan, Sacramento
Terra Blanca, Tulare
County Quarry, Hollister, Ca.

GOLD AND COPPER MINES
CALIFORNIA
AMAX Hayden Hill Mine, Lassen County, California
Homestake Mine, Lake County
Cal-Sierra, Yuba Goldfields
Mesquite Mine, Imperial County
Kinross, Timbuctoo, Ca

NEVADA AND UTAH
Denton-Rawhide, Nevada
Homestake Gold Mine, Nevada
Kennecott, Salt Lake City
Cortez, Nevada
Jerritt Canyon, Nv
Lone Tree, Nv
Twin Creeks Nv
Mule Canyon, Nv
Florida Canyon, Nv
Magma, Nv.

RECENT PUBLICATIONS
"Thirsty Power Plants a Threat to Local Water." Cascadia Times. October, 2001.
"New Power Plants Threaten Northwest Environment," Portland Oregonian, Nov. 27, 2001

Page 3 of 3

BP Cherry Point Cogen
DEIS Comment - 18

State of Washington
DEPARTMENT OF FISH AND WILDLIFE

Mailing Address: 600 Capitol Way North · Olympia, WA 98501-1091 · (360) 902-2200, TDD (360) 902-2207
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ENERGY FACILITY SITE EVALUATION COUNCIL

October 31, 2003

Mr. Thomas McKinney
BP Cherry Point Project Comments
BPA Communications Office KC-7
Post Office Box 14428
Portland, Oregon 97293-4428

Mr. Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
Post Office Box 43172
Olympia, Washington 98504-3172

Dear Mr. McKinney and Mr. Fiksdal:

SUBJECT: Comments on BP Cherry Point Cogeneration Project Draft Environmental Impact Statement DOE/EIS-0349

Washington Department of Fish and Wildlife (WDFW) would like to thank you both for the opportunity to review and provide comments on the Draft Environmental Impact Statement for the proposed BP Cherry Point Cogeneration Facility. You will find our comments listed below.

The Applicant is exploring three different options for the facility Transmission System. Two of the options require changes to the current Custer/Intalco Transmission Line No. 2. The Custer/Intalco Transmission Line crosses streams in multiple places. Work conducted in or above waters of the state requires a Hydraulic Project Approval (HPA) from WDFW. We would like to recommend that the Applicant work with the Area Habitat Biologist in that area to discuss the details of the HPA. The Area Habitat Biologist for that area is Julie Klacan and she can be reached at the WDFW Region 4 La Conner office at 360/466-4345 Ext. 272. 1

The Custer/Intalco Transmission Line No. 2 also runs within 330 feet (101 m) of a bald eagle nesting site in Sections 3 and 4 of Township 39 north and Range 1 east. Bald eagles are sensitive to disturbance within 394 feet (120 m) of their nest from the third week in March to mid June while they are nesting and feeding their young. Construction and maintenance of the transmission towers in the area of the nest should be restricted so as not to disturb the bald eagles. 2

On page 3.1-19 under *Erosion Control Procedures*, there is mention of using seed mixes known to effectively stabilize erodible soils in northwestern Washington. We would like to recommend a seed mix for controlling erosion and revegetating the disturbed areas: 3

Mr. McKinney and Mr. Fiksdal
October 31, 2003
Page 2

Calamagrostis canadensis (bluejoint reedgrass) 15%
Festuca pratensis (meadow fescue) 25%
Lolium multiforum (annual ryegrass) 25%
Poa palustis (fowl bluegrass) 25%
Trifolium repens (white clover) 10%

3 cont.

Thank you for the opportunity to provide comments. We hope that you find them helpful. If you have any questions, my phone number is 360/902-2615 and my email is kloemkak@dfw.wa.gov.

Sincerely,

Karen Kloempken

Karen Kloempken
Fish and Wildlife Biologist

KK:kk

cc: Curt Leigh
David Mudd

BP Cherry Point Cogen
DEIS Comment - 19

NW Energy Coalition
For a clean and affordable energy future

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Allen Fiksdal
EFSEC Manager
P.O. Box 43172
Olympia, WA 98504

October 30, 2003

Dear Mr. Fiksdal,

Please find enclosed my comments on the BP Cherry Point Cogeneration DEIS.
I have also sent them to you electronically.

Thank you,

Trina Blake
NW Energy Coalition

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ENERGY FACILITY SITE EVALUATION COUNCIL

TO: Members, WA State Energy Facility Site Evaluation Council

FROM: Trina Blake, NW Energy Coalition
DATE: October 30, 2003
RE: BP Cherry Point Cogeneration Project DEIS

Thank you for the opportunity to comment on the BP Cherry Point Cogeneration Project DEIS, specifically on the proposed CO2 mitigation proposal.

We appreciate the Council addressing the issue of Greenhouse Gas emissions, and including a section on its cumulative impacts. However, while the DEIS says there is "still uncertainty" about the magnitude of future impacts of global warming (section 3.2.5), EFSEC members are already clearly on record acknowledging that the risks of waiting to act on global warming are too great. The first impacts are already being felt, from reduction in the snowpack to forest infestations, and even the low-end of predicted changes will have dire consequences. The Council has heard from scientists such as Dr. Richard Gammon and the University of Washington on the impacts to Washington State from global warming. Scientists quoted in the DEIS itself predict that global warming will impact the Pacific Northwest in the next 50 years by reducing snow pack, increasing precipitation in winter and decreasing precipitation in summer, all of these leading to adverse impacts on irrigated agriculture, forests, and salmon. The region's traditional base load power source, hydroelectric dams, are also threatened by summer flows 20-30% beneath current levels, with significant impacts on summer power production and rates. These impacts to Washington, if CO2 is not reduced will be devastating to the economy and the environment. Obviously, any new plant permitted would increase emissions.

The DEIS does contain some very good proposals. First, decommissioning of the old boilers is a great idea and should be made an absolute requirement of building the proposed facility. The boilers are polluting and unnecessary, and should be permanently removed. 1

Second, fully mitigating CO2 emissions from the proposed plant through BP's corporate greenhouse gas objective is an excellent plan. However, we understand TransCanada already plans to purchase the facility permit. Because BP is committed to reducing CO2 around the globe, the company should make full mitigation a condition of sale, perhaps even working with TransCanada to mitigate CO2 emissions. Assuming that this is not made a condition of sale, we now must address the alternative proposal, which is wholly inadequate, as it is not based on sound scientific or economic principles. 2

<u>Plan if the Plant is sold:</u>

<u>Capacity Factor</u>

This plan has a capacity factor assumed to be 85%. This might be acceptable if the plant's CO2 emissions were mitigated fully, but to allow a reduced capacity without full mitigation invites gaming. Oregon requires, and this plan should too, a capacity factor to be assumed at 100%. 3

<u>Emissions Limit</u>

In calculating the emissions to be mitigated, the current Oregon standard (suggested in the DEIS), which requires emissions exceeding 0.675 lb/kwh (River Road technology minus 17%) to be mitigated, no longer reflects the most efficient combined cycle combustion turbine technology available. The Council should require mitigation of emissions from the 4 baseline of the most efficient combined cycle combustion turbine operating at the time the final mitigation plan is approved. Based on our research, the most efficient combustion turbine technology currently available is the Siemens Westinghouse W501G turbine at 0.764 lbs CO_2/kWh. Applying the 17% reduction in the Oregon standard to this technology would yield a baseline of 0.634 lbs CO_2/kWh. But we are not recommending 17%. We would like to see full mitigation as proposed under BP ownership. We have also recommended to the Council a very economical standard of 0.458 lb CO_2/kWh, based on 40 percent below emissions from a state-of-the-art combined cycle gas-fired plant (See attachment A, the Tellus economic study on CO_2 mitigation). Governor Locke has called for a minimum of 20% of total emissions to be mitigated. 4 cont.

Payment

The suggested price, $0.85/ton, reflects the outdated and insufficient Oregon standard, in practice leaving 95% of CO_2 emissions unmitigated. The time frame for payments (annual over 30 years) would effectively gut any ability of this proposal to mitigate CO_2. In order to actually mitigate a ton of CO_2 emissions, the funding must be at a level near the market cost of mitigating that ton (between $2 and $5/ton based on Seattle City Light and Climate Trust figures). This could be achieved by setting the mitigation price at the current market price (2-5 dollars/ton CO_2) and indexing the price to the CO_2 offset market for any payments that occur in the future. The DEIS proposal also endorses annual payments spread over 30 years. Annual payments would unnecessarily constrain the types of CO_2 mitigation projects that could be purchased, and thereby increase costs. The project owner should plan on providing the total amount of payment within the first five years of facility operation. That is a modification on the Oregon standard, which requires a single up front payment at the beginning of facility operation. Providing the mitigation payment up front allows the entity acquiring the offsets to purchase larger, more cost-effective mitigation projects. It also reduces any uncertainties associated with adjusting the price per ton to a market index over time. If however, EFSEC approves an annualized requirement, that requirement must apply for the entire life of the project and be indexed to market prices. In addition, the 30-year facility life proposed is based on Oregon law. Oregon uses a shortened estimated life span as an incentive to follow their monetary path and pay up front. If full upfront payment is not required; the mitigation should be required for the actual life of the proposed facility. 5

This proposal also omits administrative costs. If the proposal includes a monetary compliance path, it must explicitly include additional administrative costs of the entity managing the offset projects. As EFSEC found in its order on the Sumas Energy 2 facility, it had the legal power to impose administrative costs, and believes, in general, that it is appropriate to require the certificate holder to help pay such costs. Administrative costs are an essential part of ensuring that mitigation is accomplished in a credible manner that will count toward future regulatory requirements. The Council should recognize the true cost of the administration. In the Satsop agreement approved by Council members, administrative fees were set at 7.5%. Undercutting the real cost would further reduce the effectiveness of the mitigation, as money from the cost per ton would have to be used in order to secure projects 6

Finally, the plan must require the applicant to choose (if both are offered) between a monetary path (money paid to a third party) and mitigation obtained by the owner of the facility. To allow both invites gaming and further undercuts real mitigation. Any mitigation obtained directly by the owner of the proposed facility should be acquired at cost. To allow direct mitigation at the same price as the monetary path further reduces the tons of CO_2 mitigated 7

The extraordinary threats to Washington's environment and economy associated with greenhouse gas emissions are well documented. EFSEC's final EIS decision should strike an appropriate balance between the costs and benefits of these facilities. A strong mitigation requirement now will significantly reduce environmental costs AND financial costs. Utility and financial analysts universally project that the value of CO2 offsets and allowances will increase as binding constraints on greenhouse gases are adopted worldwide. Relatively inexpensive mitigation now is low-cost insurance against compliance costs that will rise as the right to emit CO2 becomes an increasingly scarce and valuable commodity. We urge the Council to ensure that the CO2 mitigation plan achieves a meaningful environmental goal and substantially reduces exposure to future costs associated with purchasing CO2 allowances or credits. Again, thank you for this opportunity to comment, and for your commitment to reduce the environmental and economic costs associated with CO2 emissions from this proposed facility. 8

Attachment "A"

An Economic and Financial Analysis of the Proposed CO2 Rule Comments for the Energy Facility Siting Council[1]

Michael Lazarus, Senior Scientist, Tellus Institute[2]

July 31, 2003

Introduction

I appreciate the opportunity to comment on EFSEC's proposed CO2 rule. I am a Senior Scientist with Tellus Institute, where I've done energy and environmental analysis for nearly 20 years, climate policy studies for the past 12 years, and analysis of emissions trading and offsets for the past 6 years. I work with a wide variety of clients, funders, and collaborators, including from the World Bank, USEPA, state and local agencies, foundations, project developers and brokers, and the non-governmental organizations. Among other current duties, I presently sit on Methodology Panel of the Clean Development Mechanism of the Kyoto Protocol, which is charged with developing draft guidelines and procedural recommendations for what could be considered the world's largest offset market.

Basic Approach

In this instance, I've been asked by the Northwest Energy Coalition to examine the economic and financial impacts of various possible formulations of a CO2 standard. This summary provides an overview of key assumptions and results. The analytical methodology, which combines straight-forward cash flow analysis, busbar electricity cost calculations, and cost-benefit comparisons, is detailed in an accompanying spreadsheet.

I have used widely available data and assumptions – drawn largely from Northwest Power Planning Council (NPPC) documents, supplemented by published studies by the US Department of Energy (USDOE), the Massachusetts Institute of Technology (MIT), and personal experience and contacts in the offsets market -- to calculate cost impacts across a range of proposed offset requirements (17%, 40%, and 100% of plant emissions) and mitigation prices, from the Oregon standard price[3] to the "all-in" cost of acquiring offsets (market price plus administrative and production costs).[4] For simplicity, I only consider one payment option – upfront payment spread over 5 years, financed by the developer – for a hypothetical 540 MW natural gas fired combined-cycle plant, placed in service in 2005.[5] I then look at the overall impact on the costs of

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[1] Draft results were presented at EFSEC's July 17 public meeting in Olympia. Updated results are presented here reflect further refinements of the analysis.

[2] Contact information: 119 First Ave S, Suite 400, Seattle, WA 98104, (206) 985-8124, mlaz@tellus.org.

[3] The Oregon CO2 standard price has been at \$0.85/tCO2 for a several years, after increasing 50% from its original \$0.57/tCO2 level. The price is allowed to increase by up to 50% every 2 years to more closely match prices actual paid for offsets. I assume that by 2005, the OR price will be at 0.85 x 1.5 or \$1.28/tCO2, given that offset prices are already well above this level, and that the price rises at 10%/year afterwards, roughly matching historical trends. (All "t" represent short, rather than metric, tons except where indicated)

[4] I have used rather conservative estimates of the market costs of offsets: \$2.50/tCO2 in 2003 rising to \$5/tCO2 by 2010, plus \$0.5/tCO2 for production/administrative services (contracting, M&V, baselines, etc.) that are essential for providing quality offsets. See World Bank's State and Trends in the Carbon Market reports at www.prototypecarbonfund.org

[5] Key assumptions were derived from the "Default assumptions from: NW Power Planning Council, New Resource Characterization for the Fifth Power Plan, Natural Gas Combined-cycle Gas Turbine Power Plants", August 27,

producing electricity from this power plant, and how a change in overall costs would be reflected in consumer rates, assuming such changes were passed through in rates rather than absorbed by developers as lower (or higher) profits. This assumption may overestimate rate impacts considerably.

Avoiding future compliance costs
It is important to recognize that investing in emissions reductions now hedges not only against future climate impacts, but also against the financial liabilities of major new assets responsible for significant emissions. These prospective liabilities are increasing in prominence and magnitude, as reflected in greater corporate and shareholder concern for greenhouse gas (GHG)-intensive activities, and in rising regional and national legislative activity.[6] While the timing and stringency of mandatory controls economy-wide or electric-sector-wide CO2 emissions is highly uncertain, it appears increasingly likely that such controls are coming, and that early action could translate into a competitive advantage. Indeed, they are almost universally regarded as necessary if we are to take the challenge of climate stabilization seriously.

Once mandatory CO2 emissions limits are adopted at the regional or national level, and power plants were required to hold emissions allowances for CO2 much as they must today for sulfur oxides, power plants could face very significant costs of compliance. If exchangeable with emissions allowances in the future, CO2 emissions offsets acquired under an EFSEC CO2 rule could provide an important economic asset.[7]

Consider, for instance, currently pending national legislation aimed at curbing GHG emissions, the Climate Stewardship Act (Senate Bill S.139), also referred to as the McCain-Lieberman bill. It creates a market-based cap-and-trade program to reduce emissions, patterned after the acid rain program of the 1990 Clean Air Act. As with the acid rain program, major emissions sources (including electricity generators) would be required to hold an allowance (or permit) for every ton of CO2-equivalent emissions. The Climate Stewardship Act sets a target of reducing national GHG emissions to 2000 levels by 2010, and to 1990 levels by 2016, targets far less ambitious than the Kyoto Protocol (7% below 1990 levels by 2008-2012). Emissions sources would be allowed to use "off-system credits", i.e. offsets, from non-regulated US sectors (including smaller sources, forestry and agriculture) and a wide range of international sources to meet their emissions targets, similar to what might be purchased under an EFSEC CO2 rule.[8] While the Climate Stewardship Act is viewed as having little chance under the current Congress, it is viewed as a setting the template for future legislation.[9]

2002 Draft. These include an all-inclusive capital cost of $617/kW, heat rate of 7030 btu/kWh, and availability of 92%, which I simplified to a 90% capacity factor. Remaining assumptions are documented in the accompanying spreadsheet.

[6] See, for example, Rabe, B. 2002. *Greenhouse & Statehouse: The Evolving State Government Role in Climate Change*, and Margolick, M. and Russell, D., 2001. *Corporate Greenhouse Gas Reduction Targets*, Prepared for the Pew Center on Global Climate Change, November. www.pewclimate.org

[7] If CO2 permits were grandfathered to existing sources, as was done with SO2, compliance costs would be far lower, but the value of offsets would be the same, since they would enable excess permits to be sold as a source of revenue.

[8] Note that "in-system" offsets, e.g. project activities that reduce emissions by major fuel users, could still maintain future value, depending on how the terms of the offsets contracts were negotiated.

[9] Pizer, W., Kopp, R, 2003. *Summary and Analysis of McCain-Lieberman – "Climate Stewardship Act of 2003"* Resources for the Future, January 28. www.rff.org/McCain_Lieberman_Summary.pdf

Two key elements of this legislation are particularly relevant for EFSEC deliberations:

- **Scope for offsets.** While the rules on allowable credits are not specifically defined in the legislation, it is reasonable to assume that credible and verifiable offsets – as might be purchased under the EFSEC rule – would be deemed eligible. It is unclear whether emissions reductions occurring prior to 2010 would count, but the legislation is generous with respect to crediting what is considered early action prior to this date.[10] Experience from other cap-and-trade systems (e.g. Kyoto Protocol and acid rain) suggests that offset-like instruments are likely to be recognized in CO2 emissions legislation, as it adds flexibility, lower compliance costs, and motivates action in non-capped sectors. Parallel efforts, such as the California Climate Registry and GHG Protocol, are also presently underway to help ensure that early actors, such as power plant developers buying offsets, will be rewarded under future regulation.
- **Projected allowance costs.** Several recent modeling studies have sought to estimate the future cost of allowances under the Climate Stewardship Act. Recent modeling runs by the US DOE suggest that allowances, under a scenario with considerable use of offsets, would cost $20/tCO2 in 2010 and $44/tCO2 in 2020.[11] MIT modeling studies suggest allowance costs ranging from $15/tCO2 up to $25/tCO2, under a similar scenario. While these estimates may be somewhat high for technical reasons[12], it is instructive to note that these values are nearly ten times the offsets today and projected over the rest of the decade ($3.00-$5.50/tCO2).

Overall there are four key factors that will determine the extent to which offsets purchased under the EFSEC CO2 rule might provide a future economic benefit

a) the **likelihood** of future CO2 emission caps
b) the **cost of allowances,** which is a function of how stringent this cap would be.
c) the **transferability** or validity of CO2 offsets purchased under the EFSEC rule under a future cap-and-trade system.
d) the **timing** of these caps, which will affect the risk and time value of the benefits

The risk management benefit provided by offsets is the product of these four factors.

A Scenario Approach to Assessing Risks

Scenario analysis provides a useful way to examine a situation with such speculative factors. In the section below, I will present three alternative scenarios. The first represents a situation where there is no tangible risk management benefit. CO2 emissions are either not to be capped during the operating lifetime of the power plant (e.g. by 2034), or if they are, offsets purchased

[10] In any case, a threshold date (e.g. 2010) would likely not pose a major concern, since offset contracts would likely generate emission reductions across the full 30 year life of the power plant, e.g. 2005-2034 in the case of a plant in service in 2005. It is likely that, at most, only a small fraction of offset-based emission reductions might be ineligible.

[11] These estimates are drawn from the Pew Center's review of S. 139 studies, available at http://www.pewclimate.org/policy/EIAanalysis.cfm, where they are presented in metric tons.

[12] See Pew Center report noted above and Bailie, A., Bernow, S., and Lazarus, M., (2003) *Analysis of the Climate Stewardship Act,* Tellus Institute, Boston.

today would have no value in this system.[13] The second scenario represents a situation where legislation akin to the Climate Stewardship Act is adopted, with emissions caps starting in 2010, average allowance costs of $25/tCO2 (based roughly on the above DOE and MIT analyses), and full scope for including post-2009 offsets[14] purchased under an EFSEC rule. The third is an intermediate scenario, where doubts about likelihood of emissions caps, the future validity of offsets, and projected allowance costs, combine to yield a 40% probability of offsets being worth an average of $25/tCO2 from 2010 onwards.

Under each of these scenarios, I calculate the "net" change in power plant costs resulting from an EFSEC CO2 standard. This net cost is simply the cost of acquiring offsets minus the risk management benefit of avoiding the need to buy emissions allowance under a future emissions cap, i.e.:

Net cost = Offset acquisition costs – (Avoided allowance costs x Probability of offset validity)

Scenario 1: No risk management benefit

Since under this scenario, the probability of offsets being valid instruments to reduce future allowance costs is zero by definition, the only major economic consideration is the cost of acquiring offsets.

Offset acquisition costs

To first order, calculating offset acquisition costs is relatively straightforward. It is simply the amount of CO2 emissions that need to be offset under a given target (17%, 40%, or 100%) times the assumed price strategy adopted by the rule -- e.g. the Oregon standard, an intermediate $2/tCO2, or the full-market price, which we assume starts at around $3/tCO2 today and increases to $5.5/tCO2 by 2010. Divided by the total kWh produced, this yields the "simple, unfinanced" cost of offsets for a given power plant, as shown in Table 1. On this basis, a CO2 rule stating that 17% of emissions and using the Oregon price formula would appear to add one-hundredth of a cent or 0.2% to the 4.29 cents per kWh (c/kWh) "busbar" cost of producing a kWh of electricity from a new natural gas plant.[15] If all emissions from the plant were offset at the all-inclusive market price of offsets, then this simple approach suggests that offsets would cost an average of 0.15 c/kWh, adding 3.6% to cost of production.

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[13] The latter would be equivalent to the "double jeopardy" situation, from a developer's perspective, presented by Dr. Mark Trexler at the EFSEC public hearing.

[14] Future legislation could very well grandfather offsets booked prior to this year – and indeed various climate registry and baseline protection efforts are aimed at this goal – thereby increasing the benefit (i.e. fully rewarding offsets from 2003 through the first compliance date) beyond what is assumed here.

[15] All costs are levelized across the typical 20-year amortization period of a new plant investment. Levelized natural gas costs are projected to be $3.70/MBtu, based on recent NW Power Council medium case estimates.

Table 1. Cost of offsets, simple, unfinanced (cents/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.01c *(0.2%)*	0.02c *(0.5%)*	0.05c *(1.2%)*
Int. ($2.0/tCO2)	0.01c *(0.3%)*	0.03c *(0.8%)*	0.08c *(1.9%)*
'All-in' market ($3.7/tCO2)	0.03c *(0.6%)*	0.06c *(1.4%)*	0.15c *(3.6%)*

(Percent shown as fraction of 4.29 cents per kWh busbar cost)

However, the simple approach may underestimate costs, since it presumes that developers would be able to make the five-year upfront offset payments from available cash. It is more likely that the offset requirement will increase developers' financing requirements. Financing of offset payments, in turn, would roughly double the cost of offsets, as shown in Table 2.[16] At the 40% offset requirement and intermediate price of $2/tCO2, financing of offset payments would add 0.06c/kWh (1.4%) compared with 0.03c/kWh (0.8%) in the simple, unfinanced case.

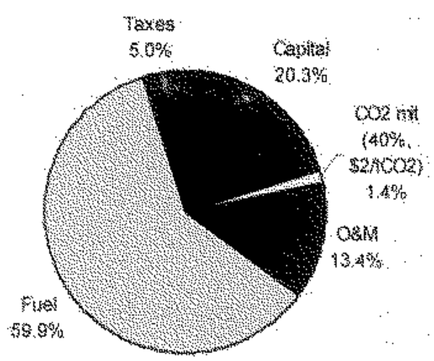
Table 2. Net change in new power plant costs, Scenario 1 - no avoided compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.02c *(0.4%)*	0.04c *(0.9%)*	0.10c *(2.3%)*
Int. ($2.0/tCO2)	0.03c *(0.6%)*	0.06c *(1.4%)*	0.15c *(3.6%)*
'All-in' market ($3.7/tCO2)	0.05c *(1.1%)*	0.11c *(2.7%)*	0.29c *(6.7%)*

(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Figure 1 shows how this 0.06c/kWh offset cost compares with other cost components of a new natural gas plant. Not surprisingly, fuel costs are predominant, and are also highly uncertain, especially in light of price surges and concerns echoed by Federal Reserve chairman Alan Greenspan. If instead of the NPPC's medium gas forecast shown here ($3.70/MBtu levelized 2005-24), their high estimate were realized ($4.56/MBtu, levelized), the cost of electricity production would rise by 0.60 c/kWh, roughly ten times the magnitude of the offset cost imposed under a 40% /$2 mitigation requirement.

Figure 1. Annualized costs for a 540 MW natural gas CCCT



[16] For the purposes of this calculation, I assume that offset payments will be financed on a similar basis as other power plant investments (20 year amortization), except that financing is purely on a debt basis (at 8.7% nominal interest rate).

Box 1. Reflecting actual mitigation amounts

It is important to not that fixing a price below the market cost of offsets effectively reduces the emissions actually mitigated, as is well recognized in the Oregon case. Since the Oregon price (e.g. \$1.28/tCO2 in 2005) is likely to cover only 34% of the total costs of acquiring offsets (including the administrative costs), under a 17% standard only 6% of emissions would actually be mitigated. At a \$2/tCO2 price and a 40% standard only 22% would be mitigated. It is important to be explicit this potential discrepancy, so the actual benefits are properly stated and to maximize credibility of the proposed rule. (See Table 3) Any discrepancy in initial price setting is also likely to magnified should offset price escalation be limited to a standard economic price index (such as CPI, PPI), since offset prices are likely to increase much faster than inflation.

Table 3. Actual "mitigation" or offsets purchased given lower-than-market prices

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon (\$1.3/tCO2)	6%	14%	34%
Int. (\$2.0/tCO2)	9%	22%	54%
'All-in' market (\$3.7/tCO2)	17%	40%	100%

Consumer rates

Increased costs would be reflected either in higher electricity rates or in lost profits by power plant owners. Private and public utility owners would be able to pass on costs to consumers directly, whereas merchant power plant developers would likely absorb much of the added cost in lost profits until a significant fraction of the market is subject to similar costs. Assuming, however, that all offset costs were somehow passed on to consumers, I estimate that by 2010 that rates would rise by from two thousandths of a cent (17% target, Oregon price) to three hundredths of a cent (100% target, full market price), as shown in Table 4.[17]

[17] For the purposes of this calculation, I have assumed that all growth in demand in the Pacific Northwest -- projected to be about 200aMW per year -- is met by new natural gas CCCT plants subject to the CO2 rule. Using this assumption about 8% of generation is subject to this charge in 2010, while about 14% is by 2020. These assumptions are likely to significantly overstate the amount of natural gas capacity built, given competition from other sources of supply within and outside the region. At the same time, however, some capacity may be built in the region for the purposes of displacing older or more costly sources throughout the West.

Table 4. Change in consumer rates, 2010, Scenario 1 - no avoided compliance costs (c/kWh)

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon ($1.3/tCO2)	0.002c *(0.0%)*	0.004c *(0.1%)*	0.010c *(0.2%)*
Int. ($2.0/tCO2)	0.003c *(0.0%)*	0.006c *(0.1%)*	0.015c *(0.3%)*
'All-in' market ($3.7/tCO2)	0.005c *(0.1%)*	0.011c *(0.2%)*	0.028c *(0.5%)*

Assuming 8% or 1712 aMW of electricity from NG CCCTs in PNW subject to CO2 rule
Assuming built 2005-2010, subject to increasing offset prices
Assuming current average rate of 5.3c/kWh

Under the 40% target and $2/tCO2 case, rates would rise about 0.006 cents, and average monthly bill would go up 8 cents for the average household, 53 cents for the average commercial customer, and $5.52 cents for the industrial customer (See Table 8 below). By 2020, these effects would just about double.

Scenario 2: Full risk management benefit
Just as the first scenario represents the most pessimistic, this scenario reflects the most optimistic outlook for recovering offset investments in the form of avoided future allowance costs. In this case, if we assume that all offsets purchased under an EFSEC rule are considered valid and interchangeable with emissions allowances under a future cap-and-trade system, at an average value of $25/tCO2 from 2010 onwards, these offsets take on a significant financial value, as shown in Table 5.

Table 5. Full value of offsets under a future cap-and-trade system (c/KWh)

	Stated offset requirement		
Price (in 2005)	17%	40%	100%
Oregon ($1.3/tCO2)	0.04c *(1.0%)*	0.10c *(2.3%)*	0.25c *(5.9%)*
Int. ($2.0/tCO2)	0.07c *(1.6%)*	0.16c *(3.7%)*	0.39c *(9.2%)*
'All-in' market ($3.7/tCO2)	0.12c *(2.9%)*	0.29c *(6.8%)*	0.73c *(17.1%)*

At 25/tCO2 allowance price, 2010 onwards
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Offsets in this case are worth from 0.04 to 0.73 cents per kWh[18], and when subtracted from the cost of buying the offsets, the net effect on electricity costs drops from 0.6% to 10.3%, as shown in Table 6. At a 40% target and $2/tCO2 price, the long-term cost of electricity drops by a tenth of a cent or 2.2%, and the maximum impact of consumer rates would be a drop of about 0.1% (see Table 8).

[18] Avoided compliance costs are discounted back to 2005 and levelized across the life of the power plant.

Table 6. Net change in new power plant costs, Scenario 2 - full avoidance of compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	-0.03c -(0.6%)	-0.06c -(1.4%)	-0.15c -(3.6%)
Int. ($2.0/tCO2)	-0.04c -(0.9%)	-0.10c -(2.2%)	-0.24c -(5.6%)
'All-in' market ($3.7/tCO2)	-0.08c -(1.8%)	-0.18c -(4.1%)	-0.44c -(10.3%)

Assuming full transferability of offsets at 25/tCO2 allowance price
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Scenario 3: Partial risk management benefit
The third scenario represents an intermediate case, recognizing that neither the pessimistic "Scenario 1" or optimistic "Scenario 2" outlook for the future value of offsets is likely to be correct. The precise likelihood and magnitude of offsets value depends on the many factors described above: likelihood of a cap, its stringency and resulting CO2 permit costs, the fungibility of offsets in this system, and ultimately the perceived quality of offsets themselves. Thought these are highly uncertain factors, EFSEC is not without influence. State and local actions, such a meaningful EFSEC CO2 rule, create increased pressure for national emissions caps. And EFSEC rules for how offsets are acquired will inevitably affect their perceived quality.

As illustrated in the Table 7, if one assumes that, on average, offsets acquired under an EFSEC rule have a 40% probability of being worth $25/tCO2 from 2010 onwards, then the avoided compliance costs roughly cancel the costs of buying offsets, and the rule has no net overall economic impact.

Table 7. Net change in new power plant costs, Scenario 3 - some avoided compliance costs (c/kWh)

Price (in 2005)	Stated offset requirement 17%	40%	100%
Oregon ($1.3/tCO2)	0.00c (0.0%)	0.00c (0.0%)	0.00c (0.0%)
Int. ($2.0/tCO2)	0.00c (0.0%)	0.00c (0.0%)	0.00c -(0.1%)
'All-in' market ($3.7/tCO2)	0.00c (0.0%)	0.00c (0.0%)	-0.01c -(0.1%)

Assuming 40% transferability of offsets at 25/tCO2 allowance price
(Percent shown as fraction of 4.29 cents per kWh busbar cost)

Assuming costs and benefits are passed on equally to consumers, there is, not surprisingly, there would be almost no effect on consumer bills, as shown in Table 8 below. Together these three scenarios can be thought of as bracketing the range of impacts this rule would have, under the assumptions used here.[19]

[19] An accompanying spreadsheet is available for reviewing all assumptions and conducting sensitivity analyses.

Table 8. Monthly bill impact, 2010, assuming $2/tCO2, 40% requirement

Price (in 2005)	Residential	Commercial	Industrial
Scenario 1 - No risk management benefit	$0.08	$0.53	$5.52
Scenario 2 - Full risk management benefit	-$0.10	-$0.65	-$6.72
Scenario 3 - Partial risk management benefit	$0.00	-$0.01	-$0.08

Based on USDOE data for WA rates and average bills by class, 2001
Assuming 8% or 1712 aMW of electricity from NG CCCTs in PNW subject to CO2 rule
Actual savings in Scenarios 2 and 3 will be lower than shown to the extent compliance costs are lower in early years of cap-and-trade system.

Conclusions
As is clear from its extensive questions and deliberations with public stakeholders, EFSEC is considering many potential options and outcomes with respect to its proposed CO2 rule. In keeping with this broad view, EFSEC commissioners may wish to consider how these options might interact with serious federal action to address the climate problem. Many observers are convinced that mandatory US emissions caps are, if not inevitable, at least required if we are to take the challenge of climate stabilization seriously. However, there is great uncertainty as to when they will be adopted, how stringent they will be, their cost implications, and the extent to which offset investments made under an EFSEC rule would be deemed creditable towards future emissions targets. As this analysis shows, resolution of these uncertainties is central to how the economics of this rule will ultimately play out.

Under the most pessimistic scenario (#1) for federal action under which EFSEC-approved offsets would have no added financial value, the costs of power from a new natural gas plant would rise from 0.4% (17% target/OR price) to 6.7% (100% target/market price). Under a 40% target and $2 price strategy, the new power cost would rise 1.4%, and, if the added costs were passed on to consumers, electric rates would rise by 0.1% by 2010, adding 8 cents to the average monthly household bill, 53 cents and $5.52 for the average commercial and industrial customers, respectively. Other uncertainties, such as the cost of gas or the fate of electricity restructuring are likely to have a much more significant impact on consumer costs.

Under the most optimistic scenario (#2) for recovering offset investments – assuming they can count almost fully against future emissions allowances costing at average of $25/tCO2 from 2010 onwards – a proposed EFSEC rule would actually reduce consumer rates and increase developer profits over the long run. In 2010, the average household bill might actually be 10 cents lower, and commercial and industrial customers might see a drop of 65 cents and $6.72, respectively, assuming a 40% target and $2/tCO2 fixed price.

Under an intermediate scenario (#3), where the combined probability of having a mandatory emissions cap-and-trade system and of EFSEC-required offsets being valid under that system comes to about 40%, the effect on power plant costs and rates is roughly a wash. This breakeven point is equivalent to assuming that from 2005 onwards emissions from all new plants will pose a liability of about $9/tCO2. This metric is similar to what Pacificorp already uses for planning purposes; its recent Integrated Resource Plan assumed that new fossil plants will have to pay

\$8/tCO2 emitted.[20] Both of these values reflect attempts to quantify three of the four key uncertainties noted above: the likelihood of future emissions caps, timing and extent of these caps, and the price of emissions allowances under such a cap. The other uncertainty, which is not addressed in Pacificorp IRP analysis, is the fungibility of EFSEC-required offsets in a cap-and-trade system.

To maximize future offset value, I strongly recommend that EFSEC create a process that encourages best practice on key issues such as baselines and additionality, leakage and permanence, and monitoring and verification. In this regard, EFSEC can look to standards being developed by the Executive Board of the Clean Development Mechanism, by the World Resources Institute and World Business Council for Sustainable Development, who will soon release their first GHG Protocol for project-based activities, and by the California Climate Registry. In addition, there are the many lessons learned by Climate Trust, Seattle City Light, and the Oregon Office of Energy.

The future liability posed by CO2 emissions from new, long-lived power plants may be very significant. If owners of 540 MW NG CCCT in service in 2005, were required to hold emissions allowance for each ton of CO2 emitted at an average of \$25/t from 2010 onward through its 30 year life, the net present value of this liability would come to \$380 million (NPV), exceeding the total cost of the plant investment itself (about \$330 million). This suggests that the less investment in mitigation done now, the greater the potential future liabilities.

This analysis has focused on a very narrow conception of economic costs and benefits – those related directly to the price of electricity production and use. However, regardless of whether one includes the liabilities for future emissions are counted in the balance sheet, they represent real economic costs to society at large, the hard-to-quantify damages from an incrementally altered climate.

[20] Pacificorp's IRP assumes a base case wherein CO2 allowance costs are \$8/tCO2 starting in FY2009. http://www.pacificorp.com/File/File25682.pdf

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ENERGY FACILITY SITE EVALUATION COUNCIL

Irina Makarow
EFS Specialist
PO Box 43172
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Re: DEIS Comments

October 31, 2003

Dear Ms. Makarow

Thank you for the opportunity to comment on the BP Cherry Point Cogeneration Project Draft Environmental Impact Statement (DEIS) DOE/EIS-0349. We believe that the DEIS provides a fairly good description of the proposed project and its potential environmental impacts (or lack thereof). We agree wholeheartedly that the proposed project will not have any significant adverse environmental impacts. We have two general comments regarding the document. 1

Our first general comment concerns the "No Action Alternative." Chapter 2 describes the No Action Alternative, and then the various sections of Chapter 3 compare the potential environmental impact of the proposed Cogeneration Project to those of the No Action Alternative. In order for the comparison of environmental impacts to be complete and accurate, however, the No Action Alternative must be properly described. Under the No Action Alternative, although the Cherry Point Cogeneration Project would not be constructed, other electrical generating facilities would need to be constructed and operated to meet growing regional electricity demand over time. Such facilities would be expected to have the same sorts of potential environmental impacts as the proposed Cogeneration Project (e.g. air emissions, CO2 emissions, water use, construction related impacts). However, the facilities providing power under the no action alternative facilities are not likely to be cogeneration facilities or to have the other advantages that the Cogeneration Project has by virtue of its integration with the refinery's existing infrastructure. Among other things, these other facilities are likely to emit more air pollutants and CO2 emissions, use more water use, burn more fuel and have more impacts associated with constructing related infrastructure and facilities. Throughout the document, the DEIS should make clear that the same amount of electricity would be generated by different facilities under the No Action Alternative, and as a result, the No Action Alternative would have more impact on the environment than the proposed Cogeneration Project. 2

Our second general comment concerns the "additional recommended mitigation" found in the DEIS. Under the State Environmental Policy Act (SEPA), recommendations for additional mitigation should be tied directly to significant impacts identified in the DEIS, and should be based upon regulations or policies formally adopted by the action agency pursuant to SEPA. The DEIS does not justify the recommendations of additional mitigation as required by law.

In addition to these general comments, we are enclosing a list of specific comments. Many of these comments are minor, pointing out typographical errors or correcting statements describing the proposed project, but others address more substantive concerns. In each case, we have tried to identify the specific section, page and paragraph to which our comment relates. 3

Please do not hesitate to contact me if you have questions regarding any of these comments, or if you need additional information to complete the Final EIS.

Sincerely,

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.cc
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Mark Moore
Wolfgang Nuehoff

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
1	MDT	1-4	1.2.1	4	5		The boiler efficiency provided in the application was 85%. However, 83% efficiency is the actual boiler efficiency and 83% efficiency was used for the boiler emission calculations.	3(1)
2	KM	1-7	1.4.1	1	1		The total project area should be 194-acres. If the DEIS is going to use 265-acres, then it should also state that the BPA transmission line ROW from the interconnection to the Custer substation is included in the total acreage.	3(2)
3	WJR	1-7	1.4.1	6		new	Add "Emergency Firewater Pump" to the bullet list.	3(3)
4	MDT	1-7	1.4.1	5		new	Add "Water Treatment Facilities" to the bullet list	3(4)
5	TS	1-7	1.4.1	5		5	Change "150 MVA step-down transformer" to "185 MVA nominal step-up transformer"	3(5)
6	TS	1-7	1.4.1	5		new	Add "One 275 MVA step-up transformer" to the bullet list.	3(6)
7	MDT	1-11	1.4.2	1	2	new	Cogeneration makes this project a more efficient producer of electricity than a standalone gas-fired combined cycle combustion turbine plant. Because the opportunities for cogeneration are limited, If this plant were not built, then another less efficient plant would be built within the region to supply the growing demand for electricity. A standalone plant would use more water, produce more air emissions, produce more green house gasses, and use more fuel per kWh of electricity produced.	3(7)
8	KM	1-13	1.6.3	1	4		Delete the last sentence and replace it with the following, "The Ferndale Pipeline would supply gas for the new Cogeneration Plant and the Refinery. If additional gas is needed during periods of peak Refinery demand, then Cascade Natural Gas would provide/transport supplemental gas to the project."	3(8)
9	KM	1-14	1.6.8	2		1	<u>230 KV Switchyard</u> - The cogeneration facility would own about 65% of the switchyard and BPA wold own about 35%. BPA's portion is just that part of the switchyard that allows the output of the plant to be routed to BPA's grid.	3(9)
10	KM	1-14	1.6.8	2		2	<u>Industrial Water Supply</u> - We expect Whatcom PUD to build, own and operate the water supply line up to the Cogeneration Project boundary. The new pipeline connection would start at the southeast corner of the Refinery and run parrallel to the existing Refinery supply line along Blaine Road.	3(10)
11	KM	1-14	1.6.8	2		3	<u>Natural Gas Suppply and Compressor Station</u> - The Cogeneration Plant would own and operate the natural gas compressor station located inside the Refinery.	3(11)
12	KM	1-14	1.6.8	2		4	<u>Intermediate Voltage Substation</u> - The Refinery would build the 230 KV to 12.5 KV substation adjacent to the existing MS3 substation on an existing graveled pad.	3(12)
13	KM	1-15	1.6.8	3		1	<u>Refinery Interface Piping Systems</u> - The Refinery would build an elevated pipeway to carry process streams such as steam and condensate between the two facilities. The pipeway would cross the utility corridor between Blaine Road and the Cogeneration boundary on a series of pipe supports called "sleepers". The length of the pipeway in this corridor is about 630 ft. The supports are placed on 37 concrete foundations constructed, which consist of two 2-foot by 2-foot concrete pedestals.	3(13)
14	KM	1-15	1.6.8	3		2	<u>Custer/Intalco Transmission System</u> - Modifications to this transmission system will be built, owned, and operated by BPA. BPA should supply this informaton.	3(14)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
15	TS	1-18	1.6.8	Table 1-2	Contruction	2	Delete second bullet. The site was surveyed for contamination during the geotech survey and no contamination was found. Sampling is not planned during clearing, grading, and trenching. However, if contamination is found during these activities, then clearing, grading and trenching would be halted until the contamination could be safely dealt with.	3(15)
16	KM	1-19		Table 1-2	Operation		Additional Mitigation Measures - We do not agree with the additional mitigation measure proposed. The facility would evaluate the potential impacts of tephra fall out and take appropriate action with regard to plant operations.	3(16)
17	WJR	1-19		Table 1-2	Operation	1	Add "or WAAQS" after NAAQS at the end of the sentence.	3(17)
18	KM	1-20		Table 1-2	Operation	1	Delete and then add, "Use appropriate measures to reduce particulate matter while transporting material in trucks, which may include covering and wetting."	3(18)
19	KM	1-20		Table 1-2	Operation	2	Delete and then add, "Use appropriate meaures to reduce and remove particulate matter from wheels before entering roads, which may include wheel washers."	3(19)
20	KM	1-20		Table 1-2	Operation	4	Delete and then add, "Maintain construction equipment in good working order to reduce CO and NOx emissions."	3(20)
21	WJR	1-20	1	Table 1-2	Operation	1	Add "or Washington Ambient Air Quality Standards" after "National Ambient Air Quality Standards" at the end of the sentence.	3(21)
22	WJR	1-21		Table 1-2	Operation		No Action Alternative - The Refinery would continue to operate utility boilers, new less efficient power plants would be built elsewhere in the region with higher air emissions and higher greenhouse gas emissions, higher water useage, and use more fuel per kWh.	3(22)
23	KM	1-27		Table 1-2	Operation	10	Additional Recommended Mitigation Measure - We do not understand what is being recommended by this item. The plant surface will be mostly concrete and gravel. There will be areas of landscaping, which will be maintained to keep noxious weeds from spreading.	3(23)
24	KM	1-36		Table 1-2	Operation	1	Delete "An eastbound and" The application specifies only a westbound turn lane.	3(24)
25	KM	1-36		Table 1-2	Operation	3	Delete "…Blaine Road/Grandview Road (SR548).." No signal is planned at the Blaine Road/Grandview Road Intersection. Move this entire bullet item to the Mitigation Measures Proposed by the Applicant.	3(25)
26	MDT	2-6	2.2.2	1	1		195 acres, not 265 acres (33+15+36+110) unless it is stated that the Transmission line corridor is from the interconnect to the Custer Substation iss included in the acreage.	3(26)
27	MDT	2-6	2.2.2	3		new	Add "Emergency Fire Water Pump" to the bullet list	3(27)
28	MDT	2-6	2.2.2	3		new	Add "Water Treatment Facilities" to the bullet list	3(28)
29	TS	2-6	2.2.2	5			Change "150 MVA step-down transformer" to "185 MVA nominal step-up transformer"	3(29)
30	TS	2-6	2.2.2	5		new	Add "One 275 MVA step-up transformer"	3(30)
31	TS	2-8	Table 2-1	5	1		Change 'universal' to "uninteruptable"	3(31)
32	MDT	2-10	Table 2-1	MS1			New Low Voltage Switchyard near MS 3 only	3(32)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
33	TS	2-10	Table 2-1	2			The decription of the high voltage swtichyard in the DEIS accurately represents the switchyard we described in the application, however, the follow describes our current thinking. We'll leave it up to EFSEC/Shapiro to determine if description in the DEIS needs to be changed. "The 230 kV switchyard will be a breaker and a half arrangement. The BPA interconnect will be two 230 kV receiving structures and four (4) 230 kV circuit breakers and eight (8) disconnects switches and associated metering, protection, control and communication. The Project interconnection to the switchyard will include four (4) 230 kV receiving structures for GSU interconnections and two (2) 230 kV receiving structures for Refinery interconnection. The remaining eight (8) circuit breakers, 24 disconnect switches and associated protection, control and communication. This results in a split of approximately a 35% BPA and 65% Project.	3(33)
34	TS	2-13	Table 2-2				The following tank sizes in the DEIS are correct, but the following represents our current thinking. We'll leave it up to EFSEC/Shapiro to determine if the tank sizes need to be modified in the application. "Condensate storage tank 600,000 not 500,000; Demineralized Water storage tank is 200,000, not 100,000; Wastewater equalization tank is 500,000, not 400,000 and Filtered water & firewater storage tank is 500,000 not 425,000."	3(34)
35	MDT	2-18	2.2.2	1	8		The rewrite the sentence to read, "The detention pond would be constructed as an unlined pond." Because the stormwater routed to this pond is uncontaminated rain water, ground water would not be affected.	3(35)
36	TS	2-18	2.2.2	2	2		Rewrite the second sentence as follows, "Storm water contained in secondary containment areas would be evaluated prior to discharge. If the water is uncontaminated, then it would be routed to the Stormwater system. If the water is contaminated, then it would be rouited to the Refinery Wastewatwer system."	3(36)
37	KM	2-19	2.2.2	5	4		This sentence states that the "maximum" water use will be approximately 2,780 gpm. That's not correct. The maximum amount of once through cooling water available from Alcoa is 2,780 gpm. The average use by the Cogen project will be 2,244 to 2,316 gpm, but the maximum instantaneous use could be higher than 2,780 gpm.	3(37)
38	MDT	2-26	2.2.2	4	2		Change "CMA1" to "CMA2". The project site detention pond will discharge to CMA2.	3(38)
39	MDT	2-27	2.2.2	3	4		Delete, "...,and would meet WSDOT and emergency vehicle requirements." Access road #3 was not intended to meet WSDOT and/or emergency vehicle access requirements.	3(39)
40	MDT	2-28	2.2.3	4	2		Rewrite the sentence, "The Application for Site Certification indicates that pile-supported concrete foundations would be used for all major equipment items and major buildings." Delete the reference to the steam turbine now being the only structure to be supported on piles.	3(40)
41	MDT	2-29	2.2.3	2	6		Change "6 to 10 feet deep" to "5 feet deep"	3(41)
42	MDT	2-29	2.2.3	2	7		Change "3 to 4 over the pipe" to "sufficient to bring the trench level up to original grade"	3(42)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
43	MDT	2-30	2.2.3	2	1		Change "150-foot" to "125-foot". While 150 ft was used in the application, the ROW will be as wide as BPA requires. We believe this will be 125 ft.	3(43)
44	TS	2-35	2.2.4	3	1		Rewrite the sentence to read, "While the cogeneration facility is generally designed to allow maintenance to occur without a complete plant shutdown, maintenance on mechanical parts of the steam turbine generator will most likely require a complete plant shutdown."	3(44)
45	MDT	2–40	2.4.1	5	1		Add, " Site 2 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 the interconnections, these process units require must be located very near existing process areas."	3(45)
46	TS	3.1-19	3.1.5	1	1		Delete first sentence and add, "The site was surveyed for contamination during the geotech survey and no contamination was found."	3(46)
47	MDT	3.2-3	3.2.1	Table 3.2-1		SO2	Delete the National three-hour primary standard for SO2 0.14. There is no national three-hour primary standard for SO2	3(47)
48	WJR	3.2-3	3.2.1	Table 3.2-1	Ozone		The eight-hour ozone standard is "157 ug/m^3" not "176 ug/m3"	3(48)
49	MDT	3.2-17	3.2.3	5	1		Delete "including background". The concentrations shown in table 3.2-9 are strictly modeled concentrations without background.	3(49)
50	WJR	3.2-18	3.2.3	2	1		Rewrite the sentence to read, "The Industrial Source Complex Prime (ISC Prime) dispersion model was used."	3(50)
51	BRP	3.2-19	3.2.3	Table 3.2-11			Change the SO2 standard for annual and 24-hour from "80" and "365" to "53" and "260" The new numbers are the WAAQS, which are more restrictive then the NAAQS.	3(51)
52	WJR	3.2-19	3.2.3	Table 3.2-11			Please change the 1-hour SO_2 standard from "1,065" to "1,050"	3(52)
53	MDT	3.2-19	3.2.3	1	6		Modify the sentence to read, "Also, the modeling results show that the annual maximum concentration of NO2 is 0.0053 ug/m3, which is well below the SIL of 0.1ug/m3."	3(53)
54	BRP	3.2-19	3.2.3	1			Add a sentence at the end of the paragraph, "Both the modeled concentrations of PM and SO2, annual and 24-hour are well below the respective SIL's in class I areas."	3(54)
55	MDT	3.2-28	3.2.3	Table 3.2-20	PM10	Net	Change "-84" to "84" The sign was entered incorrectly. We are providing a new table, which includes the effects of the changes in Molecular weight on the over all balance. This change makes the balance more complicated, but it is also more accurately describes the actual particulate balance.	3(55)
56	BRP	3.2-31	3.2.3	Table 3.2-23			New table provided with Molecular weight conversion	3(56)
57	BRP	3.2-33	3.2.3	5	2		Delete the last sentence and add, "Cooling tower modeling shows that icing will not occur."	3(57)
58	KM	3.2-34 to 3.2-35	3.2.5				The "Regulatory Framework" discussion and summary of mitigation requirements is incomplete and potentially misleading. In addition to listing the four Washington projects for which EFSEC has required greenhouse gas mitigation, the EIS should clearly state that no other operating or permitted facilities in Washington are subject to any greenhouse gas mitigation requirement.	3(58)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
59	KM	3.2-35	3.2.5	last 2			The "Project Greenhouse Gas Emissions" discussion is incomplete. An EIS should discuss the impact of the proposed project in comparison to the "no action alternative." Under the no action alternative, growing regional electric demand would be met by generating facilities other than the Cogeneration Project. Those facilities would be less efficient and more GHG-intensive than the Cogeneration Project. Therefore, operation of the Cogeneration Project would result in fewer GHG emissions than would occur under the no action alternative. It is for this reason that virtually every authority on global warming and GHG emissions recommends the increased reliance on gas-fired combined cycle combustion turbine facilities, and cogeneration facilities in particular, as an important near-term solution to rising GHG emissions.	3(59)
60	KM	3.2-35	3.2.5	last 2			In his Direct Testimony, which BP filed with EFSEC on September 19, 2003, W. David Montgomery (an internationally recognized expert on the economics of GHG reduction) estimates that the operation of the Cogeneration Project will result in 320,000 tons less CO2 being emitted compared to the No Action Alternative.	3(60)
61	KM	3.2-35	3.2.5	last ¶	2		The statement "Fugitive leaks of natural gas from the systems serving the proposed cogeneration facility are estimated to emit methane equivalent to 12% of the project's stack emissions of greenhouse gas" is not appropriate. Leaks of methane that occur at various places in the North American natural gas pipeline system are not directly related to the Cogeneration Project and are certainly not caused by the Cogeneration Project. If the Cogeneration Project were not built, natural gas would be transported to other electrical generating facilities, and system-wide transportation losses would occur in any event. If leaks are occurring in the pipeline system, it is the responsibility of entites that own and operate that system to address those leaks and mitigate them as appropriate.	3(61)
62	BRP	3.2-38	3.2.6	5	last		Please add the following sentence, "These receptors are not near the BP Cherry Point Cogeneration Project site and not effected by the Project emissions."	3(62)
63	BRP	3.2-39	3.2.6	1	2		"100 out of 18" should probably be "10 out of 18".	3(63)
64	WJR	3.2-39	3.2.6	1	2		Add a sentence at the end of the paragraph which reads, "These receptors are not near the Cherry Point Project site and are not impacted by the Cherry Point Project emissions."	3(64)
65	KM	3.2-42	3.2.6	5	6		The statement "the production of greenhouse gases could be reduced if operation of the BP cogeneration facility displaces the operation of other non-cogeneration faciltiies" is incomplete and may confuse the reader. It should go on to state that, in the region's competitive wholesale power market, power plants operate according to their merit order of cost and efficiency. Therefore, BP's cogeneration facility would displace less efficient and greater-emitting facilities. Please see the Direct Testimony of James Litchfield, W. David Montgomery, and Mark Moore filed with EFSEC by BP on September 19, 2003. In particular, David Montgomery estimated that operation of the BP facility would result in a decrease in CO2 emissions of 320,000 tons per year.	3(65)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
66	BRP	3.2-44	3.2.6	Table 3.2-28			The SO_2 24-hour impact at Abbotsford is 0.058 not 0.58.	3(66)
67	BRP	3.2-44	3.2.6	Table 3.2-29	SO2		Please change the standards for SO_2 annual and 24-hour from "80" and "365 to "53" and "260". The 53 and 260 numbers are WAAQS's and more restrictive than the NAAQS.	3(67)
68	WJR	3.2-44	3.2.6	Table 3.2-29	SO2		Please change "1,065" to "1050" for the 1-hour SO_2 standard.	3(68)
69	KM	3.2-45	3.2-7			7	Delete the bullet under additional recommended mitigation measures. Add, "Appropriate measures will be carried out to minimize PM due to the transport of material in trucks."	3(69)
70	MDT	3.2-46	3.2.7	3			Delete the paragraph and add "The Refinery has committed to removing the three older boilers within six months of beginning commercial operations."	3(70)
71	KM	3.2-46	3.2.8	6	4		The statement "The various analyses . . .indicate that air emissions associated with the proposed cogeneration facility would occur and would have an impact on the overall air quality of the region" is misleading, if not factually incorrect. The statement suggests that the project will have a noticeable impact on air quality throughout the region, but the analyses demonstrate the opposite. Even without taking into account the reductions in emissions at the refinery that will occur as a result of the cogeneration project, the modeling analyses indicate that the facility emissions will have a negligible effect on ambient concentrations of regulated pollutants in the region. Even the maximum modeled impacts at the maximum point of impact are below the "significant impact levels" or SILs established by the Department of Ecology. Modeled impacts diminish rapidly as you move away from the facility. It would be more accurate to say that the analyses indicate that the project will "have no practical effect on the overall air quality of the region."	3(71)
72	MDT	3.3-21	3.3.2	3	8		Delete and rewrite as follows, "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."	3(72)
73	MDT	3.3-22	3.3.2	4	5		Delete and rewrite as follows, "To the extent possible, construction of the water reuse facilities would occur when the ground is dry enough to work efficiently."	3(73)
74	MDT	3.3-23	3.3.2	2	3		In response to concerns about wetland C. The proposed ditch is on the downslope side of the wetland and could only drain the edge near the ditch unless the ditch intercepted a low spot in the wetland. Our approach is to use the new 1-foot contour map (and site work as necessary) to fine-tune the design of the perimeter ditch. The fundamental idea will be to keep it close to the existing elevation of the wetland to prevent draining just because of elevation difference (the drainage ditch concept). The width will be varied to manage the anticipated volume at any given point along it. If necessary, a berm will be placed on the powerplant side of the ditch to make sure the water can't escape across the site. Where the pad for the site is already elevated above the wetland, it will form a natural berm, and the only thing necessary will be to make sure the edge of the pad is impervious enough to prevent seepage from making the pad unusable. If the ditch crosses a low spot in the wetland, it may be necessary to berm the wetland side of the ditch for its distance across the low spot. With this fine-tuning, all potential f	3(74)

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DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
75	KM	3.3-23	3.3.2	5	2		There's a typo. It should read that Alcoa will provide approximately "2,780 gpm", not "2,770 gpm"	3(75)
76	MDT	3.3-28	3.3.5	5			Please add, "The project is considering a septic system as an alternative to routing sanitary sewer to the Birch Bay Water and Sewer District."	3(76)
77	MDT	3.4-14	3.4.2	2	7		Delete the sentence regarding the requirement to perform a ground water evaluation. Stormwater will be collected from uncontaminated areas of the project site and would have no effect on the groundwater.	3(77)
78	MDT	3.5-13	3.5.2	3	1		Replace "5" with "4". Only four transmission line towers are required.	3(78)
79	MDT	3.6-2	3.6.1	Table 3.6-1		Interface	The Refinery Interface Area would not be designated as "Open Space" and should be labeled "no" under the Open Space Column.	3(79)
80	MDT	3.7-23	3.7.2	4	1		Change "five" to "four". Only four new towers are required.	3(80)
81	MDT	3.7-23	3.7.2	4	4		Change "five" to "four". Only four new towers are required.	3(81)
82	MDT	3.7-35	3.7.5	1	4		Add to the last sentence, "...during initial clearing activities." After then site is cleared and graveled, the requirement to clean all equipment before leaving the site should end.	3(82)
83	KM	3.9-2	3.9.1	2	2		The statement than an increase of "3 to 5 dBA will be noticeable to most people" is not accurate without qualification. Although it may be possible for most people to discern a 3 to 5 dBA change in a laboratory setting, most people will not notice a change of less than 5 dBA in the real world. See Pre-filed Direct Testimony of David Hessler filed with EFSEC on September 29, 2003 at page 8 (A 5 dBA "increase is commonly described as barely being perceptible with careful listening").	3(83)
84	KM	3.9-6	3.9.2	4	1		The statement "some of the residential receptors' existing noise levels are shown to exceed the regulatory limit outlined in WAC 170-60," reflects a misunderstanding of the noise regulations. As correctly explained on page 3.9-2 of the DEIS, the Washington noise regulations apply to a single source of noise, rather than limiting the cumulative amount of a noise at a particular location. Therefore, it is not appropriate to say that the existing cumulative noise levels at a particular location exceed the regulatory limit. The question is whether a single specific source of noise causes sound levels to exceed the regulatory limits at the particular location.	3(84)
85	MDT	3.9-9	3.9.3	Table 3.9-5			Daytime/nighttime limits are compared against modeled plus background. This table should only compare modeled noise levels to the regulatory limits. For the same reason as above.	3(85)
86	MDT	3.9-12	3.9.6			2	Delete bullet 2. The project would agree to maintain construction equipment in good working order, but it would not agree to add additional noise attentuation features that were not already part of the original equipment.	3(86)
87	MDT	3.9-12	3.9.6			3	Delete bullet 3. The project would agree to use equipment that is maintained in good working order. The project would not specify that only the quietest available be used.	3(87)
88	KM	3.13-16	3.13.2	2	3		"2,770" should be "2,780"	3(88)

BP Cherry Point Cogeneration Project
DEIS Comments, 10-31-03

Item #	Intials	Page Number	Section Number	Paragraph Number	Sentence Number	Bullet Number	Comment	
89	MDT	3.14-9	3.14.3	3	2		The survey covered the entire area of the project upto the EFSEC boundary and the Natural gas pipeline ROW to the north. The area through the pipeline ROW (approximately 50ft) up to Grandview was not included in the survey. As with all areas of the project, if archeological remains are found, contruction activities in this area would stop until the appropriate authorities are notified.	3(89)
90	MDT	3.14-11	3.14.6	6			The completed archeological survey included detention pond 2, the interconnecting pipeway and access road #3. The substation inside the Refinery would be located on an existing gravel pad. The exact locations for the underground lines have not been determined, but the potential to find archeological resources in these areas are low. As with other all areas of the project, if archeological resources were found during excavation activities, then the appropriate authorities would be notified.	3(90)
91	DHE	3.15-9	Table 3.15-4			footnote 2	"Rate - Accidents per million vehicle miles." is erroneous, and should be corrected to "Rate - Accidents per million vehicles entering intersection."	3(91)
92	DHE	3.15-11	3.15.2	1	1		"(Access Road 1)" is in error, and should be corrected to "(Access Road 2)".	3(92)
93	DHE	3.15-11	3.15.2	1	2		Delete the second sentence, it is confusing. The primary construction access to the project is the Blaine road entrance. All other entrances would be internal.	3(93)
94	DHE	3.15-12	3.15.2	Table 3.15-6	last rows	last column	Please note. Because all the trip estimates in the application are based on 35, the actual traffic impacts are somewhat lower than the numbers in the application. These trip generation estimates for Project Operation Conditions are for 35 employees, which was BP's estimate at the time of the original traffic study two years ago. The DEIS now says 30 employees, but the trip generation has not been updated. The Total Trips for 30 employees would be 120 average weekday, 22 AM peak hour and 23 PM peak hour (Trips Entering and Exiting would change in proportion). However, since the numbers of trips generated during operation are so low, these differences in trips are not significant, and do not affect the impacts or mitigation.	3(94)
95	DHE	3.15-13	3.15.2	3	3		"(see Figure 3.1-6)" is erroneous, and should be corrected to "(see Figure 3.15-6)".	3(95)
96	KM	3.15-16	3.15.2	3	5		The sentence correctly states our earlier thoughts about barge transportation, in that it was anticipated that barge deliveries would not occur. Our current thinking is that barge deliveries are possible. Please leave this option open.	3(96)
97	DHE	3.15-17	Figure 3.15-7				At the end of the figure title, add "FOR PEAK CONSTRUCTION CONDITIONS"	3(97)
98	DHE	3.15-23	3.15.5			9	Delete "and Blaine Road/Grandview Road (SR 548)". See above comment for page 1-36, bullet number 3.	3(98)
99	MDT	3.16-1		2	5&6		Delete the last two sentences and add, "A Health and Safety Plan and Emergency and Security Plan would developed for the Cogeneration Project. These plans would coordinate with the Refinery's plans.	3(99)
100	MDT	3.16-17	3.16.2	3	2		Additional modeling would be performed for the Risk Management Plan and is not required at this time. This plan would require the facility to identify the 200 ppm endpoint. The 1000 ppm endpoint is not required.	3(100)

Expected Emissions after taking into account the effect of molecular weight

Expected Annual Emissions (tons/yr)	NOx	CO	VOC	PM_{10}	SO2	Totals
Primary Emissions						
Total from Cogeneration	181	81	28	94	50	434
Refinery Emission Reductions	(499)	(54)	(3)	(10)	(7)	(573)
Net Emissions	(318)	27	25	84	43	(139)
NOx (as NO2) to NH4NO3 Ratio	1.74					
SO2 to (NH4)2SO4 Ratio	2.06					
Secondary PM Formation Upon Aging	33%				20%	
Secondary PM Formed from NOx, SO2	104	-	-	-	21	
Secondary PM Avoided by Refinery Reductions	(286)				(3)	
Resulting Secondary Emissions						
Cogen Emissions After Secondary PM Formation	121	81	28	219	40	489
Emission Reductions After Secondary PM Formation	(334)	(54)	(3)	(299)	(6)	(696)
Net Emissions	(213)	27	25	(81)	34	(207)

NH4NO3 mol wt =	80	NH4NO3/NO2 =	1.74
(NH4)2SO4 mol wt =	132	(NH4)2SO4/SO2 =	2.06
NO2 mol wt =	46		
SO2 mol wt =	64		

BP Cherry Point Cogen
DEIS Comment - 21

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
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October 31, 2003

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ENERGY FACILITY SITE
EVALUATION COUNCIL

Mr. Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, Washington 98504-3172

Dear Mr. Fiksdal:

Re: Comments on the Draft Environmental Impact Statement (DEIS) for the BP Cherry Point Cogeneration Facility.

Thank you for providing the Department of Ecology (Ecology) with the opportunity to comment on the DEIS for the BP Cherry Point Cogeneration Facility. We have reviewed the wetland portions of the DEIS and have the following comments:

- Section 1.6.8 of the DEIS states that many aspects of the Custer/Intalco Transmission Line No. 2 remain to be resolved such as the number, type and location of potentially new transmission towers, access roads, culverts and temporary laydown, staging and assembly areas. Any or all of these features could impact wetlands, and these potential impacts have not been identified. In addition, there is no mitigation proposed for these potential impacts. The Site Certification Agreement should be conditioned to require that, if new towers need to be built in the Line No. 2 easement, detailed wetland delineations will be completed, impacts assessed, and appropriate wetland mitigation designed and planned in conjunction with, but in addition to the current proposed plan. 1

- Using stormwater in the mitigation area has implications for water quality as well as water quantity. A condition should be included in the Site Certification Agreement or 401 Water Quality Certification that requires monitoring of stormwater before it enters the mitigation area. Stormwater should be monitored at regular intervals and during and immediately after larger storm events to ensure that stormwater is adequately treated. If state water quality standards are exceeded, contingency measures will need to be identified and implemented. 2

- Although well thought out, the wetland mitigation proposal is still in a conceptual phase. The plan briefly discusses certain elements such as excavating shallow swales and other topographic modifications, but the extent and locations of these swales and modifications is not shown. Ecology recommends that the Site Certification Agreement and subsequent 401 Water Quality Certification be conditioned to require a final wetland mitigation plan. Specifically, the following elements should be included: 3

Mr. Allen Fiksdal
October 31, 2003
Page 2

- o A detailed grading plan. - This should include the exact location of the inlet channel and disperser outlets at the appropriate elevation to minimize the need for excavating shallow swales for conveying water across higher ground. Also, the mitigation plan refers to weirs in the inlet channel. Weirs should not be used in the mitigation area, since the idea behind the hydrologic restoration component of the plan was to eliminate engineered and artificial features such as ditches, to the extent possible. Although the inlet channel is necessary to convey the stormwater, it should be designed to function as simply as possible. **3 cont.**
- o Specifics on the planting plan, such as which species will be planted in what locations in which year. - At this time there is discussion about phased planting, which seems appropriate, but more detail is needed in a final plan.

- Figure 3.5-2 does not accurately reflect the wetland communities in the area. At least part of the "MF" forested area north of Brown Road in the location of the previously permitted transmission line is a forested wetland mosaic. The figure is deceiving in that it leads the reader to assume the area is mixed coniferous/deciduous forest, but not wetland. Most of the wetland areas depicted on this figure are shown as grasslands, when in fact, there are forested wetlands as well. This figure should be revised. **4**

Once again, thank you for the opportunity to comment. If you have any questions, please phone me at 425-649-7168.

Sincerely,

Susan Meyer

Susan Meyer, Wetland Specialist
Shorelands and Environmental Assistance Program

cc: Jeannie Summerhays, Ecology

11/03/2003 16:43 FAX 604 666 7294 ENVIRONMENT CANADA 001

BP Cherry Point Cogen
DEIS Comment - 22

Environment Canada Environnement Canada

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ENERGY FACILITY SITE
EVALUATION COUNCIL

November 3, 2003

Mr. Allen Fiksdal
Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172
USA

BY FAX (360) 956-2158

Dear Mr. Fiksdal:

Re: **Comments on BP Cherry Point Cogeneration Project DEIS**

I write to provide Environment Canada's comments on the September 5, 2003, Draft Environmental Impact Statement (DEIS) for the proposed BP Cherry Point Cogeneration Project ("the project"). The DEIS provides a comprehensive overview of potential environmental impacts of the project. Nonetheless, in Environment Canada's view, the final Environmental Impact Statement (EIS) should also address the issues outlined below.

The following comments draw upon an analysis of the DEIS conducted by a technical review team comprised of representatives from the Greater Vancouver Regional District, the Fraser Valley Regional District, the B.C. Ministry of Water, Land and Air Protection, and Environment Canada. I understand that this analysis has been forwarded to EFSEC by the Greater Vancouver Regional District. The technical review team analyzed air quality and greenhouse gas related impacts only, because no other environmental impacts in Canada are anticipated.

These comments address improvements to the DEIS only; Environment Canada may provide comments with respect to the project itself at the public comment stage, expected in December, 2003.

Health Effects

There is a substantial and growing body of evidence that suggests that adverse health effects would be predicted at particulate matter (less than 2.5 microns) and ozone exposure levels currently experienced in the Lower Fraser Valley.

For example, Bates et al (2003) concluded that: "*Levels of some air pollutants, particularly $PM_{2.5}$ and its wood smoke component, and ozone, in British Columbia are at levels which, on the basis of comparisons with international data, would be predicted to be causing adverse health effects,*" and went on to recommend that: "*...any improvement in air quality for PM or ozone would result in fewer negative health impacts.*"[1] In 2001, Lower Fraser Valley Medical Health Officers stated that: "*Air pollution is an important public health issue and is linked to illness and death in the lower mainland and elsewhere. This is true despite the fact that current levels of air pollution in the lower mainland are generally stable or lower than they have been in the past and that levels* 1

[1] Bates, D.V., Brauer, M., Koenig, J. Q., *Health and Air Quality 2002 – Phase 1 – Methods for Estimating and Applying Relationships Between Air Pollution and Health Effects*, British Columbia Lung Association, 2003.

Canada www.ec.gc.ca

of air pollution in the lower mainland are lower than other major cities in western North America."[2] And Vedal et al (2003) concluded from an analysis of data from Vancouver, British Columbia, between 1994 and 1996 that "*increases in low concentrations of air pollution are associated with increased daily mortality.*"[3]

In order to fully describe the health and environmental impacts of the proposed project, the final EIS should include the implications of this body of evidence with respect to the project. 1 cont.

Particulate Matter

Due to the potential implications of the body of evidence mentioned above, and the fact that the *Canada-Wide Standards for Particulate Matter (PM) and Ozone* acknowledge this body of evidence and include commitments to "continuous improvement" and "keeping clean areas clean," the final EIS should include a more thorough analysis of potential ambient concentrations of particulate matter (<2.5 microns). 2

Specifically, although the DEIS presents modeling results for worst-case ambient concentrations of PM (at the most-affected location in the Canadian Lower Fraser Valley), we understand that the models used to generate these results did not take into account the formation of secondary particulate matter. Because of the potential importance of exposure of Canadian residents to PM at levels below current objectives, the final EIS should include scientifically credible (for this airshed) modeling of worst-case ambient primary and secondary PM concentrations (including secondary particulate formation from in-plume and ambient ammonia). In order to address the worst case, such modeling should continue to ignore any "refinery offsets" or "PM adjustments," as in the DEIS, especially for consideration of short-term exposures. 3

Start-Up Scenarios

The DEIS modeled worst-case Canadian ambient concentrations of several pollutants. It is our understanding that these worst cases were defined from "maximum potential emission" scenarios, but that these scenarios did not include start-up scenarios. Informal information received subsequently from the proponent suggests that for some parameters (e.g. nitrogen oxides and carbon monoxide), the worst-case scenario for short-term exposures in Canada may be a start-up scenario. Therefore we conclude that in order to most accurately describe the environmental impacts of the project, the final EIS should include revised ambient concentration modeling results for any parameter and "objective duration" (e.g. <=24 hours) for which a start-up scenario is the worst-case scenario. (Modeled short-duration ambient concentrations should be compared to objectives, including World Health Organization objectives.) 4

Removal of Refinery Boilers

On page 3.2-46, the DEIS states:

> *Enforceable conditions requiring removal of the refinery's three utility boilers within six months of the beginning of cogeneration facility operation could allow regulatory agencies to more fully take into account refinery emission reductions in the permitting and environmental review process.* 5

---

[2] Copes, R., Blatherwick, J., Guasparini, R., Loewen, N., O'Connor, B., *Air Quality in the Lower Mainland: Patterns, Trends and Human Health*, South Fraser Health Region, 2001.
[3] Vedal, S., Brauer, M., White, R., and Petkau, J., *Air Pollution and Daily Mortality in a City with Low Levels of Pollution*, Environmental Health Perspectives, 111:1, 2003.

To facilitate decision-making concerning this potential requirement, the final EIS could include revised worst-case ambient concentration modeling results for the above scenario (i.e. post removal of refinery boilers). 5 cont.

Airshed Emissions Context

The DEIS presents estimated expected annual emissions attributable to the project, for several parameters. The final EIS would be more conducive to decision-making if these estimates were presented in the context of the estimated total emissions (for each parameter) in the Lower Fraser Valley / Whatcom County airshed. For example the final EIS might indicate the percentage of airshed emissions that the project would represent, similar to what the DEIS presently does for greenhouse gas emissions. These estimates are available from the Greater Vancouver Regional District's July 2003 *Forecast and Backcast of the 2000 Emission Inventory for the Lower Fraser Valley Airshed 1985-2025*. 6

Adjustments to Particulate Matter Emissions Estimates

The treatment of particulate matter emissions in the DEIS is in places confusing and may in some instances be incorrect. Detailed comments are provided in Attachment A. 7

I trust that you will find these comments useful. Overall, the technical review team found the DEIS to provide a helpful description of potential environmental impacts.

Sincerely,

M.D. Nassichuk
Manager, Pollution Prevention and Assessment

/attach.

Cc: Ken Cameron, Greater Vancouver Regional District
Hu Wallis, British Columbia Ministry of Water, Land and Air Protection
Hugh Sloan, Fraser Valley Regional District

Attachment A

Detailed Comments on Section 3.2 of the Draft Environmental Impact Statement

It would be helpful if the final EIS briefly discussed why expected emissions from the project exceed current emissions from the refinery boilers by different ratios for different parameters. (For example, the maximum potential PM emissions from the project appear to be 26 times higher than PM emissions from the refinery boilers at capacity, while for VOCs this ratio is 14, for SO_2 it is 7, for CO it is 3, and for NOx it is 0.5.) 7(1)

With regard to determining the effect of refinery boiler NOx and SO_2 emission reductions on secondary particulate formation, the technical review team suggested to BP representatives in January 2003 that a range of conversion rates (~2% to 40%) should be examined in the DEIS to address the lack of literature on the subject and the uncertainty contained within the conversion rate assumptions. The DEIS did not examine a range of conversion rates. It would be helpful if the final EIS did. 7(2)

In addition, the "one ton NOx forms one ton PM" and "one ton SO_2 forms one ton PM" simplifications used in the DEIS are incorrect and should be corrected in the final EIS. 7(3)

There is an apparent disagreement between Tables 3.2.8 and 3.2.9, regarding sulfur dioxide and carbon monoxide concentrations. If this is not a true disagreement, then additional clarification would be helpful. 7(4)

There is an apparent disagreement between the modeled maximum PM_{10} and $PM_{2.5}$ concentrations in Table 3.2.15, and footnote 1 of the same table. Again, if this is not a true disagreement, then additional clarification would be helpful. 7(5)

In Table 3.2-20 the Net Regional Change in PM_{10} Emissions should be +84 tpy instead of -84. Also, this table is quite confusing. The relationship between the rows could be made clearer in the final EIS. (For example, row 3 is the summation of rows 1 and 2, but this is not made clear.) 7(6)

Table 3.2-23 is confusing as presented. The relationship between the rows could be made clearer in the final EIS. Also, the last row appears to sum net emissions incorrectly. 7(7)

Lower Fraser Valley air quality monitoring data is now available for 2002; this could be substituted for the 2001 data used in the DEIS. 7(8)

BP Cherry Point Cogen
DEIS Comment - 23

Christine O. Gregoire
ATTORNEY GENERAL OF WASHINGTON
1125 Washington Street SE • PO Box 40100 • Olympia WA 98504-0100

November 3, 2003

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ENERGY FACILITY SITE EVALUATION COUNCIL

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
925 Plum Street S.E., Bldg 4
P.O. Box 43172
Olympia, WA 98504-3172

Re: BP Cherry Point Draft Environmental Impact Statement - Comments

Dear Mr. Fiksdal,

Below please find comments on the draft environmental impact statement (DEIS) for the BP Cherry Point Power Project. Thank you in advance for consideration of these comments.

Fact Sheet:

Page i, Abstract- This section states that BP proposes to construct and *"operate"* the 720 MW cogeneration facility. This is not an accurate statement. BP has actively been negotiating the sale of the facility to TransCanada. The sale appears to be imminent. The public has a right to know who will be operating this facility. Many of the environmental impacts and proposed mitigation features of this project are intricately related to operations at the BP Refinery. The sale of the Cogeneration Project has the potential to pose many questions as to the relationship that will exist between the two entities. This relationship and the impacts of sale of the project to TransCanada needs to be addressed throughout the DEIS. Accordingly, TransCanada should be referenced throughout the DEIS as the proposed operator of the facility. 1

Chapter 1 Summary

1.1 Introduction

Paragraph 1 - See comment above regarding BP's proposed *"operation"* of the project. 2

Paragraph 2 – This section states that 635 MW of power produced would be for "local" and regional consumption. In fact there is no guarantee whatsoever that power would be for local consumption. The Application for Site Certification (ASC) states that the power will be sold to BPA and put onto the northwest power grid. This being the case, it is not accurate to imply that the power produced will directly serve local demand. 3

1.2 .1 BP Cherry Point Refinery Need

This section states that refinery operations require approximately 85 MW of electricity and that historically the refinery has purchased power from third parties. The section goes on to state that this reliance on third party sources has exposed the refinery to price volatility. Implied is that construction of the facility will reduce this volatility. However, if BP sells the project as anticipated, then the proposed economic incentive would seemingly disappear because BP would 4

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Page 2

again be subject to power purchases from a third party provider. The section should acknowledge the proposed sale of the Project by BP and the impacts of the sale including potential price volatility. 4 cont.

1.2.2 National and Regional Power Need

The discussion on regional power need contains no information on supply forecast or conservation. It is not explained whether the WECC and NWPCC forecasts consider generation that is currently under construction and/or permitted within its analysis. What assumptions are made regarding conservation, renewable resources? 5

1.4.2 No Action Alternative

This section states the environmental impacts that would be avoided if the project were not built. The section fails, however, to mention the significant greenhouse gas emissions that would be avoided if the facility were not built 6

1.6.4 BP Refinery NPDES Permit Changes

This section states that "*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.*" It would seem appropriate that the water quality impacts of the Project be examined as part of this DEIS, rather than being put off for future consideration by Ecology. Accordingly the DEIS should address all of the water quality issues that have been raised. 7

1.6.7 Change of ownership of Cogeneration Project

This section fails to provide details of the potential ownership transfer to TransCanada. Many questions regarding the change of ownership have not been addressed. When would the transfer take place? Would the relationship between the refinery and the Project plant change in any way as a result of the sale? Has BP entered, or are they prepared to enter into a long term contract with Transcanda to ensure the delivery of steam and electricity to the refinery? The section mentions only the effect that the change of ownership would have on the greenhouse gas mitigation options offered. The section should, however, address the numerous other impacts that could potentially be affected by the sale of the Project. (e.g., will the refinery NPDES permit still be utilized for the Projects waste water discharge, or will TransCanada be required to obtain a separate permit?) 8

1.8 Cumulative Impacts

Section 1.8.1 Global Warming

This section states that is not possible to determine the actual impacts of cumulative GHG emissions on global warming. While it may not be possible to attribute the specific impacts of this facility on specific global warming conditions, there should be a statement that the cumulative operation of this and other fossil fuel fired facilities in the northwest will contribute to the worldwide impacts of global warming. Moreover, this section does not discuss the actual impacts of global warming on the Northwest. Cumulative impacts can not be ignored just 9

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Page 3

because it is impossible to attribute regional GHG emissions to specific impacts. Theis section needs to be re written in a manner that objectively and scientifically addresses the global warming issue. As currently written the section offers no substance of merit.. 9 cont.

1.8.2 Regional Air Quality

In this section it states that "purchase of cogeneration steam by the refinery would likely lead to the refinery shutting down three older utility boilers (emphasis added). Many of the heralded benefits of this project have been predicated upon the belief that existing boilers at the refinery will be shutdown, thereby resulting in reduction of certain criteria pollutants. It is disconcerting to this reader that words such as "*likely*" continue to be used when referring to the relationship between the generation facility and the refinery. In analyzing this project and its environmental impacts it should be made crystal clear as to how the two facilities will operate and interact. If the shutdown of existing boilers is only a hypothetical possibility then, the air quality benefit of removing boilers should not be included in any discussions on regional air quality and impacts. 10

3.2.3 Impacts of the Proposed Action
Emission Sources and Emission Controls

This section states that *"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."* There is no discussion of the impact of this "ammonia slip" on health and or the environment. Is this a significant amount of ammonia slip? Why, or why not. What are the health impacts of ammonia? Are there any ways to minimize this slippage? The section should address this issue in more detail. 11

Estimate of Actual Emissions from the Cogeneration Facility
Section 3.2-30

This section discusses at length the accuracy of the EPA test method for PM. The section states that, *"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 authors of the DEIS offer no comment or opinion as to the appropriateness of the applicants' rejection of the EPA test method. Nor is there anything included in this section from EPA as to why they believe that their testing method is appropriate. Rather, the authors of this DEIS simply adopt the statements made by the applicant in the ASC on this subject without any critique. At a minimum this section should offer additional information on views other than the applicants as to the appropriateness of the existing EPA test method as well as the EPA's comments on the method proposed by the applicant. The absence of this discussion does not aid in the understanding of the enviromental impacts. 12

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Page 4

3.2.5 Greenhouse Gas

This section offers no discussion on impacts that global warming will have, and is already having, on the Northwest. While the exact impacts of a warmer region are not entirely known, scientists do know that certain impacts such as a decrease in snowpack, and the melting of glaciers is already occurring. The specific impacts of global warming on the Northwest should be at least minimally explored in this section. 13

3.2.6 Secondary and Cumulative Impacts
Cumulative Impact of Refinery and Cogeneration Facility Reductions

This section states that, *"[I]n 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."* Again, this statement is partly attributable to the rejection of the EPA test methodology on formation of PM10. EPA's testing methodology should not be so readily rejected, or in the alternative their should be a balanced critique of the existing testing methodology prior to its rejection. This section should contain additional information on secondary and cumulative impacts using the existing EPA testing methodology. 14

3.4.2 Impacts of the Proposed Action and 3.4.4 Secondary and Cumulative Impacts

There is no discussion in either of these sections on potential water quality issues 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 the refinery NPDES permit revision process. To the extent that cumulative impacts are discussed they are given a cursory review, stating only that, *"The cogeneration facility would add 190 gpm of treated wastewater to the Strait of Georgia at Cherry Point, which is an increase of about 8% over the current discharge from the BP Cherry Point Refinery. Although a relatively small increase, this adds to the overall burden to water quality of the Strait of Georgia."* This "*discussion*" does nothing more than state the obvious. Please supplement this section to address the issues raised above. 15

Thank you for allowing CFE the opportunity to comment on the draft environmental impact statement.

Very truly yours,

MARY C. BARRETT
Senior Assistant Attorney General
(360) 664-2475

MCB:nt

BP Cherry Point Cogen
DEIS Comment - 24

Greater Vancouver Regional District
4330 Kingsway, Burnaby, British Columbia, Canada V5H 4G8

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Telephone 604-432-6375
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November 3, 2003

File: CP08 01 BPA

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ENERGY FACILITY SITE EVALUATION COUNCIL

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council (EFSEC
P.O. Box 43172
Olympia, WA 98504-3172 USA

Dear Mr. Fiksdal

Re: ***Comments on the BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement***

As the technical lead organization for Canadian air quality agencies, we wish to advise EFSEC of our comments and concerns regarding the *BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement*. These concerns have been identified by the *Interagency Technical Review Team* consisting of staff from the Greater Vancouver Regional District (GVRD), Fraser Valley Regional District (FVRD), B.C. Ministry of Water, Land and Air Protection, and Environment Canada, who reviewed the air quality section of the *Draft Environmental Impact Statement* as well as some additional information provided by the proponent.

The attached report present the issues that we believe were not addressed adequately in the DEIS and/or remain as main concerns for this project. A more detailed analysis of the DEIS and air quality related concerns/issues are provided in Attachment-A of the *Interagency Technical Review Team* report.

Thank you for the opportunity to comment on the proposed *BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement.*

Yours truly,

Hugh Kellas

for Ken Cameron
Manager, Policy and Planning

Attachment

cc Mike Nassichuk, Environment Canada
Hu Wallis, Ministry of Water, Land and Air Protection
Hugh Sloan, Fraser Valley Regional District

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Interagency Technical Review Team Comments on the BP Cherry Point Cogeneration Project – Draft Environmental Impact Statement

(October 29, 2003)

SUMMARY

On September 5, 2003, the Draft Environmental Impact Statement (DEIS) for the proposed BP Cherry Point Cogeneration Project was issued by Washington State Energy Facility Site Evaluation Council (EFSEC). The *Interagency Technical Review Team* consisting of air quality experts from the GVRD, FVRD, Ministry of Water Land and Air Protection, and Environment Canada, met with BP Cherry Point representatives and their air quality consultants on September 15, 2003 to discuss air quality issues identified by the Canadian agencies, and how they were addressed in the DEIS. New information on modelled air quality impacts of the project (e.g. isopleths of ambient air concentrations) and impacts of startup/shutdown practices (which were not included in the Draft EIS) were provided during and after the September 15th meeting.

The following is a summary of issues that the *Interagency Technical Review Team* believe were not addressed adequately in the DEIS and/or remain as main concerns for this project. These findings are based on the review of the air quality section of the Draft EIS, pre-filed testimony, and discussions with the proponent and their air quality consultants:

- **Health Effects:** There is a substantial and growing body of evidence that suggests that adverse health effects would be predicted at particulate matter and ozone exposure levels currently experienced in the Lower Fraser Valley, below current air quality objectives. For example, Bates et al (2003) concluded that: *"Levels of some air pollutants, particularly $PM_{2.5}$ and its wood smoke component, and ozone, in British Columbia are at levels which, on the basis of comparisons with international data, would be predicted to be causing adverse health effects,"* and went on to recommend that: *"...any improvement in air quality for PM or ozone would result in fewer negative health impacts."* (See Attachment-A for further information.) In order to fully describe the health and environmental impacts of the proposed project, the final EIS should analyze the implications of this body of evidence with respect to the project. 1

- **Particulate Matter (PM) Emissions:** Due to the potential implications of the body of evidence mentioned above, and the fact that the *Canada-Wide Standards for Particulate Matter (PM) and Ozone* acknowledge this body of evidence and include commitments to "continuous improvement" and "keeping clean areas clean," PM emissions from the proposed plant are an issue of potential concern. "Maximum Potential" emissions of primary PM from this project are estimated at 262 tons per year, and would be released almost entirely in the form of fine particulate ($PM_{2.5}$). "Expected" emissions which are considered as more representative of actual emissions from the proposed power plant are estimated at 232 tons per year. This has the potential to increase the overall PM_{10} and $PM_{2.5}$ emissions in the LFV airshed by 1.5% and 3%, respectively. The "expected" annual emissions presented in the DEIS, assumes 60% error in the EPA test reference method and subtracts an additional 149 tons per year of PM_{10} from the annual emissions as "PM adjustment". In the absence of additional scientific documentation, it would be difficult to justify such adjustments. 2

Comments on the BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement October 29, 2003

It is recognized that the retirement of the old refinery boilers will reduce emissions of other criteria air pollutants (e.g. NO_x and SO_x), which are precursors for fine particulate, and would help reduce the secondary PM formation in the atmosphere. However, there is uncertainty contained in the conversion rate that would affect the amount of secondary PM avoided (or formed) due to the reduction (or increase) in precursor emissions such as NO_x, SO_x and ammonia. This results in an uncertainty in the overall PM impacts of this project. A range of conversion rates should be examined in the final EIS to address the lack of literature on the subject and the uncertainty contained within the conversion rate assumptions. A more detailed analysis of primary PM emissions and secondary PM can be found in Attachment-A. 3

Given the concern around PM, the final EIS should include a more thorough analysis of potential ambient concentrations of PM_{10} and $PM_{2.5}$ than contained in the DEIS. Specifically, although the DEIS presents modeling results for worst-case ambient concentrations of PM (at the worst-case location in Canada), we understand that the models used to generate these results did not take into account the formation of secondary particulate. Because of the potential importance of exposure of Canadian residents to PM at levels below current objectives, the final EIS should include scientifically credible (for this airshed) modeling of worst-case ambient primary and secondary PM concentrations (including secondary particulate formation from in-plume and ambient ammonia). In order to address the worst case, such modeling should continue to ignore any "refinery offsets" or "PM adjustments," as in the DEIS, especially for consideration of short-term exposures. 4

- **Ammonia (NH_3) Emissions:** Ammonia emissions from the proposed plant are also an issue of potential concern. The use of selective catalytic reduction (SCR) control technology to reduce NO_x emissions, is expected to release nearly 175 tons per year of ammonia. While the proponent has provided information to indicate that the maximum predicted ammonia concentration is less than the Acceptable Source Impact Level (ASIL), it would be beneficial to also report the maximum predicted concentration in Canada. In addition, ammonia is a precursor to secondary particles (e.g. ammonium nitrate and ammonium sulfate) in the presence of NO_x and SO_x. As mentioned above, giving a consideration to the formation of additional ambient particulate due to this ammonia source would be useful when assessing the total ambient particulate concentrations (PM_{10} and $PM_{2.5}$) resulting from the project. 5

- **Start-Up Scenarios:** The DEIS modeled worst-case Canadian ambient concentrations of several pollutants. It is our understanding that these worst cases were defined from "maximum potential emission" scenarios, but that these scenarios did not include start-up scenarios. Additional information received from the proponent subsequent to the release of the DEIS suggests that for some parameters (e.g. nitrogen oxides and carbon monoxide), the worst-case scenario for short-term exposures in Canada may be a start-up scenario. Therefore we conclude that in order to most accurately describe the environmental impacts of the project, the final EIS should include revised ambient concentration modeling results for any parameter and "objective duration" (e.g. $\leq$ 24 hours) for which a start-up scenario is the worst-case scenario. 6

2

Comments on the BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement October 29, 2003

- **Airshed Emissions Context:** The DEIS presents estimated expected annual emissions attributable to the project, for several parameters. The final EIS would be more conducive to decision-making if these estimates were presented in the context of the estimated total emissions (for each parameter) in the Lower Fraser Valley / Whatcom County airshed. For example the final EIS might indicate the percentage of airshed emissions that the project would represent, similar to what the DEIS presently does for greenhouse gas emissions. These estimates are available from the Greater Vancouver Regional District's July 2003 *Forecast and Backcast of the 2000 Emission Inventory for the Lower Fraser Valley Airshed 1985-2025.* 7

- **Mitigation Measures**

  PM Emissions: Applicant's proposal to reduce refinery emissions through removal of existing refinery boilers will offset the emission of some Criteria Air Contaminants. On page 3.2-46, the DEIS states:

  Enforceable conditions requiring removal of the refinery's three utility boilers within six months of the beginning of cogeneration facility operation could allow regulatory agencies to more fully take into account refinery emission reductions in the permitting and environmental review process.

  To facilitate decision-making concerning this potential requirement, the final EIS could include revised worst-case ambient concentration modeling results for the above scenario (i.e. post removal of refinery boilers). 8

  The largest expected emissions reduction will be in NO_x emissions resulting in net reduction of 318 tons per year. $PM_{2.5}$ emissions, however, which are linked to respiratory and circulatory diseases in humans, are expected to increase by 232 tons annually. This is a significant increase when compared to the overall $PM_{2.5}$ emissions in the airshed, and will result in some increase in ambient $PM_{2.5}$ concentrations. The Applicant proposed no mitigation measures to minimize the impacts of PM emissions from the operation of the proposed power plant. 9

  Greenhouse Gas Emissions: As proposed, the project would emit more than two million tons per year of greenhouse gases to the atmosphere. The proponent company has committed itself to greenhouse gas emission reduction targets on a worldwide basis and proposed to offset GHG emissions from this project as part of BP's corporate (worldwide) GHG objective. Also, the Applicant provided an alternate GHG mitigation proposal for the cogeneration facility that would apply to the project if the facility changes ownership. Whether the facility ownership remains with BP or changes, a credible/verified documentation would help ensure that such offsets are occurring. While it is recognized that climate change is a global concern, local air quality benefits as well as other environmental and economic benefits could be realized by offsetting greenhouse gas emissions locally, within the airshed. 10

A more detailed analysis of the DEIS and air quality related concerns/comments are provided in Attachment-A.

Attachment-A: Detailed Comments on the BP Cherry Point Cogeneration Project – Draft Environmental Impact Statement

The following findings are based on the review of the air quality section (3.2) of the Draft Environmental Impact Statement, pre-filed testimony of Brian R. Phillips (Exhibits 22.0, 22.1, 22.2, and 22.3), and discussions with the Applicant and their air quality consultant.

Overview of Maximum Potential and Expected Emissions

The following table summarizes the maximum potential emissions from the proposed power plant as well as the emission reductions (offsets) from the refinery that would result from the retirement of the existing steam boilers that currently supply steam to refinery processes.

Table 1.

	Maximum Potential Emissions (tons/y)				
	NO_x	CO	VOC	PM_{10}	SO_2
Power Plant Total[1]	233	158	42	262	51
Emission Reductions from Refinery[2]	-499	-54	-3	-10	-7
Net Emissions	**-266**	**104**	**39**	**252**	**44**

[1]Including emergency generator, firewater pump and cooling tower

[2]Note that the reductions from the refinery are based on the emission capacity of the refinery boilers, and not the emissions from current boiler operations.

The following table summarizes the emission of common air contaminants from the proposed power plant (maximum potential and expected), Sumas Energy 2, BP Cherry Point refinery, Whatcom County and the Lower Fraser Valley International Airshed.

Table 2.

	Emissions Comparison (tons/year)					
	NO_x	CO	VOC	PM_{10}	$PM_{2.5}$	SO_2
BP Cherry Point Cogeneration Project (**Max. Potential**)[1]	-266	104	39	252	252	44
BP Cherry Point Cogeneration Project (**Expected-I**)[1, 2]	-318	27	25	232	232	43
BP Cherry Point Cogeneration Project (**Expected-II**)[1, 2, 3]	-318	27	25	84	84	43

Comments on the BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement October 29, 2003

Sumas Energy 2 Generation Facility (**Max. Potential**)	145	88	153	209	209	69
BP Cherry Point Refinery (2000)	2,265	362	1,519	91	65	1,735
Emission Reductions from Refinery[4]	-499	-54	-3	-10	-10	-7
Whatcom County (2000)	17,400	114,650	40,280	5,300	2,540	10,060
Lower Fraser Valley International Airshed[5] (2000)	99,900	481,930	111,200	15,360	8,960	18,900

[1] Emission reductions (offsets) from the refinery due to the removal of refinery steam boilers are taken into account for both the "maximum potential" and the "expected" emission scenarios.

[2] **"Expected-I"** emissions are based on operating conditions that are considered more representative of actual operation of the cogeneration plant where "PM adjustment" was not taken into account. Interagency Technical Review Team does not support the inclusion of "PM adjustment" in emissions unless scientific documentation from reputable sources such as US EPA is provided.

[3] **"Expected-II"** emissions are based on operating conditions that are considered more representative of actual operation of the cogeneration plant where also the "PM adjustment" (-149 tpy) is taken into account. The Applicant claims that there is 60% error in the EPA test reference method that overestimates PM emissions from natural gas-fired turbines.

[4] Potential emission reductions due to removal of refinery steam boilers.

[5] Includes emissions from the GVRD, FVRD and Whatcom County.

The NO_x emissions are expected to be reduced with this project under both "Maximum Potential" and "Expected" operating conditions. This is mainly due to the retirement of existing refinery boilers that no longer will be needed when the cogeneration plant (providing the required steam for the refinery processes) begins operating. Emissions of all other common (criteria) air contaminants (CACs), however, are expected to increase with the cogeneration project. Emissions of carbon monoxide (CO), volatile organic compounds (VOCs) and sulphur oxides (SOx) are very low when compared to local emissions as well as the overall airshed emissions. Therefore, no significant direct air quality impacts of these contaminants are expected in Canada. This is confirmed by the modelling which shows the predicted ambient concentrations to be very low compared to Canadian objectives. Particulate Matter (PM) emissions, however, appear to be significant – under both "Maximum Potential" and "Expected" conditions – and deserve special attention. 11

PM Emissions

The proponent has included two different "expected" emissions scenarios for Particulate Matter. The first scenario assumes that the expected PM emissions will be 232 tpy (as shown in the table above). The second is known as the "PM adjustment" scenario which assumes that there is a 60% error (149 tpy) in the EPA test reference method and that the expected PM emissions will be 84 tpy (including refinery reductions) instead of 232 tpy. While the *Inter-Agency Technical Review Team* acknowledges the documentation provided by the proponent with respect to the accuracy of EPA Method PRE-4/202, it is the view of the *Team* that without additional scientific documentation from peer-reviewed third party sources or the EPA to support the evidence of error in the EPA test reference method, we will continue to evaluate the expected emissions from this facility without the PM adjustment. 11 cont.

"Expected" PM_{10} emissions of 232 tons per year would increase the overall Whatcom County and Lower Fraser Valley International Airshed (PM_{10}) emissions by 4.4% and 1.5 %, respectively. Assuming all PM is released in the form of $PM_{2.5}$ the increase in the $PM_{2.5}$ emissions would be as high as 9% and 3% of the overall emissions of $PM_{2.5}$ for Whatcom County and the Lower Fraser Valley International Airshed, respectively. 12

Overview of Secondary PM and Air Quality Issues

Secondary PM

The proponent has addressed the impact that the facility will have on secondary particulate matter (PM) formation. The sensitivity of the assumptions made about the percentage of NO_x and SO_x that gets converted to secondary particulate matter is significant to this issue. Depending on which conversion rate is used and whether 60% PM adjustment (-149 tpy) is taken into account, there can be a net decrease (-81 tpy) or a net increase (224 tpy) in overall (primary plus secondary) PM. If the "PM adjustment" is not taken into account, the overall PM balance is expected to range between 68 and 224 tpy (see table below). As stated previously, it is the view of the Team that "PM adjustment" should not be taken into account unless credible, scientific documentation (e.g. from US EPA) is provided. 13

The *Inter-Agency Technical Review Team* discussed this issue with BP representatives in their meeting on January 29, 2003 and gave input with respect to conversion rates. It was felt that a range of conversion rates (~2% to 40%) should be examined in the final EIS to address the lack of literature on the subject and the uncertainty contained within the conversion rate assumptions. For the entire facility, there is a net decrease in NO_x and a net increase in SO_x (see "expected" emissions in the table above). Therefore, if a high conversion rate is used - as given in the DEIS (33% for NO_x, 20% for SO_x) - it will result in a large reduction in secondary PM from NO_x sources, but an increase in secondary PM from SO_x sources, resulting in a large net reduction in secondary PM and an increase of 68 tpy in overall PM balance. If a lower conversion rate, as suggested by the *Inter-agency Technical Review Team*, is used (10% for NO_x, 10% for SO_x), a net increase of 185 tpy in overall PM (primary plus secondary) would be expected from this facility. As shown in the following table, lower conversion rates (from NO_x and SO_x to secondary PM) would result in a higher overall PM balance. 14

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Table 3. Overall PM Balance for Three Different Scenarios/Conversion Rates

	Expected PM Emissions (tons/year)	**Secondary PM from NOx (tons/year)**	**Secondary PM from SOx (tons/year)**	**Overall PM Balance (tons/year)**
	Conversion Rate: 33 % NOx and 20 % SOx			
Power Plant Total	242	104	21	367
Refinery Reductions	-10	-286	-3	-299
Net	**232**	**-182**	**18**	**68**
	Conversion Rate: 10 % NOx and 10 % SOx			
Power Plant Total	242	31	10	283
Refinery Reductions	-10	-87	-1	-98
Net	**232**	**-56**	**9**	**185**
	Conversion Rate: 2 % NOx and 4 % SOx			
Power Plant Total	242	6	4	252
Refinery Reductions	-10	-17	-1	-28
Net	**232**	**-11**	**3**	**224**

*It is assumed that NO_x emissions are 181 tpy (plus a refinery reduction of -499), and SO_x emissions are 51 tpy (plus a refinery reduction of -7 tpy). Also, no "PM adjustment" was taken into account. Secondary PM is assumed to be ammonium nitrate and ammonium sulphate.

Ambient PM Concentrations

Modelled concentration for maximum 24-hour PM_{10} and $PM_{2.5}$ in Canada (location with
maximum impact) is 2.5 $\mu g/m^3$. The worst-case increase in the 24-hour ambient PM_{10}
concentration at a Canadian location was less than 7% over worst-case background at the same
location. Maximum change in 24-hour PM_{10} concentrations for White Rock (0.52 $\mu g/m^3$), 15
Langley (0.36 $\mu g/m^3$), Richmond (0.19 $\mu g/m^3$), and Abbotsford (0.16 $\mu g/m^3$) are predicted to be
much lower than for the Canadian location with maximum impact (Table 5). A maximum annual
PM_{10} concentration of 0.2 $\mu g/m^3$ was also predicted for the same location close to the
Canada/US border. These concentrations are based on maximum potential emissions and did not

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take into account any "PM adjustments" or secondary PM formation/reduction into account. The modelled increases in the ambient PM_{10} levels do not appear to be high for major residential areas.

Table 4. Comparison of Maximum PM_{10} Concentrations in Canada (BP vs. SE2)

Facility Name	Averaging Time	Maximum PM_{10} Concentration in Canada[1,2] (μg/m³)			Most Stringent Canadian Objective (μg/m³)
		Change	Background	Total	
BP Cherry Point Cogen. Project	**24-Hr**	2.5	39*	42*	50
	Annual	0.2	13	13	30
Sumas Energy 2 Generation Facility	**24-Hr**	3.7	52	56	50
	Annual	0.4	15	15	30

* These numbers are revised using GVRD data
[1] BP Cherry Point: Highest concentrations in Canada predicted on the US/Canada border, 12 km north of project site. Source of data is DEIS (September 2003)
[2] Sumas Energy 2: highest concentrations in Canada predicted on Sumas Mountain, Abbotsford. Source of Data is SE2 Second Revised Application (June 2001)

Table 5. Increase in Maximum PM_{10} Concentrations (BP Cherry Point Project)

Averaging Time	Increase in Maximum PM_{10} Concentrations at Various Locations* (μg/m³)					
	Max. US	Max. Canada	White Rock	Langley	Richmond	Abbotsford
24-Hr	4.3	2.5	0.52	0.36	0.19	0.16
Annual	0.25	0.2	0.06	0.04	0.01	0.01

*Data in this table is based on information provided by the proponent at a meeting with the Interagency Technical Review Team on September 15, 2003.

Results of Calpuff modelling with secondary PM formation (i.e. 24-hour isopleths and maximum concentration) should be provided, in order to determine the combined effect of primary and secondary PM on ambient air quality. Current values reported in the DEIS are from the ISC modelling, which doesn't include secondary PM. 16

Ambient Ozone Concentrations

Notably, the DEIS does not comment upon or address the impact of the proposed facility on ozone concentrations. Known to pose a health risk at current levels, ozone is a priority air quality issue in the LFV airshed and has been the focus of several scientific investigations and federal, provincial and regional air quality management initiatives. 17

Start-Up Scenarios

The DEIS modeled worst-case Canadian ambient concentrations of several pollutants. It is our understanding that these worst cases were defined from "maximum potential emission" scenarios, but that these scenarios did not include start-up scenarios. Additional information 18

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received from the proponent subsequent to the release of the DEIS suggests that for some parameters (e.g. nitrogen oxides and carbon monoxide), the worst-case scenario for short-term exposures in Canada may be a start-up scenario. Therefore we conclude that in order to most accurately describe the environmental impacts of the project, the final EIS should include revised ambient concentration modeling results for any parameter and "objective duration" (e.g. ≤ 24 hours) for which a start-up scenario is the worst-case scenario. 18 cont.

Health Effects

There is a substantial and growing body of evidence that suggests that adverse health effects would be predicted at particulate matter (less than 2.5 microns) and ozone exposure levels currently experienced in the Lower Fraser Valley, below current air quality objectives. For example, Bates et al (2003) concluded that: *"Levels of some air pollutants, particularly $PM_{2.5}$ and its wood smoke component, and ozone, in British Columbia are at levels which, on the basis of comparisons with international data, would be predicted to be causing adverse health effects,"* and went on to recommend that: *"...any improvement in air quality for PM or ozone would result in fewer negative health impacts."* Bates, D.V., Brauer, M., Koenig, J. Q., *Health and Air Quality 2002 – Phase 1 – Methods for Estimating and Applying Relationships Between Air Pollution and Health Effects*, British Columbia Lung Association, 2003.

In 2001, Lower Fraser Valley Medical Health Officers stated that:
"Air pollution is an important public health issue and is linked to illness and death in the lower mainland and elsewhere. This is true despite the fact that current levels of air pollution in the lower mainland are generally stable or lower than they have been in the past and that levels of air pollution in the lower mainland are lower than other major cities in western North America." Copes, R., Blatherwick, J., Guasparini, R., Loewen, N., O'Connor, B., *Air Quality in the Lower Mainland: Patterns, Trends and Human Health*, South Fraser Health Region, 2001.

Vedal et al (2003) concluded from an analysis of data from Vancouver, British Columbia, between 1994 and 1996 that *"increases in low concentrations of air pollution are associated with increased daily mortality."* Vedal, S., Brauer, M., White, R., and Petkau, J., *Air Pollution and Daily Mortality in a City with Low Levels of Pollution*, Environmental Health Perspectives, 111:1, 2003.

The body of evidence above suggests that the worst-case increases in ambient PM concentrations associated with the project would be statistically expected to lead to adverse health effects among some Canadian residents. 19

Mitigation Measures

Section 3.2.7 in the DEIS describes the Applicant's proposal to mitigate air emissions during the construction and operation of the energy facility. Construction emissions will be limited to fugitive dust and emissions from construction equipment powered by gasoline and diesel 20 engines. These emissions appear to be small and will only occur during the construction phase of the project. Emissions resulting from the operation of the power plant, however, appear to be significant (PM_{10} and/or $PM_{2.5}$ in particular) and should be addressed through proper mitigation measure. 20 cont.

Selective Catalytic Reduction (SCR) – The SCR technology will potentially reduce the NO_x emissions from 9 ppm to 2.5 ppm by using ammonia. In addition to being toxic, the introduction of ammonia emissions (175 tons per year) through SCR has the potential to contribute to secondary PM formation in the atmosphere. This is considered as the major drawback of the proposed SCR technology. 21

Refinery Steam Boilers – The cogeneration facility will provide steam for the refinery processes that are currently met by existing refinery steam boilers. Reducing the refinery emissions through removal of existing refinery boilers will help offset some of the Criteria Air Contaminant emissions. The largest reduction will be in NO_x emissions resulting in a net reduction of 318 tons per year.

On page 3.2-46, the DEIS states: "*Enforceable conditions requiring removal of the refinery's three utility boilers within six months of the beginning of cogeneration facility operation could allow regulatory agencies to more fully take into account refinery emission reductions in the permitting and environmental review process.*" 22

To facilitate decision-making concerning this potential requirement, the final EIS could include revised worst-case ambient concentration modeling results for the above scenario (i.e. post removal of refinery boilers).

Cogeneration Plant – The operation of the cogeneration facility is expected to increase $PM_{2.5}$ emissions by 232 tons per year under "actual" (or likely) operating conditions. This is a significant increase when compared to the overall $PM_{2.5}$ emissions in the airshed and can be expected to result in some increases in ambient $PM_{2.5}$ concentrations. Although fine particulate matter ($PM_{2.5}$) are linked to respiratory and circulatory diseases in humans and considered the most harmful among the criteria air contaminants (CACs), the Applicant proposed no mitigation measures to minimize the impacts of PM emissions from the operation of the proposed power plant. EFSEC's Site Certification Agreement required a similar facility (Sumas Energy 2) to offset 100% of particulate (PM) emissions from their operation. Offsetting $PM_{2.5}$ emissions would help manage these harmful emissions and associated ambient impacts in our airshed where approximately 2.5 million people live. 23

GHG Mitigation – According to the data provided in the DEIS (Table 3.2-25), the greenhouse gas emissions from the cogeneration project would be 5%, 37%, 58% and 61% lower than a natural gas fueled combined cycle combustion turbine, and conventional natural gas-fired, oil-fired and coal-fired boilers, respectively. This is mainly due to more efficient fuel utilization achieved by combined-cycle cogeneration plants as well as the use of a less carbon intensive fuel such as natural gas.

The Applicant proposed to mitigate the project's greenhouse gas emissions as part of BP's corporate GHG objective within the company's worldwide operations. BP's worldwide objective is to hold its net GHG emissions at the 2002 level through the year 2012. If the proposed

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cogeneration facility changed ownership in the future an alternate GHG mitigation scheme would apply. According to this proposal GHG reductions would be obtained by the facility owner or would be provided in the form of an annual payment to a qualifying organization (e.g. the Climate Trust) for 30 years, which is the assumed economic life of the project. This would offset approximately 20% of the greenhouse gases generated by this project. According to the DEIS, BC Hydro plans to offset 50% of GHG emissions from new natural gas fired power plants, and Seattle City Light targets 100% offset for all new fossil generating stations added to the City's energy mix.

Whether the facility ownership remains with BP or changes, EFSEC should ensure that a credible, verified documentation be provided for GHG offsets. Since offsetting greenhouse gas emissions within the airshed would offer additional local air quality benefits as well as other environmental and economic benefits, preference should also be given to local GHG offsets. 24

Section 3.2.8 Significant Unavoidable Impacts: It is stated in the DEIS that "No significant unavoidable adverse impacts on air quality are identified." This project, however, has the potential to increase fine particulate ($PM_{2.5}$) emissions, which are linked to respiratory and circulatory diseases in humans, by 232 tons per year. The increase in PM emissions can be expected to result in some increases in the ambient concentrations of fine particulate. In addition, over 2 million tons of greenhouse gas emissions will be emitted from this project, annually. These would result in some unavoidable environmental impacts, unless the $PM_{2.5}$ (fine particulate) and the greenhouse gas emissions are offset properly. 25

Specific Comments on the Air Quality Section (Section 3.2) of the DEIS:

Table 3.2-4 (p. 3.2-11) contains several errors which were discovered upon review of the Greater Vancouver Regional District's annual air quality reports for the years noted in the table. For ambient monitoring station 1, the 24-hour PM_{10} for 2001 is 39 (not 35), the 24-hour $PM_{2.5}$ for 2001 is 21 (not 19), and the 24-hour ozone for 2001 is 80 (not 76). For ambient monitoring station 2, the 24-hour $PM_{2.5}$ for 2001 is 19 (not 17) and the 24-hour ozone for 2001 is 84 (not 82). In the maximum column, 24-hour PM_{10} should be 39 (not 35), 1-hour CO should be 4060 (not 2900) and 1-hour ozone should be 166 (not 168). Of main significance is the increase in the maximum 24-hour PM_{10} to 39 $\mu g/m^3$. 26

Table 3.2-5 (p. 3.2-13) presents a summary of the GVRD air quality index based on a dataset limited to only one year. We feel it is more appropriate to consider at least three years of ambient air quality data for establishing current conditions, as is done in Table 3.2-4. 27

There is an apparent disagreement between Tables 3.2.8 and 3.2.9, regarding sulfur dioxide and carbon monoxide concentrations. If this is not a true disagreement, then additional clarification would be helpful. 28

Table 3.2-15 and Table 3.2-16 (p. 3.2-25) should also include the maximum 24-hour $PM_{2.5}$ concentrations in addition to the 98th percentile concentrations currently reported in the tables. 29

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Table 3.2-20 (p. 3.2-28) – Net Regional Change in [PM_{10}] Emissions is listed as -84. This should be corrected as +84. Also, this table needs to be re-organized to clarify the relationship between the rows (i.e. row 3 is the summation of row 1 and row 2; row 5 is the summation of row 3 and row 4). 29 cont.

Table 3.2-23 (p. 3.2-31) is confusing as presented. It is suggested that this table be re-organized to show the relationship between the rows (e.g. row 3 is the sum of row 1 and row 2, etc.). In addition, the effects of NO_x and SO_2 emissions/reductions on secondary particulate are calculated assuming that a one ton emission/reduction in NO_x or SO_2 results in a one ton change in secondary PM. It would me more appropriate to consider molecular weights in this determination, and to assume that the secondary PM is in the forms of ammonium nitrate and ammonium sulphate. 30

BP Cherry Point Cogen
DEIS Comment - 25

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ENERGY FACILITY SITE
EVALUATION COUNCIL

November 3, 2003

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Re: Comments to DEIS, DOE/EIS-0349.

Mr. Fiksdal:

Please accept this letter and the accompanying enclosure as Whatcom County's comments to the Draft Environmental Impact Statement (DEIS), DOE/EIS-0349, for the BP Cherry Point Cogeneration Project. The comments are organized by general topic.

Traffic
Whatcom County Public Works Engineering Division notes that according to the DEIS most of the impact on traffic from the project will be on State Route 548 (Grandview Road). During the two-year project construction period we will experience substantially more traffic (1200ADT) than when the plant is in operation (25ADT). While under existing conditions and projected road utilization the impact to most county roads will not be significant during the two-year construction period, a new land use development has been approved that will change the traffic flow at the intersection of Grandview Road and Vista Drive. Delta Line Road is to be closed at Grandview Road and realigned to Vista Drive. The traffic impacts at this intersection should be reevaluated with the new traffic volumes and flows. The new development is expected to add another 800 ADT to the intersection. Additionally, County Engineering notes the DEIS fails to adequately evaluate the need for mitigation to improve Brown Road when it is used in the course of the project. This too is an oversight which should be analyzed. 1

Geology
Douglas Goldthorp, L.G., L.E.G., L.H.G., Whatcom County Geologist, has reviewed the project DEIS and finds that it is inadequate with regard to its investigation and conclusions surrounding the geology of the site. He voices the following concerns: 2

Whatcom County DEIS Comments
Page 1

1. There is no significant discussion or analysis of the referenced faulting projecting beneath or near the proposed site as hypothesized by Dr. Don Easterbrook, Professor Emeritus of Geology, Western Washington University. 2(1)

2. The DEIS does not include an analysis of existing invaluable depth-to-bedrock, bedrock, and seismic information that has been developed by petroleum explorations over the past several decades near the project site which is available in DNR Olympia files or within private corporate files. 2(2)

3. The DEIS, which was published September 5, 2003, does not reference, discuss, or analyze an existing geotechnical investigation of the site performed by URS Corporation entitled "BP Cherry Point Cogen Project, Report of Subsurface Investigation/Laboratory Testing, URS Corporation, July 3, 2003." The final EIS should incorporate, where possible and appropriate, the findings of this additional analysis. 2(3)

4. The DEIS does not adequately review the need for a Probabilistic Seismic Hazard Assessment (PSHA) that would define the level of construction design necessary for this specific site. 2(4)

5. The DEIS does not include any significant reference or analysis of the relevant geological findings and conclusions recently established for the nearby SE2 Cogeneration facility, Energy Facility Site Evaluation Council, Application No. 99-01 and Council Order No. 768. As the geology of the two sites may exhibit commonalities, those findings and conclusions may be relevant to the present project action and should have been considered. 2(5)

6. DEIS Section 3.1.6, Significant Unavoidable Adverse Impacts, states that, "No significant unavoidable adverse impacts on earth resources are identified. Project design as well as operation and maintenance planning would minimize potential risks from natural hazards such as seismic and volcanic events." This statement was made without the benefit of all the earth resource information mentioned above, without the detailed geotechnical analysis of July 3, 2003, without a PSHA for project construction design guidance, and without any specific project design proposal. 2(6)

7. The DEIS does not address the potential benefits which an ongoing post-construction seismic monitoring program could provide for the safety of the facility and its workers. 2(7)

<u>Wildlife, Wildlife Habitat, and Wetlands</u>
Please see the accompanying report of Dr. Kate Stenberg, Ph.D., entitled "Review of BP Cherry Point Cogeneration Project, Draft Environmental Impact Statement," copy enclosed. 3

<u>Noise</u>
At the County's request, Dr. Paul Wierzba, P.Eng., Ph.D., reviewed the DEIS as to its analysis of potential noise impacts who adds: 4

1. The DEIS does not adequately consider noise impacts on nearby residences and wildlife. It focuses primarily on meeting the regulatory requirements in regard to noise emissions instead of the potential that exists for realized adverse environmental impacts of the action. The applicable regulatory limits do not necessarily guarantee that all adverse noise impacts will be avoided should those regulatory thresholds be met. Situational characteristics and concerns vary from site to site and the potential for adverse noise impacts may likewise vary accordingly. 4(1)

2. The background sound levels were not properly identified in the initial Golder study. Single spot measurements of very short duration (15 min) along the roads were taken. The times that these measurements were taken were not specified. As a result, the measurements are inadequate for assessing the existing background levels. 4(2)

3. Subsequent background measurements by Hessler at four selected locations provided suitable A-weighted background levels, but not the C-weighted values. In order to more fully assess potential adverse environmental impacts, C-weighted levels should be further investigated and assessed. C-weighted sound levels in conjunction with the A-weighted levels provide a measure of the low frequency component of noise. 4(3)

4. Suitable noise design targets for the facility were not established, either in regard to the impact on nearby residents or the impact on the wild life, in terms of individual octave band levels, or overall A-weighted and C-weighted levels (i.e., addressing the overall loudness and the low frequency component). A proper impact assessment requires some reasonable knowledge or measure of the existing background levels. A suitable target for maximum noise emissions is typically related to or based on the measure of existing background levels. Given the circumstances of the present application, a suitable target for noise emissions from the facility where the adverse impact on the surrounding wildlife and residents is acceptable, would be an overall increase of 3 dB in A-weighted and 9 dB in C-weighted sound levels at critical receptor locations. 4(4)

5. In assessing the impact on the residential receptors, the DEIS relied on the mean measured L90 background levels which were averaged over three consecutive 24-hour periods. This is not seen as appropriate. The proposed facility represents a stationary noise source which does not change substantially from day to night. The impact on the residents is the greatest during the nighttime periods. Therefore, only average nighttime background sound levels should be used in impact assessment. 4(5)

6. The DEIS failed to properly identify the most impacted residences. The most impacted residences (the dwellings with highest predicted plant noise levels) are located along the Blaine Road some 1450 to 1500 meters from the site. 4(6)

7. The statement in the DEIS that " Increases [in sound level] of less than 5 dBA are essentially inaudible" is not generally correct. In fact, an increase of 1 dBA can be quite audible if the low frequency component is considerably different. 4(7)

8. The DEIS made references to low frequency noise (LFN) and checked whether the levels were below vibration induction and loudness threshold, however, generally LFN was not considered in the impact assessment. Typically, in order to properly assess the noise impact, the predicted low frequency noise should be compared to the existing background levels, particularly in relatively quiet rural, urban, or suburban locations. 4(8)

9. The DEIS did not establish any criteria for assessing noise impact on the nearby wildlife areas. Wildlife expertise should be sought and utilized in establishing suitable criteria for such assessment. 4(9)

10. The DEIS did not consider the noise impact on the wild life in the area, particularly the heron colony and the respective staging and nesting areas. The staging area in the wetlands to the north of Grandview Road is the most impacted area. Further analysis is warranted. 4(10)

Compressor Station

Staff from the Washington Utility and Trade Commission (UTC), have recently contacted Whatcom County to discuss potential concerns regarding the proposed pressure upgrade for the natural gas line to service the BP cogeneration facility. The proposal being reviewed by the UTC includes the placement of a compressor station near the Sumas natural gas hub area. This proposal is not addressed in the current Draft EIS. 5

The siting of a compressor facility near the Sumas natural gas hub will affect agricultural lands, this is also not addressed in the Draft EIS Energy and Natural Resources Section. 6

During initial discussion with BP representatives, a compressor site was proposed for an undetermined site near the Sumas Natural Gas Hub. Whatcom County communicated with BP representatives that the establishment of a pump station in lands designated as agriculture by Whatcom County's Comprehensive Plan would require mitigation for conversion from agricultural use. The County's preference would be to put the pump station in Industrial zoned land. Subsequent discussions and published documents including the Draft and Final Potential Site Studies both issued in 2001 and the Draft EIS issued September 2003 all indicated that either there would be no new pump station (Draft Potential Site Study) or that a pump station would be located within the cogeneration site (Final Potential Site Study and Draft EIS). 7

Should BP alter its application for placement of the compressor facility to such alternative site, the Final EIS should include a full review of the compressor station's environmental impacts and should include appropriate mitigation measures including mitigation for conversion of agricultural land. 7 cont.

Transmission Lines

At page 2-24, the DEIS outlines two options for interconnection of the Cogeneration Facility to Bonneville's transmission system. Option 1 would not require the construction of any additional transmission lines between Bonneville's Intalco (Alcoa) and Custer substations, but would instead rely on a Remedial Action Scheme. Option 2 (2a and 2b) involves the construction of a new transmission line between the Intalco and Custer substations. 8

The DEIS indicates that Option 1 is the Applicant's preferred option. Whatcom County likewise prefers Option 1. The Remedial Action Scheme would not require new transmission towers, foundation work or additional wires. It would avoid the potential environmental and aesthetic impacts of constructing new lines within the existing transmission corridor.

On behalf of Whatcom County I extend my appreciation for this opportunity to offer our thoughts and comments on this critical environmental document. It is hoped the Council finds the comments useful. They are offered in the spirit of fostering the best environmental review possible for the project.

Sincerely,

DM Grant

David M. Grant
Deputy Prosecuting Attorney

Review of

BP Cherry Point Cogeneration Project

Draft Environmental Impact Statement

Prepared for

Whatcom County

October 31, 2003

Kate Stenberg, Ph.D., Principal
Quailcroft Environmental Services

Quailcroft Environmental Services

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Table of Contents:

Overview and Summary

On behalf of Whatcom County, I reviewed the Draft Environmental Impact Statement (DEIS) for the BP Cherry Point Cogeneration Project prepared by the Energy Facility Site Evaluation Council (EFSEC) and the Bonneville Power Administration (BPA), dated September 2003. I also conducted a visit to the BP Cherry Point facility and vicinity on October 12, 2003. My review raises several concerns about the conclusions in the DEIS and potential impacts of the proposed cogeneration facility. There are a number of subject areas where the DEIS does not supply adequate or accurate information which, in turn, prevents an analysis of impacts to be conducted. Both NEPA and SEPA require that impacts be disclosed in an environmental impact statement. The DEIS is inadequate when it does not provide sufficient information to either analyze potential impacts or explain why such impacts would not occur.

Likely adverse impacts include impacts to water quality and quantity; to sensitive fish and wildlife including the significant heron colony, threatened Puget Sound Chinook, and Essential Fish Habitat; critical wetland and riparian habitats; and impacts from changes in noise, light and glare. It is possible that some of these impacts will be adequately avoided, minimized or mitigated for in the project, however, the DEIS does not provide sufficient information to reach that conclusion. In addition, the wetland mitigation plan, a key component of this project, has not been available to the public for review at the projects' website where the rest of the DEIS may be found. Public involvement is a key requirement of NEPA, and this oversight compromises compliance with this element.

This review is focused on potential impacts to wildlife and habitats and does not address the adequacy of the wetland mitigation plan for functions other than wildlife habitat.

Qualifications:
I have been involved with monitoring herons in Puget Sound, primarily in King County, for over a decade and have been a member of the International Heron Working Group since its inception in 2000. I am a nationally recognized expert in the field of urban wildlife biology and am currently the chair of the national Urban Wildlife Working Group of the Wildlife Society. I have expertise in wetlands and land use planning as well. I have also consulted colleagues with expertise in noise impacts and wetland habitats in compiling the following information.

Great Blue Herons

Status

The great blue heron colony at Cherry Point is the third largest colony in the Puget Sound area of Washington. In 2002, the colony supported about 260 nests (Eissinger 2002). The herons at Cherry Point are significant because they are members of a distinct subspecies of great blue heron (*Ardea herodias fannini*). This coastal subspecies is found along the west coast of British Columbia and Washington and perhaps into Oregon. The main populations are found in the greater Puget Sound or Salish Sea area. Researchers throughout western Washington and British Columbia have noticed a downward trend in the numbers of these herons and are growing alarmed at the declines. Canadian scientists have already taken the steps needed to list the coastal subspecies of the great blue heron as "sensitive" under the Canadian version of an endangered species act and are currently collecting the data that would be required to upgrade the species to "threatened." EFSEC and BPA should ensure that their actions do not endanger the significant Cherry Point colony and lead to a listing of this species in the U.S.

Great blue herons are colony nesters, which increases their vulnerability to disturbances. As the Puget Sound region becomes increasingly developed, alternative nesting sites suitable for large colonies of herons are increasingly rare. In addition, any disturbance that disrupts the use of a heron colony, even for a few breeding seasons, can have significant impacts on the population due to the large concentration of reproductive effort in one location. 3(1)

Despite being the third largest heron colony in the Puget Sound region, the Cherry Point heron colony has experienced severe declines in recent years. Prior to 1999, the colony supported over 400 nests. It failed completely in 1999 and has only slowly recovered to its current size of about 260 nests. Any significant reduction in the surrounding habitats that support the colony could severely impact the colony.

Critical Heron Habitats

There are several critical heron habitats located within the project area and vicinity. The limiting habitats with which the Birch Bay great blue heron colony has a primary association include: the nesting colony and it's associated buffer; "staging" areas in fallow fields, riparian habitats and wetlands to the east of the colony; and critical foraging areas within a four mile radius of the nesting colony which include, wetlands, wetland buffers, fallow fields, riparian habitats, and protected marine shorelines. The heron use and importance of each of these critical areas is described in more detail below.

The project will impact each of these critical areas in the following ways. Development of the project will directly and permanently impact over 33 acres of wetland and wetland buffer within this critical foraging area. The wetland mitigation plan will affect 110 acres of the critical habitat. In the long-term, the mitigation plan may improve the overall quality of the foraging habitat, but it may adversely impact it in the short-term. The mitigation plan would appear to result in a decrease in available habitat for at least two to five years and this may be enough of a temporal loss to result in colony abandonment. The operation of the proposed cogeneration facility and associated noise impacts may also affect the herons' ability to utilize their critical foraging habitats. Finally, operation of the proposed facility may change the wastewater discharge parameters, which may affect populations of forage fish, resulting in impacts to the herons' ability to find sufficient food resources in critical marine environments.

Heron colonies are generally located in relatively undisturbed forest stands. Herons seem to require a buffer between human activities and their nest trees to be successful. Within the colony, multiple nests are located in each tree. Large colonies encompass many trees and they may "move" from year to year around a core area as the colony contracts and expands. Colonies are frequently found in stands of deciduous trees, in or adjacent to wetland and riparian areas. The Cherry Point colony is located in a stand dominated by western paper birch (*Betula papyrifera*). It is set back from the nearest street and is located adjacent to the riparian habitats of Terrell Creek. The herons nest from about March through July.

The Cherry Point colony relies heavily on the marine resources found in the shallow intertidal habitats of Birch Bay and likely also Drayton Harbor and Lummi Bay for food. Herons will fly up to twelve miles from a nesting colony to forage. However, during the nesting season, the breeding females rely on food sources closer to the colony to support themselves and their brood. The most critical areas during the nesting season would be those foraging areas within four miles of the nesting colony.

3(1) cont.

Juveniles take several weeks to learn how to forage for themselves after fledging. This critical learning period also occurs close to the nesting colony. For the Cherry Point colony, this critical foraging habitat includes the wetlands, fallow field and stream habitats of the Terrell Creek watershed. Both breeding females and juveniles rely heavily on amphibians and small mammals, as well as fish, for food. Colonies that lose these critical components of their food resources do not survive.

In addition, studies have shown that the breeding females and juveniles during these critical periods will forage in wetland buffers up to 150 feet from the edge of a wetland. Again, they are foraging for amphibians and small mammals in these upland areas. Actions that compromise the ability of these critical wetland, upland, riparian and marine environments to provide adequate food resources could have significant adverse impacts to the nesting colony. Similarly, activities that impair the herons' ability to forage in these locations would also have significant impacts to the nesting colony.

A final component of colony success is an appropriate "staging" area. This is an area near the nesting colony where herons congregate at the start of the breeding season. The function of this behavior and the requirements of an adequate staging area are poorly understood, however, all successful colonies observed include a place where this activity occurs. At the Cherry Point colony, the wetlands and fallow fields north of Grandview Road and between Jackson and Blaine Roads provide this critical function for the colony.

Given the significance of the Cherry Point heron colony and its associated critical habitats within the project area, it is highly unusual that the DEIS does not mention the presence of the herons, even in lists of species that may occur in the area. By omitting any mention of the great blue heron colony or heron use of the project area (including the proposed mitigation area), the DEIS is clearly incomplete and inadequate. 3(1) cont.

Potential Impacts to Wildlife

<u>Noise</u>

Noise impacts that need to be analyzed in the DEIS fall into two main categories, impacts to breeding wildlife and impacts to foraging wildlife. Due to the significance of the Cherry Point heron colony, potential impacts to breeding great blue herons are of primary concern. However, noise may affect the reproductive success of other species as well. Noise may simply deter individuals from occupying available habitats, thereby reducing the overall population of species and reducing the wildlife diversity of an affected area. Noise may also mask intra- and inter-specific calls that may then reduce the reproductive success of individuals. Noise may also mask warning sounds of approaching predators, thereby making individuals and their broods more vulnerable to predation. Noise similarly affects foraging individuals, reducing foraging success by interfering with the ability to detect prey and avoid predators, and by reducing the total area available to forage in.

In order for a species to occur and survive in a particular location, individuals must be able to meet all of their requirements for survival. This is the definition of "habitat." If individuals find that they are unable to find sufficient prey, avoid predators, or communicate with other individuals of their species to find mates or maintain territories, then that location can no longer be considered habitat for that species. When noise levels cause individuals to avoid an area, then the habitat area for that species has been reduced. 3(2)

Researchers agree that noise can affect an animal's physiology and behavior, and if it becomes a chronic stress, noise can be injurious to an animal's energy budget, reproductive success and long-term survival (e.g. Trimper, et al., 1998, Gese, et al., 1989, Reijnen, et al., 1996). If reproductive success and long-term survival are affected, even if individuals are still present in an area, the suitability of the habitat to support the species has been reduced. The DEIS does not address any of these potential impacts to wildlife nor does it provide adequate information to evaluate these potential impacts.

Furthermore, the studies of Brattstrom and Bondello, 1983, remind us of the very obvious point that human ears and the ears of many wildlife species, particularly herpetofauna are structured very differently and thus react to the same sounds very differently. For example, they found that while OSHA recommends that humans not be exposed to sounds of 95 dBA for more than 4 hours, lizards experienced hearing loss after only 8 minutes. 3(3)

In addition, studies with wildlife indicate that a change of even 1 dBA is perceptible to animals and the ability to discern a sound 1 dBA over the ambient noise levels may mean the difference between survival and becoming a predator's lunch (Brattstrom and Bondello 1983.) Regulatory standards for humans should not be applied to wildlife, without serious consideration of the types of wildlife and habitats present and the type of noise being evaluated. Wildlife should be evaluated as sensitive receptors. 3(3) cont.

The DEIS is very unclear about the nature of the noise that would be generated by the proposed cogeneration plant. For example, it is not clear whether the noise would be a constant continuous presence or whether the plant would cycle generators on and off creating variability in the noise. Variable noise sources sometimes appear to have a greater impact on wildlife than constant, even noise sources of the same magnitude over time. If the noise would be variable then there is a greater likelihood of significant impacts to wildlife use of both the compensatory mitigation areas (CMAs 1 and 2) and receptor sites further away, such as the heron colony. The DEIS is inadequate in its description of the noise that would be generated and the potential impacts from that noise. 3(4)

It is also important to evaluate wildlife sensitivity to noise disturbances that might be related to time of day or season. Great blue herons, for example, appear to be very sensitive to many disturbances during the "staging" and early nesting seasons. During these periods they may react to disturbances that they appear to ignore later in the breeding season and in the winter. Herons react to disturbances by flushing or flying up into the air. This extra activity may disrupt an individual's energy budget causing it to spend more time foraging and less time focused on nesting activities. Flushing during the early nesting season also exposes eggs to predation when adults fly off of nests in alarm. It is important to consider these seasonal sensitivities regardless of whether the noise is variable or constant. The DEIS inadequately evaluates potential impacts to wildlife from the noise that would be produced by the proposed plant. 3(5)

Foraging activities occur around the clock. Some species are diurnal and primarily forage during daylight hours while others are nocturnal, foraging at night. Some species, including great blue herons, forage both during the day and at night. Herons may have evolved this behavior in response to their dependence on marine food resources and the fact that one of the two low tides is likely to occur after nightfall. However, they also forage in wetlands and other non-marine habitats at night. Changes in nighttime noise measures generated by the proposed project may become critical limiting factors in the suitability of available habitats and wildlife's ability to utilize them.

Some wildlife species, such as many amphibians, utilize different habitat types during different parts of the year. For example, many native amphibian species utilize wetlands for only a short time for breeding and rearing but then they rely on forested habitats for much of the rest of the year. Noise impacts should be evaluated for the various cover types utilized by different species. 3(6)

The noise analysis in the DEIS does not reflect the greater sensitivities of wildlife receptors in wetland habitats north of Grandview Road, nor does it address the needs of the heron colony or its seasonal sensitivities. There currently is very little topography or vegetation that could attenuate sounds produced by the proposed project between the project source and the colony. Currently the primary attenuating factor appears to be simple distance. Although the modeling in the DEIS indicates a greater increase in perceived noise at some points that are at greater distances than other points. This apparent anomaly is unexplained. 3(7)

Dr. Wierzba has indicated that the modeling reported in the DEIS is based on several questionable assumptions (Wierzba, pers. comm.). The distance from the proposed project location to the heron colony is significant and it may be likely that there would be a low probability of a significant impact at the colony location. However, it is impossible to make this determination without accurate information and the DEIS should be corrected to reflect the actual conditions in the area. 3(8)

General foraging activities, on the other hand, could occur fairly close to the proposed cogeneration plant. Therefore, it is also important to have accurate information about the potential changes in the noise environment within the critical "staging" and foraging areas north of Grandview Road. If noise impacts would prevent herons from utilizing the wetland/upland complex north of the project location, then it is possible that food resources could become a critical limiting factor in the continued success of the colony. 3(9)

Construction noise is more problematic as it is variable, loud, and unpredictable. It is common for conditions to be imposed on projects to control construction noise impacts to wildlife. For example, seasonal construction limits to prevent impacts from occurring at the most sensitive times of year for particular wildlife species may be imposed. The DEIS incorrectly dismisses potential construction noise impacts by stating that they are exempt from noise standards. 3(10)

Noise impacts in the DEIS have been inaccurately and inadequately represented. The short statement in the DEIS that wildlife have adapted to the existing refinery noise simply highlights the lack of analysis on the magnitude of change in noise levels and on the impacts to all of the surrounding critical habitat areas. The lack of information about impacts to the critical "staging" and foraging areas for the Cherry Point heron colony and the likelihood of significant adverse noise impacts in these areas is a critical oversight. 3(11)

<u>Light and Glare</u>

Lights on facilities can have serious impacts to a variety of wildlife. Lights can disorient migrating birds, insects, and amphibians. The Cherry Point area is a significant area for neotropical migrants during the spring and fall migrations. Lights can also disrupt the foraging activities of nocturnal species. 3(12)

The DEIS is unclear as to the proposed heights and lighting requirements of the various parts of the proposal. The DEIS should be clarified.

It appears that the exhaust stacks for the proposed cogeneration plant will not exceed 150 feet and will not need any navigation warning lights. It should be added as a condition of the project that no stacks, towers or power poles will be lighted. This should be listed as a measure to avoid potential impacts. 3(13)

In addition, to avoid impacts to nocturnal wildlife, all outdoor lighting of the proposed cogeneration plant should be shielded to prevent any light or glare from escaping to the north of Grandview Road or up into the sky. This type of shielded lighting is commercially available and generally costs about the same as other types of outdoor lighting. 3(14)

These simple measures should allow the proposed plant to avoid most impacts of light and glare on surrounding wildlife habitats. These measures should be specifically committed to in the DEIS. 3(14) cont.

Wastewater Discharge

The Washington Department of Fish and Wildlife and The Nature Conservancy have identified the Cherry Point nearshore habitat as a priority conservation area for biodiversity (WDFW 2003.) This means that in a regional evaluation of available habitats, the Cherry Point area was identified as being very significant. Potential impacts to these habitats must be carefully documented and evaluated. The DEIS is inadequate in both its documentation and evaluation of potential impacts to the Cherry Point nearshore habitats from wastewater discharges. 3(15)

The DEIS is unclear about potential impacts from the discharge of wastewater generated by the proposed cogeneration plant. Table 3.4-5 shows a projected 1% increase in the temperature of the water being discharged. However, the DEIS does not indicate what the existing discharge temperature is, nor what the projected temperature will be. It is also not clear whether this increase occurs at the treatment plant or at the discharge point. 3(16)

In addition, the DEIS is very unclear about the status of the BP Cherry Point Refinery's current NPDES permit. In section 1.6.1 the DEIS states that the Refinery's existing NPDES permit will require revision to address water quality issues 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. The DEIS does not indicate the status of the current permit, the parameters which are currently permitted, nor how the addition of the proposed cogeneration plant wastewater will affect the allowable limits of the current permit. 3(17) The DEIS appears to assume that the additional wastewater will not be a significant addition to what is currently permitted, however, it does not provide adequate documentation to show that this assumption is correct.

The proposed cogeneration plant has recently received an Industrial Wastewater permit from the Washington Department of Ecology. It is my understanding (based on discussions with Ecology staff) that this permit primarily analyzed the addition of the wastewater to the BP Cherry Point Refinery's treatment plant and only incidentally to the discharge into marine waters. A more thorough analysis of impacts to the marine environment would occur in 2004 when the Refinery's NPDES discharge permit will need to be renewed. 3(18)

NPDES permits for industrial discharges are renewed every five years. The BP Cherry Point Refinery's permit was last authorized in October 1999. This was about the same time as the listing of several salmonids under the Endangered Species Act and prior to the passage of the Magnuson- Stevenson Fisheries Conservation and Management Act, which protects forage fish, such as herring and surf smelt. In the intervening four years, there has been a tremendous change in our understanding of the impacts of human activities, such as industrial discharges, on salmonids and forage fish. 3(19)

The DEIS appears to simply assume that since there is a valid permit currently in place there will be no impacts to these species. However, given the changes that have occurred in listings and scientific knowledge of impacts, this assumption, without additional documentation, is inadequate. The DEIS must address potential impacts to salmonids and forage fish species.

If there are impacts to the forage fish species that spawn on eelgrass beds around Cherry Point and on the beaches, then that increases the potential for adverse impacts to a wide range of species including threatened salmonids and herons. These forage fish come in close to shore to spawn just as the heron colony is at a peak need for food to support chicks in nests. Herons eat both adults and subadults. The fish habitats of Cherry Point support fish populations that are then available in the intertidal areas of Birch Bay and other protected shorelines. Changes in the quality of the wastewater discharge may affect eggs or larvae of these fish species, which may then affect the populations of those fish species. Any reduction in available food resources could significantly impact the heron colony's long-term viability. 3(20)

The potential impacts to the fisheries resources from changes in temperature and other water quality parameters must be evaluated in the DEIS. These potential impacts do not appear to have been adequately documented or evaluated in the Industrial Wastewater permit for the proposed cogeneration plant. The potential for impacts must be evaluated and documented in the DEIS. 3(21)

Stormwater Management

It appears that stormwater runoff from the proposed cogeneration plant site will simply be directed north of Grandview Road and dispersed across the landscape into the CMAs. The mitigation plan implies that the wetland mitigation area will provide water quality treatment for stormwater. It is not appropriate to use a mitigation site for stormwater treatment. 3(22)

The DEIS is unclear about which stormwater management standards will be implemented. At a minimum the proposed project should follow the 2001 Washington State Department of Ecology stormwater manual. This minimum standard should be clearly specified in the DEIS and included in the evaluation of impacts. 3(23)

The DEIS is also unclear about the amount of impervious surface that will be created, the volume of stormwater runoff expected, how water fluctuations will be managed, and treatment levels proposed. The DEIS does state that the stormwater ponds "have been designed," therefore, this information should be readily available for review and analysis. 3(24)

The dead storage portions of the proposed stormwater ponds have the potential to become both bullfrog habitat and amphibian mortality sinks. These ponds should be managed to prevent both occurrences. To prevent stormwater ponds from becoming mortality sinks for many species of native amphibians, a low curb or tight mesh fence around the perimeter of the pond will prevent adults from getting into the pond during the breeding season. 3(25)

Habitat Loss

The DEIS reaches the incorrect conclusion that because habitats that will be directly impacted are of low quality with non-native vegetation dominating, their conversion to industrial uses will somehow be of a net benefit. This conclusion is erroneous because even non-native vegetation provides some environmental benefits, including sediment retention, and infiltration. Conversion will irrevocably prevent the opportunity to restore these areas. Permanent loss of habitat is not a net benefit under any calculation. Each wildlife species needs a certain amount of space to survive within a particular area. When the available space is reduced, a species may no longer be able to use the area, even if other habitat features, such as food and shelter are present. 3(26)

In concluding that a loss of low quality habitats will somehow be a net benefit, the DEIS is incorrect and inadequate. 3(26) cont.

Wetland Mitigation Plan – Wildlife habitat Issues

The wetland mitigation plan was developed to propose compensatory mitigation for the loss of over 30 acres of wetland habitat at the proposed cogeneration plant site. This plan essentially proposes to restore the hydrology to, and control non-native plant species within, a 110 acre "compensatory mitigation area" (CMA 1 and 2). Approximately ¾ of this site is currently classified as wetland and the plan proposes to improve the hydrological functions of these wetland areas. It is also expected, though not included in the compensatory calculations, that by filling existing drainage ditches and restoring sheet flow runoff across the site, the wetland acreage will increase. The plan does not appear to propose extensive site grading or the creation of ponds. 3(27)

A more heavily engineered plan that included site recontouring would be of greater concern since there would be greater temporal impacts to the wildlife that currently use this critical area. Any design creates ponds with permanent water would also be of concern as ponds tend to attract and support non-native bull frogs that out compete the native amphibians, as well as impacting other fish and bird species. However, there are still several areas of concern for wildlife in the plan as proposed.

The wetland mitigation plan does not acknowledge the great blue heron colony's presence nor does it account for the critical role the CMAs play in the life cycle and long-term viability of the heron colony. A portion of the area north of Grandview Road in this critical heron habitat is the subject of a previous wetland mitigation conducted by the BP Cherry Point Refinery. This previous mitigation was also designed to primarily restore hydrology and control non-native plant species, but somehow has resulted in permanent, open water ponds. The implementation of the proposed wetland mitigation plan will need to be carefully monitored by an independent third party to ensure that previous implementation issues are not repeated with this project. In addition, the DEIS must include documentation on how the hydrology in the mitigation site will be managed to prevent water from permanently ponding. 3(28)

An additional hydrological concern is that of water level fluctuations. It appears that some of the waterfowl ponds that were created north of Grandview Road in the past have experienced significant water level fluctuations. It is reported that the edges of these ponds have become eroded and steeply sloped. Significant water level fluctuations can prevent native amphibians from successfully reproducing in engineered wetlands. Activities that impact the populations of native amphibians, in turn, will impact the long-term viability of the heron colony by impacting critical food resources. There is no information in the mitigation plan to demonstrate how water level fluctuations will be managed. This is of particular concern since it appears that the water for the wetland enhancement will be stormwater directed off of the proposed site and the DEIS inadequately describes the proposed stormwater management methodology. The DEIS must include additional documentation on how the hydrology in the mitigation site will be managed to prevent water level fluctuations from impacting wildlife resources. 3(29)

The wetland mitigation plan appears to be an incomplete conceptual plan, as it does not include information on timing of implementation. Wildlife habitat issues include both temporal loss of 3(30) habitat function and seasonal impacts from the proposed work. The mitigation plan describes a program of tilling and disking for two years to control non-native plant species. This would remove large sections of this critical habitat area from the heron colony's available foraging area for at least two seasons. There would also be a time lag between the time of planting and the time that the newly planted areas begin to provide adequate food resources for herons and other wildlife in the area. Disturbances that disrupt a heron colony's ability to successfully nest, which could include a loss of food resources, appear to cause colony abandonment, if the disturbance continues for two or more years (pers. obs.). That the wetland mitigation plan does not even acknowledge the potential for these impacts is of serious concern. 3(30) cont.

The mitigation plan also does not include any information on the seasonality of the proposed work. Tilling and disking activities could seriously impact a wide variety of ground nesting birds that likely currently use the CMA, if it is done during the nesting season. The plan does not provide information on the proposed frequency or timing of this work, or on the species that might be impacted in these areas. This impact must be further evaluated in the DEIS. 3(31)

The wetland mitigation plan should also include a proposal for the development of alternative colony locations. This might include the creation of increased deciduous forest cover. The most appropriate location would likely be adjacent to the forested Terrell Creek corridor. The wetland mitigation plan will be impacting some of the most critical habitat for the heron colony, but it does not include consideration of the potential impacts to the colony nor does it propose measures to improve this critical area for the herons. 3(32)

The wetland mitigation plan includes a proposal for increasing large woody debris in the CMA. However, the source of these logs will be trees that are removed from the proposed cogeneration plant site, primarily poplar and Douglas fir. These trees are described as ranging from 7 to 10 inches in diameter, at the large end of the log. Logs of these sizes will only persist in the environment for a few years at best and are unlikely to provide benefits much beyond the required monitoring period. While large woody debris, both standing (snags) and horizontal logs, can be of great benefit to wildlife, the woody debris as proposed is inadequate. 3(33)

The plan proposes to set some of these logs up as snags, only two of which will be greater than 12 inches in diameter. Snags of this diameter will not persist in the environment for any significant length of time and, due to the small diameters, their value to wildlife is quite limited. The mitigation plan further proposes to add 10-foot long crossbeams to some of these snags, which are no more than 30 feet tall. It is very unclear why the crossbeams are designed to be so long. The DEIS also states that these crossbeams are intended to provide perches for great blue herons which would use them to hunt mice and voles. Unfortunately, herons do not hunt from elevated perches. The DEIS incorrectly evaluates the impacts and benefits of the proposed mitigation plan. 3(34)

The mitigation plan goes on to propose the placement of small woody twigs in wetland areas to provide amphibian egg deposition sites. This proposal is disturbing for several reasons. First, it assumes that the site will be engineered so that a determination of where water will pond in the spring can be made. Secondly, since the small twigs would need to be anchored to prevent them from rising and falling with water level fluctuations, it assumes a level of ground disturbance that may not be justified. Finally, small twigs in a seasonally inundated wetland environment will not persist much beyond one season. The plan's reliance on an "engineered" approach to an 3(35) issue that is much better addressed through adequate vegetation and hydrology management is of great concern. 3(35) cont.

The mitigation plan also proposes to construct a few "brush shelters" for additional wildlife cover. However, as with the other constructed woody features, the sizes of the materials are too small to presume that they will persist in the environment for much more than the required monitoring period. These brush shelters are also designed to support the same herbivores that may jeopardize plantings that the snag/hunting perch poles are designed to protect. These inconsistencies in goals and management approaches need to be addressed before the proposal is finalized. 3(36)

The mitigation plan also claims credit for providing thermal cover benefits to wildlife. However, the plant species lists provided show more deciduous species to be used than coniferous species. There is no information provided about the ratio of evergreen to deciduous plants. Deciduous plants provide little thermal cover in the winter when thermal cover is most limiting in this area. Claims of thermal benefits for wildlife are unsupported in the DEIS. 3(37)

Finally, the mitigation plan contained in the DEIS, calculates that the plan will result in greater functionality of both the restoration areas and the CMA for wildlife. This result is based largely on an anticipated increase in plant diversity. However, that calculation probably overstates the potential benefits because it does not account for the potential noise and light impacts that could prevent wildlife from using these areas. It also does not account for the temporal loss of functions. It is important to include both diurnal and nocturnal wildlife use of the mitigation area and to recognize that some species, such as herons, use the area over the entire 24-hour cycle. The DEIS should include additional documentation on the impact of the wetland mitigation plan on wildlife. 3(38)

Other Species of Local Importance

The DEIS includes lists of species observed and expected within the proposed project site and the mitigation areas, including CMAs 1 and 2. While these lists are correctly identified as not being exhaustive lists of every species that might occur in the project area, they are represented as listing the most common species likely to be found there. However, these lists are curiously incomplete in some rather startling ways. The DEIS analysis based on these lists omits consideration of significant wildlife species, and, therefore, the DEIS is inadequate in its documentation and evaluation of impacts. 3(39)

A number of well-documented species occurrences are omitted. For example, while the great blue heron nesting colony is noted in passing, the critical foraging and staging habitats present within the project area are not mentioned. At a minimum, existing sources of information on wildlife use, such as the current Terrell Creek Wildlife and Habitat Baseline Report prepared for the Whatcom County Council of Governments, dated November 2002, should have been referenced for useful information. 3(40)

As authorized by the Washington State Growth Management Act, Whatcom County has identified Species of Local Importance (WCC 16.16.720 and Appendix C). Significant species that occur within the project area and which appear to be omitted from the DEIS analysis include: bald eagle (threatened); pileated woodpecker (candidate); peregrine falcon (protected); 3(41) and great blue heron (monitor). In addition, the area is used extensively by neotropical migrants, a group of passerine species that are indicators of environmental health in both temperate and tropical habitats. While not all of these species nest within the project area, they do nest within the area that is shown as being impacted by noise and they all forage within the project area. Changes to the habitats within the project area, including the CMAs, may directly affect these species. Overall effects might be positive, assuming that noise impacts are minimized, but the impacts must be evaluated in the DEIS. At a minimum the DEIS needs to evaluate potential impacts to Species of Local Importance as identified by Whatcom County. 3(41) cont.

There are also a number of significant fish species known to use the Terrell Creek corridor including the listed Puget Sound chinook, and candidate sea run cutthroat trout and Puget Sound coho. Both the cutthroat trout and coho occur in reaches of Terrell Creek between Kickerville and Jackson Roads (Eissinger 2002). As there have been unexplained fish kills in the Terrell Creek system in the past (Eissinger 2002), it would be prudent for the DEIS to include these species in the evaluation of impacts. In addition, coho are among the species that comprise Essential Fish Habitat under the Magnuson-Stevenson Fishery Conservation and Management Act. The DEIS must evaluate the projects' compliance with Federal laws. 3(42)

Cumulative Impacts

The area between Kickerville and Jackson Roads has already been the subject of at least two mitigation actions in recent years. Additional mitigation for other projects is currently proposed for this area north of Grandview Road. While it is to be hoped that each of these mitigation actions will complement the other, efforts to coordinate these activities are unclear since the DEIS does not adequately describe these actions in the cumulative impacts section. As additional critical habitats are included in various mitigation proposals, the potential cumulative impacts to herons and other wildlife, particularly temporal impacts resulting from changes in vegetation and prey species, must be documented and evaluated. The cumulative impacts section of the DEIS is inadequate in that it does not include documentation and evaluation of these cumulative habitat alterations proposed in the project area. 3(43)

Conclusions

There are a number of subject areas where the DEIS does not supply sufficient or accurate information, which prevents an adequate analysis of impacts. Likely adverse impacts include impacts to water quality and quantity; to sensitive fish and wildlife including the significant heron colony, threatened Puget Sound Chinook, and Essential Fish Habitat; critical wetland and riparian habitats; and impacts from changes in noise, and light. In addition the project are is defined too narrowly. The impact area analyzed must include the mitigation areas as well as the full area where impacts such as noise are likely to occur. By the same token, the outfall pipe that carries wastewater generated by the project to the marine environment must extend the analysis to these areas as well. The DEIS is inadequate in that it does not provide sufficient information to either analyze potential impacts or document why such impacts would not occur. 3(44)

SEPA and NEPA further require that mitigation for impacts follow a specific sequence starting with avoidance of the impact, then minimization, and finally, if there are no other alternatives, compensatory mitigation. Many impacts have not been correctly identified in the DEIS so proper mitigation sequencing is not possible. For other impacts, the mitigation sequencing has not been properly documented.

Some of the identified potential impacts would be relatively easy to mitigate for and mitigation should be included in the design. A few of these mitigation measures that should be included in the DEIS are as follows:

- All outdoor lighting should be shielded to prevent any light from extending north of Grandview Road or up into the sky.
- All stacks, cooling towers, and transmission line towers should be kept to minimum heights and must not include lights.
- Transmission towers must not include any guy wires.
- Noise production must be modeled accurately and managed more aggressively to meet the standards suggested by Dr. Wierzba (potential increases limited to 3 dB in A-weighted levels and 9 dB in C-weighted levels at sensitive receptor sites – e.g. heron foraging, staging and nesting areas.)
- Plant "start-up" should be scheduled for September or October to allow wildlife the maximum amount of time to adjust to changes in noise levels prior to the start of sensitive activity periods (e.g. breeding season staging in February and March for great blue herons.)
- If noise levels are likely to fluctuate during plant operation or maintenance, minimize such starts and stops during sensitive activity periods for wildlife.
- At a minimum, manage stormwater to meet the Washington State Department of Ecology 2001 stormwater manual.
- Install curbs or low, tight-mesh fencing around stormwater ponds to prevent amphibian reproductive mortality. 3(44) cont.
- Plant vegetative buffers (conifers) to help attenuate noise impacts and provide habitat and water quality benefits (note: there may still be significant temporal impacts.)
- All landscaping and buffer plantings between the facility and Grandview Road should consist entirely of native plant species.
- Woody debris and snags installed in the wetland restoration and mitigation areas should include materials of a size and composition that is likely to persist in the environment and provide habitat benefits for many years.

There are many areas of the DEIS that provide insufficient information to evaluate impacts. If impacts would occur, then additional mitigation measures would be necessary.

While monitoring is not mitigation, it may be part of a contingency plan to ensure performance of the mitigation plan. The mitigation plan should include contingency measures to deal with unforeseen issues or mitigation failures.

"Build it and they will come" doesn't always work with wildlife. There are many pieces to the habitat puzzle that we do not fully understand and when we try to create habitats (or restore areas), they often remain unoccupied. While the habitats in the project area are currently degraded by non-native invasive plant species and past alterations, they are still currently serving critical habitat functions. It is in the best interests of the public and the applicant to be conservative in evaluating potential impacts to the long-term viability of these habitat areas.

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BP Cherry Point Cogen
DEIS Comment - 26

November 1, 2003

Subject: BP Cherry Point Cogeneration Project

Dear Allen Fiksdal, Manager -Energy Facility Site Evaluation Council,

Thank you for this opportunity to voice our concerns about the project. We live only 3 miles from the BP Cherry Point refinery.

We have two obvious concerns about the cogeneration project. They are air quality and massive water use from the Nooksack River. The amount of electricity that the refinery needs to operate is 85 megawatts. The applicant calls for a 720 megawatt plant. We think that a large cogeneration plant coupled with the SE-1 and SE-2 powerplants will cause a cummulative degradation of our air quality that is unwarranted by our areas' electrical use. We think that if BP wants a local source of power either to buy it from SE-1 and SE-2 or bulid a smaller plant that would meet the needs of the refinery. This would also require much less water from the Nooksack River, a river that has more permits than water. It appears that lack of water rather that lack of electricity will be our county's most serious problem. 1

Again, thank you for this opportunity.

Steve and Helene Irving
2664 Brown Road
Ferndale, Wa. 98248

Steve Irving
Helene Irving

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ENERGY FACILITY SITE
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BP Cherry Point Cogen
DEIS Comment - 27

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

October 29, 2003

Reply To
Attn Of: ECO-088

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EVALUATION COUNCIL

Ref: 02-049-BPA

Thomas McKinney
Bonneville Power Administration (KC-7)
P.O. Box 14428
Portland, OR 97293-4428

Dear Mr. McKinney:

The Environmental Protection Agency (EPA) has completed its review of the draft Environmental Impact Statement (EIS) for the proposed **BP Cherry Point Cogeneration Project** (CEQ No. 030422) in accordance with our authorities and responsibilities under the National Environmental Policy Act (NEPA) and Section 309 of the Clean Air Act. The draft EIS has been prepared in response to a proposal to construct and operate a 720-megawatt natural gas-fired cogeneration facility in Whatcom County, Washington and interconnect the project with the Federal transmission system managed by the Bonneville Power Administration (BPA). The EIS evaluates the applicant's proposed power plant and a single transmission line alignment as well as the No Action alternative. An agency-preferred alternative is not explicitly identified in the draft EIS.

Based on our review and evaluation, we have assigned a rating of EC-2 (Environmental Concerns - Insufficient Information) to the draft EIS. This rating, and a summary of our comments, will be published in the *Federal Register*. A copy of the rating system used in conducting our review is enclosed for your reference.

Our concerns are related to the following topics:

Wetlands

The EIS should provide sufficient information to demonstrate that the applicant-proposed project represents the least environmentally damaging practicable alternative, a demonstration that is necessary before an Army Corps of Engineers permit can be issued pursuant to Section 404 of the Clean Water Act. As part of this demonstration, the EIS must show that impacts to waters of the United States, including wetlands, have been avoided, minimized, and mitigated, consistent with the analysis procedures outlined in the Section 404(b)(1) Guidelines (see 40 CFR Part 230). We recommend that the EIS be revised to include more detailed evaluation of alternatives that would avoid or reduce impacts to wetlands, comply with the requirements of the 404(b)(1) Guidelines, and demonstrate that the proposed project represents the least damaging practicable alternative. 1

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We are concerned with the wetland functions and values evaluation of the existing condition of the proposed mitigation sites. In reviewing the *Revised Cogeneration Project Compensatory Mitigation Plan, BP Cherry Point* (April 21, 2003), EPA finds that the functions and values of the proposed mitigation sites (CMA1 and CMA2) were rated lower than we would have rated the sites. Of particular concern was the low rating given for removing sediment, removing nutrients, removing toxic metals and recharging groundwater. Based on our field visit to the project area, EPA finds these existing wetland areas, even though they may be dominated by non-native wetland vegetation and have been ditched, still provide these functions at a high level. As a consequence, we do not believe that the mitigation planned in CMA1 and CMA2 would increase the values of these sites to the level that would offset project impacts. **2**

We recommend that additional mitigation be developed that would adequately replace the functions and values that would be lost with the permanent filling of 30.51 acres of wetlands and the temporary loss of 4.76 acres of wetlands. This mitigation should be identified in the EIS. **3**

Government-to-Government Consultation with Tribes

Section 2.7 of the draft EIS presents information related to communications and meetings that have taken place between the applicant and potentially affected Tribal entities. The information presented does not indicate that any consultations have taken place between the Federal government (BPA or the Corps of Engineers) and the governments of affected tribes, as directed by Executive Order (EO) 13175 (*Consultation and Coordination with Indian Tribal Governments*). While we believe that it is important that the project proponent work with affected Tribes, the Federal government has a unique trust relationship with tribes. We recommend that the BPA and the Corps of Engineers engage affected Tribal governments, pursuant to EO 13175, in the further development of the project and the EIS to ensure that the Federal government meets its obligation to consult with tribes on a government-to-government basis. Results from such consultations should be reported in the EIS. **4**

Thank you for the opportunity to provide comments on the draft EIS. I urge you to contact Bill Ryan of my staff at (206) 553-8561 at your earliest opportunity to discuss our comments and how they might best be addressed in the EIS.

Sincerely,

Judith Leckrone Lee

Judith Leckrone Lee, Manager
Geographic Implementation Unit

Enclosure

cc: Allen Fiksdal, EFSEC
Olivia Romano, Corps of Engineers

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BP Cherry Point Cogen
DEIS Comment - 28

~~[illegible]~~ 11/2/03

ALLAN FIKSDAL, MANAGER
ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 43172
OLYMPIA, WA 98504-3172

RE: PROPOSED BP CHERRY POINT COGENERATION PROJECT

DEAR MR. FIKSDAL,

AS I GLANCE THROUGH PORTIONS OF THE DRAFT ENVIRONMENTAL IMPACT STATEMENT FOR THE BP CHERRY POINT COGENERATION PROJECT I AM APPALLED BY THE NUMEROUS UNSUBSTANTIATED ASSUMPTIONS MADE, AND BY THE INADEQUACY OF WHICH SOME ISSUES ARE ADDRESSED, OR GLOSSED OVER.

AS YOU CAN SEE BY THE DATE OF MY LETTER, I DO NOT HAVE TIME TO ADDRESS EVEN A SMALL PORTION OF THE UNSUBSTANTIATED ASSUMPTIONS OR THE ISSUES THAT WERE INADEQUATELY ADDRESSED. I HAVE TO WONDER IF THE HUXLEY PROFESSOR AT WESTERN WASHINGTON UNIVERSITY WOULD HAVE CONCLUDED THE SAME THING ABOUT

THIS ENVIRONMENTAL IMPACT STATEMENT AS SHE DID ABOUT THE ONE F.E.R.C. WROTE FOR THE GEORGIA STRAIT PIPELINE (GSX): "IF A STUDENT HANDED THIS IN, IN MY CLASS THEY WOULD NOT RECEIVE A PASSING GRADE."

IN VOLUME 1 OF DOE/EIS-0349, CHAPTER 3, (3.3-14) IT MENTIONS WATER DISCHARGE AND WASTEWATER. NO WHERE IN THAT PARAGRAPH DOES IT EVEN ADDRESS ANY IMPACT THAT THE WASTEWATER, ALTHOUGH TREATED, MAY HAVE ON THE SALT WATER, THE SEA CREATURES, AND PLANT LIFE AT CHERRY POINT. IT IS JUST IGNORED BECAUSE THERE IS ALREADY AN EXISTING WASTE WATER DISCHARGE POINT; OUTFALL 001, INTO GEORGIA STRAIGHT 1
UNDER AN EXISTING PERMIT (NPDES PERMIT). THERE ARE MANY FACTS THAT ARE GIVEN ELSEWHERE IN THE EIS AND THERE ARE MANY STATEMENTS OF THE STATUS QUO, BUT IT DOESN'T EVEN MENTION HOW MUCH FRESH WATER IS ALREADY FLOWING INTO GEORGIA STRAIGHT AT THAT PARTICULAR CHERRY POINT OUTFALL, OR WHETHER OR NOT THERE ARE ANY LIMITS ON THE AMOUNT OF WATER THAT CAN BE DISCHARGED UNDER THE EXISTING NPDES PERMIT.

WHAT ENVIRONMENTAL IMPACT DOES 3 MILLION, 3 HUNDRED SIXTY SIX THOUSAND, 7 HUNDRED AND TWENTY GALLONS OF FRESH WATER HAVE,
(2,338 gpm x 60 x 24 = 3,366,720)

TO: ALLAN FIKSDAL
FROM: CATHY CLEVELAND
—2—

WHEN ADDED WITH THE UNDISCLOSED AMOUNT OF WATER ALREADY GUSHING OUT INTO GEORGIA STRAITS, TO MARINE ANIMAL AND PLANT LIFE? 1 cont.

WHILE THE SECTION ON HABITAT, WILDLIFE, FISHERIES, AND ENDANGERED SPECIES DOES AN INVENTORY OF SPECIES PRESENT IN THE CHERRY POINT AREA, NO WHERE DOES IT REALLY ADDRESS ANY IMPACT TO THOSE SPECIES. FOR EXAMPLE, THE EIS MENTIONS PACIFIC HERRING (3.7–12) BUT, DOES NOT MENTION THAT THE PACIFIC HERRING STOCK THAT SPAWNS AT CHERRY POINT HAS UNDERGONE A DRAMATIC DECLINE IN THE LAST 20–30 YEARS. (A REGIONAL ASSESSMENT OF THE POTENTIAL STRESSORS CAUSING THE DECLINE OF THE CHERRY POINT PACIFIC HERRING RUN AND ALTERNATIVE MANAGEMENT ENDPOINTS FOR CHERRY POINT RESERVE (WASHINGTON, USA) Wayne Landis, P. Bruce Duncan, Emily Hart Hayes, April Markiewicz, and Jill Thomas; Institute of Environmental Toxicology, Huxley College of the Environment, Western Washington University Bellingham, WA 98225 USA) SEE ALSO: CHERRY POINT HERRING REGIONAL RISK ASSESSMENT PHASE II Landis, Hayes & Markiewicz June 6, 2001 2

I AM VERY SHORT ON TIME, BUT THERE IS A WONDERFUL LIST OF BIRDS ON PAGE 3.7-6, BUT THEY ALL APPEAR TO BE "LAND" BIRDS, NOT MARINE BIRDS, SUCH AS SEAGULLS OR THE GREAT BLUE HERON, WHICH HAS A ROOKERY, OR RESERVE, WITHIN A MILE OF THE B.P. PROPERTY. MANY MARINE BIRDS HAVE SHOWN SERIOUS POPULATION DECLINES, INCLUDING REPRESENTATIVES FROM ALL NORTHWESTERN (GEORGIA STRAIT PUGET SOUND) WASHINGTON MARINE BIRD FAMILIES. (ASSESSING SOUTHERN STRAIT OF GEORGIA MARINE BIRD POPULATIONS SINCE 1980, DR. John L. Bower, Western Washington University, 2003) 3

WHY DOESN'T THE EIS SHOW ANY STUDIES OF WHAT DE-SALINIATION OF SALT WATER DOES TO THE MICROSCOPIC ORGANISMS OF THE SALT WATER FOOD ~~[illegible]~~ CHAIN. DOES IT AFFECT WHAT THE HERRING FEED ON? OR DOES IT AFFECT THE KELP BEDS THE HERRING PREFER TO INHABIT? OR DOES IT AFFECT THE MARINE ANIMAL LIFE UPON WHICH THE MARINE BIRDS FEED? I KNOW FRESH WATER KILLS MARINE LIFE. 4

AND NOW THAT THE CHERRY POINT AREA HAS BEEN DETERMINED TO BE AN AQUATIC RESERVE BY THE DEPARTMENT 5

TO: ALAN FIKSDAL
FROM: CATHY CLEVELAND
- 3 -

OF NATURAL RESOURCES, SHOULDN'T THE DNR BE ALLOWED TO SERIOUSLY LOOK INTO HOW ANY FURTHER HEAVY INDUSTRIAL GROWTH WILL IMPACT THEIR AQUATIC RESERVE? DNR SHOULD DO AN EIS TO PROTECT THE AQUATIC RESERVE. (TO ASSESS WHAT NEEDS TO BE DONE TO PROTECT THE AQUATIC RESERVE.) 5 cont.

A REGIONAL ECOLOGICAL RISK ASSESSMENT FOR THE NEAR SHORE MARINE ENVIRONMENT IN NORTHWEST WASHINGTON, WHICH ANALYZED CUMMULATIVE IMPACTS FROM MULTIPLE SOURCES OF CHEMICAL AND NON-CHEMICAL STRESSORS IN THE NEAR SHORE REGIONS AND UPLAND WATERSHEDS OF CHERRY POINT, FOUND THE CHERRY POINT REGION TO BE HIGH RISK. (REGIONAL ECOLOGICAL RISK ASSESSMENT OF A NEAR SHORE MARINE ENVIRONMENT: 6

CHERRY POINT, WA; Emily Hart Hayes and Wayne G. Landis (author to whom correspondence should be addressed), Institute of Environmental Toxicology, Huxley College of the Environment, Western Washington University, Bellingham, WA 98225-9180 USA) (Risk Assessment involved WA Dept. of Natural Resources, WA Dept. of Fish + Wildlife, WA Dept. of Ecology, National Ocean Service, the Lummi Nation, and Whatcom County Planning and Development Services + other county dept.)
AND WHAT ABOUT THE NEW PUGET SOUND

FURTHERMORE, THERE IS NO
MENTION OF ~~[illegible]~~ POTENTIAL IMPACT
OF PARTICULATES ON THE SALT WATER:
(MOST LIKELY IMPACT FROM WIND DIRECTION,
BIRCH BAY) AND FRESH WATER (MOST
LIKELY IMPACT, TERRELL CREEK, WHICH 7
IS CURRENTLY BEING CLEANED UP FOR
SALMON SPAWNING, AND VARIOUS WETLANDS).
THERE IS SOMEONE, TONY BASABE,
WHO IS SUPPOSED TO BE WORKING WITH
THE SWINOMISH INDIANS TO STUDY
THE IMPACT(S) OF PARTICULATES ON
PADILLA (OR FIDALGO) BAY AND THE ANACORTES AREA.
UNFORTUNATELY, I DID NOT FIND THE
TIME TO CONTACT HIM. IF THERE IS
INFORMATION ON THIS TOPIC, IT SHOULD 8
NOT BE IGNORED. IT MUST BE ADDRESSED.
I JUST FOUND MY E-MAIL—THIS INFORMATION SHOULD BE ON EFSEC'S WEBSITE, + EPA-ATMOSPHERIC DEPOSITIONS.
IF TOXINS IN PARTICULATES ACCUMULATE
IN FISH OR ANY OTHER MARINE SPECIES
EATIBLE BY MAN, LIKE MERCURY DOES, IT
MUST BE ADDRESSED NOW, NOT 20, 30, 40 OR
50 YEARS FROM NOW WHEN PEOPLE ARE
GETTING SICK AND/OR DYING. AND, ARE
ANY OF THESE POLLUTANTS OR PARTICULATES
FILTERING INTO TO OUR WATERSHEDS?
BY THE WAY, FOR THOSE OF YOU WHO
ARE NOT CHEMISTS, MERCURY IN THE IONIC 9
FORM, Hg^{+2}, IN THE FORM OF MERCURIC CHLORIDE,
$HgCl_2$, AND IN THE FORM OF MERCURIC OXIDE, HgO,
CAN ALL BE FOUND IN PRESENT IN OR ON
PARTICULATE MATTER. PARTICULATE MATTER,
(A HANDBOOK FOR WATERSHED MANAGERS, U.S. ENVIRONMENTAL PROT. AGENCY)

TO: ALLAN FIKSDAL
FROM: CATHY CLEVELAND

-4-

ALSO, MAY CONTAIN LEAD (Pb), CADIUM (Cd) AND MANY OTHER COMPOUNDS YOU WOULDN'T CHOOSE TO BREATH.

I BELIEVE THE ISSUE OF PARTICULATES HAS BEEN SERIOUSLY GLOSSED OVER AND HAS BEEN PRESENTED IN A CONFUSING (NOT STRAIGHT FORWARD) MANNER IN THE 3.2, AIR QUALITY SECTION. YOU SHOULD HAVE RECEIVED A LENGTHY REPORT ~~FROM~~ REGARDING PARTICULATE MATTER FROM MY FATHER, ARNE CLEVELAND. IF NOT, PLEASE ALLOW ME TO INTRODUCE IT INTO EVIDENCE AFTER THE DEADLINE FOR COMMENTS, AS IT IS CREDIBLE DATA AND FACTS + RESEARCH ON PM 2.5 (WHICH WILL BE EMITTED FROM 10

THE COGENERATION PLANT). IT CONCLUDES, AMONG OTHER THINGS THAT "THERE WILL BE SEVERE HEALTH IMPLICATIONS FOR THE WEST AS NATURAL GAS-FIRED POWER PLANTS COMMENCE SPEWING HUNDREDS OF TONS OF PM 2.5 AND AMMONIUM SULFATE ANNUALLY. IN 1997, THE EPA CONCLUDED THAT HIGH LEVELS OF FINE PARTICULATE MATTER (2.5) POSES UNACCEPTABLE HEALTH RISKS! HEALTH 11

RISKS INCLUDED, BUT ARE NOT LIMITED TO; ASTHMA, PNEUMONIA, CHRONIC OBSTRUCTIVE PULMONARY DISEASE, AND A BROAD RANGE OF EFFECTS LEADING TO HOSPITALIZATION, INCLUDING SUDDEN DEATHS FROM CHANGING HEART RHYTHMS IN PEOPLE WITH EXISTING CARDIAC PROBLEMS. (NATIONAL CAMPAIGN AGAINST DIRTY POWER). 11 cont.

I WAS UNABLE TO MEET WITH BP'S CHEMIST TO ASK MANY QUESTIONS ABOUT PARTICULATES, ESPECIALLY PM2.5. BUT, THE EIS DOES NOT EVEN ADDRESS THE FACT THAT THERE ARE CONTROL DEVISES TO TRAP PARTICULATES. I ALSO, DO NOT RECALL THE EIS ADDRESSING WHAT HAPPENS IF THE LEVEL OF PARTICULATE MATTER EMITTED IS HIGHER THAN PREDICTED? AND WERE ESTIMATIONS DETERMINED TO BE LOW IN ORDER TO AVOID A HIGHER DEGREE OF SCRUNTINY AND REGULATION?

UNFORTUNATELY, I DID NOT FIND TIME TO DO MORE ENVIRONMENTAL CHEMISTRY RESEARCH, BUT WHY WEREN'T ANY OF THE FOLLOWING METHODS OR DEVISES ADDRESSED TO REDUCE PARTICULATES?: 12

1) GRAVITATIONAL SETTLING CHAMBERS
2) CENTRIFUGAL SEPARATORS
3) WET SCRUBBERS (0.05 µm)
4) FILTERS (BAGHOUSE 0.01 µm)
5) ELECTROSTATIC PRECIPITATORS (0.005 µm)

TO: ALLAN FIKSDAL
FROM: CATHY CLEVELAND
-5-

ASTONISHINGLY,
NO WHERE IN THE ~~[illegible]~~, THE EXISTING LAND USE SECTION (3.10) DOES IT MENTION THAT THE BP REFINERY LAND IS ADJACENT TO THE BIRCH BAY ~~[illegible]~~ GROWTH MANAGEMENT AREA, WHICH IS DESIGNATED UNDER THE COUNTY COMPREHENSIVE PLAN TO BECOME A CITY. WHILE THE POPULATION SECTION (3.12 + 3.12-1) ACCURATELY STATES THE WA STATE OFFICE OF FINANCIAL MANAGEMENT NUMBERS: THAT WHATCOM COUNTY CONTAINS 2.8% OF WASHINGTON STATE'S POPULATION, IT DOES NOT MENTION THAT THERE IS OVER 5,000 PEOPLE CURRENTLY LIVING, FULL TIME IN THE BIRCH BAY GROWTH MANAGEMENT ~~[illegible]~~ AREA, AND THAT DURING THE SUMMER, THAT NUMBER TRIPLES! (U.S. CENSUS FIGURES FOR 2000; SAME CENSUS SHOWING MORE THAN 1/2 OF THE HOUSES AT BIRCH BAY ARE EMPTY AT (NON-SUMMER) JANUARY CENSUS TIME.) 13

THEREFORE, THE STATEMENT, "NORTHWEST OF THE REFINERY, SEASONAL RESIDENTIAL PROPERTIES OCCUR IN THE BAYFRONT COMMUNITY OF BIRCH BAY", IS A **GROSS MISREPRESENTATION OF THE FACTS!**
I HAD TO WONDER IF BP WROTE THIS

SECTION OF THE EIS. FOR SOME REASON, I THOUGHT THAT AN <u>INDEPENDENT</u> AGENCY, LIKE THE DEPARTMENT OF ECOLOGY, WROTE THE EIS. BUT, NO. I FLIP TO THE COVER OF THE EIS AND I SEE THAT BOTH LEAD AGENCIES ARE <u>PRO-ENERGY</u> AGENCIES. NOT THAT I AM AGAINST ENERGY — JUST NOT ENERGY WITHOUT REGARD TO THE COSTS AND WHEN IT IS DONE RATHER, FOR A LACK OF A BETTER WORD, DISHONESTLY, VIA THE EIS. IN LAW, THEY USE THE ~~WORDS~~ TERMS, "CONFLICT OF INTEREST" AND "APPEARANCE OF IMPROPRIETY." THERE IS <u>TRULY</u> A CONFLICT OF INTEREST WHEN THE SAME AGENCY WHO "SITES" THE POWER PLANT LOCATION, ALSO WRITES THE EIS. NO WONDER I HAVE SEEN SO MANY INADEQUATELY ADDRESSED ISSUES AND UNSUBSTANTIATED ASSUMPTIONS AND FACTS. 14

WANDERING OFF-TRACK FOR A MINUTE, ...
FOR EXAMPLE, THE SECTION ON ODOR (3.2-9) <u>MISREPRESENTS THE FACTS</u>. MY FATHER, <u>ALONE</u>, HAS MADE <u>MORE THAN</u> "<u>SEVERAL</u>" COMPLAINTS TO NWAPA REGARDING SULFUR SMELL. CITIZENS AND NEIGHBORS HAVE TOLD ME THEY COMPLAINED AT THE BIRCH BAY PLANNING MEETINGS, AND I EVEN HEARD MULTIPLE COMPLAINTS WHEN I TOURED THE REFINERY WITH ~~THE~~ A GROUP OF CITIZENS. LOCAL OFFICIALS <u>NEVER</u> DETECT THE SULFUR BECAUSE IT IS <u>EMITTED AT NIGHT</u>, 15

TO: ALLAN FIKSDAL
FROM: CATHY CLEVELAND

—6—

USUALLY AROUND 11pm OR 1 OR 2Am
OR ANYTIME WHEN OFFICIALS ARE NOT
AROUND TO CHECK. eg. HOLIDAYS I WORKED FOR
THE DEPARTMENT OF JUSTICE ON
THE EXXON VALDEZ CASE - SCIENTISTS
KNOW THAT CRUDE OIL FROM ALASKA
HAS A HIGHER CONTENT OF SULFUR
THAN (MIDDLE EASTERN) SAUDI OIL. ARCO AND BP
RECEIVE OIL FROM ALASKA, SO
LET'S STOP PLAYING THIS GAME THAT
THERE HAVE NEVER BEEN SULFUR
EMISSIONS FROM THAT REFINERY. * !!!! 16
ONE DOES NOT SMELL SULFUR AS
FREQUENTLY AS ONE DID IN THE
PAST, SO MAYBE BP HAS IMPLEMENTED
A PROCESS TO REDUCE THE EMISSION
OF SULFUR.
* MY ENVIRONMENTAL CHEMISTRY, + MOORE + MOORE
TEXTBOOK SPECIFICALLY MENTIONS THAT SULFUR IS
IN FOUND IN BOTH FOSSIL FUELS,
COAL AND PETROLEUM. SO, I
FIND IT DISTURBING THAT REFINERY
OFFICIALS RESPOND TO CITIZENS
AS IF THEY HAVE AN OVERACTIVE
IMAGINATION WHEN THEY MENTION
SULFUR EMISSIONS, AND ALLUDE TO THE
BUILD-UP ON THE CARS AT BIRCH BAY AS, "POLLEN"

AIR QUALITY STANDARDS (3.2-1) SECTION.
PURSUANT TO THE CLEAN AIR ACT OF 1970, THE EPA ESTABLISHED AIR QUALITY STANDARDS FOR THE FOLLOWING AIR POLLUTANTS, INCLUDING PARTICULATE MATTER PM10 AND PM 2.5.
SO, THEN WHY DO VARIOUS TABLES NOT EVEN INDICATE HOURLY EMISSIONS OF $PM_{2.5}$? EG. TABLES 3.2-6, 3.2-7, 3.2-9, 3.2-20, 3.2-22, 3.2-23, 3.2-29, AND 3.2-21; ESPECIALLY IMPORTANT 3.2-20 AND 3.2-21 WHICH WOULD SHOW OVERALL REDUCTION OF EMISSION, IF ANY, OF PM2.5.
ONCE AGAIN, IMPORTANT DATA IS OMITTED! 17

THE AIR QUALITY SECTION ALSO DOES NOT MENTION WHAT THE SIGNIFICANT EMISSION RATE THRESHOLDS ARE IN WAC 173-400-030, NOR DOES THE EIS SPECIFICALLY SAY BY WHAT AMOUNT, QUANTITY, OR VOLUME THE PROPOSED PROJECT WOULD BE **EXCEEDING** THE 100 tpy OF NO_x, CO_2, PM_{10} AND $PM_{2.5}$.
THE NUMBERS SHOULD BE UPFRONT. ONE SHOULD NOT HAVE TO GUESS BY LOOKING AT VARIOUS TABLES. (3.2-5)
JUST BECAUSE "PM 2.5" IS NOT A REGULATED POLLUTANT UNDER THE PSD PROGRAM AT THIS TIME" (3.2-5) DOES NOT IN ANY WAY **EXEMPT** IT FROM FEDERAL REGULATION UNDER THE CLEAN AIR ACT. SOMEHOW AFTER THIS STATEMENT PM 2.5 IS IGNORED AS MUCH AS POSSIBLE. 18

TO: ALLEN FIKSDAL
FROM: CATHY CLEVELAND
-7-

MITIGATION MEASURES ARE ~~[illegible]~~ TOTALLY INADEQUATE. (3.2-36) THERE SHOULD BE, AT MINIMUM, FINES FOR EXCEEDING ANY AND ALL LIMITS ON POLLUTION, NOT JUST CO_2; AND ESPECIALLY PARTICULATE MATTER.

PERSONALLY, I BELIEVE THE ONLY ETHICAL AND EQUITABLE MITIGATION FOR EXCEEDING $PM_{2.5}$ EMISSIONS IS A FUND FOR FUTURE MEDICAL ~~[illegible]~~ EXPENSES FOR $PM_{2.5}$ RELATED MEDICAL PROBLEMS. I THINK ALL BIRCH BAY CITIZENS SHOULD GET A BASE-LINE HEALTH EXAM BEFORE THE CO-GEN PLANT IS FINISHED. AND, IF NO ONE SMOKES IN THEIR FAMILY, POSSIBLY/HOPEFULLY PROXIMATE CAUSE CAN BE ESTABLISHED, AND MEDICAL EXPENSES WILL BE AWARDED. 19

ALSO, NO WHERE IN THE SECTION ON AIR QUALITY (3.2) DOES IT MENTION THE **SYNERGISTIC EFFECT** BETWEEN TWO POLLUTANTS. THE TOTAL INFLUENCE OR AFFECT OF BOTH POLLUTANTS COMBINED IS GREATER THAN THE SUM OF THE NEGATIVE CONSEQUENCES EACH 20

WOULD PRODUCE ALONE. [THE SYNERGESTIC EFFECT MAY HAVE ALSO BEEN IGNORED AMONG MANY OTHER PHYSICAL, CHEMICAL AND THERMO DYNAMIC LAWS AND PRINCIPLES DUE TO ASSUMPTIONS AND QUESTIONABLE ACCUMULATION OF RESEARCH DATA IN THAT ONE, LONE TEST REPORT, WHICH BP WOULD LIKE TO RELY ON TO SUPPORT THEIR APPLICATION§ Prepared by Stephanie Wien and Glen England at GE Energy and Environmental Research Corporation, Irvine, CA, October 23, 2002 — Another energy company biased test] 21

A SYNERGESTIC EFFECT HAS BEEN DOCUMENTED BETWEEN PARTICULATES AND SULFUR OXIDES. PARTICULATES SERVE AS NUCLEATION SITES FOR FORMULATION OF WATER AND/OR FOG DROPLETS, AND THEIR LARGE SURFACE AREA ALLOWS THE CATALYSIS OF OXIDATION OF SO_2. OXIDATION OF SULFUROUS AND SULFURIC ACID FORMED BY THE REACTION OF SO_2 WITH WATER IS QUITE RAPID. SULFURIC ACID IS OFTEN ABSORBED ON THE SURFACES OF PARTICLES WHOSE DIAMETERS FALL IN PRECISELY THE RANGE TO BE ABSORBED DEEP INTO THE LUNGS (IN THE BROCHIOLES AND ALVEOLI). FROM THERE, BIO-CHEMICAL REACTIONS MAKE BREATHING MORE DIFFICULT AND STRAIN THE VICTIM'S HEART, LEADING TO BOTH ACUTE AND CHRONIC HEALTH DAMAGE. NONE OF THE ABOVE IMPACTS ARE DISCUSSED OR EVEN MENTIONED IN THE EIS. 22

(ENVIROMENTAL CHEMISTRY, MOORE + MOORE)

-8-

THERE ARE MANY, MANY MORE THINGS THAT SHOULD BE ADDRESSED IN THE EIS. IT IS ALMOST MIDNIGHT ON SUNDAY. I HAVE WORKED ON THIS FOR EIGHT HOURS. (UNABLE TO DO SO PREVIOUSLY BECAUSE I HAVE BEEN OUT OF TOWN FOR THE LAST MONTH AND A HALF ON WEEKENDS & MY ONLY REAL TIME TO ADDRESS THESE ISSUES. I TAKE A BUS TO WORK, SO MY WORK DAY IS 11 HOURS FROM THE TIME A LEAVE HOME UNTIL THE TIME I ARRIVE HOME.) SO, AS YOU CAN SEE, THE AVERAGE CITIZEN DOES NOT REALLY HAVE MUCH TIME TO RESPOND TO SOMETHING THAT WILL SO DRAMATICALLY AND PERMANENTLY CHANGE THEIR LIFE.

I WOULD ASK, THAT IF YOU MUST APPROVE THIS DUE TO FEDERAL POLITICAL PRESSURE, AT MOST THAT YOU ONLY ALLOW ENOUGH ENERGY FOR BP TO USE ON THEIR REFINERY. OTHER ALTERNATIVES WERE NOT SERIOUSLY ADDRESSED / LOOK AT OTHER SITES — THE INTALCO PLANT IS TRULY IN A RURAL AREA. IF THEY LEAVE, THAT SITE WOULD BE MORE APPROPRIATE. THERE ARE PLANS FOR TRANSMISSION 23

LINES
~~WIRES~~ TO BE BUILT ANYWAY. FOR THE SAKE OF PEOPLE'S HEALTH, IT IS IRRESPONSIBLE TO PUT A POWER PLANT ALMOST IN THE MIDST OF A GROWING CITY, KNOWING THE SERIOUS, INEVITABLE HEALTH CONSEQUENCES.

SINCERELY,
Cathy Cleveland

CATHY CLEVELAND
4961 MORGAN DRIVE
BLAINE, WA 98230
(H) (360) 371-9056
(W) (360) 650-3380

P.S. IF THIS NEEDS TO BE TYPED, I CAN TYPE IT NEXT WEEKEND AND MAIL IT TO YOU ON NOVEMBER 10TH

BP Cherry Point Cogen
DEIS Comment - 29

THE BERGS
7585 Sterling Ave., Birch Bay, WA 98230
Kathy (360) 371-0171 *Dick*

November 1, 2003

RECEIVED
NOV 04
ENERGY FACILITY SITE
EVALUATION COUNCIL

Allen J. Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olympia, WA 98504-3172

Dear Mr. Fiksdal:

Re: BP Cherry Point Cogeneration Project Draft EIS

It is with grave concern that I write this letter regarding the Cogeneration Project. My concern is for two issues: 1. Air quality, and 2. Noise.

1. Air Quality – It is most disconcerting to be told by the BP spokesman that when the modeling results were higher than BP liked, they proceeded to change the model so that results met their desired result. What good is modeling, what confidence can we have in the modeling results, why should the results be relied upon under these conditions? Even with the BP desired results, the most harmful pollutants, PM2.5 at an estimated 270 tons per year, will be carried by the prevailing south wind over the fastest growing urban growth area in Whatcom County as measured by the Census between 1990 and 2000. Because Birch Bay is a resort community as well, with the population doubling, even tripling, during the summer months, that many more people, especially the children and senior adults, will be exposed to very hazardous conditions. Short of not building the cogen plant at all, at least proper monitoring should take place with a stop generating order in place to reduce the hazard during peak hazardous conditions. 1

2. Noise – Despite repeated requests and explanations regarding the noise pollution from the existing BP Cherry Point Refinery, noise-monitoring stations have never been placed where the noise is most prevalent and irritating. Again, how can the noise monitoring results be relied upon for decision-making purposes when the results of the monitoring are skewed in BPs favor rather than based on the reality of the residents' experience? Again, short of not building the cogen plant at all, at least appropriate monitoring should take place and a stop generating/stop refining order should be in place when noise levels reach the point of interrupting sleep at night. 2

Unfortunately, the BP heavy industry property is literally right across the street from an urban growth area that has always been a resort area. Activities at BP must, therefore, pass the test of operating accordingly, even though they exist in a heavy industry zoned area.

Your consideration of these concerns and matters will be greatly appreciated.

Kathy Berg

Kathy Berg

BP Cherry Point Cogen
DEIS Comment - 30

Makarow, Irina (EFSEC)

From:	Tom Pratum [tkpratum@romarr.com]
Posted At:	Monday, November 03, 2003 10:04 PM
Conversation:	BP DEIS Comment
Posted To:	EFSEC
Subject:	BP DEIS Comment

Thank you for the opportunity to comment on the BP Co-generation Facility DEIS. In this comment, I wish only to make two points:

1. Water quantity and quality (sections 3.3 and 3.4). Water quantity is being measured against what is currently used by Intalco for once-through cooling of an air compressor (approx 2,700 gpm). It is stated that, if the Intalco plant continues at full operation, this water will be used again for cooling of the co-generation plant, thereby creating no net increase in water use from the Nooksack River. However, it is highly unlikely that Intalco will continue at anywhere near full operation. In such a case, the co-generation plant will indeed result in a net increase in water withdrawals over what would be present if the plant were not to come into existence. To state otherwise is somewhat dishonest. In addition to this somewhat misleading presentation of the water usage, it should be noted that 1 this water will then be discharged into the Strait of Georgia with chemical and physical parameters much different from what would come out of the Nooksack River, or if it were just to proceed through the Intalco air compressor. Even if we compare the water quality parameters of the water from Intalco with what would come out of the co-generation facility after treatment, we see that the temperature would increase from 21.4 C (70.5 F) to 93.8 F and COD would increase from ND (not detectable) to 323 lbs/day. This is significant for these two parameters, and that assumes Intalco still supplies the cooling water. If this water were to instead come from the Nooksack River the comparison looks very much more grim. 2
This level of increased water usage and water quality degradation is clearly unacceptable - especially given the fact that most of the electricity generated by this facility is destined for distant markets, and will not in any way mitigate the local environmental impacts.

2. Wildlife Habitat (section 3.7) In this section, there is scant mention of the effect of the project on the protected heronry located fairly close to the site. As the document states "Increased noise levels created by heavy machinery could cause birds to abandon their nests ....." Given that such a possibility is acknowledged, it would be reassuring if the applicant provided more information to ensure that this will not occur at the heronry. 3

Tom Pratum
2241 North Shore Road
Bellingham, WA 98226-9416

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ENERGY FACILITY SITE
EVALUATION COUNCIL

November 1, 2003

Allen J. Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olumpia, WA 98504-3172

Dear Mr. Fiksdal:

Re: BP Cherry Point Cogeneration Project Draft EIS

I am a Birch Bay community resident and have attended the Scoping and Draft EIS public meetings in Blaine regarding the BP Cogeneration project . The air quality impacts to the Birch Bay community as well as the noise impact needs to be addressed in a way that can be understood by the community. I have been told that the EIS document is written so the public can understand the cumulative impacts of the project, but that is not the case. The public has been led to believe that all emissions will be reduced when in fact some of the more harmful pollutants (PM2.5) will be increased by an estimated 270 tons per year. The statement about reduction of total criteria pollutants would only be significant if the toxicity of each one was equivalent, which is not the case. The Birch Bay community has the right to be told the truth in language that is clear. The EIS should put this issue into context to ensure that it is undersood by the public. No health risks have been explained. The projected impacts on air quality and noise calculated by modeling must be followed up with adequate monitoring of the actual impacts on the Birch Bay community. 1

I would like to ensure that the EIS require the following:

- Clear language denoting which air pollutants would increase.
- A process for informing and educating a growing Birch Bay community of the potential acute and chronic health risks from PM2.5 especially to children and senior adults.
- A requirement for compliance and continuous monitoring of PM2.5 in specific sites throughout the Birch Bay community. 2
- A requirement to limit monitoring bias by requiring a PM2.5 quality assurance program. This will provide data with minimal bias so that decision makers and the Birch Bay community can address the concerns associated with fine particles in the atmosphere.
- A requirement for monitoring noise pollution making sure the actual impact meets the modeling expectation and promises.
- Emergency planning and risk management for the Birch Bay community due to an accidental catastrophic event or the release of ammonia stored or transported from the site.

The Birch Bay community is an urban growth area in Whatcom County and the population triples in the summer due to the seasonal/resort residemts, tourists and campers. Birch Bay is becoming a significant destination for retirement. Senior adults as well as children are more susceptible to the health risks of PM2.5. The cumulative impacts of this project need to be made very clear so that the Birch Bay community has the opportunity to understand its impact on air quality, noise pollution, wild life and the environment. I am asking the EIS to be clear and truthful and to educate, inform, plan and prepare for the short and long term impacts of this project on the Birch Bay community. It is your reponsibility and our obligation to ask for nothing less. 3

Sincerely,

Doralee Booth

Doralee Booth
Birch Bay Steering Committee

BP Cherry Point Cogen
DEIS Comment - 32

WILLIAMS RESEARCH
John Paul Williams, Principal Investigator
INDUSTRIAL RESEARCH

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November 3, 2003

BP Cherry Point Project Comments
BPA Communications Office KC-7
POB 14428
Portland ORE 97293-4428

Dear Sir/Ms:

Here are corrected comments and attached exhibits regarding the BP Cherry Point Cogen DEIS, on behalf of the Washington State Association. An earlier version of these comments, without exhibits, was submitted earlier by attorney Gerald Steel.

Yours,

John Williams

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ENERGY FACILITY SITE
EVALUATION COUNCIL

COMMENTS ON THE DEIS FOR THE BP POWER PLANT
PURPOSE AND NEED

One of the purposes and needs for this project is the need to provide the predicted additional electrical generation capacity for the future needs of the region. This projected need, according to the Northwest Power Planning Council's power forecasts for the region, predicted that by 2015, the needed regional increase in power would range from an additional 2035 megawatts (MW) under the medium prediction, to 4120 MW under medium-high, and 7507 under the high prediction.

However, those predictions are already almost two years old. Since those predictions were made, the following plants have gone on-line:

Chehalis	520 MW
Hermiston	650 MW
Frederickson	250 MW
Coyote #2 Springs	280 MW
Klamath Cogen	484 MW
expansion	100
Combine Hills	41
SP Newsprint	96
small projects	100

TOTAL 2521 MW 1

In other words, enough facilities with "firm" power generation have already been constructed to provide far more energy what would be needed for the next ten years under the "medium" prediction. In addition, another 519 MW of non-firm wind generating capacity have also been constructed.

NEWLY CONSTRUCTED WIND GENERATION

Stateline	119 MW
Stateline II	37
Klondike	24
Condon	50
Transalta	200
Nine Canyon	48
Vancycle	41
TOTAL	**519 MW**

PARTLY CONSTRUCTED
The following gas-fired plants are also partly constructed:

Goldendale	250
Mint Farm	300
Satsop	650

TOTAL 1200 MW

At this point, the region has enough new energy facilities already running, and under construction, to meet the medium-high prediction for needed energy capacity for the next twelve years, and for the next 22 years under the medium energy needs prediction.

ALREADY PERMITTED
The following gas-fired plants are fully permitted

Sumas II	660
Wallula	1300
Umatilla	600
PGE	560
Port Westward	600
Plymouth	300
Col. River En.	44
Ore. Eng.	93
Boise/StH	141
West Linn	94

TOTAL 4400 MW

1 cont.

TOTAL RECENTLY COMMISSIONED, RUNNING, UNDER CONSTRUCTION, AND ALREADY PERMITTED: 8100 MW.

In summary there is already enough new energy generation built, under construction, and fully permitted, to supply even the highest prediction of new energy need for the next twelve years, and the medium-high prediction for the next 22 years, **without the BP project**. [1] These figures do not even take into consideration the thousands of megawatts of additional projects that are even now seeking permits, including but not limited to the Wanapa project, Calpine/Turner, Peoples Energy/Klamath Falls, and Coburg, which collectively add to another 3500 MW in capacity.

[1]The DEIS at Table 3-26 features a partial list of newly commissioned thermal plants, plants under construction, and plants fully permitted which totals 6504 MW. The DEIS list considerably underestimates the amount of current, under-construction and fully permitted generation, for instance by misstating the production of HPP, which is 649 MW, not 546 as claimed in the DEIS.

CONCLUSION
The DEIS fails to demonstrate a need for a 720 MW plant at BP to meet regional energy needs for the next 22 years, since more than enough plants have already been constructed, are under construction, are fully permitted, and are in the permit process, to meet even the highest predictions of energy needs. 1 cont.

ALTERNATIVE SIZE
One alternative that was rejected without an adequate discussion would be sizing the power plant to supply only the amount of electricity and stream that the refinery can consume.
The DEIS claims that a smaller plant would not provide economic energy, and would be an uncertain steam supplier. But not enough details were supplied to justify this dismissal of an important alternative.

Only an 85 MW plant was considered when this alternative was rejected. A slightly larger plant, for instance 100 or 200 Mw, which would provide more than enough energy for BP, and would also provide considerable excess stream generating capacity, and some energy for outside sales, was apparently not studied. If the plant were smaller, it could still supply its contractual obligations, but there would be less significant impacts, especially air emissions.

For instance, here is a list of several other cogeneration facilities which would supply an extrapolated 510,000 lb/hour of steam that BP needs, without producing the immense amount of air pollution and water use generated by the proposed 720 MW power plant

NAME OF FACILITY	MW	LB/STEAM/HOUR	Extrapolated* MW/510k lb/STEAM
Sun Mill, Okeelanta, Fla	75	1,300,000	29
UW-Madison	45	600,000	37
G-P, Camas, Wash.	11	140,000	39
Petro Canada Macay River	165	1,584,000	52
Hershey's, Oakdale, CA	5.6	50,000	56
Scott Paper, Everett, Wa	47	435,000	56
NIH	23	180,000	64
Coca-Cola Leesburg	3.6	22,000	82
Auburndale	7.2	44,000	82
UC Berkeley	24	100,000	120
Grays Ferry/Trigen	170	800,000	106
Aries	45	187,000	120
ExxonMobil, Baytown, TX	160	560,000	143
United Cogen, SF, CA	30	100,000	150
Carseland Cogen	80	264,000	152
Solvay/Jemeppe-Sambre	90	286,000	158

2

UW-Madison	150	400,000	188
Oxychem, Ingleside, TX	440	1,100,000	210
Bear Creek	80	165,000	242

*This figure is a scaled-up estimate of what megawatt plant would also generate 510,000 lb/hour of steam, given the figures presented for each particular facility. All plants except G-P/Camas and Scott Paper are natural gas fired.

100-200 MW PLANT WOULD MEET ALL THE PROJECT'S NEEDS

Based on the median generating capacity figure for these cogeneration plants, it can be extrapolated that a 100-200 MW facility is fully capable of generating 510,000 lb/hour of process steam for use at BP. In practice, this approximately sized plant appears to be in common use for steam generating hosts of this magnitude. At least six plants on the list generate over 510,000 lb/hour of steam and their energy capacity ranges from 45 to 440 Mw. For instance, the Petro Canada, ExxonMobil, and the Gray's Ferry cogeneration plants generate over 1.5 million lb/hour, 560,000 lb/hour, and 800,000 lb/hour of steam while generating 160-170 MW of electricity. 2 cont.

Only a single plant on this list is even half as large as the BP proposal. This information suggests that the BP proposal is clearly oversized, given the steam needs of the refinery, and the energy projections for the region.

A far smaller cogeneration plant of only about 20% of the proposed size of the BP plant, would be fully capable of meeting the purpose and need stated in the DEIS, while producing only about 20% of the projected air and water pollution, and water use.

ALTERNATIVE POLLUTION CONTROL–ELIMINATE AMMONIA THREAT

The power plant will store anhydrous ammonia, and emit ammonia for use in their SCR air pollution scrubbing system. This present dangers to public health and to air quality. The DEIS should have discussed several alternatives to use of anhydrous ammonia that present far less risk to human health and safety. These alternatives include a non-ammonia scrubber system, use of aqueous ammonia, or use of urea. 3

AMMONIA STORAGE AND TRANSPORT

The proposed power plant will use, handle, store and transport large amounts of ammonia. Ammonia is listed on the EPA's list of extremely hazardous chemicals. The State of Louisiana has recently tightened regulations governing handling of ammonia.
It is prudent to minimize the use and storage of any hazardous chemicals such as ammonia. Nonetheless, BP proposes to transport, use and store large additional quantities of ammonia on site.

The DEIS is deficient in failing to describe and address the possible consequences of transporting, piping, storing and emitting hundreds of thousands of pounds of ammonia at this 4

Page 4 of 23

facility every year. There are two issues regarding ammonia. The first issue is the constant release of ammonia from this facility under normal operating conditions. The second issue is the risk of ammonia releases from the storage and transportation of this hazardous chemical. 4 cont.

AMMONIA EMISSIONS UNDER NORMAL OPERATING CONDITIONS

Ammonia may be emitted from the project at 5 parts per million (ppm) which is one/half of the odor threshold. There are other ammonia sources in this area, including other power plants, and refineries, whose emissions could contribute to an ambient ammonia level. These other ammonia sources were not evaluated in the DEIS. In this case it is possible that the ammonia odor threshold could be exceeded under adverse air quality mixing conditions, such as inversions. These nearby ammonia sources should have been inventoried, because those sources 5
may cumulatively contribute to formation of secondary particulate.

But no controls for ammonia are discussed, nor is there any modeling that accounts for potential ambient levels of ammonia that would cumulatively join with the proposed facility's emissions. The impacts of ammonia emissions on PM formation were discussed earlier.

NON AMMONIA SCRUBBER SYSTEM--BENEFITS OF SCONOx WERE NOT ADEQUATELY CONSIDERED

SCONOX is an alternative pollution scrubbing system that does not use ammonia. SCONOX should have been comprehensively discussed as an alternative to the proposed project. The SCR system proposed for use by the Applicants results in a number of environmental problems that are reduced or eliminated with the use of SCONOx. These problems include: (1) hazards from accidental releases of the ammonia used in the SCR system during its transportation and handling; (2) the formation of particulate matter from the oxidation of SO_2 in the SCR catalyst; (3) the formation of particulate matter from reactions between ammonia and SO_2; (4) generation and disposal of the hazardous SCR catalyst at the end of its useful life; (5) inability to control NOx and CO emissions during startups and shutdowns; (6) increase in NO_2 from the use of dry low NOx combustor.

SCONOX would produce greater control of NOX and other pollutants, and eliminate ammonia 6
emissions, and the threat of releases from storage and transport of ammonia. The EPA has recently ruled that SCONOX is considered technically "Available" for NOX control on natural gas fired turbine power plants. The SCONOX controls on two UC-San Diego Solar 130S turbines, control NOx to 1.0 ppm or below, and also control CO to below .04 ppm, according to San Diego Air pollution Control District Source tests.

Although the DEIS rejected SCONOX based on cost, the California Air Resources Board BACT evaluation comparison reports for combustion turbines, rated SCONOX as only slightly more expensive than SCR.

LOW NOX BURNERS

The newest generation of low-NOx burners appropriate for power plants can reportedly lower

NOx emissions to below 5 ppm, without using ammonia and producing ammonia emissions and crating the hazards of ammonia storage and transport. The DEIS should have discussed these devices as an alternative. 6 cont.

THE DEIS FAILED TO CONSIDER HOW AMMONIA SLIP WILL ADD TO PM10 EMISSIONS

The DEIS failed to describe the reactions between SO3, NH3, and NO2, which form salts, some of which are emitted to the atmosphere and some of which deposit within the HRSG. Equations can be used to estimate a portion of the secondary PM_{10} that is formed from ammonia slip. Secondary PM_{10} can be formed by reaction of ammonia with SO_3 and NO_2 emitted by the gas turbines and present in the stack gases and plume as well as additional SO_3 and NO_2 that are present downwind in the atmosphere.

Additional ammonium nitrate could form from the reaction of NO_2 in the atmosphere with any emitted ammonia. This additional PM_{10} may not have been included in the Project's emissions estimates. Apparently the formation of secondary PM10, ammonia nitrate, from the proposed project, was not done in the DEIS, so the combined PM10 emissions will be more than what was estimated. BPA's own EIS on the Wallula Power project admitted ammonia emissions could produce as much as 460% of their own weight as secondary particulate. 7

AMMONIA EMISSIONS' PM_{10} FORMATION CAUSES VISIBILITY REDUCTION

The ammonia emissions from the proposed facility will contribute to the secondary formation of PM-10 in the project vicinity. The contribution of ammonia to secondary PM formation was not discussed in the DEIS. The fact that ammonia/PM reactions actually occur and cause visibility impacts is well documented in the technical literature. A noted atmospheric textbook, for example, contains this vivid description of the problem (Pitts and Pitts, 1999,[2] p. 284):

> "The formation of ammonium nitrate has some interesting implications for visibility reduction. In the Los Angeles air basin, for example, the major NOx sources are at the western, upwind end of the air basin. Approximately 40 miles east in the vicinity of Chino, there is a large agricultural areas that has significant emissions of ammonia...under typical meteorological conditions, air is carried inland during the day, with NOx being oxidized to HNO3 as the air mass moves downwind. When it reaches the agricultural area, the HNO3 reacts with gaseous NH3 to form ammonium nitrate..the particles formed by such gas-to-particle conversion processes are in the size range where they scatter light efficiently, giving the appearance of a very hazy or smoggy atmosphere even though other manifestations of smog such as ozone levels may not be highly elevated."

AMMONIA RELATED PM_{10} FORMATION ENDANGERS BIOTA

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[2] Barbara J. Finlayson-Pitts and James N. Pitts, Jr., Chemistry of the Upper and Lower Atmosphere. Theory, Experiments, and Applications, Academic Press, San Diego, 1999.

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The majority of the ammonia slip reacts with NOx to form ammonium nitrate, which is a form of PM10. This PM10 can be deposited on surrounding hills, located immediately adjacent to the site. This is an especially significant impact, especially if there is already a high level of ammonia compounds emitted in the vicinity of the project. There are many other large ammonia sources in the vicinity of the project, including the Encogen, Tenaska, and March Point projects, and other power plants and large refrigeration facilities.

The Federal Land Managers conducts the IMPROVE air monitoring project in the Columbia Gorge area. IMPROVE's results show than almost 40% of fine particulate in the Gorge vicinity is made up of ammonia compounds; ammonium sulfate and ammonium nitrate. These same ammonia compounds could form additional concentrations of PM in the vicinity of the BP plant.

This additional PM10 would increase the Project's reported contribution to soil nitrogen. The impact of this additional ammonium nitrate has not been evaluated and must be to fully evaluate the environmental impacts of SCR. Ammonia emissions are discussed further in the following comments. These types of reactions, as described above, are a potentially significant impact that should have been discussed in the DEIS. 8

In summary, the DEIS appears to have underestimated the resulting concentrations of PM 10 from the project. These underestimations need to be considered in light of the Federal Land Managers certifications that significance degradation of air quality in nearby Class I areas are already being exceeded. This certification by federal agencies of an already occurring significant impact, that will be increased by the proposed project, was not mentioned in the DEIS

For these reasons, the subject of the health and environmental effects of PM-10 and the plant's contribution individually and cumulatively, should have been presented in depth. Many recently published studies demonstrate that PM-10 and TSP are far more harmful that previously considered. In one study of the Seattle area, days of high particulate concentrations in the air were correlated with increased hospital visits for asthma. In another series of similar studies, days of high particulate concentrations were correlated with days of high death rates in Santa Clara, California, Steubenville, Ohio, Birmingham, Alabama, and Philadelphia, Pennsylvania, among seven separate studies on this topic. Particulate have been recently, convincingly implicated in harm to pulmonary function.

IMPACTS OF INCREASED PM CONCENTRATIONS BELOW THE NAAQS NOT CONSIDERED

Some important conclusions from these studies is that harmful health effects occur even when particulate concentrations are far, far below the legal limits, there is no apparent particulate threshold for adverse health effects, and that harmful health effects are apparently caused by very minor increase in particulate concentrations. This means that even though the Project will not cause violations of the PM legal limits it could still cause significant health impacts. Construction will also create about 1 ton of TSP per acre of disturbance per month. Construction equipment, truck and car traffic related to this project, both in the construction and operation stage, will be an additional PM-10 and TSP source.

It appears from these studies that <u>any</u> increase in PM-10 and TSP levels will cause an adverse health impact. This is a significant health impact that should have been discussed in an EIS. There are important environmental impacts from PM-10 emissions, also. 9

<u>RISKS OF AMMONIA RELEASES</u>

The plant will store hundreds of thousand of pounds of ammonia on site, and millions of pounds of ammonia will be transported to this site every year. But the DEIS does not describe the likelihood of a transportation accident, the numbers of truck trips bearing ammonia, the possible size of any ammonia releases from a truck accident, the inability of this rural area's emergency response system to react to a large release, the neighborhoods and businesses that would be threatened by a release, or the risk and effects of a release from the ammonia tanks at the power plant, including the risk and effect of a tank failure. 10

In fact, the DEIS is virtually silent on this troubling subject, of large scale ammonia releases from transport and storage of large amounts of ammonia on the site, and how, or whether, emergency responses will be conducted. Ammonia releases are fairly common. A study submitted to the Congress revealed there have been over 1000 ammonia releases over one nine year period, which caused 801 injuries, 9 deaths, and 61 evacuations of over 22,000 people. [3]

For instance, there was a release of ammonia in August, 2001 from the Pratt & Whitney power plant in East Hartford, Conn., that caused the shutdown of nearby streets for five hours and led to the evacuation of 20 people. For this reason the commentors urge that the DEIS should have discuss ammonia hazards, and the ability to respond, from storage and transport releases, and any requirements to comply with the CAA amendments governing storage and transport of ammonia and other hazardous materials.

The facility will use anhydrous ammonia which is the most hazardous form of ammonia, and the type of ammonia most often implicated in releases causing injuries, deaths, and evacuations of thousands of people.

<u>AMMONIA ALTERNATIVES</u>

The DEIS evaluation should have studied alternatives types of ammonia to be stored and used, for instance the use of urea instead of ammonia, or the use of aqueous ammonia, and alternative transport methods for ammonia. Anhydrous ammonia should be specifically banned from use because of the increased dangers from its releases. 11

The DEIS' evaluation should also study the potential impacts of large scale ammonia releases 12

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[3]Report to Congress Section 112(r) (10) Clean Air Act as Amended. EPA 550-r-93-002. December, 1993.

from different site locations, and the release impacts from different types of transport accidents. 12 cont.

SOME RECENT RELEASES OF AMMONIA (not a complete list)

evacuations	injuries	location	gallons released
1000	65	Quebec	" "
1500	0	Morro Bay, CA	300
100-300	n/a	Wauwatosa, Wi	n/a
125	n/a	Columbus Jct, IA	200
36	1300	Minot, ND	about 140,000
280	4	Washington, IND	Not provided
not known	15	St. Paul, MN	not provided
not known	9	Lorain, Ohio	10 pounds
230	5	Old Monroe, MO	not known
200	1	New Plymouth, NZ	not known

The Project may be subject to the Title III requirements regarding storage of hazardous materials, but those requirements, including a hazard assessment and risk management program, have not yet been developed and reviewed by the public and the relevant agencies. These requirements should have been fulfilled in time for these proceedings, so that the public can evaluate this project's risks in a single round of reviews and meetings. 13

ALTERNATIVE DESIGNS TO REDUCE WATER USE AND DISCHARGE

The proposed plant will use water cooling. It will consume an average of over 2200 gallons per minute of water; or more than 3 million gallons per day. It will also discharge about 190-260 gpm. (About 300,000 gallons/day)

Over 2200 gallons/minute (Over 3 million gallons per day) is a very high rate of water use for this size of power plant. Many power plants are designed to generate far more energy, while at the same time using far less water than is proposed for this plant. For instance, the proposed natural gas fired Chehalis power generates almost as much energy (520 vs 720 MW) as the BP proposal, but will use only about 7% as much water. The Chehalis plant is solely air cooled.

Many power plants are also able to function without discharging 200 gpm or more of waste water, also, including the Sumas I plant. The DEIS should have more comprehensively discussed alternative designs of the facility that would reduce water use and discharge, as follows. While the DEIS rejected these alternatives as too costly, the widespread use of these water conservation methods indicates that any increased costs are relatively insignificant. 14

For instance, the BP facility will use far more water to generate 700 MW, than will the Lakefield Junction plant in Minnesota, to generate over 600 MW. Diamond Energy's Nevada plant will use only 20-50 af/year (about 40,000 gallons/day) to generate 500 MW, according to published accounts. Colorado Springs/Fountain will use only 80 gpm to generate 480 MW, compared to BP water use of over 2000 gpm, (well over 3000 af) according to published accounts.

If many other power producers can bear these slightly increased costs, and in the process conserve billions of gallons of water, than the DEIS should conduct a more stringent review of the purported reasons for rejecting water conservation measures out of hand. 14 cont.

AIR COOLING

This alternative would include complete air cooling, rather than partial water cooling for the facility. The commentors are aware of many existing and proposed power plants that are solely air cooled, including the two Neil Simpson plants and the Wyodak plant in Wyoming, the permitted Chehalis Power facility in the State of Washington, the Doswell facility in Virginia, the Matimba and Kendal powerhouses in South Africa, the Rosebud plant in Montana, the Linden and Sayreville plants in New Jersey, Colorado Springs near Fountain, Colorado, Diamond Generating, near Goodsprings, Nevada, Duke, and Miriant, both near Las Vegas, Reliant's Choctaw County projects near French Camp, Mississippi, and its Hunterstown, Pennsylvania, project, Taiyuan #2 in China, Trakya in Turkey, Uran III in India, Tousa in Iran, and the Camarillo facility in Ventura County, California.

In addition, most large power plants permitted recently in California have been exclusively air cooled, including Sutter Power, and Otay Mesa. Total Air cooling of the BP plant could reduce water use by 70% or more, and would save about 2 million gallons/day.

HYBRID COOLING SYSTEMS

These plant designs use a combination of both air and water cooling, and are in use at the West Cogeneration plant in Germany, and the Exeter Energy plant in Conn., USA. Three Mountain Power is California is another hybrid cooled plant, as is Mass Power's Indian Orchard plant. Water use is cut approximately in half.

ZERO DISCHARGE PLANTS

These types of facilities extensively re-treat and re-use their waste water, often with the reverse osmosis membrane process. Public Service in New Mexico has employed this technology for over 20 years, as does the Massena. New York plant, Ocean State in Burrillville, Rhode Island, and FJ Gannon in Florida. There are several variations on this process, including brine concentration. We understand that HPD plant, in Naperville, Illinois, uses this process. Staged cooling, used at Pasco in Dade County, Florida employs this alternative. The nearby Sumas I plant is zero discharge.

The DEIS rejected zero discharge after a truncated discussion that concluded the costs of trucking out waste water solids was too high. The treatment plant for this effluent is going to have solids that will need trucking and disposal, in any event. This was not an adequate discussed of an alternative that would not require the commitment of this massive amount of water for the power plant, and which is in active use at many other competitive power plants. 15

WATER QUALITY AND QUANTITY IMPACTS

The DEIS at 2-27 states that the waste water will have to be concentrated at a ratio of 15-1 before it will be discharged. The water tests in the DEIS did not present an analysis of the trace metals and radioactive materials that may be finally present in the cooling water. Even if these types of materials area present in very small amounts, they will be concentrated by 1500% by the cooling cycles, and this activity could produce a significant concentration of potentially toxic materials in the discharge water. 16

WETLANDS

The DEIS claims that about 30 acres of wetlands will be destroyed by the project, and about 100 acres will be rehabilitated. Again, however, the DEIS fails to inform the reviewers that the degrading of these and directly adjacent wetlands, and the ultimate rehabilitation of other wetlands, is actually the product of two contemporaneous projects; the cogen plant and the isomerization (Isom) unit.

In fact, the Isom unit is currently undergoing its own review by the Army Corps of Engineers, whom admits that the construction lay down area, and the resulting lost wetlands, for the Isom unit (the Brown Road Materials Storage Area)is next to the lay down area, and lost wetlands, for the cogen unit. The wetlands areas proposed for rehabilitation for both the Isom and Cogen units are also contiguous, north of Grandview Road. 17

But the DEIS fails to discuss the cumulative impacts of the Isom and the Cogen projects on any resources, including but not limited to wetlands. For instance, the proposed cogen laydown area west of Blaine Road would appear to conflict with the proposed plans for wetlands water conveyance that are part of the Isom project wetlands mitigation plans. 18

SOME REHABILITATED AREAS ARE EFFLUENT TREATMENT PONDS, NOT WETLANDS

The DEIS admits that effluent from the cogen's oil-water separator will be discharged to the ponds in CMA-1. The DEIS claims these and other areas provide rehabilitated wetlands which mitigate for the losses of over 30 acres of natural wetlands. But if an industrial uses a ponded area to receive effluent, the recipient area is part of a wastewater treatment plant, not a "wetland." In summary, some of the claimed "mitigation" wetlands are not really wetlands, those ponds are actually water treatment facilities.

For this reason, Ecology publications state that "wetlands" created for stormwater treatment are "high risk" because they may receive high sediment and debris loading, or may accumulate toxic materials and become dangerous to wildlife. For this reason much higher replacement ratios are justified. (DOE Publication 92-8, p.14) The DEIS should describe what acreage of rehabilitated areas are being used for receipt of stormwater, so that commentors can determine if an appropriate replacement ratio of wetlands is actually being provided. 19

DEIS FAILED TO CONSIDER CUMULATIVE IMPACTS WITH THE ISOM CONSTRUCTION AND OTHER RAPIDLY UPCOMING CLEAN FUEL PROJECTS

The DEIS' failure to discuss the closely related and physically adjacent Isom construction job and its impacts, and the other elements of the ongoing Clean Fuels projects at BP and the neighboring refineries. All of these project will have cumulative air quality, traffic, and socio-economic impacts in combination with the impacts from the BP Cogen. The DEIS' failure to discuss these cumulative impacts violates NEPA (40 CFR 1508.7) and SEPA, which both require a study of cumulative impacts of nearby projects taking place at the same time. 20

PIPELINE IMPACTS

The proposed power plant and its support facilities include a natural gas pipeline lateral. There are many other natural gas pipelines around the country, and in the Northwest, that were constructed according to federal standards. But in the Northwest alone, pipelines have blown up three times within the last few years.

A pipeline near Bonneville Dam exploded and burned on February 27, 1999. The roar from the explosion was heard for two miles. The 300 foot high fireball was so huge it was visible for miles. Route 14 in Washington was closed to protect the public. Press accounts state that earth movement from recent heavy rains may have been responsible for the pipeline break. The fire destroyed a resort hotel that was under construction and a nearby dwelling.

Near Kalama, Washington, a natural gas pipeline broke in February, 1997. Again, a 300 foot high fireball blazed into the sky. And just one day earlier, the same pipeline exploded and burned near the BP site, Bellingham, Washington.

In March of 1995, that same pipeline had raptured and blew up near Castle Rock, Washington. After that 1995 explosion, the company removed soil from 300 feet of the pipeline, to relieve any stress. But less than two years later, it blew up again. Again, soil movement was the cause of the pipeline breakage, according to published accounts.

There have been a total of at least ten large natural gas pipeline explosions, since 1978 in the Northwest, including other ruptures in Stevenson, Washington, La Grande, Oregon, and Montpelier, Idaho. All of these explosions have been on the Williams Pipeline system that may supply this proposed power plant.

A few years ago, a construction backhoe caused a leak in a Northwest Natural Gas pipeline recently in Rainier. Seventy five people were evacuated. There is other evidence regarding the potential impact on public health and safety from natural gas pipelines.

Earlier this year, at least six people were killed in a natural gas pipeline explosion near Carlsbad, New Mexico, and another six were injured. Landslides in Ventura county, California ruptured several natural gas pipelines in February, 1998, again after heavy rain. Between 1965 and 1986, there have been 250 pipeline failures in the United States as a result of stress corrosion cracking, caused by a combination of water, soil types, and gas temperature within the pipelines.

Twenty-one people were killed during 1995 from natural gas pipeline accidents.[4] A Transwestern Pipeline natural gas pipeline exploded on August 20, 1994 in New Mexico, near the Rio Grande River, damaging a bridge. An October, 1994 explosion of a pipeline in Torrance, California, injured 30. A December, 1989 pipeline rupture caused by a farmer's plow, triggered the evacuation of 600 people in Butler, Illinois.

In March, 1994, a natural gas pipeline exploded in New Jersey, killing and injuring scores of people and creating a 30 foot deep crater and a fire that destroyed eight buildings and severely damaged six more buildings.

All of these pipelines were constructed to federal standards, and monitored by federal agencies. The DEIS should explain, how with all the mitigation measures and careful engineering, pipelines, including facilities in Washington State, on the very pipeline that will service this power plant, can still blow up. When these events occurred in a populated areas, there may be heavy loss of life and property. These pipeline explosions are significant impacts. Additional protective measures should be discussed and implemented, and the problems that caused this explosion should be carefully explained at length in an revised DEIS. 21

But the DEIS did not discuss pipeline accidents, also known as "service incidents." A service incident is reportable if there is a gas leak causing a death or serious injury, gas ignition, over $5000 in property damage, if it occurred during a test, if it required immediate repair, or if a portion of the line was taken out of service because of the incident.

An revised DEIS should be prepared to describe the likely scenario of service incidents on the pipeline serving the power plant, perhaps by describing several of the recent explosions on this pipeline and at similar pipelines. 22

Descriptions of a range of several recent incidents should be provided, so that readers and commentors can be appraised of the possible impacts of service incidents. This is appropriate because service incidents can be expected over a 50 year life span for these pipelines. The DEIS should also have discussed whether, and how local agencies in this area would respond to a pipeline explosion and fire. 23

POWER PLANT ACCIDENTS

The DEIS failed to discuss the potential for accidents and explosions at this proposed facility. On occasion, similar power plants have experienced fires and explosions that have damaged property and killed people.

On October 8th, 2002, a massive explosion at the Florida Power & Light natural gas fired Palm

[4] New York Times, 4/9/97, p. 1.

Beach plant rocked two counties, followed by a hydrogen-fed fire. The explosion shook houses and rattled windows, and was as loud as a sonic boom. In January, 2002, there was a hydrogen explosion and a resulting fire at the natural gas fired BC Hydro plant in Port Moody, BC.

Less than two weeks ago, on October 1, 2002, there was a nine-alarm fire at the Sithe power plant in Boston, that began in a hydrogen generator. The fire and explosion caused $10 million in property damage.

The BP DEIS does not apparently even mention the use of hydrogen at that plant, or list it as being stored on site. We understand that hydrogen is routinely used and stored at natural gas fired and other power plants similar to BP, including but not limited to these three plants, that have blown up recently. But this potential impact from explosives and fires from caused or fed by hydrogen, and the impact on emergency services to respond, was not adequately discussed in the DEIS. 24

At the Sithe blaze, 180 firefighters had to respond. The natural gas fired turbine at the Doswell power plant in Virginia recently suffered an catastrophic fire and explosion. It took 75 fire fighters to quell the resulting fire The DEIS should have discussed what will happen if hundreds of fire fighters are needed to respond to a problem at BP.

There were other explosions and fires at power plants recently. An explosion and fire rocked the Black Hills Power and Light power plant in Wyoming, in June, 2002. A back-up generator blew up and caused a "major" fire at the Allegheny Energy plant in Pennsylvania, in July, 2002. Firefighters from at least five communities had to respond to the blaze. A pressure relief valve activation at the Mirant plan in Zeeland, Michigan in August, 2002 caused diversion of traffic, to avoid released gasses.. Three workers were killed at a fire in the O'Brien Newark, New Jersey Cogeneration power plant fire recently. At least 20 other fires have been recorded over the last 10 years at power plants, causing another death and $417 million in property damage. The most severe fires often involved the release of lube oil, which ignited. Thousands of gallons of lube oil will be stored at BP.[5]

There were 272 to 557 equipment failures and accidents per year at power boilers and pressure vessels since 1992, causing almost 200 injuries and 29 deaths, and another 145 to 387 failures, and another 270 injuries and 54 deaths, from unfired pressure vessels, according to Power Magazine, Jan-Feb., 2001, p 53.

Because Power plants typically store and use many materials that present a danger of fire and explosion, such as hydrogen and lube oil, some of these hundreds of annual accidents at power plants cause injuries, and losses of life and property beyond the power plant boundaries, and require a large response of emergency personnel, as previously described. The dangers from the use and storage of these materials, and even the types of materials to be stored at BP, and the 25

[5]Most of these narratives are from the Chemical Safety Board's web site.

ability or lack thereof of local fire departments to respond, was not discussed in the DEIS. These kinds of serious accidents are significant impacts that should be discussed in an EIS. 25 cont.

CUMULATIVE EFFECTS OF INCREASED USAGE OF NATURAL GAS

The EIS did not discuss the adverse impacts from the increased exploration and processing of gas in Canada, in part sparked by the development of these this project.

Discussions of Canadian impacts is mandated by Presidential findings during the Carter Administration regarding the scope of NEPA-covered projects. A description of Cross-border impacts are also appropriate, considering that the Canada Energy Board requires assessments of impacts in the United States, when evaluating proposals for Canadian pipelines. 26

Nor did the DEIS adequately discuss the cumulative impacts of this project and the many other power projects in the Northwest, on the natural gas supplies. Although this very topic was the subject of a chapter in the Wallula Power EIS, it received inadequate discussion in this document, even though the cumulative impact of some of the recently proposed power plants in the Northwest, was the additional consumption of over 6% of domestic natural gas reserves.

PM-10

ADDITIONAL PM SOURCES

. The DEIS also lacks adequate information to assure commentors that its calculations included the impact from formation of secondary PM by conversion of ammonia. While the DEIS did discuss secondary formation of PM from conversion of nitrogen and sulfur compounds, the DEIS did not discuss secondary formation of PM by conversion from airborne ammonia compounds. 27

This plant will emit hundreds of tons per year (TPY) of PM-10 from its turbines alone PM-10 is fine particulate that is capable of being drawn deep into the lungs. PM-10 is highly damaging to human health. But in addition to the power plant exhaust, there are other sources of PM-10 and total suspended particulate (TSP) from this project, including the cooling tower.

COOLING TOWER DRIFT

The cooling towers are PM-10 and TSP sources, to the degree which the cooling water contain solids, which are emitted from the cooling tower exhaust as particulate. A large power plant using water high in solids content can emit many tons per year of PM-10 and TSP. For instance the Goldendale Energy plant was predicted to emit 6.6 TPY of PM, and BP is 300% larger. The PM emissions from the cooling tower will contribute significantly to the ambient air concentrations of PM_{10} concentrations. The effluents have low exit temperatures, low exit velocities and correspondingly are low in momentum and buoyancy. Switching to full air cooling would also reduce PM and TSP emissions, since a cooling tower will no longer be needed. 28

Cooling tower emissions also contain salts, metals, water treatment chemicals, and other contaminants, which could degrade the quality of soils, and affect human health, wherever the cooling tower drift is deposited. .

IMPACTS FROM WATER DISCHARGES

The DEIS does not list water treatment chemicals to be used at the plant, and does not list any details of the toxicity of inhibitors or algicides that would be discharged. Lacking a complete discussion of the possibly pollutants in these sources's discharge, it is not possible to conclude that the this source's waste water will not contribute to water treatment problems. These chemicals could also be discharged in the cooling tower discharges. 29

SOLID WASTES

Water treatment for a large power plant can generate as much as 10 tons per month of wastes, as backwash, or filter cake. There are other waste streams, including spent catalyst, which is a hazardous waste. Catalyst wastes could be avoided by used of the SCONOX scrubber system. This generation of wastes was never described adequately in the DEIS. The materials contained in this wastes, the amount to be produced, its destiny, and its impacts on landfill capacity should all have been discussed. 30

STORMWATER RUNOFF AND SPILLS

The project will include the creation of impervious surfaces. This will cause the generation of millions of gallons of storm water runoff. This water will be tainted with oil, grease, and other contaminants present on the site and its parking lot and roof. The DEIS did not describe adequately the quality of this runoff, its destiny, and its potential impacts on nearby wetlands and surface waters. While there would be unlined detention ponds the DEIS did not describe to what degree these ponds will treat the storm water to remove pollutants before it is allowed to infiltrate into the ground water. 31

While an oil/water separator will be present, the DEIS did not assure commentors about the degree to which stormwater will be channelized through the separator. Nor did the DEIS describe the fate of wastes that are separated from the storm water. The DEIS did not describe the project's compliance with the DOE Stormwater Management rules. For instance, use of oil/water separators is actually criticized as having limited application, in DOE guidance manuals. The DEIS did not describe why a separator was appropriate for this location, or why alternative methods of storm water pollution control were not used. [6] 32

LEGIONNAIRES DISEASE

The DEIS did not provide a table of materials stored on site that listed biocides known to be effective against Legionnaires Disease. This disease breeds in moist, warm climates, including cooling towers such as those to be used by BP. It has been spread through the discharge of steam 33

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[6]Department of Ecology. Stormwater Management Manual. Chapter III-7. #91-75.

from cooling towers. In March, 2001, for instance, two Ford employees died in Ohio after exposure to Legionnaires' Disease, spread by the facility's industrial cooling towers. Legionnaires Disease organisms have also bee found in the CEGB power plant's cooling tower water, near Stafford, England. Since it is not apparent that BP plans to use appropriate chemical treatment of its cooling tower system to stifle development of the relevant bacteria, there is a threat of Legionnaires Disease from this facility. This should be discussed in a revised DEIS. 33 cont.

POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)
The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure. EMF exposure is another potentially significant impact that was not discussed in the DEIS. 34

POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)
This project will include a new power line. The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure, and the impacts to avian species which collide with above ground power lines.. Bird Mortality from the new power lines and EMF exposure are other potentially significant impacts that should have been discussed in the DEIS, and power line burial should be discussed as a mitigating factor, and a method of avoiding impacts on the nearby sensitive areas.

The power lines associated with this project, as currently proposed, are a potentially significant factor. The DEIS should have addressed to what degree power line burial would address this concern,.

There are many examples of burial of high voltage power lines of considerable length. Since the proposed lines are about 3000 feet long, burial of this line would reduce the visual impact of the project would protect avian species, would reduce the project's above ground "footprint," and would add only about 1/10% of one percent to the project costs; about $500,000.

Some example of actual and proposed burials of large pipeline include the 345 kV line that would be buried for 1700 feet to go under the Namekagon River near Trego, Wisconsin.

Sierra Pacific is burying a 14,000 volt line for about 2000 feet near downtown (Lake) Tahoe City, according to the company's June 9, 1999 press release.

Sierra Pacific is also burying a 120,000 volt (120kV) line for about 1700 feet near Carson City, Nevada, according to the company's April 19, 1999 press release.

Sierra Pacific's longest underground line is 2.6 miles, according to their Media Relations department.

The California Public Utility Commission's consultants, Aspen Environmental, prepared a study of an all-underground route for a 230 kV line near Pleasanton, California (Pleasanton Weekly. "Objectors, Proponents speak out on PG&E Power Line Plan." 2/16/01)

The Sumas II Power Plant has proposed a buried 230 kV line for 1.4 miles, in Abbotsford, Canada, as part of its trans-border proposal. (Canada Newswire. "NSB Receives a Revised DEIS from Sumas Energy II to Construct an International Power Line." October 2000)

The Sargent & Lundy engineering firm's advertising materials list several underground transmission lines for which they provided engineering, including a 115/138-kV line, a 230 kV line in Washington Dc, a 1800 foot 115-kV line in Baltimore, five 230-kV lines in China, two 69 kV lines in Iowa, a 1300 foot 138-kV line in Tennessee, and a one-mile, 138-kV line in Salt Lake City.

This litany of buried transmission lines indicates that this is a practicable, feasible and economic alternative design for this portion of the project. It would reduce the visual and land use impact of the project. For this reason a burial alternative, should have been presented in the DEIS.

QUESTIONS ABOUT THE EMISSIONS OFFSETS

The power plant will be permitted to emit the following annual tonnages.

NOx	239
CO	158
VOC	41
PM10	251
SO2	51

BP will purportedly shut down existing boilers, creating the following offsets:

NOx	499
CO	54
VOC	28
PM	94
SO2	7

The DEIS claimed this would have the following net impacts

NOx	-249
CO	104
VOC	13
PM	156
SO2	43

This list does not include the increased NH3 emissions of another 346 TPY. While the NH3 emissions are not a criteria pollution, it is still a toxic air emission, and an important source of secondary particulate matter, which is a criteria pollutant. Indeed, there is some evidence that 35

BP's new power plant NH_3 emissions will be responsible for an increase of as much as 1400 TPY of secondary PM.

DEIS DID NOT INCLUDE THE EMISSIONS INCREASES FROM THE CONTEMPORANEOUS ISOMERIZATION PROJECT

This data also does not include the contemporaneous isomerization project at BP. The isomerization project will be constructed at the same time as the Cogen project, it will share the same construction lay-down yard, and in fact will share the same wetlands mitigation plan with the Cogen. The isomerization project will cause the following increases in air pollution, according to an on-line description of the project by EPA Region 10: 36

POLLUTANT	TONS/YR	DEIS CLAIMED CHANGES	NET INCREASE W/ ISOM
NOX	166	-249	-76
PM	11	156	167
SO2	84	43	127
VOC`	31	13	44
CO	47	31	78
H2SO4	2		38*
NH3			173*

*Includes totals from Table 3.2-13

DEIS DID NOT ADEQUATELY DISCLOSE INFORMATION ABOUT THE PURPORTED EMISSIONS REDUCTIONS FROM THE SHUTDOWN OF THE REFINERY BOILERS

ERCs must be surplus, permanent, and verifiable. The boilers that will be shut down are old, and may be shut down after the Clean Fuels project provides new boilers, so these sources would permanently emit at the levels which the DEIS claims as credits. RACT (Reasonable Available Control Technology) of BACT determinations should be made to determine realistic Emission offsets credits. Another indication that the emissions credits are not permanent is the requirement of the BP Consent Decree which mandates NOx reductions at the Cherry Point refinery. These sources may not be permitted to function at the current levels, anyway.

The DEIS also admits that new boilers will be constructed during the upcoming Clean Fuels Project. (p. 3.2-28) For this reason, the DEIS inappropriately deducted the old boilers' emissions from new cogen emissions during its discussion of the net project impacts. In other words, the old boilers' emissions are going away very soon, cogen or no cogen. The DEIS needed to discuss the emissions from the new Clean Fuel boilers, as the only proper, legitimate offsetting emissions reductions that could be deducted from the new Cogen emissions. Since the DEIS failed to consider the permitted emissions from the boilers that are about to be constructed, the DEIS's claims of new air quality benefits are misleading and untrue. 37

Emission reduction credit guidance from the EPA (cited later in this document) generally suggests that the low value of actual emissions, vs. permitted emissions should be employed to determine the appropriate ERC. But the DEIS does not say if the figures given for the boiler emissions were permitted or actual emissions.

DEIS DID NOT DISCUSS THE NOX REDUCTIONS MANDATED UNDER THE BP CONSENT DECREE

Furthermore, BP is under the strictures of a Consent Decree with the Federal EPA, under which BP is required to reduce its NOx emissions at the majority of its heaters and other equipment at the Cherry Point Refinery. The Consent Decree also set limits on how BP can characterize NOx emissions reductions from equipment subject to the Consent Decree. The DEIS did not discuss the relationship between the NOx reductions required under the consent decree, and the NOx reductions from shutdown of the utility boilers, that is discussed in the DEIS.

This discussion should be required in the DEIS because ERCs must be surplus, quantifiable and permanent. If the old boilers were not shut down, it is doubtful that the old boiler emissions would have continued permanently at their current rate, because at some point RACT would have been mandated. Thus the boilers' emissions above RACT levels are not surplus, because some reductions will soon be required by law. 37 cont.

Permanent ERCs should not be based on past, high, emission rates, since those rates will not continue indefinitely, due to imposition of RACT, and the requirements of the Consent Decree, among other factors.

Federal register discussions state that VOC sources can be considered to impact ozone non-attainment areas within 36 hours wind travel time, because precursor emissions that occur within 36 hours traveltime of each other interact to form oxidant.[1]

Based on these discussions, The commentors ask that the old boilers at BP can be considered to contribute to the recent non-attainment status of the Seattle and Vancouver BC areas. EPA policy discussions suggest that RACT emission rates should be considered, rather than actual emission rates, or whichever is lower, for sources that are in non-attainment areas.[2]

The commentors are also concerned that several other criteria be followed in determining an acceptable amount of ERCs from the old boiler shutdown. The DEIS should establish that the Washington SIP does not already include, as part of its attainment plans, emissions reductions from shutdowns and the phasing out of aged emission units.

Some SIPs assume a quantity of reductions from new plant openings and existing plant shutdowns. These SIPs incorporate into their attainment strategy a net "turnover" reduction in emissions because new plants will be cleaner than the old shutdown plants.

If the Washington SIP includes this sort of "turnover" emissions reduction as part of an implementation strategy, then ERCs from the shutdown of the old BP boilers should not be granted, otherwise those emissions reductions would be double counted. (Federal Register 4/7/82, p. 15081)

In addition, if the Washington SIP contains emissions limits for the BP old boilers that are lower than BP's computation of its ERCs, then the SIP limits should be used to compute ERCs instead. (Federal Register, 1/16/79, p. 3284)

In summary, the old boiler actual emission rates should be compared with RACT/BACT emission rates from similar units, and the lower of those two rates should be used in the DEIS discussion of emissions reductions from the old boilers' shutdown.

AIR TOXICS

The new cogen project will emit several highly hazardous air toxics, including benzene and formaldehyde, and others, which are listed at Table 3.2-13. Toxics such as Acrolien, (and several metals), are emitted at amounts exceeding the Small Quantity Emissions Rate for both the hourly and annual emissions rate. But the DEIS fails to describe whether the project will result in greater or lesser emissions of these and other air toxics. The DEIS does not compare the emissions of air toxics from the cogen project, with the purported "reductions" caused by the shut down of the older utility boilers. 38

The DEIS should have performed this comparison. It is not wise or legal to trade increases in comparatively hazardous air pollutants for decreases in relatively less harmful pollutants. Such a trade should be fully disclosed and discussed on an DEIS. As one treatise on this topic stated:

> "Certainly no one should be allowed to trade an increase in a more harmful pollutant for a decrease in a more benign one simply because it is cheaper to do so...if an increase in a hazardous pollutant were to be traded for a decrease in a more benign one the net effect would be a greater threat to public health despite the equivalence in pollutant quantities" [3]

But the trade-off of some decreases in NOx emissions from the old boilers, for increased emissions in formaldehyde and benzene emissions and other VOCs and air toxics from the BP Cogen, is a trade of comparatively benign pollutants for more harmful pollutants. In particular, benzene increases as a trade for reduction of generic emissions are explicitly prohibited.

EPA guidance documents regarding pollution trades and reductions clearly and plainly state:

> "(E)ven within a category (such as VOCs), pollutants that pose significant health hazards cannot be traded against less harmful pollutants ... The emissions of ...<u>benzene</u> which (is) listed under section 112, may be increased at one emission point ... <u>only as long as there is a compensating decrease</u> in the emission of the same pollutants at another emission point at the same location or a contiguous location ... Sources may equally trade

> hazardous pollutants with nonhazardous pollutants in the same criteria pollutant category only in the cases where the source decreases the emission of the hazardous pollutant.(emphasis and parentheses comment added) [4]

A later update of this guidance document continued to maintain the ban on trades of hazardous for non-hazardous pollutants, and specifically proscribed trades involving increases in benzene emissions:

> "Emissions Trades Should Not Increase Hazardous Pollutants. Where pollutants have been listed under Section 112, but are not yet subject to specific regulations...states may allow trades consisting of equivalent increases and decreases of the same listed pollutant ... the State may also approve trades in which reductions of hazardous pollutants compensate for increases in non-hazardous pollutants....a source may trade benzene for any non-hazardous VOC, if the benzene emissions are decreased." [5]

This coverage of this quotation would also apply both to formaldehyde, which was listed under Section 112 as part of the Clean Air act amendments of 1990, and to benzene, which was listed at an earlier time under Section 112. Language in the amended Section 112 also addresses trades of hazardous pollutants as follows;

> "A physical change in ... a major source which results in a greater than de minimis increase in actual emissions of a hazardous air pollutant ... will be offset by an equal or greater decrease in ... emissions of another hazardous air pollutant ... which is deemed more hazardous." [6]

CONCLUSIONS

ERCs from the old boilers shutdown should be limited to the RACT emissions from these boilers, or the actual boiler emissions, or the emissions of the Clean Fuel Project replacement boiler, whichever is lower. If these boilers are supposed to be shut down or controlled under the Consent Decree, those reductions should not be considered credits at all. Reductions in non-toxic air emissions should not be described as offsetting increased emissions of air toxics. If air toxic emissions will actually rise, the DEIS should say so and provide details.

ENDNOTES

1.Federal Register, Vol. 44, No. 11, January 16, 1969. P. 3278- 9.

2. Federal Register, 4/7/82, p. 15080.

3. Landau, Jack. "Economic Dream or Environmental Nightmare? The Legality of the "Bubble Concept" in Air and Water Pollution Control." Environmental Affairs. Vol. 8:705, pp. 770 and 780.)

4. Federal Register Vol. 44, No. 239, December 11, 1979, page 71784.

5. Federal Register, Vol. 47, No. 67, April 7, 1982, pp. 15082-3.

6.Public Law 101-548, Nov. 15, 1990, 104 Stat.2544.,Section 112, (g)(1)(A).

November 9, 2003

RECEIVED

NOV 10 2003

ENERGY FACILITY SITE EVALUATION COUNCIL

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council
PO Box 43172
Olympia, WA 98504-3172

Re: Proposed BP Cherry Point Co-Generation Plant
Noise, Prefiled Direct Testimony, and Exhibits 24.0, et al.

Dear Mr. Fiksdal,

I spoke with Irina Makarow last Tuesday. She was returning my call from the previous Sunday in which I requested more time to respond to Exhibit 24.0, Applicant's Prefiled Direct Testimony, David M. Hessler, and attached reports, which was mailed to me after the October 1st co-generation meeting in Blaine, Washington. Ms. Makarow said that I could have until this Monday, November 10, 2003, to respond. Thank you for extending the comment period so that I could respond to the supplemental materials I received.

Attached please find my affidavit regarding noise. I will attempt to response to some of David Hessler's testimony and noise studies.

I perceive more than several flaws, inaccuracies, and unsubstantiated statements, conclusions, and presumptions in the noise monitoring and testing done by Hessler Associates, Inc. It takes time to refer to all the documents and I would also like to try to address issues other than those covered by the noise expert hired by Whatcom County.

Baseline Noise Monitoring

Per the sworn statements in the Affidavit:

1. Baseline monitoring needs to be done in the Cottonwood Beach area, where the citizens requested monitoring. 1

2. Baseline monitoring also needs to be done at night, especially when the sky is clear. 2

3. Baseline monitoring needs to be done when the level of refinery noise is sufficient to cause complaints from citizens. 3

My Affidavit testifies to BP knowledge that noise is louder during times when equipment is being shut down and started up. Therefore, noise needs to be monitored during the time that equipment is being shut down and fired back up again as part of the baseline study. Ms. Cleveland's testimony also states that Cottonwood Beach residents have volunteered to have 4 noise monitoring equipment and noise monitoring studies done on their property, thus totally invalidating the Hesseler Associates' concern regarding private property access issues (draft EIS, 3-9.6, September 5, 2003). 4 cont.

Current Noise Levels

On page 3-9.6 of the draft EIS, at the end of the 2nd paragraph. it says, "The results of the existing conditions for day and night periods are presented in Table 3-9.5." Table 3-9.5 (on page 3-9.9) is entitled: Estimated noise levels combining modeled and background noise.

Where are the baseline noise study result showing what the baseline noise levels are today? How can we examine the results and validity of the Hessler methodology if we do not have the data of the current day and night noise levels? 5

WAC 173-60-040 and maximum noise levels

The second paragraph of page 3-9.6 in the draft EIS states the noise levels range from 47 dBA to a high of 68 dBA during the day, and 39 dBA to 65 dBA during the night.

WAC 173-60-040 states the noise limitations to be: 6

during the day	noise from a class C property going to a class A property:	60 dBA
during the night	noise from a class C property going to a class A property: (reduced by 10 dBA)	50 dBA

What, if any, evidence has been submitted that shows that the BP refinery changes production in the evening in order to reduce the amount of noise emitted by the refinery?

I am physically too tired to force my brain to continue to analyze the data, but I have lots of comments written all over the study. It just takes a lot of time and energy to document my comments and write them in a coherent manner.

Sincerely,

Cathy Cleveland

BEFORE THE STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL

IN RE APPLICATION NO 2002-01 BP WEST COAST PRODUCTS, LLC BP CHERRY POINT COGENERATION PROJECT	)	AFFIDAVIT OF CATHY CLEVELAND

1. My name is Cathy Cleveland. I have been at Birch Bay during the summers since the early 1960s, before the Atlantic Richfield/ARCO/British Petroleum/BP refinery was built. I lived on Birch Bay Drive while I was in college, and currently, I live in the Cottonwood Beach area of Birch Bay at 4961 Morgan Drive.

2. On January 15, 2003, I attended a general information meeting for the public regarding the proposed BP Cherry Point cogeneration plant at the Blaine Public Library at 7:00 p.m.

3. We were introduced to (1) Michael Luftin, Assistant Attorney General, Counsel for the Environment, who would be an information source regarding this project and the proceedings, as well as an advocate for the Whatcom County citizens who would be affected by the co-generation plant, (2) Mike Koffman from GASP (Generations Affected by Senseless Power), (3) Michael Torpey, the BP Environmental Manager responsible for the project and environmental permitting, (4) Michael Abenhoff, public relations, and (5) I believe, Bill Kidd, Internal Affairs for BP in the Northwest and Arizona.

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4. These people told us about the BP's permit application. They explained the permitting process and that the draft environment impact statement was not done yet. They told us who the intervenors were, as of November 5, 2002, and other information about the proposed co-generation plant and the proposed mitigations. They also talked about pollution and particulate matter.

5. After all above-mentioned people spoke, they opened the meeting up to the audience to ask questions and to express concerns regarding the impacts of the proposed plant and to mention issues the people wanted addressed in the EIS, so BP could "mitigate" the impacts.

6. The Assistant Attorney General appeared to be writing down all of the citizen's issues. BP officials noted some of the issues. I naively believed that the Assistant Attorney General would make sure all the issues were addressed, so I did not write down all the issues expressed by the citizens present at the meeting.

7. Several concerns were raised about noise.

8. The major concerns, based on a past history with the refinery, were the accuracy, effectiveness, and the location of the monitoring. Historically, noise monitoring has been done in locations where the noise is quieter than the area from which the citizens have made complaints, or in areas where the BP refinery noise is barely audible, if at all, such as a location out at Birch Bay Village (where the prevailing winds do not typically move the noise towards Birch Bay Village). Therefore, citizens expressed their concerns about the validity of the monitoring, i.e., that monitoring has previously been done in a manner to validate and justify BP and ARCO's assertions that noise is always within the regulatory limits.

9. I did not document who, but one of the Cottonwood Beach residents, stated that the BP noise already wakes them up at night and that they wanted monitoring in the Cottonwood Beach neighborhood. Several others spoke up to confirm that resident's assertion, and said

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that they too were frequently awakened at night by refinery noise. To date, noise monitoring has not been done in the Cottonwood Beach area. (Please note that where later monitoring was done, near Councilperson Roy residence, is not Cottonwood Beach, but is a beach area south of Cottonwood Beach.) See also, page 3.9-4 in the EIS, which lists 15 noise-monitoring sites, but does not include Cottonwood Beach. I cannot state for certainty, that it was at the January meeting that Cottonwood residents stated that they would not object to noise monitoring on their property, but in fact, they would welcome it. BP is and has been aware of citizen's agreeing to have monitoring on their property. If this was not stated at this meeting, it certainly was stated at other meeting where BP representatives were present.

10. At the meeting, I specifically asked about the noise "modeling" that was being done in the lab. I asked if it was being done in a dry box. The answer was, "Yes."

11. I asked that they do a model that accurately reflects the reality of what is really happening at Birch Bay. First of all, almost all the noise complaints are at night, contrary to the unsubstantiated assumption and claim made by Hessler Associates, Inc., in the April 16, 2003, memo; Exhibit 24.1 DMH-1. The citizens who have been most vocal about complaints are from the Cottonwood Beach area. Therefore, modeling done in a dry box is inaccurate and is wholly lacking in validity, as it does not accurately reflect the area in which the sound will be traveling.

Second, sound travels different through dry air than it does through damp, cool evening air. During a sunny day in the summer, from the north end of the State Park, one can only hear a motorcycle accelerate and decelerate at stop signs, until the first stop on the Blaine Road. But, on a cool, clear, damp evening, you can hear the motorcycle starting and stopping at stop signs, going up past California Creek to Grubby's, more than an additional two miles from the Blaine Road. On cloudy days or evenings, one would not hear the motorcycle noise as far away, as the clouds tend to have a muffling affect on the noise.

Third, I also stated that sound travels different over water, and that the sound traveling from the refinery to the Cottonwood Beach area is traveling across the water without obstructions to muffle or disperse the noise. When asked, I was told that the modeling in the box also contained trees. So, I requested that some modeling be done without trees, and just over water. When I made these statements, both the Assistant Attorney General and a BP official, (Michael Torpey?), wrote some notes on their paper and said that this would be addressed. The EIS does not mention that any accurate modeling was done, despite a specific request that it be done.

12. BP representatives (usually Michael Abenhoff) regularly attended the Steering Committee meetings for the Birch Bay subarea Growth Management planning for last several years and they heard complaints about the refinery's pollution and noise at those meetings. They were well aware of noise complaints and that the Cottonwood Beach area, in particular, received a lot of noise from the refinery that woke people up at night.

13. Elizabeth Daley attended a couple of the meetings. She gave me her business card and asked me to call her when the noise woke me up at night. I called her many times in 2002. I am not sure if I saved a record of my calls to her in 2002. Ms. Daley told me that BP has to report complaints, so I would think that either BP or whoever the regulating agency is or the agency to whom BP reports complaints should have a record of my complaints, as well as complaints from others.

14. Since the noise problem did not improve, I decided to write down the dates of my complaints on my calendar starting in 2003; that is, the complaints I remembered to write down on my calendar. The dates on my calendar are as follows: (Please note that I sleep in two different bedrooms depending on how cold it is, and when I am home. My actual bedroom is upstairs on the side of the house gets the entire BP refinery noise. The guest bedroom is downstairs on the other side of the house and is quite insulated from BP noise by the rest of the house. It has a heated waterbed that is too hot to sleep on during the summer when there is BP noise. Therefore, in the winter, there may have been more refinery noise than I reported, only because I was not sleeping where I would hear the

noise.) (1) January 6, 2003, 12:45 AM, (2) January 27, 2003, 4:00 AM, (3) February 15, 2003, (AM time not recorded) low rumbling noise with a very large puff of stream coming from the refinery, and (4) February 19, 2003, 11:30 PM –12:00AM, low level rumbling noise with a large puff of steam coming from the refinery.

15. Elizabeth Daley usually returned my phone calls to let me know that she received my complaint. I did not document the date that she last called me to let me know that she thought the origin of the noise of my complaints was during "turn around" times, where they had to shut down and start up refinery equipment. She said that this only happened a couple times a year and that the noise was inevitable and unavoidable. After her call, I stopped documenting my complaints. Subsequent to my last conversation with Ms. Daley, refinery noise levels have significantly decreased. Some of us have wondering if this was for monitoring purposes, as well as for public relations while BP goes through the process of getting the co-generation plant approved.

16. More could be included in this affidavit, but time limits prevent further statements.

I swear under the penalty of perjury under the laws of the State of Washington that the above statements are true and accurate (except possibly for spelling of names and typographical errors).

____

Cathy Cleveland

BEFORE THE STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL

In the matter of:)
Application No. 2002-01)
)
BP WEST COAST PRODUCTS, LLC,) Public Comment Meeting
) on the Draft EIS
BP CHERRY POINT) Pages 1 - 25
COGENERATION PROJECT)
_________________________________)

A Public Meeting in the above matter was held in the presence of a court reporter on October 1, 2003, at 7:00 p.m., at 975 H Street, in Blaine, Washington, before Energy Facility Site Evaluation Council Members.

* * * * *

MR. FIKSDAL: First, we have to come up are Mark Lawrence, Rob Pochert, and then Dan Newell.

COMMENTS BY MARK LAWRENCE

Mark Lawrence, 813 Fieldston, Bellingham, Washington 98225. I'm in support of this cogen plant with BP. At a time of slow economic recovery Whatcom County has a unique opportunity to bring a power source for future development and also a power source for development that's here in Whatcom County right now. 1(1)

Whatcom County is a unique location. We have a port that is available for deep water. We also have lots of energy of the community to bring this to it. I'm a very small business owner in Whatcom County. I work all over the State of Washington and Idaho. Whatcom

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County needs a source of income. Whatcom County can I don't think continue to go without a self-source of income and having some stable source of energy. With Alcoa having their issues and some other issues in Whatcom County, we need to have a stable environment for business to continue to support our tax base. Therefore, I support Whatcom County's approval and the state's approval for this cogeneration plant. Thank you.

MR. FIKSDAL: Thank you.

Mr. Pochert. Please excuse me for ruining your name. My last name is Fiksdal, and nobody can say that, so I think I have some leeway.

COMMENT BY ROB POCHERT

Actually you did quite well. I'm Rob Pochert. I'm the president of the Bellingham Whatcom County Economic Development Council. We're located at 105 East Holly Street in Bellingham.

While the Economic Development Council's primary interest is creating new jobs in Whatcom County, we also have an interest in the impacts that some of these job creations of other industrial-type activities have on the quality of life here in Whatcom County. As we became familiar with BP's project, obviously some of the questions that I asked and our staff asked, "Just what are some of these impacts?" And I think the reduction in 2(1) pollutants, the mitigation of CO_2, Oregon's standards, and I'm from Oregon, so I know what it's like living under those standards, and utilizing the state of technology that is available to reduce emissions have all been very favorable. The potential reuse and recycling of water from another industrial facility I think has got strong merits, and obviously let's not overlook the fact that we have an electrical generator here with inner community that can provide some stability in a time of what appears to be uncertain, long-term electrical supplies, particularly in light of projected short falls and growing needs for electricity.

2(1) cont.

We also recognize obviously the economic benefits, both in taxes that will be paid to the state, as well as the County. The full time jobs that are going to be located there, as well as the six to seven hundred construction jobs. Looking at a very conservative three to one multiplier these are going to have some very significant economic and financial impacts for Whatcom County. The EDC and Western Washington's Center for Economic and Business Research is going to be looking more in-depth at just exactly what are the economic impacts that Whatcom County can expect to receive in the future, and we plan to submit that written document before your November deadline. Thank you.

2(2)

MR. FIKSDAL: Thank you. Mr. Newell.

COMMENTS BY DAN NEWELL

My name is Dan Newell, and I'm the principal of Blaine High School, and we are at 770 Mitchell Street, Blaine, Washington 98230. I'm speaking on behalf of Dr. Marian Barrington, the newly appointed superintendent of Blaine School District who represents the Blaine School Board for the purposes of this meeting.

With the addition of a cogen plant at BP Cherry Point Refinery, it would add a number of additional benefits to the citizens and the students of the Blaine School District. Currently the Blaine School District assessed valuation is approximately 2.2 billion dollars, and the majority of this high assessment is due to BP and because of the high assessed value the citizens of the Blaine School District benefit from a very low levy assessment. By the addition of the cogen plant the assessed valuation would increase by approximately 500 million dollars, bringing our total assessed value some 2.7 billion. Such an increase would result in a taxpayer of the Blaine School District paying approximately $1.23 per thousand dollars of assessed valuation. Currently we pay $1.73. As you can see with the additional assessed value our citizens will be saving 50 cents per thousand. On our current levy this equates to a savings of $75 per

3(1)

year on a $150,000 home.

Due to these low levy rates the Blaine School District has always been able to pass our levies. Our levy rate in comparison with other districts with rates of upwards of three dollars per thousand enables Blaine the distinct advantage. We not only pass our levies, but we are able to run a levy to the maximum the state will allow. Not all districts are able to do this because it's cost prohibitive to their taxpayers. 3(1) cont.

Currently the Blaine School District's operation levy is approximately 21 percent of our current budget. It is with the passage of the levy that the Blaine School District has been able to offer an exemplary program which draws people from across the state and sometimes the nation. This low dollar per thousand levy rate also provides the district great opportunities for the passage of our general obligation bonds. It is with these bonds the district built our schools, your children's classrooms, gymnasiums, cafeterias, playgrounds, and this wonderful performing arts center that we are sitting in. The district has recently remodeled and built a number of structures with the 19.6 million dollar bond. We have one remaining project to complete, and that's our administrative service center. Our estimated completion time will be the summer of 2004.

Along with the substantial savings to our taxpayers comes a number of jobs, and this would enable a number of people in the Blaine area to have the opportunity to apply for approximately 900 or more available positions. Our students would benefit from this as they complete high school and college enabling them to move onto a wonderful career with BP. Currently our students are given an in-depth tour of BP during the beginning of each school year. By maintaining a working relationship with this company, our students have been exposed to the industry which has been a constant in our Blaine area and the number of students who do complete college and stay in this area providing more career opportunities and keeping our families together. Thank you very much for your time.

MR. FIKSDAL: Thank you. The next three people that are signed up it's either Will or Wy Bannerman.

MR. BANNERMAN: Wy Bannerman.

MR. FIKSDAL: Fred Schuhmacher and Sam Crawford.

COMMENT OF WYMAN BANNERMAN

My name is Wyman Bannerman, and I live at 3455 Kluken Road, which is very near the intersection of the Valley View Road in Grandview. Needless to say I have view property just from the name of the two roads.

My concern, and I've voiced this concern at all the meetings so far, is the change in your power lines. When we first talked at the first meeting, there was some chance that they were going to put in a high capacity conductor cable and not change any of the towers, just put these cables on the present towers. As I talked to the engineers and BPA and stuff right now that's no longer feasible. It's too expensive or the cables are too heavy or something or other. 4(1)

The two options that we have left are the monopole towers or the lattice steel uprights. The lattice steel uprights are ugly, and I have a picture of them here. It's the center one right here.

MR. FIKSDAL: Thank you.

MR. BANNERMAN: As you can see in the center of that fixture -- that picture is taken on the eastern part of the Grandview Road where these lines feed the Custer Substation, and they've put in a series of towers. That center tower in there is the one that I objected to, and that's one of the two choices left. The other choice is the monopole, which is a single pole tower. They have pictures out in the lobby of that. In fact, these pictures are taken at the crest of the hill on my property.

The one problem I have with the pictures is that they blotted out Mount Baker which it sits if you look at the east picture there, Mount Baker should be sitting right there. It's gone for some reason. But I'd 4(2)
like to as they talk about studying these different options they mention the remedial action schemes. In the remedial action schemes they've studied what are they going to do with the power if one of the big powers lines falls down, and the temperature is over 85 degrees, and Alcoa is running full-bore, and BP is running full-bore, and the power plant is running full-bore, where is power going to go or something. Of course, all of these things can't possibly happen at once, but they have to plan for that. The one thing they left out of their scheme is the fact that there is presently a hundred megawatts of power coming through PSE to feed Arco right now. When they talk about trying to reduce the power from all these concepts they forget to mention that those power lines could be 4(3)
used to run a hundred megawatts back to somewhere. And they said they talked about that a little bit, but BPA and PSE evidently don't work together, so I would like some more explanation on that I guess. Thank you very much.

MR. FIKSDAL: Mr. Schuhmacher.

COMMENTS BY FRED SCHUHMACHER

My name is Fred Schuhmacher. I live at

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5583, Whitehorn Way --

MR. FIKSDAL: Could you speak a little closer. Thank you.

MR. SCHUHMACHER: -- in Blaine.

In May of this year I attended a presentation by BP and TransCanada Corporation through the Whatcom County Council Natural Resource Committee on the proposed cogeneration facility at Cherry Point. I came away from that meeting with several concerns about the project as it was presented, and I wrote a letter to EFSEC on the following day. I am here to go over again some of the concerns that I expressed in that letter. My main concern is water cooling for this project. The original public presentation by BP emphasized the benefits of air cooling with its minimum impact on the environment. To change it now to water cooling would impose several adverse effects on the environment, such as water cooling and the associated cooling towers will require water, and the effluent from the cooling towers will result with an additional burden on the water quality in the outfall area of Cherry Point. No cooling tower or effluent would be necessary in air cooling. The cooling towers will create large quantities of vapor during operation. Cooling water is treated to prevent corrosion and algae formation. Traces of dissolved chemicals are in the water vapor and

5(1)

can be carried away by prevailing winds. At present a vapor from the refinery sometimes creates plumes of vapor that at times form a cloud cover over Birch Bay. The operation of a 720-megawatt power plant would increase this problem by several magnitudes. None of these issues would be there with air cooling. 5(1) cont.

I recognize that water cooling will result in some savings to the builder, but this must not take precedence over consideration for the residents of the area and the environment.

Another comment or point is I just would like to address the purpose of this project. The project is titled BP Cogeneration Project. While I endorse the use of cogeneration for BP, I differ on the main purpose of the project. BP will only use about 12 percent of the power produced, and the other 88 percent will be sold on the open market by TransCanada, the eventual owner/operator of the power plant. For that reason the project should be put forward as the TransCanada or BP power plant project. You cannot call in it any other way. That's all. 5(2)

MR. FIKSDAL: Thank you very much. Council Member Crawford.

COMMENTS BY SAM CRAWFORD

Good evening, Council Members. I have

written a letter regarding the application you're considering to the BP Cherry Point Cogeneration Project, and I would like to read this letter into the record at tonight's open house.

I'm Sam Crawford, Whatcom County Council, 311 Grand Avenue, Bellingham, Washington, and my home address is 1627 Diamond Loop, Bellingham, Washington.

I should note that as a member of the Whatcom County Council, I speak from my own perspective. The County Council has not formally taken a position on this application. However, I can assure you that I've spoken to many of my constituents throughout Whatcom County whom I represent, and I am honored to informally speak for them.

As I review the Draft Environmental Impact Statement for this project, which I'm going to put down because this is heavy, dated September 5, 2003, I see the Applicant is required to compare the impacts of the proposal to the impacts of no action. In most cases the no action impacts are generally described correspondingly as no impact.

In light of the proponent's prepared materials describing the positive aspects of this project, one could view no action, that is no construction of this facility, as detrimental actually in a number of ways. 6(1)

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I'm going to name a few.

There would be no new steam source to be provided to the existing facility thus necessitating the continued use of older, less efficient, more polluting oil. Greenhouse gas offsets would not occur in other facilities. Thirty years of proposed greenhouse gas mitigation would not occur. Recycling of Alcoa Intalco Works cooling water would not occur. Post use treatment of this recycled water with updated treatment before discharge to the Puget Sound would not occur. Wetland enhancements to the CMA 1 and CMA 2 two sites creating low hydraulic resonance time that enhances existing wetlands and restores drained wetlands would not occur. A wetland enhancement ratio of nearly 3.6 to 1. Yes, I did do the math myself. Effecting the enhancement of 110 acres of wetlands would not occur. Wildlife habitat quality improvements associated with wetland enhancement along with planting, cultivating, and monitoring of native trees, plants, and grasses would not occur. An aggressive noxious weed control program overseen by the Whatcom County Noxious Weed Control Board would not occur. Six hundred and thirty five megawatts of needed additional electrical power would not be supplied to the Northwest Power Grid. Further industrial development of land zoned and set aside specifically for this type of use under

6(1) cont.

Whatcom County zoning rules and the Whatcom County Comprehensive Plan would not occur at this time. The opportunity for 30 additional living wage jobs in Whatcom County would be lost, and the revenue generation of approximately 6 million dollars in annual property taxes to be paid by this facility would not occur. 6(1) cont.

I should mention there is no doubt that the County portion of this revenue is badly needed during this time of budget shortfalls.

When one considers these attributes of the proposed project, it is an oversimplification to say the no action alternative has no impact on Whatcom County. Much of my time on the County Council is spent working on discussing and implementing planning for the future. This planning practice involves a myriad of potential impacts and results in an attempt to envision a future that is vibrant, attractive, and provides the highest qualities of life for succeeding generations of Whatcom County Citizens. This proposal does have the potential to fit in well to that vision in many perspectives. No action in and of itself would speak volumes about the future of your county.

Based on my reading of the Draft Environmental Impact Statement, I see this project as an important component of our designated and zoned heavy 6(1) impact industrial portion of Whatcom County. I urge you to work cooperatively with the Applicant to carefully consider the concerns of the community, along with any negative impacts that may be associated with the project, and permit the construction of this facility in a manner that benefits the people of Whatcom County, as well as the Applicant.

6(2) cont.

I appreciate your time and the opportunity to comment. Thank you.

MR. FIKSDAL: Thank you.

The next three people are the last name is Eventoff.

MR. EVENTOFF: Right here.

MR. FIKSDAL: Okay. You're next. Sandra Abernathy and Wendy Steffensen.

COMMENT BY FRANK EVENTOFF

I am Frank Eventoff, 7086 Atwood Road, Ferndale, and my primary concerns are environmental. I hear what everybody is saying. I can't disagree with anything. It sounds good. Like what the gentleman said about air cooling, I don't know much about it, but it sounds like it makes some sense. I guess I have questions like is bigger better? And maybe balance should be considered over growth. Do we need more electricity that would be generated by fossil fuels? We're hearing distorts of this planet and maybe alternative energy would be, renewable energy would be a wiser investment. I'm just looking at the energy scams that have happened and where California is now in this whole regional thing and all; that there's so much that we don't know about what's going on behind the scenes, and so we really -- do we really know where our energy requirements stand today and do we need more energy? I don't know that. Maybe you do. I don't. But it would sure be nice to address that question before we go using more fossil fuels anyway.

I'm just also concerned that I've been following Sumas 2 a bit and the Fraser Air Valley, Fraser Air Valley Basin, and I'm wondering is this going to impact the air quality and the buildup of pollutants in that air basin? So I guess that's about it. It might serve the government well to educate us, the populous, about being more energy efficient, more emphasis on efficient products than more power. Thank you. 7(1)

MR. FIKSDAL: Thank you. Ms. Abernathy.

COMMENTS BY SANDRA ABERNATHY

I actually signed up on the wrong sheet, so I'm going to say a little bit anyway. I haven't dramatically read the report. So my name is Sandra Abernathy and I live at 6905 Holeman Avenue, which is at Point Whitehorn, so it's nearby, and I also have other

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family members that live near the plant.

My concern I would agree with Mr. Schuhmacher that I am concerned about the air quality, especially being downwind. I don't live downwind, but I have other family members that live directly downwind. And obviously the point that I'm trying to make right now is that there is a lot of smell from the BP plant now, and I'm concerned that there would be additional smell and additional pollution with the prevailing southerly winds in that area, but I haven't read it. 8(1)

MR. FIKSDAL: Well, thank you.

Ms. Steffensen.

COMMENTS BY WENDY STEFFENSEN

My name is Wendy Steffensen. I'm the North Sound Bay Keeper. I work at Resources. The address there is 1155 North State Street, Suite 623, Bellingham, 98225.

I was interested to hear what Councilman Crawford had to say because I haven't read all of the documents, but I skimmed it pretty thoroughly, and I didn't come away with the same rosey picture of the environment that he did.

So one of my concerns is that in terms of the fresh water system, the wetlands, Terrell Creek, and Lake Terrell, I didn't really see a cumulative assessment of what's going on with that system. I see that we're 9(1)

9(1) cont.

going to be draining and filling some wetlands. We have stormwater impacts. We're going to have air pollution that's going to settle on this system, as well as potential, a great potential for acid rain. And although acid rain was mentioned here and stormwater was mentioned, the system, a cumulative look at the system wasn't taken in terms of flora and fauna and the hydrologic connectivity of the area, so that is one concern I have.

9(2)

And then another thing I noted in terms of the wetlands in the Draft EIS they mentioned that the wetlands were not significant or not high quality wetlands, but yet when you go back to the appendix Washington Fish and Wildlife calls those same areas high priority habitat, so I think there's some disconnect there.

9(3)

I also noted that like many of these documents we disconnect what happens in the air versus what happens in the water. It's like we believe that what goes up in the air doesn't affect the water; that there's not cross media contamination. So I would really like to see an analysis of how is that air pollution affecting water; what portion of air pollution is becoming water pollution.

9(4)

I guess there was in terms of discharge, water and air discharge, we are looking at better technology now, but I also noted we are discharging heavy metals. And a lot of these heavy metals are persistent biocumulative toxins, so, again, I have great deal of concern about this. Ecology is trying to phase out the discharge of persistent biocumulative toxins and yet this wasn't adequately addressed in the report.

9(4) cont.

I also looked at the need analysis. In general terms we talked about the regional needs, but there was no mention of how is this going to fit with SE2 and GFX, those proposed projects that may be coming on line, and so I was wondering why there was no mention of those.

9(5)

And in addition we have a herring reserve very close by, and there was no mention of the herring reserve, and I'm wondering what potential disturbance there could occur to that herring reserve. Thank you.

9(6)

MR. FIKSDAL: Thank you very much.

I don't have anymore -- oh, there is some more. Sorry.

Thank you. Alan Van Hook has signed up to speak.

COMMENTS BY ALAN VAN HOOK

I have a very short comment. I'm Alan Van Hook. My address is Box 549, Blaine, Washington. And I'm a very small competitor for this project because I generate electricity, and I just went through a very frustrating process with Puget Power, so I understand something about the frustration and the difficulties.

I agree with the fellow who said that the purpose of the plant is probably primarily not cogeneration, but obviously it's somewhat. I had a question that probably I can address if I'm able to get Chapter 2, which I don't believe was included in the handouts tonight but is apparently available, and that was alluded to by one of the folks who talked about the air pollution products in that I know from long ago that it was well recognized that there's negative synergy between the release of heavy metals and the petroleum products 10(1)
vapors release. So that may have already been done, and I don't know. But I would be real interested to see a cumulative analysis, which may have been done, between the improvements that have been mentioned by Representative Crawford and others and the net effect in terms of the balance of heavy metals and petroleum products that are bound to be in the air, so obviously there's better technologies available now than were in place when the original refinery was put in.

And I'm not personally privy to what's going to happen with the Intalco Aluminum Smelter process, so, 10(2)
you know, whether that's a cumulative effect. You know,

if it's been evaluated both ways, with and without Intalco operating as a smelter, etc. 10(2) cont.

And I will say and my recent research tells me that we are going to be needing additional energy in this area by the year 2012 to 2013. The question is probably not whether we're going to generate but where is it going to come from. So one of the alternatives I see that Puget Power is planning on coming up with some of the power from coal-fired plants which I think is very interesting in light of the siting process that would be going on with that. So I would like to see in the alternatives, if it hasn't been done, some kind of analysis of, you know, what are the air pollution, water pollution scenarios versus burning this finite resource natural gas versus burning coal or other alternatives because we're not going to get it all from wind power because we have to have capacity that's, you know, available on a day-by-day basis. 10(3)

So anyway I'm just commenting mostly whether some of these items may have been addressed in which case I just haven't seen it, and that's probably my fault, so I was just curious whether they have been addressed. Thank you.

MR. FIKSDAL: Thank you. That is the end of the list of people that's signed up. Is there anybody that wishes to give a comment that didn't sign up?

Back there. I might add while -- come on up -- that if you want a copy of the EIS just ask us, and we'll get you a copy. Give us your and name address. If you don't want the big paper copy to lug around, it's available on our website which I think is probably on one of the sheets that you got. It's www.efsec.wa.gov, and that is all on that too.

Give us your name.

COMMENTS BY KATHY CLEVELAND

Hi, I'm Kathy Cleveland. I live at 4961 Morgan Drive. I'm not really prepared to speak, but I have to speak anyways. I agree with what Wendy said, and I wish there was more people that had an understanding of the environment that could read this because I think a lot of things are not adequately or wholly addressed. There are things that would like to be swept under the carpet; that basically by the time it comes to a public hearing this is already a done deal, so we just kind of mitigate things to help us out.

One of the things that I think is not adequately addressed is the issue on particulates. I would like a much further study done on that. There is somebody that might have time to do it that works with Huxley College at Western that now works with the

11(1)

Swinomish Indians down by Lummi Bay that directly studied particulates going into the water and what happens and what's the long-term effect of that, saving the particulates in the air. 11(1) cont.

Also at one of our first meetings here up in the Blaine Library about a year ago citizens addressed some issues that they would like to see the mitigation on, and one of those issues was sound. And I was at a public -- the refinery had an open house about a month ago and another citizen brought up the fact and asked, "Did you put a sound monitor in the area of Cottonwood?" And they said, "No." They still had not done it. It may have been done recently, but it doesn't do any good to do testing or bogus testing, and say, "Oh, look. We've had this out here in this area." Like Birch Bay Villa is on the hill where they don't get any noise. So if you do your testing where your results are known and the results are going to come out in your favor, that is not accurate and fair testing or modeling of what's really going to be going on. 11(2)

I haven't had time -- I'll speak with Michael Lufkin afterwards about what has and has not been done. I have a list buried somewhere of all of the things that citizens wanted mitigated. I guess I'll have to follow up on each and every one.

Thank you for your time.

MR. FIKSDAL: Thank you. Is there anybody else that would like to give a comment on the Draft Environmental Impact Statement?

I see no hands raised. I guess there are none, so that will conclude our comments for tonight and conclude this meeting. I want to thank you very much for coming. It's very important for the Council and for the Applicant and everybody to hear your comments. Your comments will be addressed in the Final Environmental Impact Statement that the Council and Bonneville will prepare. I also want to remind everybody that the Council will have another opportunity for public comment during their adjudicative hearing process, and it's scheduled now for December. There will be a time that you can address the Council again. If you aren't on our mailing list and want to be on the mailing list to receive notices of those hearings, sign up with Mariah out at the table as you leave or you can go to our website and email. Our email address is efsec. -- anyway it's on your list somewhere. Again, thank you very much. Again, the close of comment is November 3, 2003. With that, thank you again. Good night.

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(Public meeting was adjourned at 7:51 p.m.)

I N D E X

A F F I D A V I T

I, Shaun Linse, CCR, Certified Court Reporter, do hereby certify that the foregoing transcript prepared under my direction is a true and accurate record of the proceedings taken on October 1, 2003, in Blaine, Washington.

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Shaun Linse, CCR

CCR NO. LI-NS-ES-M4020H