COVER SHEET

Beaufort Sea Oil and Gas Development/Northstar Project

Environmental Impact Statement

1999

Draft (   ) Final (X)

Type of Action:

Administrative **(x)** Legislative ( )

Area of Proposed Effect:

Offshore marine environment and onshore North Slope of Alaska Coastal Plain

Lead Agency:

U.S. Army Corps of Engineers, Alaska

Cooperating Agencies:

U.S. Department of the Interior, Minerals Management Service

U.S. Department of the Interior, Fish and Wildlife Service

U.S. Department of Commerce, National Marine Fisheries Service

U.S. Environmental Protection Agency

Regional Contact:

U.S. Army Engineer District, Alaska

Regulatory Branch

Mr. Timothy Jennings

P.O. Box 898

Anchorage, Alaska North Slope Borough, Alaska

99506-0898

1-800-478-2712 (In Alaska)

(907) 753-2712 (Outside Alaska)

ABSTRACT

BP Exploration (Alaska) Inc. (BPXA) proposes to produce oil from the Northstar Unit located approximately 6 miles (9.6 kilometers) offshore of the Point Storkersen area in the Alaskan Beaufort Sea. BPXA's proposed action for the Northstar Unit is a self-contained offshore development/production facility located on a gravel island in 39 feet (12 meters) of water. The gravel island would be constructed over the remains of Seal Island, which was built by Shell Oil Company to conduct exploratory activities within the Northstar Unit during the 1980s.

Construction of two pipelines buried in a single trench from Seal Island to existing onshore facilities to transport hydrocarbons to and from the Northstar Unit is proposed. The pipelines include one 10-inch (25 centimeter) common carrier pipeline from Seal Island to Pump Station No. 1 to transport sales quality oil to

the Trans Alaska Pipeline System. A second 10-inch (25 centimeter) pipeline would transport high-pressure gas from the Central Compressor Plant in the Prudhoe Bay Unit to Seal Island to assist with the gas cycling process used to deplete the Northstar reservoir.

BPXA determined the Northstar Unit contains approximately 158 million barrels of recoverable, high quality crude oil. Production facilities on Seal Island would be designed to produce up to 65,000 barrels of crude oil and 500 million standard cubic feet (14 million cubic meters) of natural gas per day. There would be producing wells, gas injection wells, and either one or two Class I industrial waste disposal wells. The life of the proposed Northstar Unit development is anticipated to be approximately 15 years.

BEAUFORT SEA OIL AND GAS DEVELOPMENT/ NORTHSTAR PROJECT

FINAL ENVIRONMENTAL IMPACT STATEMENT

Appendix A:

Appendices B Through K:

Appendix K (Continued) Through P

Appendix K Public Comments Received on the Draft Environmental Impact Statement

Appendix L Response to Public Comments

Appendix M Biological Opinions

Appendix N Final Underground Injection Control Permit

Appendix O Preliminary Final National Pollutant Discharge Elimination System Permit

Appendix P Reports of the Cold Regions Research and Engineering Laboratory

BEAUFORT SEA OIL AND GAS DEVELOPMENT/
NORTHSTAR PROJECT

FINAL ENVIRONMENTAL IMPACT STATEMENT

TABLE OF CONTENTS

DRAFT EIS TABLE OF CONTENTS

CHAPTER 3.0 OIL AND GAS DEVELOPMENT/PRODUCTION OPTIONS FOR THE ALASKAN BEAUFORT SEA

DRAFT EIS TABLE OF CONTENTS (Cont.)

Section **Title** **Page**

Volume II (Cont.)

CHAPTER 3.0 OIL AND GAS DEVELOPMENT/PRODUCTION OPTIONS FOR THE ALASKAN BEAUFORT SEA (Cont.)

CHAPTER 4.0 NORTHSTAR UNIT DEVELOPMENT/PRODUCTION ALTERNATIVES

Volume III

CHAPTER 5.0 AFFECTED PHYSICAL ENVIRONMENT AND IMPACTS

DRAFT EIS TABLE OF CONTENTS (Cont.)

Section **Title** **Page**

Volume III (Cont.)

6.0 AFFECTED BIOLOGICAL ENVIRONMENT AND IMPACTS

CHAPTER 7.0 AFFECTED HUMAN ENVIRONMENT AND IMPACTS

DRAFT EIS TABLE OF CONTENTS (Cont.)

Section **Title** **Page**

Volume IV (Cont.)

CHAPTER 8.0 EFFECTS OF OIL ON THE PHYSICAL, BIOLOGICAL, AND HUMAN ENVIRONMENTS (Cont.)

CHAPTER 9.0 EFFECTS OF NOISE ON THE BIOLOGICAL AND HUMAN ENVIRONMENTS

CHAPTER 10.0 CUMULATIVE EFFECTS

DRAFT EIS TABLE OF CONTENTS (Cont.)

Section **Title** **Page**

Volume IV (Cont.)

CHAPTER 10.0 CUMULATIVE EFFECTS (Cont.)

CHAPTER 11.0 - COMPARISON OF PROJECT ALTERNATIVES AND THEIR IMPACTS

CHAPTER 12.0 LIST OF PREPARERS

CHAPTER 13.0 CONSULTATION AND COORDINATION

Volume IV (Cont.)

APPENDICES

EXECUTIVE SUMMARY

TABLE OF CONTENTS

EXECUTIVE SUMMARY

TABLES

FIGURES

FIGURES (Cont.)

Figure ES-22 Northstar Development Project Alternative 5

LIST OF ACRONYMS AND ABBREVIATIONS

BPXA	BP Exploration (Alaska) Inc.
°C	degrees Celsius
CCP	Central Compressor Plant
CEQ	Council on Environmental Quality
CIDS	Concrete Island Drilling Structure
Corps	U.S. Army Engineer District, Alaska
DEIS	Draft Environmental Impact Statement
DPP	Development and Production Plan
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
ESA	Endangered Species Act
°F	degrees Fahrenheit
FEIS	Final Environmental Impact Statement
ft	foot, feet
IWC	International Whaling Commission
km	kilometer(s)
m	meter(s)
m^3	cubic meter(s)
MLLW	mean lower low water
MOA	Municipality of Anchorage
MMS	Minerals Management Service
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
NPDES	National Pollutant Discharge Elimination System
NSB	North Slope Borough
OCS	Outer Continental Shelf

ODCE Ocean Discharge Criteria Evaluation

% percent

pH potential of Hydrogen (measures the acidity or alkalinity of a substance)

PM1 Point McIntyre No. 1

ROD Record of Decision

TAPS Trans Alaska Pipeline System

UIC Underground Injection Control (Permit)

USDOI U.S. Department of the Interior

USFWS U.S. Fish and Wildlife Service

VSMs vertical support members

yd^3 cubic yard(s)

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1.0 INTRODUCTION

1.1 PURPOSE OF AND NEED FOR ACTION

BP Exploration (Alaska) Inc. (BPXA) submitted a permit application to comply with Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act to the U.S. Army Engineer District, Alaska (Corps). The application initiated the review process for BPXA's proposed project to develop and produce oil and gas from the Northstar Unit. The purpose of BPXA's proposed project is to recover oil from the Northstar Unit and to transport and sell sales quality crude oil to U.S. and world markets. The need for BPXA's proposed project is to help satisfy the demand for domestic oil resources at a time when production, including Alaska's contribution, is in decline.

The National Environmental Policy Act (NEPA) requires preparation of an Environmental Impact Statement (EIS) prior to any federal action that may significantly affect the quality of the human environment. The EIS is intended to provide federal agencies with information about the consequences of a proposed project and to disclose that information to the public, soliciting their comments, prior to the agencies making decisions on the project. For federal agencies, the purpose of the EIS is to meet those information needs and to meet their NEPA requirements.

Assuming the role of lead federal agency, the Corps initiated a cooperative agency agreement with four other federal agencies and the North Slope Borough (NSB) which have regulatory responsibilities. The Minerals Management Service (MMS), U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), Environmental Protection Agency (EPA), and NSB are cooperating agencies. This Beaufort Sea Oil and Gas Development/Northstar Project Environmental Impact Statement has been prepared by the lead and cooperating agencies, with the assistance of a third-party EIS contractor, funded by BPXA.

The Corps and cooperating agencies have determined that an EIS is required because:

- The Northstar Project would be the first offshore oil and gas development/production facility in the Alaskan Beaufort Sea without a causeway to shore, and the first to include a connection to onshore facilities by a buried subsea pipeline.

- Risks of oil spills from an offshore development/production island and a subsea pipeline system exposed to ice hazards require further analysis.

- Response limitations for oil spills under sea ice or in broken ice, and concerns regarding the effects of such spills, require further analysis.

- The effects of long-term, year-round offshore oil and gas development/production activities, particularly the noise they generate, on subsistence resources and the subsistence lifestyle of NSB residents require further analysis.

1.2 OVERVIEW OF BPXA'S PROPOSED ACTION

BPXA proposes to produce crude oil from the Northstar Unit which is located between 2 and 8 miles (3.2 and 12.9 kilometers [km]) offshore from Point

Storkersen, in the Alaskan Beaufort Sea (Figure ES-1). The unit is adjacent to the Prudhoe Bay industrial complex, approximately 20 miles (32 km) northwest of Deadhorse, and approximately 60 miles (97 km) east of Nuiqsut, a Native Alaskan (Inupiat) community. The Prudhoe Bay industrial complex includes oil and gas production and processing facilities that produce North Slope crude oil; Deadhorse is an industrial/commercial center that is largely comprised of oil field service companies and oil field workers.

Drilling, processing, and production is proposed from a gravel island constructed over the remains of a gravel island built by Shell Oil Company to conduct oil and gas exploration/drilling within the Northstar Unit during the 1980s (see project details in Appendix A of the EIS, *"BP Exploration (Alaska) Inc.'s Final Project Description"*). BPXA's proposed project includes drilling 15 production wells, 7 gas injection wells, and 1 or 2 waste disposal wells from the island. Approximately 500 million standard cubic feet per day of produced gas and approximately 100 million standard cubic feet per day of additional gas from the Central Compressor Plant (CCP), located onshore in the Prudhoe Bay Unit, would be injected into the reservoir (gas cycling) to maintain pressure and maximize production. Offshore pipelines (oil and gas) would be buried beneath the sea floor to protect them from ice gouging, strudel scour, and other natural forces; onshore pipelines would be constructed on vertical support members (VSMs). Crude oil production estimates total 158 million barrels over the anticipated 15-year life of the reservoir; maximum daily production is estimated at 65,000 barrels of oil per day. Sales quality crude oil would be transported by pipeline to Pump Station No. 1 of the Trans Alaska Pipeline System (TAPS) for the transport to the oil terminal at the Port of Valdez.

Approximately 700 to 800 tanker trips per year leaving the Valdez marine terminal are currently required to accommodate current North Slope production (USDOI, MMS, 1996:IV.4-30). Production of recoverable reserves from the Northstar reservoir could require the operation of additional tankers from the Valdez marine terminal. It is estimated that 198 tankers over the life of the project would be required to accommodate Northstar reservoir production (the average capacity of tankers calling at the Valdez Marine Terminal is approximately 800,000 barrels). At peak production, tanker trip requirements would increase over current levels. Thirty tanker trips per year during peak production years 2, 3, and 4 could be required approximately, a 4.3% increase over current levels. After production has peaked, additional tanker movements decrease to 1 by the 15th year of production. These estimates do not include North Slope decreases in field production or possible increases in production from additional developments, and decreases in oil production overall may more than offset the need for increased tanker trips as a result of Northstar production.

1.3 AGENCY GOALS FOR THE EIS

The Corps and the cooperating agencies developed specific goals for the EIS process, including:

- Develop this EIS, at the applicant's request, in parallel with the engineering and design of BPXA's proposed project to allow: a) the EIS process to begin sooner, potentially speeding up decisions and permitting; b) BPXA, the agencies, and the public to exchange ideas about project design as

Figure ES-1 (Page 1)

Figure ES-1 (Page 2)

engineering progressed; and c) mitigation measures to be incorporated as part of the proposed project's overall design to minimize or avoid potentially significant impacts (Table ES-1).

- Incorporate Traditional Knowledge of the indigenous people of the North Slope in a way that allows agencies to use these data as part of their decision-making. Traditional Knowledge was collected early in the EIS process and was cited from existing sources and past testimony; this information is applied to the evaluation of project impacts.

- Present the issues identified in EIS scoping, and address them in a way that allows readers to locate information of interest and track the issues. For example, the affected environment and environmental consequences for each topic are presented together to aid the reader in using this multi-volume EIS.

- Describe a broad view of oil and gas technologies applicable to the development/production activities in the Alaskan Beaufort Sea environment to set the stage for selection of alternatives for Northstar Unit development and also make this information applicable to future proposed oil and gas development/production projects.

- Include information necessary for cooperating agencies' approval processes to facilitate a more timely and streamlined approach. Specifically, a Biological Assessment, a draft National Pollutant Discharge Elimination System (NPDES) Permit and Fact Sheet, an Ocean Discharge Criteria Evaluation (ODCE) in support of the NPDES permit and ocean dumping permit (Section 103 of the Marine Protection, Research, and Sanctuaries Act of 1972), and a draft Underground Injection Control (UIC) Permit and Fact Sheet were appended to this EIS and rely on this EIS information and NEPA documentation.

- It is a goal of the lead and cooperating agencies to develop a consistent, unified position regarding which alternatives will move forward with their decision-making process. Agencies have identified to the extent possible preferred alternatives in Section 11.9. Final agency decisions will be made in the Records of Decision (ROD) after consideration of the Final EIS (FEIS) and all comments received.

In addition, the cooperative agencies chose a format that accomplished several objectives:

- Present Traditional Knowledge and western science in an objective manner, without drawing conclusions as to which information is better, allowing the reader and the decision-maker to draw their own conclusions.

- Organize the chapters to focus the reader's attention to the big issues (oil spills and noise).

- Rely on appendices (Project Description, Biological Assessment, Draft NPDES Permit) that were prepared for the Northstar Project to provide the reader with more information than would otherwise be included in an EIS.

Table ES-1 (Page 1)

Table ES-1 (Page 2)

- *Incorporate considerably more information and analyses than is usual in an EIS, to reflect that the proposed project incorporates new ideas to oil development on the North Slope.*

- *Cross-reference chapters and appendices whenever possible to minimize redundancy.*

- *Organize the EIS in a manner to make it more responsive to local requests.*

1.4 AGENCY RESPONSIBILITIES

Agency actions required for development of the Northstar Unit are summarized in Table ES-2. Permits for oil and gas development/production of the Northstar Unit will not be issued prior to RODs being issued by the lead and cooperating agencies and state review and issuance of a coastal zone consistency determination. Approvals and permits issued by all federal agencies are discussed below.

Floodplain Management: The EIS identifies existing flood plains within the project area, identifies the various project alternatives as being within or outside those flood plains, and describes potential impacts of facilities located within flood plains. This information is used by all federal agencies for their floodplain management considerations, as required by Executive Order 11988.

Wetland Protection: The same information provided in the EIS for the Corps in its Section 404 permitting process is used by federal agencies for wetlands protection considerations as required by Executive Order 11990.

Government to Government Coordination: Four federally recognized tribal governments (Native Village of Barrow, Native Village of Kaktovik, Native Village of Nuiqsut, Inupiat Community of the Arctic Slope) from the North Slope of Alaska were contacted and extended an opportunity to participate in the development of the EIS. This involvement is required by Executive Order 13084, which was intended, in part, to establish regular and meaningful consultation and collaboration with federally recognized tribal governments in the development of regulatory practices on federal matters that significantly or uniquely affect their communities.

Environmental Justice: The EIS addresses federal agencies' compliance with Executive Order 12898 regarding Environmental Justice in the issuance of permits and approvals. Compliance with the Executive Order also applies to the RODs issued by federal agencies.

1.5 SUMMARY OF THE SCOPING PROCESS AND KEY ISSUES IDENTIFIED

A *Notice of Intent* was published in the Federal Register on November 24, 1995, announcing the preparation of an EIS for the proposed Northstar Unit development and the opportunity for public input. Public scoping meetings were held in March, April, and May of 1996 in Barrow, Nuiqsut, Kaktovik, Fairbanks, Valdez, and Anchorage. Smaller, informal public involvement meetings were held in addition to the public scoping meetings. These meetings served the dual purpose of receiving scoping comments and collecting Traditional Knowledge of the Inupiat people of the Alaskan Beaufort Sea region.

Table ES-2 (Page 1)

Table ES-2 (Page 2)

Table ES-2 (Page 3)

Details on scoping meetings, issues identified at meetings, and the full text of oral and written comments are included in the *"Scoping Report - Beaufort Sea Oil and Gas Development/Northstar Project"* dated July 15, 1996. This document was located in city offices at Barrow, Kaktovik, and Nuiqsut; the NSB office in Barrow; the Alaska Eskimo Whaling Commission office in Barrow; city libraries in Anchorage, Fairbanks, and Valdez; and is available from the Corps' Anchorage office (see contact address on cover sheet). Oral and written comments received from the public and agencies during the scoping period are summarized below.

- **General Comments** - Comments regarding cumulative impacts of additional Alaska Beaufort Sea development, and permitting issues.

- **Project Design** - Comments regarding design of the production platform/island, subsea pipelines, and island resupply.

- **Physical Environment** - Comments regarding sea ice dynamics and oil spill prevention/response.

- **Biological Environment** - Comments regarding impacts of offshore development on marine mammals and pipeline impacts to terrestrial ecology, wetlands, and wildlife.

- **Human Environment** - Comments regarding subsistence traditional lifestyle and knowledge, cultural resources, and cumulative impacts.

Although a wide range of comments was received, the focus of most concerns was on two issues. The first was the effects of construction and long-term operations noise in the Alaskan Beaufort Sea on the migration routes of bowhead whales and the consequences for the subsistence harvest of whales. The second major issue was the potential for, and difficulty of containing and cleaning up, a large oil spill from offshore facilities, especially in broken ice conditions, and the resulting expectation of significant impacts on the marine ecosystem. These issues, and the request that Traditional Knowledge shared over the past 20 years be used in this assessment, were important in developing the structure of the document as discussed below.

The cooperating agencies committed to collecting and incorporating Traditional Knowledge in preparing the EIS, in part to meet requirements outlined in Executive Order 12898 regarding Environmental Justice. Traditional Knowledge has been a factor in reaching conclusions of significant impacts, developing mitigation measures, and recommending project design changes.

1.6 DEIS REVIEW

A Notice of Availability was published in the Federal Register (62FR28375) for the Draft EIS (DEIS) on May 22, 1998, and the DEIS was released for public review and comment on June 1, 1998. Notices of Availability also were announced through newspapers and mailing lists. The DEIS review was extended from an original 60-day period and continued through August 31, 1998, following requests for an extension of the comment period.

The DEIS was available to any member of the public requesting a copy. Over 260 complete sets of the DEIS and an additional 548 copies of the Executive Summary (Volume 1) were mailed to interested parties for review. The Executive Summary also was available for viewing on the Internet, and complete sets of the seven volume document were available at libraries and city offices in Anchorage, Barrow, Fairbanks, Juneau, Kaktovik, Nuiqsut, and Valdez and at the Corps' offices in Anchorage. The Corps and cooperating agencies held informal workshops to familiarize interested parties with the document during June and July 1998, and formal public hearings were held during July at Nuiqsut, Kaktovik, Barrow, Fairbanks, and Anchorage (refer to Appendix K for workshop and hearing dates).

A total of 435 letters were received from federal, state and municipal, and federally recognized tribal governments, businesses, organizations, and individuals. Public testimony was received from approximately 105 individuals. All comments (letters and testimony) were reviewed and, in accordance with NEPA, substantive comments were addressed in the FEIS. Copies of comments received (letters and testimony) are provided in Appendix K; responses to comments are provided in Appendix L. Substantive comments that affected elements of the EIS were incorporated into this document.

1.7 ORGANIZATION OF THE EIS

This EIS addresses issues raised in scoping and issues related to decision making. It tracks these issues through the analysis of project impacts. The document was constructed to be user-friendly, respond to scoping concerns, and support several approval processes (e.g., Endangered Species Act [ESA], NPDES, Ocean Dumping), as well as support decisions on future offshore projects. The chapter on Traditional Knowledge responds to North Slope residents' concern about their input not being taken seriously in the past. Traditional Knowledge sections at the beginning of chapters, as well as Traditional Knowledge used alongside western science, allow the reader to quickly find Traditional Knowledge information in the document. The Affected Environment sections are placed next to Environmental Consequences for each of the topic subsections to make the EIS easier to use. For example, if a reader is interested in fish, all the information about fish is found together. While this format may result in some redundancies, we have adopted this approach to facilitate the diverse group of reviewers who are often very issue-specific in their interests.

The analysis of offshore development/production options in the Alaskan Beaufort Sea is presented in Chapter 3. The purpose is to present a broad, initial view of development options for this first offshore project with a subsea pipeline. It is intended that much of this EIS be useable for future oil and gas development by substituting project-specific information in Chapter 4 and reassessing impacts as needed for project-specific alternatives. Oil and noise information and impacts were placed into separate chapters (8 and 9, respectively) for two reasons: 1) to accommodate the volume of background information needed to understand the assessment of oil and noise impacts, and 2) to focus on spilled oil and increased noise in the marine environment as primary issues for the Northstar Unit development.

Chapter 1.0 - Introduction introduces BPXA's proposed project and describes the purpose and need for the project and the EIS. This chapter presents the goals of this EIS and explains how the document is organized. It also includes a brief discussion of decisions to be made and a summary of the scoping process and key issues identified.

Chapter 2.0 - Traditional Knowledge explains what Traditional Knowledge and subsistence mean and their cultural importance. It describes the process for gathering Traditional Knowledge and using it in this document. This information is placed at the beginning of the EIS to provide the context for use of Traditional Knowledge in the remainder of the document.

The EIS then goes from general perspective to particular perspective:

Chapter 3.0 - Oil and Gas Development/Production Options for the Alaskan Beaufort Sea presents a summary of the range of oil and gas development/production technologies applicable to the Alaskan Beaufort Sea. This chapter then analyzes these technologies to identify a short list of development/production options to be evaluated further in the EIS. This analysis continues in Chapter 4, using information applicable to the Northstar Unit, and its results provide the basis for identification of the action alternatives evaluated in more detail throughout this EIS. This approach allows an initial broad consideration of options for the Northstar Project, which may be applicable to the evaluation of future oil and gas development/production proposals at other locations in the Alaskan Beaufort Sea.

Chapter 4.0 - Northstar Unit Development/Production Alternatives provides information about the Northstar Unit and reservoir needed to analyze technical options for offshore development/production at the Northstar Unit. Development/production options for the Northstar Unit are identified and linked to form reasonable project alternatives for this development. As required by NEPA, a No Action Alternative is also analyzed as the basis for assessing impacts.

The EIS then presents a description of environment and impacts. To allow review of particular resource descriptions and expected impacts to those resources, the affected environments and associated project impacts are presented in the same chapter.

Chapter 5.0 (Affected Physical Environment and Impacts), **Chapter 6.0 (Affected Biological Environment and Impacts), and Chapter 7.0 (Affected Human Environment and Impacts)** present information regarding the existing physical, biological, and human environments that would be affected by the project alternatives. The second part of each section, "Environmental Consequences," discusses potential impacts from construction, operation, maintenance, and abandonment of alternatives identified in Chapter 4. Summaries in these chapters identify unavoidable adverse effects, short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and irreversible and irretrievable effects. Information in these chapters also supports associated approval processes (e.g., NPDES Permit, ESA - Biological Assessment, Ocean Dumping), which allows cross-referencing among EIS sections and appendices and avoids repetition of information.

Recognizing the significant amount of concern and interest in issues associated with both oil spills and noise effects, the EIS provides a chapter specifically dealing with each.

Chapter 8.0 - Effects of Oil on the Physical, Biological, and Human Environments presents the likelihood of spills at different sites, background information, identification of resources of particular concern, and realistic assessment of impacts from spilled oil. The probability of an oil spill for each of the project alternatives is estimated. This chapter describes the impacts of oil on the physical, biological, and human environments (at the large scale) to address concerns raised in scoping and to enable readers to find information on potential oil spills and their impacts in one place in the document. General effects of oil on resources (on a small scale) are described in Chapters 5, 6, and 7. Information is presented (when available) for the key species. When such species-specific information is not available, information may be presented from related species or from a different area. Because the effect of oil on resources was a key issue identified in scoping, a separate chapter has been dedicated to address this concern.

Chapter 9.0 - Effects of Noise on the Biological Environments describes and explains noise, noise studies, and animal reactions to noise to predict/assess impacts of project alternatives. Noise impact was a concern raised repeatedly during scoping. This chapter provides information addressing that concern. An analysis of potential impacts from construction, operation, maintenance, and abandonment of each of the alternatives identified in Chapter 4 is included.

The EIS then continues to completion by describing reasonably expected cumulative effects and comparing the project alternatives and their impacts.

Chapter 10.0 - Cumulative Effects presents an analysis of past, current, and reasonably foreseeable future actions that, in combination with development/production of the Northstar Unit, may cause cumulative effects on the physical, biological, and human environments. Exploration, construction, operation, and production activities associated with foreseeable future projects are described. This chapter provides an understanding of what impact the Northstar Unit development, in conjunction with other existing and/or future North Slope developments, would have on the environment.

Chapter 11.0 - Comparison of Project Alternatives and their Impacts presents a summary of the magnitude and significance of environmental impacts associated with each alternative identified in this EIS. The information is presented in a comparative format to highlight environmental issues and principal differences among alternatives.

Chapter 12.0 - List of Preparers presents a list of individuals contributing to the preparation of this EIS, including agencies who provided assistance in the overall development and coordination.

Chapter 13.0 - Consultation and Coordination identifies federal and state agencies consulted during preparation of this EIS along with NSB personnel, special interest groups, and other individuals who provided information and assistance.
A **Glossary** is included to define technical terms and other potentially unfamiliar words and phrases.

An **Index** of keywords, as required by NEPA, is included to assist the reader in locating information in this EIS. In addition, an index of keywords pertaining specifically to Traditional Knowledge topics is included.

Appendices to the EIS have been developed to provide supplemental technical information and supporting data:

Appendix A - BP Exploration (Alaska) Inc.'s Final Project Description is BPXA's description of its proposed Northstar Development Project (Final Project Description, Revision 1, dated March 27, 1997, with subsequent modifications). It is provided to ensure that all reviewers (state, federal, local, and public) have the same information and level of detail to assess the proposed project. This project description also serves as the Development and Production Plan for the MMS's approval.

Appendix B - Biological Assessment was prepared to conform with the requirements of Section 7 (a)(2) of the ESA of 1973, as amended, regarding threatened or endangered species potentially affected by BPXA's proposed project. As part of the Section 7 consultation process, the Biological Assessment was submitted to the NMFS and USFWS separately from the EIS. The Biological Assessment addresses potential effects to threatened and endangered species as a result of development/production of the Northstar Unit. It also addresses potential effects of the subsequent transport of crude oil along the U.S. west coast and routes to refinery destinations. The Biological Assessment references some analyses which can be found in the biological, noise, and oil chapters of this EIS. Refer to the DEIS for this document.

Appendix C - Updated Mailing List shows agencies, groups, and interested individuals receiving newsletters and announcements regarding the development of the EIS.

Appendix D - Northstar Unit Lease Stipulation Summaries and Applicable Alaska Regulations includes summaries of lease stipulations issued by the U.S. Department of the Interior (USDOI), Bureau of Land Management. These Outer Continental Shelf (OCS) functions were transferred by Executive Order to the MMS on October 1, 1982, for the two federal leases that comprise portions of the Northstar Unit. Summaries of stipulations issued by the Alaska Department of Natural Resources and the State of Alaska Division of Minerals and Energy Management, which govern oil and gas exploration and development activities from the five individual state leases that comprise the remainder of the Northstar Unit, are also included. Select Alaska statutes specific to the proposed project are included.

Appendix E - Technical Appendices is a listing of technical documents prepared by BPXA and used in preparation of the EIS.

Appendix F - Draft National Pollutant Discharge Elimination System Permit provides limitations and monitoring requirements for discharges from BPXA's proposed project into local marine waters. Refer to the DEIS for this document.

Appendix G - National Pollutant Discharge Elimination System Fact Sheet provides technical information supporting the limits and monitoring requirements in the NPDES Permit. A significant portion of this information is derived from the EIS, including the project description (Appendix A) and oceanographic data (Section 5.5). Appendix G includes the nature of the marine discharges, the local environment into which these discharges may be made, the need for mixing zones, and the rationale for monitoring requirements. In addition, biological data from the EIS (Chapter 6) are used in this Fact Sheet to support its risk assessment. Refer to the DEIS for this document.

Appendix H - Ocean Discharge Criteria Evaluation (ODCE) provides an evaluation of the possibility of unreasonable degradation due to marine discharges from the Seal Island facilities. This evaluation is based on the ten criteria requirements set forth in 40 CFR 125.121. In addition, this ODCE summarizes recommended monitoring requirements detailed in Appendix F. Discharges, physical oceanography, sea ice, and biological communities data for this ODCE were taken from the EIS. Refer to the DEIS for this document.

Appendix I - Section 103 Evaluation is a document required by the Marine Protection, Research and Sanctuaries Act of 1972 for evaluating the transport and ocean disposal of dredged waste material. This appendix provides information about dredged material and the substrate at the disposal sites, such as grain size and potential contaminants, to support agency decisions about disposal of waste materials from pipeline trenching. The Corps issues permits for the transportation of dredged material for the purpose of ocean disposal, and the EPA must concur with the proposed disposal site. Refer to the DEIS for this document.

Appendix J - Draft Underground Injection Control (UIC) Permit defines both the general permit conditions and well specific conditions for the proposed Northstar non-hazardous material injection well. This injection well will receive numerous waste streams ranging from process related material to treated domestic wastewater and surface run-off. Appendix J includes the UIC well permit conditions as well as monitoring and reporting requirements and plugging and abandonment requirements. Refer to the DEIS for this document.

Appendix K - Public Comments Received on the Draft Environmental Impact Statement provides comments, both written letters and oral testimony, received during the public comment period for the Northstar Development Project EIS from June 1, 1998 through August 31, 1998, in accordance with 40 CFR 1506.9. To comply with NEPA, all comments received must be acknowledged, and substantive comments addressed. These comments have been bracketed in this appendix and corresponding responses can be found in Appendix L.

Appendix L - Response to Comments provides responses to comments received during the official public comment period, identified by the comment number, and prepared by technical authors specializing in each field. Responses were drafted to meet NEPA, Council on Environmental Quality (CEQ), and Corps guidelines.

Appendix M - Biological Opinions contains the Biological Opinions of the USFWS and NMFS on the Northstar Development Project, based on the Biological Assessment (presented in Appendix B of the DEIS).

Appendix N - Final Underground Injection Control Permit contains the final version of the UIC Permit. The draft version was previously published in the DEIS as Appendix J.

Appendix O - Preliminary Final National Pollutant Discharge Elimination System Permit contains the final version of the NPDES Permit. The draft version was previously published in the DEIS as Appendix F.

Appendix P - Reports of the Cold Regions Research and Engineering Laboratory contains reports concerning shoreline erosion, permafrost at the sea/land transition zone, and loads placed on ice near a slot in a thickened ice sheet. These first two topics are important for assessing the integrity of the subsea pipeline from Seal Island as it transitions to an onshore pipeline. The third topic is relevant to subsea pipeline construction activities.

2.0 TRADITIONAL KNOWLEDGE

In this EIS, Traditional Knowledge refers to the experience, familiarity, and awareness of the Inupiat Eskimo residents who have lived continuously for thousands of years off the land and waters of the North Slope. Traditional Knowledge is passed along from generation to generation, but also adapts to reflect changes in technology and socioeconomic conditions. This knowledge includes, but is not limited to, expertise on weather, sea ice, currents, fish and wildlife, historic and current uses of the land and water for subsistence activities and other traditional uses, and impacts of human activities on wildlife and the environment (refer to EIS, Chapter 2).

The importance of Traditional Knowledge is better understood and respected if its origins in the subsistence culture are made clear. North Slope Inupiat Eskimo culture, like other Alaska Native cultures, is characterized by the importance of harvesting, processing, distributing, storing, and consuming wild foods (SRB&A and PJUCS, 1993:3-5), and the ability to utilize resources for clothing, shelter, fuel, tools, and ceremonial items.

Within a culture based on the harvest of wild resources, the most significant beliefs and values revolve around three fundamental relationships: 1) the relationship between humans and the environment (including wild resources); 2) the relationship among human beings; and 3) the relationship between the people and their ancestry (SRB&A and PJUCS, 1993:4-5). The importance of the first two relationships stems from human dependence on one another and the environment for survival. The third relationship demonstrates the dependence on knowledge and skills passed from generation to generation and the belief that those who came before knew the correct and proper way to live.

The goal of subsistence is to maintain these relationships by harvesting in a manner respectful to the environment while accumulating resources that can be consumed and shared with other members of the community. Successful subsistence is not only resource harvesting by an individual for his own use but includes the distribution of those resources through a network of social ties anchored by kinship.

Historically, Traditional Knowledge of local indigenous people has not been addressed adequately in environmental assessments or impact statements. Instead, EISs have relied primarily on western scientific knowledge and analysis. In particular, the Inupiat Eskimo people of northern Alaska have been continually frustrated by what they perceive to be a lack of attention to and respect for information they have provided to federal and state agencies during the planning process for oil and gas lease sales and related exploration and development projects.

A Traditional Knowledge work plan was developed to guide the collection of Traditional Knowledge and its incorporation into the EIS (Chapter 2). The work plan was developed with the assistance of an informal peer review group assembled by the NSB and other cooperating agencies. It contained the following three elements:

- A review of Traditional Knowledge provided by past testimony from North Slope organizations and residents on proposed oil and gas lease sales and exploration and development projects.

- Collection of Traditional Knowledge from residents of Barrow, Nuiqsut, and Kaktovik.

- Incorporation of Traditional Knowledge in a meaningful way into appropriate sections of the EIS.

Traditional Knowledge of the project area was gathered from whaling captains, their wives, elders, and other individuals who have spent a great amount of time on the land and sea participating in subsistence activities. They are respected by their communities for this knowledge. Available written and taped transcripts were collected from previous meetings related to state and federal oil and gas lease sales, proposed oil exploration and development projects, and other relevant topics. A listing of historic sources of testimony and coordination/communication with the residents of Barrow, Nuiqsut, and Kaktovik utilized for this EIS are shown in Tables ES-3 and ES-4, respectively. The database of Traditional Knowledge developed from this effort will be available for public use. It is expected to be maintained by the NSB.

Information collected was divided into four Traditional Knowledge categories:

- Information on Characteristics of the Physical, Biological, and Human Environment - Primarily baseline environmental characteristics, this information represents what is normally thought of as Traditional Knowledge.

- Issues and Concerns Related to Oil and Gas Activities Based on Traditional Knowledge - While not directly Traditional Knowledge, issues and concerns reflect Traditional Knowledge of the environment and potential impacts of proposed development, including specifics of oil and noise impacts.

- Informed Views Related to the Potential Impacts of the Proposed Project Based on Traditional Knowledge - This information was offered in testimony or specifically asked for in interview

Table ES-3 (Page 1)

Table ES-4 (Page 1)

Table ES-4 (Page 2)

questions. These views reflect Traditional Knowledge of the environment and potential impacts of proposed development.

- Observations Regarding Project Design, Construction, and Operation Based on Traditional Knowledge - In reviewing BPXA's proposed project, observations and suggestions were made on project design, construction, and operation. The intent of these observations and suggestions was to improve safety and avoid or minimize impacts.

Traditional Knowledge from past testimony on North Slope projects related to oil and gas exploration and development and the 1996 community data collection efforts was incorporated into the EIS. Information on characteristics of the physical, biological, and human environment and the effects of oil and noise on these environments was incorporated into the affected environment sections (of Chapters 5 through 9). Issues and concerns related to oil and gas development and informed views related to the potential impacts of BPXA's proposed project were incorporated into discussions of environmental consequences. Observations regarding project design, construction, and operation characteristics also were incorporated into environmental consequences sections.

The cooperating agencies committed to collecting and incorporating Traditional Knowledge in preparing the EIS in part to meet requirements outlined in Executive Order 12898 regarding Environmental Justice.

3.0 OIL AND GAS DEVELOPMENT/PRODUCTION OPTIONS

FOR THE ALASKAN BEAUFORT SEA

3.1 OVERVIEW OF THE PROJECT AREA

The Beaufort Sea comprises the southern part of the Arctic Ocean, extended between Canada's Banks Island to the east and the Chukchi Sea to the west. The 37- to 75-mile (60 to 121 km) wide continental shelf beneath the Alaskan Beaufort Sea portion extends from the Canadian border west to the Barrow Sea Valley. The seafloor is mostly flat and featureless, and gradually dips in a northerly direction. Water depths on the continental shelf are generally less than 600 feet (ft) (183 meters [m]). Characteristically, bottom sediments are composed of sands and silt. Exceptions are exemplified by an area near the Sagavanirktok River Delta where a collection of boulders and cobble (the Boulder Patch) has been identified. This unusual hard substrate is found in only a few areas, and supports a biological community uncommon in the Alaskan Beaufort Sea. As a consequence, this substrate is of particular interest to resource agencies. A series of natural barrier islands parallel portions of the coastline 1 to 20 miles (1.6 to 32 km) offshore. The low relief barrier islands are continuously reshaped as a result of currents and erosion.

Zones of sea ice found in the Alaskan Beaufort Sea include the landfast zone, stamukhi (shear) zone, and the polar pack-ice zone. The landfast ice zone usually extends from shore to water depths of approximately 65 ft (20 m) in winter, with ice thickness in the range of 4 to 7 ft (1.2 to 2.1 m) (Figure ES-2). Ice freezes to the seafloor in depths less than 7 ft (2.1 m) and becomes bottomfast or grounded. The remainder of the landfast ice is floating on deeper water. Seaward of the landfast zone is the stamukhi zone. In the stamukhi zone relatively stable landfast ice and mobile pack-ice interact, resulting in ice ridges and open water leads. The stamukhi zone typically extends from water depths of 65 ft (20 m) to the edge of the continental shelf. The polar pack-ice zone, which is the body of ice that never completely thaws, extends seaward of the stamukhi zone and covers much of the northern Arctic Ocean. This zone includes first-year ice, multi-year ice, and large ice islands.

Sea ice conditions vary seasonally and affect the scheduling and nature of construction and operation activities for offshore facilities in the Alaskan Beaufort Sea. The solid ice season usually occurs from November through April. During this period, offshore construction in the landfast ice zone can occur from the ice surface. Ice roads are generally used for access during this period. The springtime broken ice season extends from mid-May to mid- July. Another broken ice season occurs during fall freeze up from mid-September to November. During broken ice seasons, access to offshore structures is by helicopter. Boats can be used during open water and light ice season from mid-July to mid-September. Sea ice also affects distribution and movement of animals such as the bowhead whale, which migrates eastward through stamukhi zone leads in the spring, and westward through open water closer to shore in the fall. Ringed seals use floating landfast ice in winter and pack ice during summer while bearded seals use the pack ice all year. Polar bears are closely tied to the movement of sea ice, reaching the coastal areas in September and October and leaving with the receding ice in April and May.

Landfast sea ice adjacent to river deltas becomes flooded during early breakup (mid-May to early June) with meltwater from inland drainages that thaws before coastal waters. Drainage of this floodwater through holes in floating sea ice typically occurs in water depths between 6 and 20 ft (1.8 and 6 m). This drainage results in an erosive phenomenon on the seafloor called strudel scouring, which excavates depressions in the seafloor. A second phenomena affecting structures is ice gouging, which leaves long linear depressions in the seafloor. Ice gouging is caused by grounding and movement of large pieces of ice pushed by winds and currents.

Onshore, the Arctic Coastal Plain extends north from the Brooks Range foothills to the Arctic Ocean. It is characterized by flat to gently rolling terrain, and much of it is covered by shallow thaw-lake basins, ponds and deeper lakes. The area is mostly wetlands and includes valuable habitat for migratory waterfowl, shorebirds, and caribou. Habitats considered to be of especially high value include ponds with *Arctophila fulva* (an emergent grass), which is heavily used by waterfowl during breeding, molting and brood-rearing periods; islands in the Sagavanirktok River delta used for nesting by snow geese; coastal saline marshes used by brant, snow geese, and shorebirds for feeding and brood-rearing; and freshwater streams deep enough to remain unfrozen during winter, which are essential overwintering habitats for grayling and anadromous fish. Mean annual temperature is approximately 11° Fahrenheit (-12.2° Celsius), and permafrost (ground that remains below freezing temperatures from one winter to the next) is continuous across the coastal plain.

Figure ES-2 (Page 1)

Figure ES-2 (Page 2)

Although some oil and gas construction activities are possible during summer, the majority of construction in the Arctic takes place during winter because frozen ground and frozen sea ice provide solid surfaces for access to work sites without construction of permanent roads. Temporary ice roads are often constructed during winter across the tundra and ponds to access work sites. Rolligons and tracked vehicles are used with little damage to the vegetation or soil once the active layer of soil is frozen. Work is discontinued in extreme wind and cold, but VSM installation, pipeline construction, excavation of gravel from mine sites, placement of gravel for roads, pads and islands and movement of large modules or drill rigs over roads or over ice are routinely conducted in sub-zero temperatures.

The NSB is the largest, northernmost, geographic municipality in Alaska, covering approximately 88,000 square miles (227,920 square km). In 1993, the NSB had a recorded population of 6,538 residents living in eight permanent communities. The majority of residents are indigenous Inupiat Eskimos. The community of Barrow, the seat of government of the NSB, is located just southwest of Point Barrow on the Chukchi Sea coast (Figure ES-3). Two other North Slope communities with direct access to the Alaskan Beaufort Sea are Nuiqsut, located approximately 16 miles (26 km) inland on the Colville River, and Kaktovik, located on Barter Island in the eastern Alaskan Beaufort Sea. The Inupiat residents of the North Slope have retained a largely traditional, subsistence-based lifestyle. Harvesting, processing, and distributing bowhead whale is particularly important to the Inupiat culture, and subsistence activities are a significant part of the overall North Slope economy.

The all-gravel Dalton Highway connecting Deadhorse to Fairbanks, is the only road to the North Slope. There is no permanent road access to the other communities, although occasional construction of an ice road provides a connection between Nuiqsut and the industrial complex at Deadhorse. Residents travel between communities and to subsistence harvest sites by boat, airplane, and snowmachine as conditions permit. The Barrow and Deadhorse airports and the Prudhoe Bay airstrip are the only airstrips capable of handling large aircraft. A short open-water season on the Chukchi and Alaskan Beaufort Seas allows limited annual barge transport of materials and fuel to coastal communities and Deadhorse.

3.2 EXISTING OIL AND GAS FACILITIES

Existing offshore facilities, such as gravel islands previously used for exploration activities, may provide opportunities for the development of offshore oil and gas resources if they are, or can be located within reasonable proximity to the reservoir to be produced. Seventeen gravel islands have been constructed in waters less than 50 ft (15.2 m) deep in the Alaskan Beaufort Sea for exploration drilling since 1975. Most of these remain in some form including Seal and Northstar Islands, within the Northstar Unit which were abandoned by removal of all equipment and erosion protection. The natural barrier islands also have been used for exploration drilling activities and for staging areas for materials such as drill pipe and spill response equipment in support of exploration activities. In addition to gravel islands, ice islands have been constructed for exploration drilling during winter. Drillships and bottom-founded drilling structures also have been used for exploration drilling in the Alaskan Beaufort Sea. One of these, a bottom-founded Concrete Island Drilling Structure (CIDS), is currently located in Camden Bay, off the coast of the Arctic National Wildlife Refuge. The CIDS and other exploration structures may be suitable, with modification, for use as offshore production structures.

Existing onshore and offshore facilities in the Prudhoe Bay area are likely to provide support for future oil and gas development/production in the Alaskan Beaufort Sea (Figure ES-4). It usually would be more economical to use existing facilities, especially if they have excess capacity, therefore offshore development is likely to connect to or use onshore processing facilities, the Dalton Highway, and the TAPS.

Sharing or co-location of facilities could reduce the extent of new onshore development on the North Slope. Development costs and regulatory requirements already result in some oil field facilities being shared between the two main operators on the North Slope, BPXA and ARCO Alaska, Inc. For example, processing facilities originally constructed to support development of one oil field are used for nearby developments as additional discoveries are made. Pipelines that carry oil between units require a state right-of-way permit and are designated as common carrier pipelines. The TAPS is a common carrier pipeline.

Current oil and gas facilities on the North Slope include: Duck Island, Prudhoe Bay, Kuparuk, Milne Point, Lisburne, Badami, and Tarn. Facilities and reservoirs associated with these units are summarized in Table ES-5.

3.3 PROCESS FOR SELECTION OF OIL AND GAS DEVELOPMENT OPTIONS FOR THE ALASKAN BEAUFORT SEA

A range of oil and gas development/production technologies was evaluated to assess the applicability of each for use in the Alaskan Beaufort Sea. These options were first considered broadly for all situations across the Beaufort Sea (Chapter 3 of EIS). Then realistic options were selected for the site specific conditions at the Northstar Unit (e.g., water depth, distance offshore, ice regime, existing uses of the area) (Chapter 4 of EIS). Components of an oil and gas development/production project evaluated include:

- Oil and gas drilling methods.
- Oil and gas offshore production structures.
- Oil and gas recovery methods.
- Oil and gas processing methods.
- Product transportation options.
- Development/production facilities abandonment/reuse potential.

A diagram showing the process for selecting the development/production location and structure type for the Northstar Unit is presented on Figure ES-5. The flow diagram presumes that development from an onshore site or an existing offshore structure is generally preferable to the installation of new offshore structures. Specific project proposals that would not otherwise be identified using this flow diagram could still be evaluated in response to an applicant's request.

Figure ES-3 (Page 1)

Figure ES-3 (Page 2)

Figure ES-4a (Page 1)

Figure ES-4a (Page 2)

Figure ES-4b (Page 1)

Figure ES-4b (Page 2)

Figure ES-4c (Page 1)

Figure ES-4c (Page 2)

Figure ES-5 (Page 1)

Figure ES-5 (Page 2)

Table ES-5 (Page 1)

The same type of process is used to select the other components from the feasible options to complete project alternatives. Environmental information and scoping concerns collected early in the NEPA process are used to develop alternatives which are distinct and respond to the range of issues to be evaluated in the EIS. For example, alternatives with a pipeline landfall location on a natural shoreline and another on an existing manmade causeway address concerns about stability of the permafrost transition zone. However, not all possible landfalls of each type need to be evaluated.

3.4 ALTERNATIVES CONSIDERED BUT ELIMINATED FROM DETAILED ANALYSIS

Development/Production Location and Structure Type:

- Onshore.
  - Too far to reach Northstar reservoir from onshore.
- Barrier islands.
  - Have high value as nesting habitat.
  - Too far from Northstar reservoir.
- Northstar Island shoal.
  - Cannot reach enough of Northstar reservoir.
  - Exposure to larger ice movements than sites closer to shore creates high risk to facilities.
- New location within 4 miles (6.4 km) of most productive portion of Northstar reservoir.
  - Cost cannot be justified by additional oil reached (vs. Seal Island location).

- Likelihood for extending current limits of directional drilling from Seal Island in future.

- Molikpaq CIDS and Single Steel Drilling Caisson.
  - High costs for modifications.
  - Greater underwater transmission of noise.
- Subsea silos and caverns.
  - High cost.
- Seafloor templates.
  - Water depth too shallow.
- New purpose-built structure.
  - Higher cost and longer lead time than modifying existing structures.

Oil and Gas Recovery Options:

- Primary Recovery.
  - Not economic (5% to 20% recovery).
- Gas lift.
  - Not appropriate because of composition of Northstar reservoir fluids.
- Water injection.
  - Not economic (35% to 45% recovery).

- Waterflood
  - Seawater treatment plant required.
  - Marine discharges of filtrate.

Oil and Gas Processing Options:

- Partial offshore and partial onshore processing.

  - Results in greater negative impacts to wildlife and habitat due to expansion of onshore facilities.

- Full onshore processing.

  - Results in greater negative impacts to wildlife and habitat due to new onshore facilities.

  - Difficult to transfer three-phase fluids.

Product Transportation Options:

- Tankers and barges.
  - Greater spill risk than pipelines.
  - High costs due to additional facilities needed.
  - Repeated dredging required.
- Pipeline installed on the surface of the seafloor.
  - High risk of damage by ice or ship anchors.
- Pipeline buried in gravel causeway.
  - Significant negative impacts to water circulation movements.
  - High cost to construct, especially with adequate breaches/bridges.
- Double-walled pipe

  - Available information is not sufficient to indicate that double-walled pipe is as good or better design than single-walled pipe.

  - Control of construction (welding) defects and prevention of corrosion would be more complex for a double-walled pipe.

- Double-wall pipe would also involve numerous installation constraints that could limit or prohibit single season construction.
- Repair of a damaged double-walled pipelined would be more difficult than repairing a single- walled pipeline.

Offshore Pipeline Route and Landfall Options:

- Route straight to West Dock.
  - Longer distance in water depths greater than 10 ft (3 m).
- Landfall location outside the Point Storkersen to West Dock range.
  - Need for gas from onshore could result in two separate pipeline routes.
  - No excess capacity at facilities near landfall to support Northstar processing.
  - Longer pipeline distances increase risk of pipeline spills and increase costs.
- Other landfall locations between Point Storkersen and West Dock.
  - Some areas of high value saline marsh to be avoided.

Onshore Pipeline Route Options:

- Other angled routes between Point Storkersen landfall and closest pipe/roads.
  - Pipeline would cross more ponds and high value basin-wetland complexes.
  - Pipeline would disrupt more undeveloped tundra.
- Other routes through oil field following existing roads and pipelines.
  - Many variations possible, most are more complex and longer.

Gravel Source Options:

- *Offshore sites.*
  - *None known within any reasonable distance of the Northstar Unit.*
  - *Negative impacts to marine mammals and other organisms may be significant.*
- *Reuse of gravel islands.*
  - *Use of Northstar Island shoal would be disruptive to whales.*
  - *Use of Northstar Island shoal would be logistically difficult.*
  - *No other islands are within a reasonable distance of the Northstar Unit.*

Spoils Disposal Options:

- *Onshore.*
  - *Saline material not acceptable to use onshore as it kills terrestrial vegetation.*
- *Shallow water (bottomfast ice) within lagoons.*
  - *Additional sediments could block water circulation and navigation if depths less than 4 ft (1.2 m).*
  - *Few areas deeper than 4 ft (1.2 m).*

Construction Schedule Options:

- *Summertime trenching and pipe laying.*
  - *Environmental impacts increase greatly due to presence of whales, seals, fish, and birds.*
  - *No storage space for excavated trench material for backfilling.*

- Very limited work season, potentially none at all if ice does not leave the area.

3.5 ALTERNATIVES SELECTED FOR EVALUATION IN THIS EIS

3.5.1 Project Components and Selection Criteria

The broad range of oil and gas technological options evaluated for the Alaskan Beaufort Sea were narrowed down to the following list of options to support long-term oil and gas development/production from the Northstar Unit. The most important criteria used to select these options are also listed.

Oil and Gas Drilling Methods:

- Directional drilling.
  - Only one development/production structure required.
  - Can reach most of reservoir from one location.

Development/Production Location and Structure Type:

- Reconstructed gravel Seal Island.

- Much of gravel volume is already in place.
- Lowest noise transmission of all structure types.
- Can withstand ice movements.
- Can reach most of reservoir.

Oil and Gas Recovery Options:

- Gas cycling.
  - 61% recovery predicted.
  - Appropriate for reservoir and supplemental gas available.

Oil and Gas Processing Options:

- Full offshore processing.
  - Keeps more impacts offshore where less habitat and fewer wildlife are disturbed.
  - Allows transport of more stable, safer product.

Product Transportation Options:

- Buried subsea pipeline.
  - Safest option with few direct impacts.

Offshore Pipeline Route and Landfall Options:

- Shortest route between Seal Island and 10-ft (3 m) contour.

- Minimizes exposure to large ice floes.
- Minimizes need for slower, deeper water construction method.

- Straight route to Point Storkersen landfall.
  - Minimizes pipeline lengths.
  - Minimizes exposure to ice outside the barrier islands.
- Eastern route to landfall near Point McIntyre.
  - Smaller impacts to undisturbed tundra habitat at landfall.
- Eastern route to landfall on West Dock.
  - Avoids crossing permafrost transition zone.
  - Avoids all impacts to undisturbed tundra habitat at landfall.

Onshore Pipeline Route Options:

- Route straight to Pump Station No. 1 from Point Storkersen.
  - Minimizes pipeline length.
- Eastern route from Point Storkersen to Point McIntyre.
  - Less impact to undisturbed tundra.
  - Allows for future development to west or offshore to join pipeline corridor.
- Route from Point McIntyre to West Dock Staging Pad.
  - Even less impact to undisturbed tundra.
  - Valve station and onshore pipeline accessible by road.
- Route from West Dock Staging Pad to the CCP and Pump Station No. 1.
  - Maximizes use of existing disturbed areas.
  - Valve station and almost all onshore pipeline accessible by road.

Gravel Source Options:

- Use and rehabilitate new site in Kuparuk River Delta.
  - Sparsely vegetated site with little overburden to move and replace.
  - Close distance to Seal Island.
  - Single winter use results in rapid rehabilitation and no permanent roads.
- Use of Kuparuk Deadarm mine site.
  - Backup source if new site cannot be used and source for additional gravel needs (maintenance, caribou crossings).
- Use of Put 23 Mine site.
  - Backup source for additional gravel needs.

Spoils Disposal Options:

- Offshore in the floating-fast ice zone and outside the barrier islands.
  - Achieves good dispersion of waste material.

Construction Schedule Options:

- Winter trenching, pipeline construction, and gravel haul and placement.
  - Minimizes impacts to bowhead whales, vegetation, fish and birds.
  - Minimizes water quality impacts (turbidity).

Selection of project components results in the specific project alternatives (action alternatives) described below for the Northstar Project. A No Action alternative also is considered to serve as a basis for comparing and evaluating potential impacts of the action alternatives. Differences among the action alternatives primarily represent pipeline corridor alignments (Figure ES-6) and resulting maintenance and operation differences.

- Alternative 1 - No Action
- Alternative 2 - Point Storkersen Landfall/BPXA's Proposed Action
- Alternative 3 - Point Storkersen Landfall to West Dock Staging Pad.
- Alternative 4 - Point McIntyre Landfall to West Dock Staging Pad.
- Alternative 5 - West Dock Landfall

3.5.2 Alternative 1 - No Action

The No Action Alternative represents the case where Northstar Unit development/production would not occur at this time. The remains of Seal Island would continue to erode in accordance with approved abandonment plans. Potential impacts to the physical, biological, and human resources as described in alternatives 2, 3, 4, and 5 would be avoided. Potential significant impacts to marine mammals (bowhead whales and polar bears) and migratory birds (e.g., common, king, and spectacled eiders, and oldsquaws) would be avoided. A nominally estimated 158 million barrels of recoverable reserves from the Northstar reservoir would remain in place and economic benefits to the state, federal government, NSB, and the Municipality of Anchorage (MOA) would not be realized.

3.5.3 Common Elements of the Action Alternatives (2, 3, 4, and 5)

Alternatives 2, 3, 4, and 5 share many common elements. These include: water sources; the gravel source; ice roads for gravel hauling between the gravel mine site and Seal Island; reconstruction of Seal Island designed to withstand water and sea ice forces; installation of island facilities to support drilling and processing; use of buried subsea pipelines for transporting oil and gas; construction techniques for offshore and onshore pipelines (although alignments differ among alternatives); drilling activities; full processing of sales quality crude oil on the island; inspection and maintenance activities that would be carried out during the life of the project; construction seasons; waste water disposal; and abandonment options. The four action alternatives differ in offshore pipeline routes, landfall locations, onshore pipeline routes, and valve station locations. The details described below are from BPXA's proposal (Alternative 2) and are considered applicable to all action alternatives because these components are the same for Alternatives 2, 3, 4, and 5.

3.5.3.1 Proposed Construction Activities

Freshwater Sources for Ice Road Construction: Many of the permitted freshwater sources in the project area are not useable during the winter because they are too shallow and either freeze, or nearly freeze, solid. The Kuparuk Deadarm mine site, located approximately 5 to 6 miles (8 to 9.7 km) up the Kuparuk River, would be the most probable source of freshwater for ice road construction associated with the Northstar Development Project. The Kuparuk Deadarm source is within 3 miles (4.8 km) of BPXA's proposed Northstar gravel mine location in the Kuparuk River Delta and could be accessed by an ice road on the Kuparuk River. Although the Kuparuk Deadarm source has fish in it, it is a deep source that is currently permitted for removal of up to 100 million gallons (378.5 million liters) of water per year. This source is replenished each year during breakup.

Gravel Sources: A new gravel mine site near the mouth of the Kuparuk River is proposed as a source of gravel to reconstruct Seal Island (Figure ES-7). The site is close to Seal Island, minimizing haul distance, in a region of riverine barrens and floodplain alluvium (BPXA, 1997:7.2-1); therefore, little overburden will need to be removed. The mine site would only be used during one winter season and would be rehabilitated to provide shallow and deep water habitat for fish once mining activities have been completed. This location would require construction of an onshore ice road for approximately 2 miles (3.2 km) on the Kuparuk River from the mine site to the river mouth.

Additional, smaller quantities of gravel would be obtained from the existing, permitted Kuparuk Deadarm mine site or the Put 23 mine site near the mouth of the Putuligayuk River for caribou and road crossings (Figure ES-8). These sites could be used as a primary gravel source in the event that the Kuparuk Delta gravel source for island construction could not be permitted or was determined inadequate.

Ice Roads: An ice road would be constructed over sea ice from the West Dock causeway to the mouth of the Kuparuk River, and south through the Kuparuk River Delta to the proposed gravel mine site (Figure ES-8). A second ice road would be constructed from the gravel mine site to Seal Island. Additional ice roads paralleling the onshore pipeline alignment and along existing onshore pipelines would be constructed to assist with onshore pipeline construction activities.

The offshore ice roads would be approximately 200-ft (61 m) wide. Seawater for thickening the offshore ice would be obtained by drilling holes through the existing sea ice and pumping salt water to the surface using specially designed rolligon pumps. The top layer of onshore and offshore ice roads would be made from freshwater. Ice pads would be constructed by the use of snow and spraying freshwater over the surface of the frozen tundra.

Figure ES-6 (Page 1)

Figure ES-6 (Page 2)

Figure ES-7 (Page 1)

Figure ES-7 (Page 2)

Figure ES-8 (Page 1)

Figure ES-8 (Page 2)

Seal Island Reconstruction and Facilities: Approximately 400,000 to 500,000 cubic yards (yd^3) (306,000 to 382,000 cubic meters [m^3]) of existing gravel would be reused at Seal Island. Approximately 700,000 to 800,000 yd^3 (535,185 to 612,640 m^3) of additional gravel would be hauled to the island by ice road. Gravel would be hauled in large volume trucks from the gravel mine site to a temporary stockpile and reload (staging) area inside the barrier islands on bottomfast ice (Figure ES-8). This staging area would be necessary for lighter dump trucks that must be used to transport gravel to Seal Island over floating landfast ice. The dump trucks would deposit loads on the existing Seal Island surface.

Island slopes would be graded and shaped during the subsequent open water season prior to installation of a linked concrete mat armor island slope protection system. The working surface of the island would be a rectangle surrounded on all four sides by sheet piling (Figure ES-9). On the west side of the island, where storms are most intense, the wall would rise to an elevation of 27 ft (8.2 m) above mean lower low water (MLLW)(Figure ES-10). On the east side of the island, the wall would rise to an elevation of 21 ft (6.4 m) above MLLW.

Open-cell sheet pile with a top elevation of 7 ft (2.1 m) above MLLW would be used on the south side of the island for a docking area. The sheet pile wall would be installed between March and May, before the submerged gravel berm is shaped and the concrete mats are placed. A 55- by 62-ft (16.8 by 19 m) platform on the southwest corner of the island would be designated for landing helicopters. A 215-ft (65.5 m) high cantilevered flare tower would be located in the northwest corner of the island.

The process and gas compression modules would be constructed offsite, transported via ocean-going barges, and installed on Seal Island. In addition to these modules, a permanent quarters module, drilling related equipment, and other facilities would be installed on Seal Island. An "artist's rendition" of the completed Seal Island facility showing material colors (gray, beige, rust, natural concrete) is shown in Figure ES-11.

Offshore Pipeline Construction: While pipeline lengths and alignments would differ among Alternatives 2, 3, 4, and 5, construction techniques would be the same. Pipeline segments would be transported by truck to an approximately 5,000 by 750-ft (1,524 by 228.6 m) staging area prepared on the bottomfast ice adjacent to the pipeline corridor. Ice roads and staging areas for Alternative 2, shown on Figure ES-8, would be the same for Alternatives 3, but would be moved eastward to locations along the alternative pipeline routes for Alternatives 4 and 5. Pipeline segments would be welded into 5,000-ft (1,524 m) sections (pipeline strings) at the staging area.

A slot would be cut in the ice along the subsea pipeline route. Blocks of ice would be removed by backhoes and front end loaders would move the ice away from the work site (Figure ES-12). A trench would be excavated in the seafloor for pipeline installation. The trench walls would be vertical in the area of landfast ice (Figure ES-13) and trapezoidal in floating ice areas (Figure ES-14). Trench depth would range from 7 to 9 ft (2.1 to 2.7 m). The bottom of the trench would be cut to the desired final grade by use of a hydraulic excavator, which discharges the excavated spoils back into the trench. Tracked equipment would tow pipeline strings to the side of the trench (Figure ES-15), where they would be welded together and lowered through the opening into the seafloor trench. Backfilling with excavated trench material would be performed concurrently with pipe laying activities. Pipelines would be pressure tested with a glycol/water mixture prior to use.

Offshore Buried Pipelines, Landfall Location: At the landfall the pipelines transition from buried subsea pipelines to aboveground onshore pipelines. At these locations, a gravel pad would be constructed to support the pipelines leak detection equipment and quick closure valves. Except for Alternative 5 on the causeway, the pad would be set back approximately 110 ft (33.5 m) from the shoreline bluff to protect it from coastal erosion, storm surge, and ice override events (Figure ES-16). A gravel berm would also be constructed around the north and west sides of the pad to further protect the facilities from ice override events. For Alternative 2, the pad would be 70 by 135 ft (21.3 by 41 m) which includes a helicopter landing area. For Alternative 3, the valve facilities would be located on a 75 by 75 ft (21.3 by 21.3 m) pad near the intersection with the Point McIntyre pipeline. The pipeline would transition to aboveground in the same manner and location as Alternative 2 at Point Storkersen; however, the Point Storkersen pad would be smaller, approximately 50 by 50 ft (15.2 by 15.2 m). The landfall transition for Alternative 4 would be the same as Alternatives 2 and 3 (Figures ES-16 and ES-17), except it would be located at the alternate site. The gravel pad would need to be approximately 75 by 75 ft (23 by 23 m). The landfall transition for Alternative 5 would occur on an all gravel substrate, otherwise it would resemble Alternatives 3 and 4; the shoreline setback would be approximately 50 ft (15.2 m) from the edge of the causeway.

The trench through the transition zone to the gravel pad would be 8 ft (2.4 m) wide. This allows for backfilling with select material (gravel) around the pipelines. The onshore portion would be finished with a layer of soil and revegetated (not applicable for Alternative 5).

Onshore Pipeline Construction:

VSM and Pipeline Installation: VSM holes would be drilled and the tailings transported to the Put 23 mine site or the newly opened Kuparuk Delta mine site for disposal. VSM assemblies would be set in the holes, and the holes are typically backfilled with sand slurry or foam. Upon completion of VSM installation for segments of the pipeline, joints of line pipe would be transported to the site, strung along the pipeline alignment, and welded together to form a continuous string.

Putuligayuk River Crossing: The Putuligayuk River crossing would be an aboveground crossing that spans the river. VSMs would be used to support the oil pipeline across the span. The support(s) would be installed from the surface of the ice by drilling a hole through the ice and the underlying soil until the required pile length is achieved. The VSMs would be designed to resist the impact forces of ice at breakup..

Valve Stations: Both the oil and gas pipelines would have automated quick closure valves located at Seal Island. At the pipeline landfall, valves similar to those used at Seal Island would be installed in a building on a gravel pad (Alternatives 2 and 4) and on West Dock causeway (Alternative 5). A manually-operated isolation valve would be placed on each side of the Putuligayuk River crossing. A remotely controlled shut-

Figure ES-9 (Page 1)

Figure ES-9 (Page 2)

Figure ES-10 (Page 1)

Figure ES-10 (Page 2)

Figure ES-11 (Page 1)

Figure ES-11 (Page 2)

Figure ES-12 (Page 1)

Figure ES-12 (Page 2)

Figure ES-13 (Page 1)

Figure ES-13 (Page 2)

Figure ES-14 (Page 1)

Figure ES-14 (Page 2)

Figure ES-15 (Page 1)

Figure ES-15 (Page 2)

Figure ES-16 (Page 1)

Figure ES-16 (Page 2)

Figure ES-17(Page 1)

Figure ES-17 (Page 2)

down valve would be located at the end of the oil pipeline at Pump Station No.1. The valves will help to reduce oil spill volumes.

<u>Pig Launching/Receiving Facilities</u>: At the island, pig launching and receiving facilities would be incorporated within the process module and would be permanent. The pig launcher for the gas pipeline at CCP would be installed on a small (170- by 85-ft [51.8 by 25.9 m]) gravel extension of the CCP pad.

3.5.3.2 Proposed Drilling Activities

Well Drilling Program: Initially 23 wells would be drilled: 15 oil producers, 7 gas injectors, and 1 Class I industrial waste disposal well. An additional 14 well slots allow for reservoir uncertainties, infill drilling and an additional waste disposal well, if necessary.

The drilling rig anticipated for use is the Nabors 33E rig. This rig can be broken down into light loads and trucked over floating ice roads, or mobilized by barge. The drilling rig would provide its own power using generators fired by fuel gas imported to the island via the gas pipeline. This source would be used until the processing facilities become operational, and fuel gas would be supplied to the drilling rig by island processing facilities.

Once drilling activities commence, they would continue for approximately 2 to 2.5 years until all planned wells were drilled and completed. For the single season construction schedule, the drilling rig, drilling equipment and materials, and supplies for five wells (the Class I industrial waste disposal well would be drilled first, followed by a gas injector and three oil producers) would be mobilized by barge in September, immediately after sealift of production facilities. It is anticipated that these wells would be drilled during freeze-up, when the island would have to rely on helicopter support for additional material supplies.

For all development wells, there would be a diverter installed for drilling all surface hole sections, and a blowout preventor stack would be utilized for drilling all intermediate and reservoir hole sections. Wells would have subsurface safety valves in the well completion string and have wellhead controls and valving consisting of a master valve (manual), surface safety valve (actuated), wing valve (manual), and swab valve (manual).

3.5.3.3 Proposed Operations/Maintenance Activities

Electrical Power: Once production facilities are operational, base-load power requirements would be approximately 18 megawatts provided by multiple gas-fired turbine generators. Emergency power would be provided by two 2,600-kilowatt diesel generators installed during construction.

Flare: The flare would combust natural gas releases that may result during oil processing (e.g., safety purges of equipment, glycol regenerator), and from equipment being started-up/shutdown for maintenance. The flare tower, which will have both low and high pressure flare tips, will meet State of Alaska opacity requirements, and API 520/521 guidelines would be used for vent system and flare design. The low pressure flare would operate continuously through pilot and feed gas to the system. The high pressure flare would operate only as required. Flaring would not be expected more than 30 days per year.

Pipeline Operations/Maintenance:

Corrosion Protection: Offshore pipelines would be coated with fusion-bonded epoxy to protect against exterior pipeline wall corrosion. In addition, a cathodic protection system would consist of anodes attached to the pipelines to help prevent corrosion along offshore segments of the pipelines.

The onshore oil and gas pipeline would have a polyurethane foam coating to prevent heat loss. Since this would be covered by a protective metal jacket, it requires little maintenance. At road and caribou crossings, pipelines would be coated externally to prevent localized corrosion.

The transported fluids are expected to have low potential for inducing corrosion of the inside pipeline walls (due to low water and sulfur content). Therefore, a corrosion allowance has not been included in the pipeline wall thickness, and an internal protective coating would not be provided.

Leak Detection: The pipeline would be monitored on a continuous basis by the Supervisory Control and Data Acquisition system and operating personnel will be provided real-time information on pipeline status. This system can detect changes in flow rate to 0.15% of daily flow volume. To obtain early warning of potential leak points or pipeline deformation, pipelines would be checked periodically by inspection pigs which can detect changes in wall thickness and geometry.

Visual surveys would be performed to detect chronic leaks below the threshold of the leak detection system. Weekly aerial surveillance would be performed during the summer over the offshore and onshore pipeline routes to visually detect oil spills. In the winter, holes would be drilled through the ice over the pipeline to search for evidence of hydrocarbon that could have entered the marine environment through a pipeline leak. The oiled area would then be delineated by drilling additional holes through the ice. Some onshore pipelines would be inspected visually from existing roads along pipeline right-of-ways. Response to small and large leaks will be described in the operator's Oil Discharge Prevention and Contingency Plan which will be prepared prior to project operations.

Pigging: Pigging would be performed to measure wall thicknesses; determine pipeline geometry; assess any mechanical damage; clean and remove any paraffin, scale, and sediment buildup; and distribute any pipeline corrosion inhibitor, if necessary. Table 4-10 provides details of the proposed pig runs.

For the purpose of performing the pigging activities, the oil pipeline would have pig launching facilities at Seal Island and receiving facilities at Pump Station No. 1. The gas pipeline would have a pig launcher installed onshore at the gas supply point, and the pig receiver would be located on Seal Island. Transportation of the pigs and the necessary supplies to and from the island would be part of the routine island supply.

Pipeline Repairs: Repairs to the onshore pipeline can be accomplished year-round. During summer, repairs can be accomplished using rolligons and by helicopter. Repairs to the onshore pipeline during winter would be undertaken using rolligons, helicopters, and if necessary, along ice roads. The complexity of performing repairs to the offshore pipelines increases with water depth. Pipeline damage caused by internal or external corrosion or external forces would require pipeline excavation, and replacement or repair of pipe segments using underwater divers, welding, and pressure testing equipment. Repair operations would be carried out from a locally available barge in the summer. Winter repair activities would be performed from the ice surface using techniques and equipment similar to those used during construction. Performance of repairs may be difficult or impossible during freezeup or breakup due to unsafe conditions for personnel. In this situation, the damaged pipeline would be closed by isolation valves until repairs could be made.

3.5.3.4 Solid Wastes and Water Discharges

Excess trench spoils would be disposed of immediately north of the barrier islands in water depths greater than 5 ft (1.5 m). Figure ES-18 shows spoils disposal sites for Alternatives 2 and 3; for Alternatives 4 and 5, disposal sites would be similar (equal to or greater than 5 ft [1.5 m] water depths and outside the barrier islands) but along the more eastward pipeline route. Material stored in the disposal area would be flattened to an average height of 1-ft (0.3 m) to prevent creation of a mound on the seafloor. Maximum height of individual features would not exceed 2 ft (0.6 m). Some residual trenched material, less than 3 ft (1 m) deep also may be disposed in an area along the west side of the offshore trench where water depths are greater than 5 ft (1.5 m).

Domestic, drilling, and/or sanitary wastes generated during drilling activities would be either stored on-site until permanent island disposal facilities are in operation, or backhauled to existing waste disposal facilities onshore. Once the Class 1 industrial waste disposal well has been drilled and completed, and a cuttings grind and inject well installed on the island, drilling muds and cuttings would be disposed of via the Class I industrial waste disposal well. Under no circumstances would drilling muds and cuttings be discharged to the marine environment.

Proposed operational discharges to marine waters are summarized below by outfall identifier, and include:

- Outfall 001 - Commingled outfall from: 001(a) - continuous flush system, 001(b) - brine effluent associated with the potable water system, 001(c) - effluent from the domestic/sanitary wastewater treatment system (temporary marine discharge during periods when the Class I waste disposal well is not available).

- Outfall 002 - Seawater discharged through fire suppression system during annual tests.

- Outfall 005 - Dewatering discharge from construction of seawater intake and outfall lines due to seepage through subsea gravel.

Except for Outfall 005, the source of water feeding these operational outfalls would be seawater collected through a seawater intake system. Seawater from the intake system would be utilized by various facility operations. Table ES-6 provides additional details for the above outfalls, including: flowrates, temperatures, pH, salinity, biochemical oxygen demand, total suspended solids, total residual chlorine, turbidity, sediments, toxics, and fecal coliforms.

3.5.3.5 Construction Schedule

The project could be constructed during either a single winter season or a two winter season program. A two-season program, in which only island reconstruction is done the first year, would reduce logistical problems. As a result of permit scheduling and/or other factors external to the project, a single season construction schedule may be required. In a single season construction schedule, all major construction activities, including island construction, onshore and offshore pipeline installation, and island infrastructure and module installation/hookup would occur in one year. The exception to this would be the installation of road and caribou crossings which would occur prior to the start of island construction activities. It should be noted that the gravel haul for island construction and pipeline installation would be carried out during the winter, regardless of construction program. Table ES-7 presents a likely scenario for a single-season construction schedule, and Table ES-8 presents a likely scenario for a two season construction schedule.

3.5.3.6 Abandonment Activities

BPXA will be required to develop a Northstar Unit development/production facilities Abandonment Plan when the reservoir is depleted. The abandonment plan will require approval by the Corps, the Alaska Department of Natural Resources, and MMS before implementation. The plan would include an assessment of the environmental consequences of the abandonment activities.

Abandonment activities would take several months to complete and could involve a range of scenarios. Two likely scenarios are: 1) removal of all facilities associated with Northstar Unit Development, including Seal Island slope protection, island infrastructure, and onshore and offshore pipelines; and 2) abandonment of all island infrastructure, onshore pipeline removal, and offshore pipelines removed or abandoned in place, leaving Seal Island in place for possible reuse. Reuse of the pipelines by other projects could eliminate the need for additional pipelines to existing onshore facilities. Seal Island also could be used for non-oil and gas activities such as a staging camp for local residents for subsistence hunting (e.g. seals and bowhead whales), a research facility, or part of the expanding tourism industry.

3.5.4 Alternative 2 - Point Storkersen Landfall/BPXA's Proposed Action

Alternative 2 includes a pipeline alignment straight from Seal Island to landfall near Point Storkersen (Figure ES-19). A gravel pad would be constructed approximately 110 ft (33.5 m) from the shoreline bluff. The onshore oil pipeline follows a fairly direct path from Point Storkersen to Pump Station No. 1. The natural gas supply line from the CCP would parallel existing pipelines to the vicinity of Dead Chicken Lake and then

Figure ES-18 (Page 1)

Figure ES-18 (Page 2)

parallel the oil line north to Seal Island. More detailed pipeline corridor information for Alternative 2 is presented in Table ES-9.

This alternative has no permanent road access to the pipeline or the valve station pad at the landfall. Surface access would be provided by soft tired vehicles and/or helicopters. In order to provide quick access to the valve station, the gravel pad would be sized (70- by 135-ft [21.3 by 41 m]) to accommodate helicopter landings. A gas-fired generator on this pad would receive its fuel from a tap off the gas line going to Seal Island. The generator would charge a battery bank which would power all instrumentation for leak detection and monitoring, communications, and automated valve status and control. The battery bank would be sized to provide up to 15 days of power should the generator be off line. The actuated shut-in valves for the oil and

gas pipelines would be fail safe (i.e. requires power to keep them open, with a spring return to close the valve in the event of power failure). These facilities would be contained within a small protective enclosure.

3.5.5 Alternative 3 - Point Storkersen Landfall to West Dock Staging Pad

Alternative 3 also includes a pipeline alignment straight from Seal Island to landfall near Point Storkersen (Figure ES-20). The buried subsea pipeline would transition to aboveground pipelines in the same manner and location as that described for Alternative 2. A small gravel pad, approximately 50 by 50 ft (15.2 by 15.2 m) in size, surrounded by a protective gravel berm, would be constructed to accommodate transition from subsea to aboveground. From this point the oil and gas pipeline corridor turns east until it intersects the existing pipeline corridor between drill pad Point McIntyre 1 (PM1) and the West Dock Staging Pad. A check valve would be placed in the oil line at the landfall, and a small gravel valve pad (75 by 75 ft [23 by 23 m]) would be constructed adjacent to the point of intersection with the existing pipeline corridor between PM1 and the West Dock Staging Pad. Quick closure, automated valves and instrumentation at this pad would be powered by electricity from the existing onshore power grid.

The oil and gas pipelines then parallel the existing pipeline corridor to the West Dock Staging Pad, where they turn south following an existing pipeline and roadway corridor to the CCP. The gas pipeline terminates at the CCP. The oil pipeline continues from the CCP to Pump Station No. 1 via a combination of existing and new pipeline and/or roadway corridors. More detailed pipeline corridor information for this alternative is presented in Table ES-10. Access to all but 6.7 miles (10.8 km) of the Alternative 3 onshore pipeline is possible year-round from existing roads.

Freshwater sources for ice road construction may vary from those for Alternative 2 (they would parallel the new pipeline alignments). Volume of freshwater needed for ice roads differs from Alternative 2 (see footnote in Table ES-10). Since the onshore pipelines are longer, construction time or manpower would be greater than for Alternative 2 (Table ES-11).

Table ES-6 (Page 1)

Table ES-7 (Page 1)

Table ES-7 (Page 2)

Table ES-8 (Page 1)

Table ES-8 (Page 2)

Figure ES-19 (Page 1)

Figure ES-19 (Page 2)

Table ES-9 (Page 1)

Table ES-10 (Page 1)

Figure ES-20 (Page 1)

Figure ES-20 (Page 2)

Table ES-11 (Page 1)

3.5.6 Alternative 4 - Point McIntyre Landfall to West Dock Staging Pad

Alternative 4 includes the same offshore pipeline corridor from Seal Island as does Alternatives 2 and 3 until it reaches the southern boundary of the Northstar Unit (Figure ES-21). The offshore corridor then turns southeast toward West Dock, staying north of Stump Island in water depths between 5 and 12 ft (1.5 and 3.6 m). As the corridor approaches West Dock at the east end of Stump Island, it turns in a southwest direction, making landfall approximately midway between PM1 and the West Dock Staging Pad. A small gravel pad (75 by 75 ft [23 by 23 m]) would be constructed approximately 110 ft (33.5 m) from the shoreline bluff near an existing pipeline that extends between PM1 and West Dock Staging Pad to accommodate the buried subsea pipeline transition to aboveground. The valves and instrumentation on this pad would be powered by the existing onshore power grid.

The oil and gas pipelines then would parallel the Point McIntyre pipeline corridor to the West Dock Staging Pad. From the West Dock Staging Pad, the pipelines are routed to the CCP and on to Pump Station No. 1, the same as described for Alternative 3. More detailed pipeline corridor information for this alternative is presented in Table ES-12. Access to the entire onshore pipeline for Alternative 4 is possible year-round from existing roads. The valve station also is accessible by permanent road.

The onshore and offshore pipeline alignments would also require that ice road lengths and locations differ from those presented for Alternatives 2 and 3 (they would parallel the new onshore and offshore pipeline alignments). Freshwater sources for ice road construction may vary from those described for Alternatives 2 and 3 (see footnote in Table ES-12). In addition, offshore pipeline staging areas and trench spoils disposal areas would be relocated along the offshore pipeline alignment. Since the offshore and onshore pipeline alignments are longer, construction time or manpower would be larger than those presented for Alternatives 2 and 3 (Table ES-11).

3.5.7 Alternative 5 - West Dock Landfall

Alternative 5 includes the same offshore pipeline corridor from Seal Island as Alternative 4, to the eastern end of Stump Island where it continues in a straight line to West Dock (Figure ES-22). Although landfall could theoretically be anywhere on the West Dock causeway, it is shown at Dock Head 2. The oil and gas pipelines then transition to aboveground approximately 40 to 50 ft (12.2 to 15.2 m) from the edge of the causeway, paralleling the causeway to the West Dock Staging Pad. From the West Dock Staging Pad, the pipelines are routed to the CCP and on to Pump Station No. 1 the same as described for Alternatives 3 and 4. More detailed pipeline corridor information for this alternative is presented in Table ES-13. Access to the entire onshore pipeline for Alternative 5, and the valve station is possible year-round from existing roads and the causeway.

This alternative would require approximately 290,000 to 300,000 yd^3 (221,700 to 229,400 m^3) of gravel fill material to be placed along the west side of the West Dock causeway to widen it by approximately 50 ft

Table ES-12 (Page 1)

Figure ES-21 (Page 1)

Figure ES-21 (Page 2)

Figure ES-22 (Page 1)

Figure ES-22 (Page 2)

Table ES-13 (Page 1)

(15.2 m) between the landfall and the West Dock Staging Pad, a distance of approximately 0.9 miles (1.5 km). This fill would accommodate a valve pad (75 by 75 ft [23 by 23 m]) and VSMs for the oil and gas pipelines. This additional width is necessary because of conflicts with existing pipelines and cables.

The West Dock landfall does not require the 110-ft (33.5 m) shoreline bluff setback because the area is protected from ice override by the causeway. The site also does not require pipeline bedding backfill at the landfall or revegetation of disturbed tundra. The onshore and offshore pipeline alignments would require different ice road lengths and locations than Alternatives 2, 3, and 4 (they would parallel the new onshore and offshore pipeline alignment). Freshwater sources for ice road construction also differ from Alternatives 2, 3, and 4 (see footnote in Table ES-13).

4.0 SUMMARY AND COMPARISON OF ALTERNATIVES

This section presents a summary of each project alternative as well as a comparison of the environmental impacts associated with each alternative (Table ES-14). Two types of impacts are being considered in this summary -- those due to routine operations (e.g. noise, erosion, etc.) which are expected to occur, and those due to accidental events (e.g. large oil spill) which are possible but unlikely to occur.

To communicate clearly the results of the environmental impact analysis presented in this document, standard terminology is used consistent with CEQ NEPA regulations (40 CFR 1508.27). In this document, impacts are defined as those changes to the existing environment that have either a beneficial or adverse consequence as a result of project construction, operation, maintenance, or abandonment activities. Impacts are described in terms of frequency, duration, general scope and/or size, and intensity. The combinations of frequency, duration, scope/size, and intensity of identified adverse impacts are described as follows:

- None - (no change) No impacts are anticipated when subject resources are not present or activities are not expected to affect those resources that are present.

- Negligible - Impacts on subject resources may occur as a result of project activities, but are not measurable.

- Minor - Impacts that have a measurable effect, and individually may or may not require avoidance or minimization to mitigate that effect, as determined by the responsible agency.

- Significant - As described in the CEQ regulations, significant impacts are to be considered both in context and intensity. These impacts have a measurable effect and, individually or cumulatively, require avoidance or minimization to mitigate the effect.

Table ES-14 (Page 1)

Table ES-14 (Page 2)

Table ES-14 (Page 3)

Table ES-14 (Page 4)

Table ES-14 (page 5)

The assessment of potential impacts of oil spills on physical, biological, and human resources is based on the assumed occurrence of several events, none of which are certain to occur. This system employs a type of worst-case analysis. The assumptions for this analysis include:

- An oil spill greater than 1,000 barrels will occur.
- The oil spill occurs during the season each specific resource is present, or is most susceptible to adverse effects (or an earlier spill was not effectively cleaned up or sufficiently weathered to prevent resource impact).
- The spilled oil contacts the resource of concern.
- Oil spill response efforts are not considered to reduce the impact of the spill on each resource of concern.

The potential impacts to polar bears, sea ducks, and spectacled eiders represent reasonable estimates for this type of analysis and do not reflect the upper limit for injury and mortality in the event of a spill much larger than 1,000 barrels.

4.1 ALTERNATIVE 1 - NO ACTION

The No Action Alternative would not produce any of the project-specific impacts which result from the action alternatives. This alternative would leave Seal Island in its present condition, and no environmental disturbance associated with island reconstruction and related onshore gravel mining operations would occur. Impacts associated with Northstar offshore facilities operation or the construction and operation of related pipeline facilities would not occur. This alternative would not accomplish BPXA's project objective of producing the Northstar Unit oil and gas resources, which have been projected at 158 million barrels of recoverable oil over the 15-year project life. The No Action Alternative would not contribute any of the socioeconomic benefits associated with the action alternatives. These benefits include an estimated $478.9 million gross revenue to the State of Alaska, $306.3 million in federal revenue, $64.3 million in revenue to the NSB, $3 million in revenue to the MOA over the project life, 730 construction jobs, 100 annual operation and project support jobs, and over $307 million in wages.

In addition to action-specific impacts, NEPA requires the consideration of potential cumulative impacts. As defined by 40 CFR 1508.7, cumulative impacts include the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions. Alternative 1 (No Action) would not contribute to any incremental increase to the cumulative impact of other actions. However, none of the cumulative impacts identified would be avoided by selection of Alternative 1. Alternatives 2, 3, 4, and 5 would each result in comparable contributions to the cumulative impacts of other actions, which include:

- Cumulative impacts from other offshore development proposals on subsistence whaling caused by bowhead whale avoidance of industrial noise and resulting potential migration corridor deflection. This potential effect could result in longer travel distances and increased time requirements to achieve a comparable catch, with an increased likelihood of meat spoilage. Whaling is inherently hazardous, and increased time and travel distances correspond to increased personal safety risks. In addition, any increased impact on or risk to the bowhead whale population could result in a reduction of the bowhead whale harvest quota set by the International Whaling Commission (IWC). The contribution to this cumulative effect associated with offshore seismic survey activities could be effectively reduced by management of this activity to avoid whale disturbance.

- Existing and potential future offshore oil and gas development (state and federal) was estimated to result in a 95.2 percent chance of a large spill (greater than 1,000 barrels). Without Northstar, cumulative spill risk is calculated as 93.7 percent.

- Cumulative impacts to visual resources associated with increased industrialization in natural areas and addition of artificial lighting in a broader geographic area.

- Cumulative impacts to land use associated with the geographic expansion of industrial operations beyond the existing developed Prudhoe Bay/Kuparuk area, and the intensification of operations in developed areas.

- Cumulative revenue decline associated with a projected decline in North Slope oil production from a 1995 level of 1.45 million barrels per day to 0.384 million barrels per day by the year 2015. Expanded production from existing development and known fields over this period has been estimated to deliver up to 6.47 billion barrels from 1997 to 2020, which would not fully offset the projected decline. The Northstar Unit development would contribute to this partial offset, and would represent approximately 2.4 percent of the total oil production during the project life.

4.2 ALTERNATIVE 2 - POINT STORKERSEN LANDFALL/BPXA PROPOSAL

Alternative 2, the BPXA preferred alternative, would result in several direct impacts that distinguish it from the other identified alternatives (Table ES-14). Construction costs associated with this alternative are the lowest of all action alternatives (Table ES-15) (total construction cost of approximately $405 million, which includes between $52.8 and $73.48 million estimated cost associated with pipeline and ice road construction). Impacts common to Alternative 2 and all other action alternatives (Alternatives 3, 4, and 5) include the following:

- Addition of visible lighting in an offshore area, and contribution to cumulative visual impacts associated with predicted increased offshore development.

Table ES-15 (Page 1)

- Project-related impact on subsistence whaling caused by bowhead whale avoidance response to noise generated at Seal Island and project-related vessel and helicopter noise and activity. This response to noise is subject to disagreement among experts, but reports of whale avoidance of similar noise and activity suggest that bowhead whale avoidance of the Seal Island area to 6 miles (9.6 km) could occur under unusually quiet conditions during their migration through this area. This avoidance is considered significant to subsistence harvesting because it could expose whalers to increased hazards associated with having to travel greater distances from shore and spending more time at sea. It would also increase the likelihood of meat spoilage and, should increase risk to whales be perceived by the IWC, the subsistence harvest quota could be reduced. However, significant long-term displacement of bowhead whales is not expected to occur as a result of Northstar operations.

- The number and timing of offshore helicopter overflights during construction would result in significant impacts to common eiders and oldsquaw.

- Potential volumes of a large oil spill associated with Northstar Unit development and production facilities, including 15,000 barrels per day for 15 days from a well blowout, and a total of 2,800 barrels from a Seal Island diesel tank rupture (single discharge). Potential oil spill volumes associated with pipelines vary by alternative, and are addressed separately.

- Within a 3-day period following a spill event, marine resources located within approximately 12 miles (19.3 km) of Seal Island, have a higher than

3% probability of contact; beyond about 50 miles (80 km) from Seal Island, probability of contact with oil (up to 180 days after a large spill) is generally much less than 10%.

- Possible contact of 100 miles (160 km) of the coast within 3 days by a large oil spill if response actions not taken.

- The calculated total probability of one or more large oil spills (greater than 1,000 barrels) from any source is approximately 11% to 24% over the 15-year project life.

- Minor contribution to the cumulative probability (95.2%) of a large oil spill (greater than 1,000 barrels) over the project lifetime. The Northstar Unit production would represent 2.4% of the cumulative oil production during the project life, and represents an increased cumulative risk which is less than the uncertainty inherent in this calculation. For this reason, the cumulative spill risk associated with Alternative 2 is considered the same as the ongoing risk associated with the No Action Alternative.

- Project-related socioeconomic benefits over the project life include contribution of $478.9 million revenue to the State of Alaska, $306.3 million in federal revenue, $64.3 million in revenue to the NSB, and $3 million to the MOA. Additional socioeconomic benefits include 730 construction jobs, 100 annual operation and project support jobs, and total wages of over $307 million. This project would contribute 2.4% of the total projected North Slope oil production during the 15-year project life, and would reduce the projected rate of production decline and associated decline in state and NSB revenues.

Alternative 2 would also result in several impacts which distinguish it from one or more of the other action alternatives. These impacts are:

- The offshore pipeline route is directly through Gwydyr Bay and the nearshore lagoon system (common impact with Alternative 3, but not common with Alternative 4 or 5). In the unlikely event of an oil spill, this route would limit the effectiveness of booming to protect the lagoon habitat from oil contamination.

- Oil spill response equipment would be staged at West Dock. In the event of an oil spill, response time to the nearshore pipeline for Alternative 2 (common with Alternative 3) would be greater than for Alternatives 4 and 5.

- Pipeline landfall issues (common impact with Alternatives 3 and 4, but not common with Alternative 5) include a concern that trenching across the shoreline transition zone could result in local thaw bulb creation and associated subsidence and instability. An additional concern regarding a trenched shoreline crossing is the possibility of local erosion. Both these concerns (subsidence and erosion) could represent a hazard to pipeline integrity. This may require increased monitoring and maintenance and may pose an increased risk of pipe failure and resulting oil spill, as compared to a causeway shoreline crossing, such as in Alternative 5.

- Contribution to cumulative land use impacts by establishing a new industrial corridor from Point Storkersen which could facilitate the development of the Gwydyr Bay area. This impact would also result from Alternative 3. Alternatives 1, 4, and 5 would not facilitate development in the Gwydyr Bay area.

- The onshore pipeline route from Point Storkersen to Pump Station No. 1 traverses 9.55 miles (15.37 km) of undeveloped tundra in a roadless area. This pipeline route would add an industrial facility across a large area of presently undisturbed wildlife habitat. The pipeline itself does not represent a significant biological impact, but routine inspections by helicopter could cause disturbances to several species of wildlife. Also of concern is the potential damage associated with equipment and personnel access to the pipeline in response to unplanned maintenance or an oil spill during the summer.

- Project-specific impacts and contribution to onshore cumulative visual impacts by geographic expansion and intensification of industrial development, including the addition of a 9.55-mile (15.37 km) pipeline route across an undeveloped area. Though other action alternatives also contribute to the cumulative visual impact, Alternative 2 represents the greatest contribution due to the onshore pipeline route.
- The calculated maximum volumes of potential oil spills associated with Alternative 2 pipelines include: 3,600 barrels from an offshore pipeline rupture, 6,400 barrels from an onshore pipeline rupture, and 6,600 barrels

from an offshore or onshore chronic pipeline leak. Potential volumes from pipeline spills associated with this alternative are the least of all action alternatives. Other potential volumes from a spill are identical for all action alternatives.

- The probability of one or more pipeline spills greater than 1,000 barrels is 4.5% to 19%. These calculated probabilities do not reflect concerns related to permafrost thawing at the trenched shoreline crossing, which may increase the risk of pipe failure and oil spillage in this area. No statistics are available to calculate spill probabilities associated with this site-specific hazard. A similar site-specific hazard and related spill risk is associated with Alternatives 3 and 4.

4.3 ALTERNATIVE 3 - POINT STORKERSEN LANDFALL TO WEST DOCK STAGING PAD

Alternative 3 includes the same offshore facility (reconstruction of Seal Island) and the same offshore pipeline route (including the Point Storkersen landfall) as discussed for Alternative 2. The onshore pipeline route, however, is directed eastward from Point Storkersen and traverses approximately 3.6 miles (5.8 km) of undeveloped land prior to reaching existing pipeline corridors and roadways in the Prudhoe Bay industrial complex. The remainder of the pipeline mostly follows existing roadways and pipeline corridors to Pump Station No. 1. This alternative involves a total construction cost of approximately $415 million, including pipeline and ice road construction costs of between $57.44 and $83.52 million. Offshore and landfall related impacts of this alternative would be identical to those described for Alternative 2, but onshore impacts would be reduced (Table ES-14). Additional features of this alternative which distinguish it from other alternatives include:

- The offshore pipeline route is directly through Gwydyr Bay and the nearshore lagoon system (common impact with Alternative 2, but not common with Alternative 4 or 5). In the unlikely event of an oil spill, this route would limit the effectiveness of booming to protect the lagoon habitat from oil contamination.

- Oil spill response equipment would be stated at West Dock. In the event of an oil spill, response time to the nearshore pipeline for Alternative 3 (common with Alternative 2) would be greater than for Alternatives 4 and 5.

- Impacts related to unplanned maintenance access to the Point Storkersen landfall during the summer and potential landfall subsidence and erosion hazards described for Alternative 2 would also apply to this alternative. These concerns do not apply to Alternatives 1 and 5.

- Contribution to cumulative land use impacts by establishing a new industrial corridor to Point Storkersen which could facilitate future development in the Gwydyr Bay area. This impact could also result from Alternative 2. Alternatives 1, 4, and 5 would not facilitate development in the Gwydyr Bay area.

- The onshore pipeline route from Point Storkersen to the existing pipeline and roadway corridor to the east would cross 3.6 miles (5.8 km) of undeveloped land in a roadless area. An additional overland segment approximately 3.1 miles (5 km) long is located in the southern portion of this pipeline route, but this area is in a developed industrial area within 1.5 miles (2.4 km) of existing roads and is not expected to result in impacts comparable to the other open land pipeline corridors. The 3.1-mile (5 km) southern segment is also part of Alternatives 4 and 5.

- Wildlife disturbance from pipeline inspection helicopter overflights would occur along the 6.7-mile (10.7 km) route in undeveloped habitat. This represents less undeveloped tundra habitat disturbance than Alternative 2, and greater disturbance than Alternatives 1, 4, and 5.

- Project-specific impacts and contribution to onshore cumulative visual impacts by geographic expansion and intensification of industrial development, including the addition of a 3.6-mile (5.8 km) long pipeline segment which would extend the onshore industrial development approximately 2.7 miles (4.3 km) west of the existing Prudhoe Bay developed area. This impact would be less substantial than that associated with Alternative 2, due to the shorter length of pipeline in undeveloped areas and proximity to existing development, but represents greater visual impact than that associated with Alternatives 4 and 5.

- The calculated maximum volumes of potential pipeline spills include: 3,600 barrels from an offshore pipeline rupture, 8,700 barrels from an onshore pipeline rupture, 6,600 barrels from on offshore chronic pipeline leak, and 8,900 barrels from on onshore chronic pipeline leak. Potential offshore pipeline spill volumes are comparable to Alternative 2, and less than Alternatives 4 and 5. Potential onshore pipeline spill volumes are the greatest of all alternatives.

- The probability of one or more pipeline spills greater than 1,000 barrels is 5.6% to 19%. These probabilities do not reflect the concern regarding permafrost thawing at the trenched shoreline crossing which may increase the risk of pipe failure and resulting oil spillage. Considering the level of uncertainty inherent in spill risk calculations, the calculated risk of an oil spill associated with this alternative should not be viewed as substantially different than the risk associated with Alternatives 2, 4, or 5.

4.4 ALTERNATIVE 4 - POINT MCINTYRE LANDFALL TO WEST DOCK STAGING PAD

Alternative 4 includes the same offshore facility (reconstruction of Seal Island) as Alternatives 2, 3, and 5, but incorporates a different offshore pipeline route, a different landfall location (near Point McIntyre), and an onshore pipeline route which is located entirely within the existing Prudhoe Bay industrial complex. This alternative involves a total construction cost of approximately $413 million, including pipeline and ice road construction costs of between $54.37 and $81.3 million. Offshore impacts associated with construction and normal operations would be comparable to Alternatives 2, 3, and 5. The pipeline landfall involves a trenched shoreline crossing, and involves the same concerns regarding hazards, repeated maintenance, and possible spill risk associated with permafrost thaw bulb subsidence and shoreline erosion as discussed in relation to Alternatives 2 and 3. Additional features of this alternative which distinguish it from other alternatives include:

- The offshore pipeline route mostly avoid Gwydyr Bay, except for that portion off the eastern end of Stump Island to the shoreline landfall (not common with Alternative 2, 3, or 5). In the unlikely event of an oil spill, this route would limit the effectiveness of booming to protect the lagoon habitat from oil contamination.

- Oil spill response equipment would be staged at West Dock. In the event of an oil spill, response time to the nearshore pipeline for Alternative 4 (common with Alternative 5) would be less than for Alternatives 2 and 3.

- Although the trenched shoreline crossing could require repeated maintenance associated with shoreline erosion and thaw-related subsidence, the proximity of the Point McIntyre landfall site to existing roadways substantially reduces potential access-related damage associated with repeated maintenance at the landfall site. The overall onshore impact from Alternative 4 would be less than that of Alternative 2 or 3. Similar impacts are not associated with Alternatives 1 and 5.

- This alternative would not facilitate the development of the Gwydyr Bay area through the westward extension of the industrial pipeline corridors.

Alternatives 2 and 3 could facilitate Gwydyr Bay development; however, Alternative 5 does not.

- Onshore visual impacts would be minimized by routing the onshore pipeline within an existing industrial area.

- Helicopter overflights along the onshore pipeline route would be less likely to disturb wildlife than Alternatives 2 and 3 because the route is in an existing industrial area. Alternative 5 represents a comparable, access-related advantage.

- The location of the onshore pipeline within an existing industrial area in proximity to roadway access reduces access-related damage associated with unplanned pipe maintenance and spill response during the summer. Alternative 5 represents a comparable access-related advantage.

- The calculated maximum volumes of potential pipeline spills include: 5,300 barrels from an offshore pipeline rupture, 6,800 barrels from the onshore pipeline rupture, 8,200 barrels from on offshore chronic pipeline leak, and 7,000 barrels from an onshore chronic pipeline leak. This alternative involves the greatest potential volume of spillage from the offshore pipeline, and potential onshore pipeline spill volumes comparable to Alternatives 2 and 5.
- The probability of one or more pipeline spills greater than 1,000 barrels is 5.5% to 19%. This alternative involves similar concerns regarding permafrost thaw bulb subsidence and shoreline erosion at the landfall site as

discussed for Alternatives 2 and 3. Alternative 5 would avoid this risk of pipeline damage associated with permafrost thaw bulb subsidence and shoreline erosion.

4.5 ALTERNATIVE 5 - WEST DOCK LANDFALL

Alternative 5 includes the same offshore facility (reconstruction of Seal Island) as Alternatives 2, 3, and 4, and follows an offshore pipeline route nearly identical to Alternative 4. Instead of crossing a natural shoreline in a pipeline trench, however, this alternative would be routed to a location on West Dock free of permafrost (typically at a water depth greater than 6.5 ft [2.0 m]), as determined by site-specific geotechnical data). The pipeline would be installed on a widened, filled causeway, and would cross the natural shoreline buried within this fill. The pipeline landfall would be within the gravel fill of the widened West Dock causeway and, once through the riser, would continue aboveground on VSMs to the onshore elevated, pipeline facilities. From the West Dock Staging Pad, the onshore pipeline route would follow the same route as Alternatives 3 and 4. The shoreline crossing on the West Dock causeway and elimination of the Alternative 4 pipeline segment from Point McIntyre to the West Dock Staging Pad are the only differences between this alternative and Alternative 4. Alternative 5 involves the most costly construction, with a total construction cost of approximately $418 million (including between $58.07 and $86.58 million associated with pipeline and ice road construction). Widening of the causeway itself would cost approximately $5.7 million. Offshore impacts of construction and normal operations are comparable to Alternatives 2, 3, and 4. The distinguishing characteristics of Alternative 5 include:

- The offshore pipeline route completely avoids Gwydyr Bay and the nearshore lagoon system. In the unlikely event of an oil spill, Gwydyr Bay could be protected from oil contamination by booming off the lagoon (i.e., placing oil containment booms between West Dock and Stump Island, and between Stump and Egg Islands).

- Oil spill response equipment would be staged at West Dock. In the event of an oil spill, response time to the nearshore pipeline for Alternative 5 (common with Alternative 4) would be less than for Alternatives 2 and 3.

- Alternative 5 would require the widening of the West Dock causeway by the addition of fill. This will cause approximately 5.5 acres (2.2 hectares) of the shallow, previously disturbed seafloor adjacent to the causeway to be covered, which would be considered a minor impact. If this fill activity occurs during summer, temporary water quality impacts would occur that are not associated with the other three action alternatives. Because this fill placement involves the widening of an existing causeway, and the existing causeway breach would not be affected, no impact on local water circulation is expected. Although the shoreline crossing associated with this alternative is different than the other three action alternatives, local water quality effects of this alternative are relatively minor and do not distinguish Alternative 5 from other action alternatives.
- Pipeline landfall on a solid-fill causeway eliminates the permafrost thaw bulb subsidence hazard and shoreline erosion hazard common to all other action alternatives. This represents an advantage in terms of reduced risk of

pipeline damage that could result in an oil spill, and elimination of maintenance activity in a natural shoreline area.

- This alternative would not facilitate the development of the Gwydyr Bay area through the westward extension of industrial pipeline corridors. Alternatives 2 and 3 facilitate Gwydyr Bay development, but Alternative 4 would not.

- Onshore visual impacts would be eliminated by routing the onshore pipeline within an existing industrial area.

- Helicopter overflights along the onshore pipeline route would be less likely to disturb wildlife than Alternatives 2 and 3, because the entire route is in an existing industrial area. Pipeline inspection by vehicle would be accommodated by existing roadway access along this route. Alternative 4 represents a comparable access-related advantage.

- Location of the onshore pipeline entirely within an existing industrial area and in proximity to roadway access reduce access-related damage associated with unplanned pipe maintenance and spill response during the summer. Alternative 4 represents a similar advantage.

- The calculated maximum volumes of potential pipeline oil spills include: 5,200 barrels from an offshore pipeline rupture, 6,700 barrels from an onshore pipeline rupture, 8,100 barrels from an offshore chronic pipeline leak, and 6,900 barrels from an onshore chronic pipeline leak. These volumes are comparable to the spill volumes associated with Alternative 4, and involve greater potential volumes of spillage from the offshore pipeline than those associated with Alternatives 2 and 3.

- The probability of one or more pipeline spills greater than 1,000 barrels is 5.4% to 19%. Concerns related to permafrost thawing at the shoreline crossing and associated spill risk which are common to Alternatives 2, 3, and 4 are eliminated with this alternative.

4.6 COMPARATIVE IMPACTS OF ALTERNATIVES

The principal differences among alternatives are discussed in relation to specific impacts below. Impacts include both those due to expected general operations of the project and those due to accidental events which are probabilistic (such as large oil spills) and may not occur. Unless otherwise indicated below, Alternative 1 would not result in the impacts discussed.

4.6.1 Shoreline Landfall Issues

Alternatives 2, 3, and 4 all include pipeline landfall sites at natural shorelines. The installation of a buried sea floor pipeline in an excavated trench across the permafrost transition zone could result in local thaw bulb creation and associated subsidence. Such subsidence could result in increased maintenance requirements at the landfall site, including the addition of fill to maintain the shoreline. Repeated maintenance activities could result in repeated disturbances of local vegetation and increase local erosion. Stresses on the pipeline caused by subsidence could also increase the risk of pipe failure and a resulting oil spill. The magnitude of this increased risk and its potential effect on the total probability of a major oil spill associated with Alternatives 2, 3, and 4 cannot be calculated with presently available data. Alternative 5 does not involve pipeline installation across a natural shoreline, and these related impacts would not occur.

4.6.2 Maintenance Impacts on Vegetation

Impacts associated with routine maintenance activities would differ among the alternatives. Alternative 2 is expected to result in the greatest routine maintenance impact, primarily as a result of potential overland access to the 9.55-mile (15.37 km) overland pipeline segment in a presently inaccessible area. Access to this pipeline during summer months could result in damage to native vegetation well beyond the immediate vicinity of the pipeline. Alternative 3 would result in similar potential disturbances along the 3.6-mile (5.8 km) pipe segment from Point Storkersen to existing oil facility roadways, but access in this area could be confined to the pipeline route itself. Alternatives 3, 4, and 5 all include a 3.1-mile (5 km) onshore pipeline segment on currently undeveloped land, but this segment is within the existing industrial area and intersects existing roadways at either end. For this reason, access to this pipeline segment could be confined to the pipeline corridor, and is not expected to result in substantial routine maintenance impacts.

Additional routine maintenance impacts could be associated with the maintenance of natural shoreline crossings. Alternatives 2 and 3 present the greatest impact in this regard as a result of the location of the Point Storkersen landfall site approximately 2.7 miles (4.3 km) from the nearest roadway (straight line distance). Because access to the landfall site could require overland access during summer months, vegetation disturbances could extend beyond the immediate vicinity of the Alternative 2 pipeline route. Access could be confined to the pipeline corridor in the case of Alternative 3, but this would result in repeated disturbance of natural vegetation along the 3.6-mile (5.8 km) long pipeline route from the landfall site to existing roadways. The Point McIntyre landfall site associated with Alternative 4 is located in close proximity to existing roadways (0.3-mile [0.5 km]) within the existing industrial area, and access-related vegetation disturbance in this area would be minor. The Alternative 5 landfall at the West Dock causeway would avoid all landfall maintenance impacts to natural vegetation.

4.6.3 Operational Disturbance of Wildlife

Disturbance of wildlife from operations activities is associated with weekly helicopter overflights along the pipeline route, helicopter transport of personnel/supplies to Seal Island during the spring and fall, and vessel transport to Seal Island during open water. Helicopter overflights along the pipeline associated with Alternative 2 represent the greatest level of impact, as a result of the 9.55-mile (15.37 km) overland pipeline segment across largely undeveloped tundra. These overflights, during the summer months, could result in minor impacts to caribou in the area and to tundra nesting birds (including threatened spectacled eiders) in a corridor along the onshore pipeline. However, appropriate measures to avoid or minimize the potential effect will be recommended by the USFWS. Alternative 3 would result in similar impacts; however, these would be to a 6.7-mile (10.8 km) pipeline, including the 3.5 mile (5.8 km) pipeline segment from Point Storkersen to the existing road system near Point McIntyre. Alternatives 4 and 5 would require helicopter overflights along the pipeline of approximately 3.1 miles (5 km) for routine inspections.

The impact of helicopter overflights between the mainland and Seal Island will be common to all alternative routes. These impacts would involve disturbances to nesting common eiders on the barrier islands and occasional disturbances to nesting or brood-rearing brant if flight paths include the Kuparuk River Delta. Helicopter overflights also have the potential to disturb nesting or brood-rearing activities of spectacled eiders within the flight path, which would be considered a minor impact. Noise and activity associated with the operation of the Seal Island facility, and related vessel transport operations, could result in bowhead whale avoidance response during migration periods. This impact is not expected to directly harm individual whales or whale populations, but may be important to the consideration of potential subsistence activity impacts (discussed separately in Section 11.8.4).

Cumulative impacts to sea ducks (common eiders and oldsquaw) due to helicopter flights during construction are considered significant. All action alternatives (Alternatives 2, 3, 4, and 5) would result in the same potential minor bowhead whale avoidance impact.

4.6.4 Impacts of Facility Operations on Subsistence

All action alternatives would have comparable operational impacts to subsistence activities. During normal operation of the Seal Island facility, bowhead whale avoidance of industrial noise and activity could require whalers to travel further offshore in search of whales. This would represent several significant effects on the subsistence activity, including: increased safety risks to whalers, reduced harvest success caused by longer time required for each whale, and potential meat spoilage associated with longer transport distances. In addition, should the IWC perceive any increased impact on or risk to the whale population, the bowhead harvest quota could be reduced. Project-related activities would contribute to cumulative effects on the bowhead whale migration route associated with increased offshore development, which could be significant to subsistence activities.

4.6.5 Expansion of Developed Area

All action alternatives would result in the addition of a new industrial facility in the offshore area. However, these alternatives are distinctly different with regard to onshore land use impacts. Alternative 2 represents the greatest onshore land use impact, and would establish a new overland pipeline corridor in an existing undeveloped area from Point Storkersen to Pump Station No. 1. In addition to the expansion and intensification of the industrial complex in the Prudhoe Bay - Kuparuk area, Alternative 2 could contribute to the further development in the Gwydyr Bay area by establishing a pipeline corridor closer to that area. Alternative 3 would also expand industrial land uses by extension of Prudhoe Bay area pipeline corridors westward to Point Storkersen, but the consolidation of most of the Alternative 3 onshore pipeline along existing industrial corridors reduces the overall impact in comparison to Alternative 2. Alternative 3 is comparable to

Alternative 2 in the potential contribution to future development in the Gwydyr Bay area. The consolidation of the onshore pipeline routes with existing industrial corridors represented by Alternatives 4 and 5 effectively eliminates new onshore land use impacts associated with these alternatives. Alternatives 4 and 5 also do not contribute to potential future development in the Gwydyr Bay area.

4.6.6 Socioeconomics

All action alternatives are expected to generate comparable contributions to State of Alaska, federal, and local revenues and create the same number of jobs. This includes the contribution of $478.9 million gross state royalty and tax revenues, $306.3 million in federal tax and royalty revenues, $64.3 million in tax revenues to the NSB, and $3 million in tax revenues to the MOA over the 15-year project life. This represents a substantial beneficial impact on State of Alaska revenues, since the North Slope oil and gas revenues represent the primary source of state revenues. The Northstar Project would represent approximately 2.4% of the total currently projected North Slope oil production during its project life. Construction employment would generate 730 jobs, 100 annual long-term (15-year) facility operation and project support jobs, and total wages of over $307 million. None of the revenue and employment benefits would result from the No Action Alternative (Alternative 1).

4.6.7 Visual/Aesthetic Impacts

All action alternatives would result in comparable offshore visual impacts associated with the addition of artificial lighting and industrial facilities on Seal Island.

However, onshore visual impacts would be substantially different. Alternative 2 would result in the greatest visual impact associated with the addition of a 9.55-mile (15.37 km) elevated pipeline across a currently undeveloped area. Alternative 3 would result in similar impacts along a shorter elevated pipeline segment (3.6 miles [5.8 km]) from Point Storkersen to existing Prudhoe Bay industrial facilities. Alternatives 4 and 5 would not result in new onshore visual impacts because their onshore pipeline routes are within or close to existing industrial corridors of the Prudhoe Bay industrial area.

4.6.8 Likelihood of a Large Oil Spill

Each action alternative presents a risk of 11%/12% to 24% (any cause) over the 15-year project life of an oil spill greater than 1,000 barrels. Calculated probabilities of one or more pipeline spills greater than 1,000 barrels over the entire project lifetime are: Alternative 2 – 4.5% to 19%; Alternative 3 – 5.6% to 19%; Alternative 4 – 5.5% to 19%; and Alternative 5 – 5.4 to 19%%. The calculations used to develop these probabilities consider a large database, including facilities in non-arctic locations. As a result, they are subject to substantial uncertainty and the relatively minor differences resulting from these calculations are not considered substantial enough to effectively distinguish between the action alternatives.

Specific design features of individual facilities are important to the level of spill risk associated with those facilities. The natural shoreline landfalls at Point Storkersen and Point McIntyre associated with Alternatives 2, 3, and 4 are expected to represent some increased risk as compared to the West Dock causeway landfall for

Alternative 5. This increased risk is associated with thaw bulb related subsidence and shoreline erosion at the landfall site. No data are presently available which can be used to verify this impact conclusion, or to quantify the contribution of this impact to spill occurrence probabilities.

4.6.9 Potential Oil Spill Volumes

The potential volume of spilled oil varies among alternatives (Table ES-16). This variation is entirely related to differences in pipeline lengths, since Seal Island facilities would be identical for all alternatives. The potential pipeline spill volumes would be least for Alternative 2, with calculated rupture/chronic leak volumes of 3,600/6,600 barrels from the offshore pipeline segment and 6,400/6,600 barrels from the onshore pipeline segment. Alternative 3 would result in the same offshore pipeline spill volume as Alternative 2 (3,600/6,600 barrels), but could result in substantially greater onshore spill volume of 8,700 /8,900 barrels. Alternatives 4 and 5 present substantially greater potential offshore spill volumes (5,300/8,200 barrels and 5,200/8,100 barrels, respectively). Use of buried, remotely operable pipeline valves to reduce these volumes could introduce considerable operational difficulty concerning valve inspection and maintenance, and may introduce a design feature with a much higher risk of failure (and resulting spillage) than a continuously welded steel pipeline. For these reasons, installation of valves along the offshore portion of these pipelines is not considered appropriate. Onshore pipeline spill volumes associated with Alternatives 4 and 5 would be slightly greater than Alternative 2 (6,800/7,000 and 6,700/6,900 barrels, respectively), and these differences are not considered significant.

4.6.10 Potential Oil Spill Impacts

Although the action alternatives could result in different volumes of offshore pipeline spills, other offshore spills associated with Seal Island facilities would be identical. In addition, even the smallest of the calculated offshore pipeline spill volumes of 3,600 barrels could be substantial enough to result in significant adverse impacts, as identified in this EIS. However, the offshore pipeline route for Alternative 4 would mostly avoid Gwydyr Bay, except for that portion off the eastern end of Stump Island to the shoreline landfall. Alternative 5 would completely avoid Gwydyr Bay. This would likely reduce the potential oil spill related impact to the birds and fish using Gwydyr Bay. For Alternative 5, oil spill response tactics for an offshore spill would include the placement of booms which could preclude oil from entering into the Gwydyr Bay/Simpson Lagoon system. Additionally, since oil spill response equipment would be staged from West Dock, a more rapid response would be possible for the nearshore portions of the pipeline for Alternatives 4 and 5. Offshore spill

Table ES-16 (Page 1)

responses for Alternatives 2 and 4 would not be as rapid, because the nearshore portions of those pipelines would be further from West Dock.

Significant adverse impacts which could occur in connection with a major offshore spill from any of the action alternatives include: direct mortality of bowhead whales if oil contacts the spring lead system coincident with migration: mortality to polar bears caused by oil contact, thermoregulation loss, and ingestion of oil-contaminated prey; elimination or severe disruption to subsistence activities and potential long-term adverse effects on offshore subsistence activities due to deflection of whales reduced populations of subsistence resources and possible oil contamination of available subsistence resources, such as bowhead whales, seals, birds, and fish.

Onshore spill impacts vary substantially among the action alternatives. Although the onshore spill volume associated with Alternative 2 is the least of all action alternatives, this alternative would result in the greatest onshore spill impact. The Alternative 2 pipeline route across 9.55 miles (15.37 km) of existing undeveloped land, well removed from existing industrial development, would expose relatively undisturbed vegetation and wildlife resources to the impacts of an oil spill. Alternatives 3, 4, and 5 cross 3.1 miles (5 km) of undeveloped tundra near the southern terminus of the alignment. In addition, access to the onshore spill site by response equipment would require overland access. If a spill occurs during summer months, disturbances to vegetation caused by equipment access could extend the disturbed area well beyond the immediate vicinity of oil contamination. Similar disturbance of vegetation and overland access impacts could occur in connection with Alternative 3, but this impact is not as great as Alternative 2 because only 3.6

miles (5.8 km) of the Alternative 3 pipeline route is located outside the existing developed industrial area. The remainder of the Alternative 3 onshore pipeline route, and all of the Alternatives 4 and 5 onshore pipeline routes, are located within the existing industrial area. These routes follow existing roadways and pipeline corridors over most of their lengths, and one overland segment in the southern portion of these routes occurs near existing roadways and is surrounded by industrial development. Spill impacts in the existing industrial area are considered less substantial than those in undeveloped areas due to available year-round access and the level of existing disturbance already present in the industrial area.

4.7 UNAVOIDABLE ADVERSE EFFECTS, RELATIONSHIP BETWEEN THE LOCAL SHORT-TERM USES AND LONG-TERM PRODUCTIVITY, AND IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

Unavoidable adverse effects, the relationship between local short-term uses and long-term productivity, and irreversible and irretrievable commitments of resources issues are essentially the same among all action alternatives; therefore, distinctions among individual alternatives have not been identified. Significant adverse impacts for the Northstar project would result from oil spills and noise disturbance. These impacts were presented in Chapters 5 through 9 and are summarized below.

- *Oil Spill - Contamination (sheens or free product) of soils, sediments, and surface water bodies from direct oiling and deposition of tar balls.*
- *Oil Spill - Mortality of polar bears from ingestion of oil during grooming, consumption of oiled prey, or loss of insulation and subsequent hypothermia.*

- *Oil Spill – Mortality of freshwater invertebrates; potential long-term impacts to various life stages due to contamination of sediments.*

- *Oil Spill – Damage to sensitive coastline vegetation from oil spill response activities.*

- *Oil Spill – Mortality of sea ducks (including spectacled eiders) in marine waters or lagoon areas due to direct contact with oil if a spill occurred during the open water period.*

- *Oil spill – Injury and/or mortality of bowhead whales from oil contacting the spring lead system coincident with migration.*

- *Oil Spill – Reduction or suspension of subsistence harvesting due to displacement or mortality of marine mammals (including bowhead whales), fish, and waterfowl, or fears of resource contamination.*

- *Oil Spill – Irreparable damage to historic artifacts and interference with radiocarbon dating tests from contact with spilled oil; damage to the integrity of coastal and onshore cultural/archaeological sites from spill response activities.*

- *Oil Spill – Damage to North Slope and statewide socioeconomics due to loss of revenues and increased costs; sudden increase in high wage paying jobs and subsequent inflation due to hiring of local labor for cleanup operations;*

reduced access to community services due to a rapid expansion of workforce needed for cleanup operations.

- Noise – Reduction or elimination of bowhead whale subsistence harvest due to deflection of whales resulting from noise produced during project construction, operation, or maintenance activities.

- Noise – Disturbance to molting oldsquaw and common eiders in lagoons from helicopter overflights during construction activities.

4.8 IDENTIFICATION OF THE PREFERRED ALTERNATIVE

NEPA requires that the lead and cooperating agencies identify their preferred alternative and document the reasons supporting this determination. This selected alternative is commonly referred to as the "agency preferred alternative."

4.8.1 Agency-Preferred Alternative

The agency preferred alternative is that alternative which the agency believes would fulfill its statutory mission and responsibilities, giving consideration to environmental, economic, technical, and other factors. The agency preferred alternative is distinct from the "environmentally preferred alternative." The environmentally preferred alternative is ordinarily the alternative which causes the least damage to the biological and physical environment and best protects historic, cultural, and natural resources. Although the agency preferred alternative and the environmentally preferred alternative may be the same, this is not always the case. Due to the differing missions, responsibilities, and regulations of the cooperating agencies, their perspectives on an "agency preferred" alternative are different. The following information is provided to clarify the agencies' perspectives and the processes followed to reach agency decisions.

4.8.1.1 U.S. Army Engineer District, Alaska

The Corps is neither an opponent nor a proponent of the applicant's proposed alternative action. For the proposed Northstar development, the applicant's final proposal has been identified as Alternative 2 (applicant's preferred alternative) and is fully described in Appendix A to this document.

In order to make a permit decision for activities involving discharges under Section 404 of the Clean Water Act, the Corps applies the EPA's 404(b)(1) guidelines on evaluation of alternatives for disposal sites for dredged or fill material (40 CFR Part 230). This EIS has evaluated the applicant's proposal (Alternative 2), the No Action Alternative, and three additional action alternatives. The Corps will also use the range of alternatives in this document when conducting its 404(b)(1) alternative analysis. If the Corps determines that one or more of the alternatives is a substantially less damaging practicable alternative as compared to the applicant's proposal, the Corps may deny the applicant's request for a permit for Alternative 2. From a NEPA perspective, the Corps could select from the range of all alternatives evaluated in this document. A preliminary 404(b)(1) analysis for the applicant's proposal (Alternative 2) is included in the Corps' public notice soliciting comments on the FEIS.

The Corps also conducts a public interest review of all relevant factors (33 CFR Part 320.4(a)) in order to make a permit decision. The public interest review is still in progress, with the release of this FEIS, the solicitation of public comments on the FEIS, and the solicitation of public comments on the decision of whether or not to grant a permit for the applicant's proposal. This public interest review portion of the decision whether to issue a permit will be based on an evaluation of the probable impacts, including cumulative impacts of the proposed activity and its intended use on the public interest. Evaluation of the probable impacts which the proposed activity may have on the public interest requires a careful weighing of all those factors which become relevant in each particular case. The benefits which reasonably may be expected to accrue from the proposal must be balanced against its reasonably foreseeable detriments. The decision whether to authorize a proposal and, if so, the conditions under which it will be allowed to occur, are therefore, determined by the outcome of the general balancing process. That decision should reflect the national concern for both protection and utilization of important resources. All factors which may be relevant to the proposal must be considered, including the cumulative effects thereof. Among those are: conservation, economics, aesthetics, general environmental concerns, wetlands, cultural values, fish and wildlife values, flood hazards, floodplain values, land use, navigation, shore erosion and accretion, recreation, water supply and conservation, water quality, energy needs, safety, food and fiber production, mineral needs, considerations of property ownership, and, in general, the needs and welfare of the people.

The Corps' permit decision, which includes the public interest review and final 404(b)(1) guidelines analysis, will be completed in the Corps' ROD. Decision options available to the District Engineer will be to issue the permit, issue with modifications and/or conditions, or deny the permit. The Corps cannot take a position on a proposed project until the evaluation of the project using the 404(b)(1) guidelines is finalized, the public interest review is completed, and a ROD has been prepared and approved. Therefore, the Corps cannot identify its agency preferred alternative in the EIS (see 33 CFR Part 325, Appendix B). The Corps will make its permit decision after the ROD has been approved, which will occur after the 30-day comment period on the FEIS. For activities involving 404 discharges, a permit will be denied if the discharge that would be authorized by such permit would not comply with the EPA's 404(b)(l) guidelines. Subject to the preceding sentence and any other applicable guidelines or criteria (see 33 CFR 320.2 and 320.3), a permit will be granted unless the District Engineer determines that it would be contrary to the public interest.

4.8.1.2 U.S. Environmental Protection Agency

The EPA is proposing to issue a NPDES permit as described in Appendix O. Because of the responsibilities that the EPA has under the Clean Water Act, the EPA does not promote the selection of one project alternative over another. The EPA will review and act according to its Clean Water Act authorities following the Corps' decision-making process (Section 11.9.1.1).

4.8.1.3 Minerals Management Service

Under the OCS Lands Act of 1953 (67 Stat. 462), as amended (43 U.S.C. et seq. [1994]), the USDOI is required to manage the leasing, exploration, development, and production of oil and gas resources on the Federal OCS, and requires that the Secretary oversee the OCS oil and gas program. The Secretary is also charged with balancing orderly resource development with protection of the human, marine, and coastal environments, while simultaneously ensuring that the public receives an equitable return for these resources. As an agency of the USDOI, the MMS is responsible for the mineral leasing of OCS lands and for the supervision of offshore operations after lease issuance. A lease gives the lessee the exclusive right and privilege to drill for, develop, and produce oil and gas resources on that lease, subject to existing laws and regulations. Once a lease is awarded, the MMS' Regional Supervisor for Field Operations is responsible for approving, supervising, and regulating operations conducted on the lease.

As required by 30 CFR 250.204, the MMS will carefully analyze the information submitted by BPXA for this project, as well as the analysis presented in the FEIS and any comments received, prior to making any final decision on the Development and Production Plan (DPP). In this context, the MMS is a cooperating agency on this EIS. This EIS has evaluated the applicant's proposal (Alternative 2), plus the No Action Alternative and three additional action alternatives related to pipeline routing. Upon completion of this review, the MMS will either approve, disapprove, or require modifications to the DPP. This action will not take place until after the FEIS is released. The MMS has up to 60 days following release of the FEIS to take action on the proposed DPP pursuant to 250.204(l). No OCS development and production activities can be conducted unless and until a DPP is approved, and the project has received coastal consistency concurrence by the State of Alaska.

Based on available information, the MMS identifies Alternative 2 as its preferred alternative. Among the five alternatives analyzed in the EIS, Alternative 2 meets MMS's legal and regulatory responsibilities for the timely and safe development of offshore oil and gas resources. Two principal benefits are discussed below.

Shortest Offshore Pipeline Segment. One of the most significant public concerns raised throughout the public process has been the risk of oil spills from the proposed subsea pipeline. Although the FEIS finds that there is not a significant difference in the statistical oil spill probability among the alternatives, the MMS concludes that adopting the shortest offshore pipeline segment is prudent and the most responsible alternative given the public's concerns. None of the action alternatives analyzed in the FEIS clearly provide a greater level of safety or reduce oil spill risk.

The State of Alaska, in its comments on the DEIS, endorsed Alternative 2. The state noted that the shortest offshore segment is preferable. The state, which has direct regulatory authority on project pipelines, also noted that an exhaustive review of the Alternative 2 pipeline route had been completed and that the state was prepared to issue a right-of-way lease for the proposed pipeline route.

The NSB has also endorsed Alternative 2. The NSB Assembly has recommended approval to re-zone the area around Northstar which will allow the project to proceed. The NSB stated that the greater the length of pipeline under water, the greater the risk of a leak or damage to this pipeline. The NSB endorses BPXA's proposal to install offshore pipelines in a trench of sufficient depth to avoid contact with extreme event ice gouge, and to be below the maximum incision depth to avoid damage due to soil motions beneath the ice keel, and placing backfill material over the pipelines will provide protection from ice pounding and ice wallowing. The NSB believes BPXA's proposal is consistent with the NSB's policy requiring offshore oil transport systems to be specifically designed to withstand geological hazards, specifically sea ice.

Timely Development Schedule and Lost Royalty Income: Alternative 2 is BPXA's preferred alternative. Site-specific surveys, facilities design, and engineering have been completed for this alternative and have been under review by appropriate state and federal agencies for several years. Construction schedules and first production are directly tied to these efforts. Any and each of the action alternative pipeline routes analyzed in the FEIS (except Alternative 2) would require a new and complete re-engineering of the pipeline, including additional field surveys to support design. The State of Alaska noted in its comments on the DEIS that any and each of the alternative pipeline routes would require submittal of a new right-of-way application, which would require the state right-of-way process to start over. Conducting additional field studies, pipeline and other facilities re-design, and initiating a new right-of-way application review could delay the project construction schedule another 1 to 2 years. None of the alternative pipeline routes analyzed in the FEIS show a clear or significant environmental benefit or savings over Alternative 2, which would suggest that an additional 1 to 2-year delay in the project start up is not justified.

The Northstar Project will provide direct and significant royalty revenue to the federal government and the State of Alaska. The state in its comments on the

DEIS, endorsed Alternative 2 on the basis that it would provide for the most timely completion of the project and, accordingly, royalty income to the state.

Delay of the project would also directly affect employment. The FEIS concludes that 730 jobs will be created and will generate approximately $52 million in Alaskan wages during the construction phase alone. Project operation, with an estimated 100 annual jobs and payroll of $255 million, could be similarly delayed. Substantial public comment was directed at the employment benefits of the project.

The MMS notes that, in selecting an agency preferred alternative in the FEIS, it is providing the public with some anticipation on how the project could proceed. Preferred alternatives are based on regulatory authorities and responsibilities and the information presented within the FEIS. The MMS's final decisions may or may not match the agency preferred alternative, pending any resulting information following publication of the FEIS and completion of their DPP review, and completion of the MMS' ROD.

4.8.1.4 National Marine Fisheries Service

The NMFS does not promote the selection of one project alternative over another as the preferred action alternative. Rather, since all the alternatives (with the exception of Alternative 1 - No Action) will have impacts on the NMFS' trust resources, the NMFS promotes the incorporation of mitigation measures to avoid, minimize, and/or compensate for impacts to trust resources. The NMFS will provide this information to the Corps and cooperating agencies under the ESA, the Marine Mammal Protection Act, and the Fish and Wildlife Coordination Act.

4.8.1.5 U.S. Fish & Wildlife Service

The USFWS will not select an alternative for publication in this EIS. The USFWS is presently evaluating the potential impacts of this project on trust resources, particularly migratory birds (including the threatened spectacled eider), and marine mammals (polar bears). Because the management and responsibility of these wildlife resources and the habitats on which they depend are responsibilities of the USFWS, as mandated by the Fish and Wildlife Coordination Act, Migratory Bird Treaty Act, ESA, and the Marine Mammal Protection Act, the USFWS will not recommend an alternative until publication and review of the FEIS. If the USFWS recommends an alternative other than Alternative 1 (No Action), they will recommend mitigation measures to avoid, minimize, or compensate for impacts to trust resources.

4.8.1.6 North Slope Borough

The NSB has been a non-federal cooperating agency in the preparation of this EIS and has been constrained by the requirements of its zoning ordinance to render a decision on the Northstar Project prior to publication of the document. BPXA submitted a rezone and Master Plan application to the NSB on September 15, 1998, and did not waive NSB compliance with the review and action timelines specified for such requests in the NSB Municipal Code. Without reliance upon or reference to this FEIS, the NSB Assembly, on December 1, 1998, approved the applicant's proposed rezone of the project area, which included BPXA's proposed project (Alternative 2). The Assembly's approval included several mitigation measures and becomes effective upon final approval of this FEIS.

4.8.2 The Environmentally Preferred Action Alternative

The environmentally preferred alternative(s) [40 CFR 1505. 2(b)] is the alternative that will promote the national environmental policy as expressed in NEPA's Section 101. Ordinarily, this means the alternative that causes the least damage to the biological and physical environment; it also means the alternative which best protects, preserves, and enhances historic, cultural, and natural resources. An action alternative must satisfy the applicant's purpose and need [33 CFR 325, Appendix B, 9b (5a)]. In this case, only Alternatives 2 through 5 meet this criteria (e.g., Alternative 1 – the No Action Alternative does not meets the applicant's purpose and need). In addition, identification of an environmentally preferred alternative considers only impacts to the physical, biological, and human environments; it does not take into account agency statutory missions or project cost factors. These two factors are considered by each agency in their determination of a preferred alternative (See Section 11.9.1). The agency preferred alternative need not be the same as the environmentally preferred alternative or the applicant's preferred alternative.

Alternative 5 was identified as the environmentally preferred alternative in the DEIS. A large number of comments regarding the environmentally preferred alternative were received and the need to further describe and discuss the rationale for choosing the environmentally preferred alternative was recognized. After reviewing all comments from the DEIS, and reevaluating the assessment of alternatives and related impacts, the lead and federal cooperating agencies (except for the MMS) are reconfirming Alternative 5 as the environmentally preferred action alternative for the following reasons (for a more complete comparison of alternatives and impacts see the previous sections in Chapter 11, in particular Sections 11.7 and 11.8):

- Although the offshore pipeline length is longer than Alternatives 2 and 3, and the corresponding probability of an oil spill is slightly higher (1.6%, 1.6%, 2.4%, and 2.4% from Alternatives 2, 3, 4, and 5, respectively), considering the level of uncertainty inherent in spill probability calculations, the calculated risk of an oil spill associated with all action alternatives would be similar (starts at 4.5%, 5.6%, 5.5%, and 5.4% for Alternatives 2, 3, 4, and 5, respectively, and ranges to 19% for all action alternatives). Additionally, pipeline design and maintenance considerations could reduce the probability of an oil spill for any of the action alternatives (Section 8.5.3).

- Although the potential offshore pipeline spill volume is greater for Alternative 5, as compared to Alternatives 2 and 3 (3,600, 3,600, and 5,200 barrels for a pipeline rupture of Alternatives 2, 3, and 5, respectively), and even the smallest of the calculated offshore spill volumes of 3,600 barrels could be substantial enough to result in significant adverse impacts. Thus, the offshore pipeline spill volumes for all of the action alternatives could cause significant adverse impacts.

- The offshore pipeline route completely avoids Gwydyr Bay and the nearshore lagoon system, an important area for migrating, rearing, and feeding marine and anadromous fish; and for molting, staging, and brood-rearing migratory birds. In the unlikely event of an oil spill, Gwydyr Bay could be protected from oil contamination by booming off the lagoon (i.e., placing oil containment booms between West Dock and Stump Island, and between Stump and Egg Islands). In comparison, Alternatives 2 and 3 offshore pipelines would be routed directly through the heart of the nearshore lagoon, while Alternative 4 would be routed through the eastern end of the lagoon.

- Oil spill response equipment would be staged at West Dock. In the event of an oil spill, this would allow for a more rapid response to the nearshore pipeline for Alternatives 4 and 5, as compared to spill response to the nearshore pipeline for Alternatives 2 and 3.

- The pipeline landfall on the West Dock causeway is intended to avoid the permafrost thaw bulb subsidence and shoreline erosion issues, which eliminates the permafrost thaw bulb subsidence hazard and shoreline erosion hazard common to all other action alternatives. This could be an advantage in terms of reduced risk of pipeline damage from differential thaw settlement that could result in an oil spill. In addition, this pipeline landfall on to West Dock would result in the elimination of maintenance activity that would otherwise be necessary in a natural shoreline area. In comparison, Alternatives 2, 3, and 4 would not avoid the natural shoreline issues of permafrost and erosion.

- Although approximately 5.5 acres (2.2 hectares) of shallow seafloor adjacent to West Dock causeway would be covered, this impact would be minor. Additionally, the causeway breach, a 650-ft (198 m) bridged opening, would not be affected and no additional impacts to local water circulation would be expected.

- Location of the onshore pipeline entirely within an existing industrial area and in proximity to roadway access would: increase the probability of leak detection, reduce oil spill response time, and reduce access-related damage associated with oil spill response and unplanned pipe maintenance during the summer.

- Routine inspections and maintenance of onshore pipelines would be performed from existing roads, as opposed to the use of helicopters for Alternatives 2, 3, and 4. This would decrease the disturbance to wildlife from helicopter overflights.

- Locating onshore pipelines in an existing corridor would likely decrease impacts to caribou moving through the area; other alternatives would require caribou to cross new onshore pipeline corridors.

- Onshore visual impacts would be reduced by routing the onshore pipeline within an existing industrial area.

Because NEPA rules allow more than one alternative to be identified as environmentally preferable, the MMS considers Alternatives 2 and 3 as its preferences for environmentally preferred alternatives. The MMS believes that there are substantive differences between the route of the offshore portion of the pipeline under Alternatives 2 and 3 compared to the Alternative 5 route outside the barrier islands. A major concern identified for the Northstar Project has been the offshore pipeline segment, especially since this is the first such design. MMS believes it is preferable to minimize the length of the offshore segment for this first application. Pipeline construction and monitoring issues, especially as they relate to the different ice characteristics within and outside the barrier islands, will be more manageable within the barrier islands. Alternatives 2 and 3 provide the shortest route to reduce the size and likelihood of an offshore oil spill and associated impacts. These differences lead the MMS to conclude that the offshore segment used in Alternatives 2 and 3 is environmentally preferable. The differences in impacts between Alternatives 2 and 3 are not sufficient to define which of the two would be environmentally preferable at this time. As required by NEPA rules, the MMS will make a final judgment on its environmentally preferred alternative in its ROD for the Northstar Project.

The NEPA process provides each federal agency with the opportunity to state its environmentally preferred alternative(s) in the DEIS, FEIS, and ultimately, in its ROD.

4.9 MITIGATION MEASURES

Mitigation measures are the means by which the range and intensity of project induced changes to the existing baseline conditions are compensated for, avoided, or reduced. In the case of this EIS for the Northstar Project, the cooperating agencies have developed a list of mitigation measures aimed at reducing or avoiding the identified significant environmental impacts expected to result from the project. This EIS is the appropriate means to present environmental impacts and associated mitigation measures.

The mitigation measures identified in this section represent a list of possible means to reduce impacts. If an action alternative is chosen, the mitigation measures will include some or all of the measures identified in this section. However, federal agencies are not limited to selecting mitigation measures from this list. Public comment on the FEIS may identify new mitigation measures. Each federal agency with decision-making authority on the Northstar Project will incorporate its own set of mitigation measures into its ROD that may become conditions or stipulations on their permit or action.

4.9.1 Federal Lease Sale Stipulations

There have been a number of federal offshore lease sales in the Alaskan Beaufort Sea since 1979. The most recent federal lease sale on the North Slope was Lease Sale 170, held August 5, 1998. The granting of any lease to a private party is accompanied by a list of stipulations addressing issues, such as: the protection of historic and archaeological sites, environmental training, the requirement to use pipelines for transporting oil if technically feasible, special measures to protect biological and subsistence resources, and discharges into marine waters. The original federal lease stipulations for Northstar presently in effect are summarized in Appendix D of this EIS, and must be complied with by the lease holders when developing the Northstar Unit.

4.9.2 Mitigation Measures Under Active Consideration by Cooperating Agencies

Potential mitigation measures were identified by the cooperating agencies participating in the direction of this EIS based on their assessment of the likely environmental consequences of the Northstar Project. It is important to note that many potential environmental consequences of this project have already been minimized or avoided through integration of Traditional Knowledge and modern science into the applicant's project design (See Table 1-3). These design features have been assessed in the impact analyses of Chapters 5 through 11. However, the cooperating agencies identified the following measures to further reduce or avoid the remaining environmental consequences identified in Chapters 5 through 11. The intent of each measure is described; the actual wording of a measure will be developed by each agency according to their regulatory authority and responsibility. Mitigation measures that may be developed as part of the ROD are summarized as follows:

- Avoid potential injury and mortality to migratory birds, especially sea ducks (including threatened spectacled eiders), the applicant will lower and orient in an east-west direction, the construction crane (and any additional equipment of significant height) when equipment is not in use.

- Modify (via paint or lighting) structures or facilities to decrease the potential of bird strikes because Seal Island is within the migratory corridor of spring, fall, and molt-migrating waterfowl (king, common, and spectacled eiders, oldsquaws, black brant) and other birds (Pacific, red-throated, and yellow-billed loons, red and red-necked phalaropes).

- Require the purchase of *Breco* buoys (Navenco Marine Company) or other similar acoustic scaring devices to disperse sea ducks and other migratory birds from an oil spill area to augment secondary oil spill response capabilities.

- Prepare and implement bear-interaction plans to minimize conflicts between bears and humans. These plans shall include measures to: (a) minimize attraction of polar bears to Seal Island; (b) organize layout of buildings and work areas to minimize human/bear interactions; (c) warn personnel of bears near or on Seal Island and along offshore/onshore pipeline routes and identify proper procedures to be followed; (d) if authorized, deter bears from Seal Island and along offshore/onshore pipeline routes; (e) provide contingencies in the event bears do not leave the site or cannot deterred by authorized personnel; (f) discuss proper storage and disposal of materials that may be toxic to bears; and (g) provide a systematic record of bears on the site and in the immediate area. The applicant shall develop educational programs and camp layout and management plans as they prepare operations plans. These plans shall be developed in consultation with appropriate federal, state, and NSB regulatory and resource agencies.

- Because polar bears are known to den predominantly within 25 miles (40 km) of the coast, operators shall consult with the USFWS (907-786-3800) prior to initiating activities in such habitat between October 30 and April 15.

- Establish flight corridors for helicopter traffic to and from Seal Island. The objective of this measure is to minimize the impact of helicopter noise on nesting spectacled eiders, nesting brant, common eiders on the barrier islands, and molting waterfowl in nearshore lagoons. It is also intended to minimize noise impacts on denning seals, polar bears, and migrating whales.

- Establish of vessel corridors to maximize separation between vessels and migrating whales. These would likely be seasonal restrictions and would apply during the fall whale migration. In particular, icebreaking barge operations related to maintaining a corridor between West Dock and Seal Island during broken/thin ice conditions cannot commence in the fall prior to October 15.

- Activities shall not be conducted nor pass within 1 mile (1.6 km) of any known polar bear dens and all observed dens shall be reported to the Marine Mammals Management Office, USFWS (907-786-3800) within 24 hours. This buffer zone will remain in effect from the time of detection, until the female bear/cubs leaves the denning area in the spring. The USFWS will evaluate these instances on a case-by-case basis to determine the appropriate action. Potential responses may range from cessation or modification of work to conducting additional monitoring.

- Require the preparation of an agency approved plan that demonstrates: 1) a reduction in oil spill risk, 2) increased leak detection under ice, and 3) increased oil spill response capability.

- Require use of the agitation technique for pile installation instead of pile driving during certain periods. Such a measure is intended to reduce noise impacts on marine mammals.

- Require a barge-based oil spill response plan. Three icebreaking barges would be used as the foundation of an on-site oil spill response plan. The barges would support oil cleanup crews, house equipment, and serve as a holding facility for recovered oil.

- Require complete shutdown of the pipeline during broken ice conditions. Such a measure is intended to minimize the risk of an oil spill when clean-up efficiencies are likely to be low.

- Require pre-staging of oil spill response equipment to protect biologically important sites, such as river deltas, lagoons, and barrier islands. This measure is intended to reduce the risk of an oil spill reaching and adversely affecting sensitive species in these important habitats.

- Require a well relief plan for a well blowout event. This measure is intended to ensure that emergency equipment is close by in the event of a well blow out, so that control of the well will be regained as quickly as possible, to maximize safety and reduce harm to the environment.

- Restrict construction and operation activities that may affect marine mammals (e.g., drilling, ball mill, pile driving). This measure is intended to reduce noise impacts to marine mammals and potential effects on subsistence.

- Prohibit drilling the first development well into the targeted hydrocarbon formation(s) during broken ice conditions. Such a requirement is intended to provide the applicant and the permitting agencies with an opportunity to test well integrity prior to the next development step and reduce the chance of an oil spill.

- Prohibit the drilling of exploration wells into untested formations during broken ice conditions. Such a measure is intended to reduce the chance of an oil spill occurring when oil spill cleanup efficiencies are likely to be low.

- Establish time periods for certain construction activities to minimize environmental consequences. Such activities would likely include: pipeline trenching, onshore and offshore gravel placement, spoil disposal offshore, gravel hauling, road construction, pipe construction, and pipeline testing.

- Establish a citizen's advisory board to address impacts to subsistence and to recommend to the government and the applicant solutions to any identified problems.

- Require additional site-specific geotechnical data prior to construction along the pipeline route in the shoal area and at the pipeline landfall. This data will be employed in a geotechnical analysis as specified in a plan requiring approval prior to construction. This plan will also specify the geotechnical sampling methodologies and sites.

- Require the use, if practicable, of arctic grade, low sulfur (0.05%) diesel fuel during the first year of drilling.

4.9.3 Monitoring Programs and Studies

Where environmental information is lacking, or where monitoring is required as a prerequisite to enforcement of permit conditions, federal agencies may require that the applicant conduct or financially support monitoring programs or further studies on various issues. The following have been identified as potential monitoring programs for the project:

- A monitoring program to investigate avian injury and mortality at Seal Island. The issue centers on whether facilities (towers, buildings, wires, and seawall) on Seal Island pose a hazard to birds. The study would need to be conducted from approximately May 1st through November 15th for a minimum of 5 years to monitor bird collisions during various ice conditions and lead patterns during bird migration periods.

- An acoustic monitoring program to measure actual frequency and noise level at various distances from Seal Island during the construction and initial operation of facilities on Seal Island. The program should be conducted for at least 3 years, beginning with initial gravel placement on the island. This study is intended to better understand noise impacts to marine mammals and to determine the noise signature from project operations.

- Conduct or support studies that investigate the impact of noise from the project on bowhead whale migration. The intent is to both understand the effects of the Northstar project and to provide information necessary for consideration of future offshore development.

- A monitoring program to characterize pre- and post-construction sediment chemistry. This would be conducted along the pipeline trench with location reference sites.

- A monitoring program to track disposed material from trench excavation. The objective is to document how far these sediments travel and to determine if excessive subsea mounding occurs to determine compliance with permit conditions.

- A monitoring program to measure water quality and sediments around Seal Island. The objective is to gather data that can be used by the applicant and the agencies in determining whether the project is in compliance with permit conditions. In addition, this data may be used to inform the decision-maker when permit reissuance may be sought by the applicant.

- Require an erosion monitoring and remedial action plan to protect the pipeline landfall site in the event of unexpectedly large erosion events or rates. This plan should include both a monitoring component and a description of the remedial actions that may be employed in the event the landfall shoreline requires stabilization.

- Require an ice-override monitoring and action plan to protect the pipeline transition site in the event of unexpectedly large ice-override events.

- Because the specific timing of migration and distribution of sea ducks (common, king and threatened spectacled eiders, oldsquaws) and other migratory birds (e.g., Pacific, red-throated, and yellow-billed loons, red and red-necked phalaropes) have been inadequately described, and because this offshore development may impact these resources, the applicant may be required to conduct research using aerial surveys, migration watches, ground surveys of barrier islands, and the use of radar to describe spring, fall, and molt migrations and potential staging/molting areas of migratory birds.

- The applicant may be required to conduct aerial surveys of polar bears during certain times of the year around Seal Island and along the offshore/onshore pipeline corridors to minimize effects of the proposed development.

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TABLE ES-1
MITIGATION MEASURES INCORPORATED INTO BPXA's PROPOSED PROJECT

Action	Effects
System Design	
Cathodic protection of offshore pipelines	Reduce potential pipeline corrosion and pipeline failure
SCADA system for real-time monitoring of flows and to detect leaks, including Pressure Point Analysis for leak detection	Reduce/minimize potential oil spills to the environment
Valves at Putuligayuk River crossing	System back-up to reduce the volume of an oil spill to the river
Catwalk access to Putuligayuk River valves	Minimize impacts to tundra
Enclosure of the shore approach SCADA valve	Reduce the potential for failure and resulting oil spill; containment of oil should failure occur
Placement of conex units directly on gravel island surface	Elimination of sheltered areas that could be used by polar bears or other wildlife
Deck discharge catch basins	Reduce/minimize potential contaminant releases to the marine environment
Check valve at pipeline terminus (PS1) to prevent backflow	Reduce/minimize potential oil spills to the environment
Installation of quick-closure valves at Seal Island and at the landfall	Reduce/minimize potential oil spills to the environment
Discharge of domestic wastewater, process water, etc. into disposal well	Minimize waste discharges and impacts to the environment
Use of double-walled containers for hazardous materials	Reduce/minimize potential contaminant releases to the environment
Storage of lubrication oils in seal-welded floor buildings	Reduce/minimize potential contaminant releases to the environment
Reinjection of produced water	Minimize waste discharges and impacts to the environment
Construction of pipelines on 5-foot (1.5 m) high VSMs and routing pipe through existing caribou crossings	Minimize impacts to caribou movements
A 75-foot (22.9 m) wide bench and gravel berms around island perimeter	Minimize potential damage to island from ice and waves
Sheet pile walls around island perimeter	Reduce potential contaminant releases to the marine environment by preventing damage to island facilities
Dry low NO_x emissions technology and BACT applied to all main air emissions pollution sources (e.g., power generator and gas compression turbines)	Reduces air emission pollutants to atmosphere
Drilling and production facilities on gravel island	Minimize noise transmission into the water column compared with other platform options
Grind and inject facility and disposal of drill cuttings and fluids to disposal well	Eliminates storage and transportation of drilling wastes
110-foot (33.5 m) setback of shoreline valve pad	Maintain clear shoreline corridor for caribou passage and provide protection from ice override

TABLE ES-1 (Cont.)
MITIGATION MEASURES INCORPORATED INTO BPXA's PROPOSED PROJECT

Action	Effects
Construction Methods	
Winter construction	Minimize potential impacts to tundra, subsistence hunting, and migratory species
Construction of ice roads	Minimize potential impacts to tundra; reduce need to acquire permanent access right-of-way
Subsea burial of offshore pipelines	Minimize the potential for pipeline failure and oil spills to the marine environment
Post-construction revegetation of pipe trench at landfall	Minimize impacts to tundra and stabilize permafrost soils
Containment drip pans to be used during hydrostatic testing	Reduce the potential for contaminant release
Use of frozen water bodies as staging areas during construction	Reduce land requirements for right-of-way; minimize impacts to tundra
Storage/reuse of overburden at gravel excavation site	Reduce impacts to the site and improved site restoration potential
Gravel excavation and rehabilitation work at new mine site	Rapid creation of scarce deep overwintering fish habitat
Disposal of pipeline trench spoils in water depths greater than 5 feet	Avoid blocking of circulation in shallow water and maximize natural dispersion
Construction of island on top of existing island remnant	Minimize impacts to seafloor and amount of new gravel needed from mine site
All drilling powered with fuel gas engines	Minimize diesel storage on island and reduces air emissions compared with normal North Slope diesel fueled drilling
Operation Measures	
Continuous manning of the facility	Reduce the possibility of an oil release to the environment; minimize the volume should a release occur
Visual surveillance of pipeline during operation	Rapid detection of oil releases to the environment and minimize volume spilled should one occur
Oil discharge prevention and contingency plan will be prepared	Reduce the risk of oil spills; minimize volume spilled should one occur; expedite clean up to minimize effects
Additional wall thickness (over standard) of pipelines	Reduced risk of pipeline failure
Periodic pipeline inspections using intelligent pigs	Early detection of structural problems that may lead to pipe failure
Dechlorination of any discharge with the potential to carry chlorine into the marine environment	Elimination of chlorine discharges to marine environment
Use of muted colors on island facilities	Reduce visual contrast of island structures and respond to Traditional Knowledge concerns.

Notes:
BACT = Best Available Control Technology
m = Meter
NO_X = Oxides of Nitrogen
PS1 = Pump Station No. 1
SCADA = Supervisory Control and Data Acquisition
VSM = Vertical Support Member

TABLE ES-1
MITIGATION MEASURES INCORPORATED INTO BPXA's PROPOSED PROJECT

Action	Effects
System Design	
Cathodic protection of offshore pipelines	Reduce potential pipeline corrosion and pipeline failure
SCADA system for real-time monitoring of flows and to detect leaks, including Pressure Point Analysis for leak detection	Reduce/minimize potential oil spills to the environment
Valves at Putuligayuk River crossing	System back-up to reduce the volume of an oil spill to the river
Catwalk access to Putuligayuk River valves	Minimize impacts to tundra
Enclosure of the shore approach SCADA valve	Reduce the potential for failure and resulting oil spill; containment of oil should failure occur
Placement of conex units directly on gravel island surface	Elimination of sheltered areas that could be used by polar bears or other wildlife
Deck discharge catch basins	Reduce/minimize potential contaminant releases to the marine environment
Check valve at pipeline terminus (PS1) to prevent backflow	Reduce/minimize potential oil spills to the environment
Installation of quick-closure valves at Seal Island and at the landfall	Reduce/minimize potential oil spills to the environment
Discharge of domestic wastewater, process water, etc. into disposal well	Minimize waste discharges and impacts to the environment
Use of double-walled containers for hazardous materials	Reduce/minimize potential contaminant releases to the environment
Storage of lubrication oils in seal-welded floor buildings	Reduce/minimize potential contaminant releases to the environment
Reinjection of produced water	Minimize waste discharges and impacts to the environment
Construction of pipelines on 5-foot (1.5 m) high VSMs and routing pipe through existing caribou crossings	Minimize impacts to caribou movements
A 75-foot (22.9 m) wide bench and gravel berms around island perimeter	Minimize potential damage to island from ice and waves
Sheet pile walls around island perimeter	Reduce potential contaminant releases to the marine environment by preventing damage to island facilities
Dry low NO_x emissions technology and BACT applied to all main air emissions pollution sources (e.g., power generator and gas compression turbines)	Reduces air emission pollutants to atmosphere
Drilling and production facilities on gravel island	Minimize noise transmission into the water column compared with other platform options
Grind and inject facility and disposal of drill cuttings and fluids to disposal well	Eliminates storage and transportation of drilling wastes
110-foot (33.5 m) setback of shoreline valve pad	Maintain clear shoreline corridor for caribou passage and provide protection from ice override

TABLE ES-1 (Cont.)
MITIGATION MEASURES INCORPORATED INTO BPXA's PROPOSED PROJECT

Action	Effects
Construction Methods	
Winter construction	Minimize potential impacts to tundra, subsistence hunting, and migratory species
Construction of ice roads	Minimize potential impacts to tundra; reduce need to acquire permanent access right-of-way
Subsea burial of offshore pipelines	Minimize the potential for pipeline failure and oil spills to the marine environment
Post-construction revegetation of pipe trench at landfall	Minimize impacts to tundra and stabilize permafrost soils
Containment drip pans to be used during hydrostatic testing	Reduce the potential for contaminant release
Use of frozen water bodies as staging areas during construction	Reduce land requirements for right-of-way; minimize impacts to tundra
Storage/reuse of overburden at gravel excavation site	Reduce impacts to the site and improved site restoration potential
Gravel excavation and rehabilitation work at new mine site	Rapid creation of scarce deep overwintering fish habitat
Disposal of pipeline trench spoils in water depths greater than 5 feet	Avoid blocking of circulation in shallow water and maximize natural dispersion
Construction of island on top of existing island remnant	Minimize impacts to seafloor and amount of new gravel needed from mine site
All drilling powered with fuel gas engines	Minimize diesel storage on island and reduces air emissions compared with normal North Slope diesel fueled drilling
Operation Measures	
Continuous manning of the facility	Reduce the possibility of an oil release to the environment; minimize the volume should a release occur
Visual surveillance of pipeline during operation	Rapid detection of oil releases to the environment and minimize volume spilled should one occur
Oil discharge prevention and contingency plan will be prepared	Reduce the risk of oil spills; minimize volume spilled should one occur; expedite clean up to minimize effects
Additional wall thickness (over standard) of pipelines	Reduced risk of pipeline failure
Periodic pipeline inspections using intelligent pigs	Early detection of structural problems that may lead to pipe failure
Dechlorination of any discharge with the potential to carry chlorine into the marine environment	Elimination of chlorine discharges to marine environment
Use of muted colors on island facilities	Reduce visual contrast of island structures and respond to Traditional Knowledge concerns.

Notes:
BACT = Best Available Control Technology
m = Meter
NO_X = Oxides of Nitrogen
PS1 = Pump Station No. 1
SCADA = Supervisory Control and Data Acquisition
VSM = Vertical Support Member

TABLE ES-2
FEDERAL, STATE, AND NORTH SLOPE BOROUGH PERMITS AND/OR APPROVALS FOR DEVELOPMENT/PRODUCTION OF THE NORTHSTAR UNIT

Regulatory Agency	Permit/Approval Requirements
Federal Agencies	
U.S. Army Corps of Engineers (Corps)	X Issues a Section 404 permit under the Federal Water Pollution Control Act of 1972, as amended (Clean Water Act) (33 USC 1344) for discharge of dredged and fill material into U.S. waters, including wetlands. X Issues a Section 10 permit under the Rivers and Harbors Act of 1899 (33 USC 403) for structures or work in, or affecting, navigable waters of the U.S. X Issues a Section 103 Ocean Dumping permit under Section 103 of the Marine Protection, Research, and Sanctuaries Act of 1972 (MPRSA) for transport of dredged material for ocean disposal.
U.S. Environmental Protection Agency (EPA)	X Issues a National Pollutant Discharge and Elimination System (NPDES) Permit, Fact Sheet, and Ocean Discharge Criteria Evaluation (ODCE) under Section 402, Federal Water Pollution Control Act of 1972, as amended (Clean Water Act) (33 USC 1251) for discharges into the marine environment. X Authority obligated to Alaska Department of Environmental Conservation (ADEC) to issue air quality permits for facilities operating within state jurisdiction, a Title V operating permit and a Prevention of Significant Deterioration (PSD) permit under the Clean Air Act, as amended (42 USC 7401), to address air pollutant emissions. X Issues an Underground Injection Control Class I Industrial Well permit under the Safe Drinking Water Act (40 CFR 124 A, 40 CFR 144, 40 CFR 146) for underground injection of Class I (industrial) waste materials. • Requires a spill prevention containment, and countermeasure (SPCC) Plan to be developed by the owner and operators. X Conducts a review and evaluation of the Draft and Final Environmental Impact Statements (EISs) for compliance with Council on Environmental Qualities (CEQ) guidelines (40 CFR 1500-1508) and Section 309 of the Clean Air Act. X Reviews and must concur with the Corps on a Section 103 evaluation under the MPRSA for ocean discharges of trench dredging spoils.
Minerals Management Service (MMS)	X Reviews/approves a Development and Production Plan of Operation under Sections 11 and 25 of the Outer Continental Shelf (OCS) Lands Act (42 USC Sec 1340 and 1351), 30 CFR 250, for development and production of federal leases. X Authority for review and approval of an Oil Discharge Prevention and Contingency Plan (ODPCP) and Certification of Financial Responsibility (COFR) under Section 4202(b)(4) of the Oil Pollution Act of 1990 (OPA90); Sec. 311(j)(5) of the Federal Water Pollution Control Act; 30 CFR 254, for accidental oil discharge into navigable waters.

TABLE ES-2 (Cont.)
FEDERAL, STATE, AND NORTH SLOPE BOROUGH PERMITS AND/OR APPROVALS
FOR DEVELOPMENT/PRODUCTION OF THE NORTHSTAR UNIT

Regulatory Agency	Permit/Approval Requirements
Federal Agencies (Cont.)	
U.S. Fish and Wildlife Service (USFWS)	X Endangered Species Act Consultation under the Endangered Species Act of 1973, Section 7(a)(2) for effects to threatened or endangered species. X Fish and wildlife consultation under Fish and Wildlife Coordination Act for effects to fish and wildlife resources. X Issues a Letter of Authorization under the Marine Mammal Protection Act for incidental takes of marine mammals (under USFWS' jurisdiction). X Issues Incidental Harassment Authorization under the Marine Mammal Protection Act for incidental takes of marine mammals (under USFWS' jurisdiction).
National Marine Fisheries Service (NMFS)	X Consultation under Section 7(a)(2) of the Endangered Species Act of 1973 for effects to threatened or endangered species. X Fish and wildlife consultation under Fish and Wildlife Coordination Act for effects to fish and wildlife resources. X Marine mammal consultation under the Marine Mammal Protection Act for effects to marine mammals (under NMFS' jurisdiction). X Issues incidental Harassment Authorization under the Marine Mammal Protection Act for incidental takes of marine mammals (under NMFS' jurisdiction).
North Slope Borough	
North Slope Borough (NSB)	X Rezoning and Master Plan Revision/Statement of Conformance for project development and construction activities related to the island, pipeline, valve pads, and mine site. X Coastal Zone Consistency Determination under the Coastal Zone Management Act of 1972, as amended in 1976 (16 USC 1451) (AS 46.40 Alaska Coastal Management Program, 1977; Borough Ordinance 90-39 [6/19/90]), to address project planning of development within the coastal zone.
State of Alaska	
Alaska Department of Environmental Conservation (ADEC)	X Issues a Certificate of Reasonable Assurance under Section 401, Federal Water Pollution Control Act of 1972, as amended in 1977 (Clean Water Act) (33 USC 1341); AS 46.03.020; 11 AAC 15; 18 AAC 70; 18 AAC 72 for discharge of dredged and fill material into U.S. waters. X Issues a Wastewater Permit for Class I well. X Issues a Solid Waste Permit for grind and inject waste handling facility. X Issues a Certificate of Reasonable Assurance/NPDES and Mixing Zone Approval under Section 402, Federal Water Pollution Control Act of 1972, as amended (Clean Water Act) (33 USC 1341 et seq.); AS 46.03.020, .100, .110, .120, & .710; 11 AAC 15; 18 AAC 15, 70, 010 & 72.500 for wastewater disposal into all state waters. X Reviews and approves the ODPCP and the COFR under AS 46.04.030, 18 AAC 75 et seq. for storage or transport of oil. X Issues a Title V Operating Permit and a PSD construction permit under Clean Air Act Amendments (Title V) for air pollutant emissions.

TABLE ES-2 (Cont.)
FEDERAL, STATE, AND NORTH SLOPE BOROUGH PERMITS AND/OR APPROVALS FOR DEVELOPMENT/PRODUCTION OF THE NORTHSTAR UNIT

Regulatory Agency	Permit/Approval Requirements
State of Alaska (Cont.)	
Department of Fish and Game (ADFG)	X Issues a Fish Habitat Permit for (Kuparuk River Delta mine site; Putuligayak River pipeline crossing) AS 16.05.840 (Fishway Act) and AS 16.05.870 (Anadromous Fish Act).
Alaska Oil & Gas Conservation Commission (AOGCC)	X Class II Well Area Injection Order and issues an Annular Injection Permit under 20 AAC 025.402 for the underground injection of Class II fluids (nonhazardous) from drilling operations.
Office of the Governor/Division of Governmental Coordination (DGC)	X Conducts a Coastal Zone Consistency review under Coastal Zone Management Act of 1972, as amended in 1976 (16 USC 1451 et seq.); AS 46.40 Alaska Coastal Management Program Act of 1977; 6 AAC 50 and issues determination of consistency of proposed development within the coastal zone.
Department of Natural Resources (DNR), Division of Land	X Issues a Material Sales Contract under AS 38.05.850; 11 AAC 71.070 through .075 for mining and purchase of gravel from state lands. X Issues Right-of-way and Land Use permits under AS 38.05.850 for use of state land; ice road construction on state land and state freshwater bodies.
Division of Oil and Gas	X Issues a Lease Operation Plan approval under AS 38.35.020 for oil and gas development on state leases.
Division of Mining and Water Management	X Issues a Temporary Water Use and Water Rights permit under AS 46.15 for water use necessary for construction and operations.
Joint Pipeline Office	X Issues pipeline right-of-way leases for pipeline construction and operation across state lands under AS 38.35.020.
DNR, State Historic Preservation Office (SHPO)	X Issues a Cultural Resources Concurrence under the National Historic Preservation Act of 1966, as amended (16 USC 470 et seq.); AS 41.35.010 to .240, Alaska Historic Preservation Act, for developments that may affect historic or archaeological sites.

TABLE ES-3
HISTORIC SOURCES OF TESTIMONY

Sale/Project	Type of Meeting/Testimony	Date	Location
MMS Sale BF Beaufort Sea Lease	AK Public Testimony	5/15/79	Kaktovik
MMS Sale BF Beaufort Sea Lease	AK Public Testimony	5/16/79	Nuiqsut
MMS Sale BF Beaufort Sea Lease	AK Public Testimony	6/04/79	Barrow
Beaufort Sea Seasonal Drilling	Memo from Tom Albert	12/22/81	
Beaufort Sea EIS (Diapir)	Public Hearing	2/03/82	Nuiqsut
Beaufort Sea EIS (Diapir)	Public Hearing	2/04/82	Kaktovik
MMS Diapir Sale 71 DEIS	Public Hearing	2/02/82	Barrow
MMS Diapir Field DEIS	Public Hearing	June 1984	Barrow
MMS Lease Sale 97 Beaufort DEIS	Proceedings	12/08/86	Barrow
MMS Lease Sale 97 Beaufort DEIS	Proceedings	12/09/86	Wainwright
MMS Lease Sale 97 Beaufort DEIS	Proceedings	12/10/86	Kaktovik
MMS Lease Sale 97 Beaufort DEIS	Proceedings	12/12/86	Nuiqsut
MMS Lease Sale 124 Public DEIS	Public Hearing	4/17/90	Barrow
MMS Lease Sale 124 Public DEIS	Public Hearing	4/18/90	Kaktovik
MMS Lease Sale 124 Public DEIS	Public Hearing	4/19/90	Nuiqsut
MMS Lease Sale 144	Public Hearing	11/06/95	Nuiqsut
MMS Lease Sale 144	Public Hearing	11/07/95	Kaktovik
MMS Lease Sale 144	Public Hearing	11/08/95	Barrow
Endicott Development Project	Public Hearing	3/05/84	Anchorage
Endicott Development Project	Public Hearing	3/01/84	Barrow
Endicott Development Project	Public Hearing	2/29/84	Nuiqsut
Endicott Development Project	Public Hearing	3/02/84	Kaktovik

Notes: AK = Alaska
DEIS = Draft Environmental Impact Statement
EIS = Environmental Impact Statement
MMS = Minerals Management Service

TABLE ES-4
COORDINATION/COMMUNICATIONS WITH COMMUNITY RESIDENTS

Community	Resident
BARROW	Craig George, Biologist, Department of Wildlife Management, NSB
	Edward Itta, President, Barrow Whaling Captains Association
	Arnold Brower, Jr., Mayor=s office NSB, Barrow Whaling Captains Association boardmember
	Burton Rexford, Alaska Eskimo Whaling Commission Chairman, Barrow Whaling Captains Association boardmember
	John Nusunginya, whaling captain
	James Ahsoak, whaling captain
	Barrow Whaling Captains Association, fall 1996 meeting
NUIQSUT	Leonard Lampe, Vice Mayor, City of Nuiqsut
	Joy Oyagak, Clerk, City of Nuiqsut; whaling captain=s wife
	Agnes Kasak, City of Nuiqsut
	Terza Hopson, Elder
	Thomas Napageak, Commissioner and Chairman, Alaska Eskimo Nuiqsut Whaling Commission; President, Kuukpik Corporation; whaling captain
	Lucy Ahkiviana, Elder
	Isaac Nukapigak, Kuukpik Corporation
	Tony Cabinboy, subsistence hunter, fisherman
	A few unidentified elders
	Archie Ahkiviana, whaling captain
	Frank Long, Jr., whaling captain
	Patsy Tukle, whaling captain
	Jonah Nukapigak, whaling captain
	Leonard Tukle, whaling captain
	Thomas Ahtuangaruak, Sr., whaling captain
	Helen Tukle, interpreter, whaling captain=s wife
	Gordon Brown, Mayor, City of Nuiqsut
	Roger Ahnupkana, subsistence hunter, fisherman
	Raymond Neakok, Sr., Recruiter, Ilisagvik College

TABLE ES-4 (Cont.)
COORDINATION/COMMUNICATIONS WITH COMMUNITY RESIDENTS

Community	Resident
NUIQSUT(Cont.)	Martha Falk, Recruiter, Ilisagvik College
	Lanston Chinn, Kuukpik Corporation
	Sandra Hopson, Kuukpik Corporation
	Joseph Napageak, Kuukpik Corporation
	Hattie Long, Elder, whaling captain=s wife
KAKTOVIK	Lon Sonsalla, Mayor, City of Kaktovik
	Karl Francis, Consultant to Kaktovik
	Nora Jane Kaveolook, City Council Member, City of Kaktovik
	Susie Akootchook, NSB Kaktovik Village Coordinator
	Carla Sims, employee, City of Kaktovik
	Herman Aishanna, Kaktovik resident

Notes: NSB = North Slope Borough

TABLE ES-5
SUMMARY OF CURRENT OIL AND GAS FACILITIES, NORTHSTAR PROJECT AREA[1]

Unit or Area/Field	Initial Production (Year)	1996 Oil Production (MMBBL)	Estimated Remaining Reserves (end of 1996) (MMBBL)	Facilities								
				Disturbed Area (Roads, Pads, & Airstrips) (Acres)	Gravel Roads (Miles)	Pipelines (Miles)	Gravel Mines		Reserve Pits		Wells (No.)	Pads/ Platforms (No.)
							(No.)	(Acres)	(No.)	(Acres)		
Duck Island												
Endicott	1987	27.663	258	392	15	29	1	179	0	0	105	2
Sag Delta N.	1989	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]
Sag Delta	1989	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]	--[2]
Prudhoe Bay												
Prudhoe Bay	1977	312.609	3,443	4,590	200	145	6	726	106	560	1,256	38
Lisburne	1981	5.139	57	213	18	50	--	--	10	16	81	5
Niakuk	1994	11.045	90	22	--	5	--	--	--	--	18	--
West Beach	1994	0.499	30	--	--	--	--	--	--	--	1	--
N. Prudhoe Bay	1993	0.129	75	--	--	--	--	--	--	--	1	--
Pt. McIntyre	1993	58.751	312	33	--	12	--	--	--	--	47	--
Kuparuk												
Kuparuk	1981	99.459	1,275	1,435	94	134	5	564	126	161	835	34
West Sak	1998	--	279	--	--	--	0	0	--	--	50	--
Milne Point												
Milne Point	1985	12.686	210	205	19	40	1	43	--	--	110	4
Cascade	1996	--	50	31	--	--	--	--	--	--	--	--
Schrader Bluff	1991	1.068	281	--	--	--	--	--	--	--	22	--
Sag River	1994	0.346	19	--	--	--	--	--	--	--	3	--
NPRA												
East Barrow	1981	--[3]	--[3]	--	--	--	--	--	--	--	--	--
South Barrow	1950	--[3]	--[3]	--	--	--	--	--	--	--	--	--
Walakpa	1993	--[3]	--[3]	--	--	--	--	--	--	--	--	--
Badami												
Badami	1998	--	120	85	4.5	35	1	89	0	0	50	2
Tarn												
Tarn	1998	--	50	73	10	10	1	--	0	0	40	2

Notes:
1 = Information in this table was developed from USDOI, BLM, 1998: IV-A-44-45. The cumulative development area and existing developments are shown on Figure 10-2.
2 = Included in Endicott details
3 = These developments produce natural gas, and do not contribute oil production to North Slope oil transportation facilities
-- = Not applicable
MMBBL = Million barrels
No. = Number
NPRA = National Petroleum Reserve, Alaska

TABLE ES-6
DISCHARGE CHARACTERISTICS

Outfall No.		001(a)	001(b)	001(c)	002	005
Source		**Flush-water**	**Potable Water System (Brine)**	**Wastewater Treatment System**	**Fire Suppression Test Water**	**Construction Dewatering**
Flow Rate (gpd)	max.	21,600	18,060	9,360	88,200 (30 min.)	2,000,000
	avg.	21,600	3,528	2,800	--	1,000,000
Temp. (°C)	summer	amb. + 0.7	amb. + 6.0 avg	16-18 avg. 18 max.	amb.	--
	winter	amb. + 1.0	amb. + 7.0 max		No Test	amb.
pH (SU)		Combined: amb. ±0.7			amb.	amb.
Salinity (ppt)		amb.	32-65	0	amb.	amb.
BOD (mg/L)	max.	0	0	25	amb.	--
	avg.	0	0	15	amb.	--
TSS (mg/L)	max.	amb.	1.8 x amb.	34	amb	Note 1
	avg.	amb.	1.8 x amb.	25	amb.	Note 1
TRC (mg/L)	max.	≤0.002	0	0	amb.	amb.
	avg.	≤0.002	0	0	amb.	amb.
Turbidity (NTU)	max.	amb.	1.8 x amb.	--	amb.	Note 1
	avg.	amb.	1.8 x amb.	--	amb.	Note 1
Sediment	max.	amb.	0	0	amb.	Note 1
	avg.	amb.	0	0	amb.	Note 1
Toxics, mg/L		0	15 [2]	0	amb.	0
Fecal Coliform No./100 ml	max.	0	0	210	amb.	--
	avg.	0	0	16	amb.	--

Notes: 1 = The values of suspended solids, turbidity, and sediment (settleable solids) to be discharged from Outfall 005 will likely be higher than ambient. This discharge will occur discontinuously during a 2 to 4 week period in early spring (April - May).

2 = The listed concentration accounts for scale inhibiters added to the desalination plant influent and assumes that the concentration is conserved throughout the desalination plant. Toxics data is supplied in the NPDES Permit Application. 15 parts per million of scale inhibitor will be added at the influent to the desalination plant. This substance is described in the NPDES Permit Application as slightly toxic to humans through ingestion and as a skin, lung, and eye irritant.

amb. = Ambient
avg. = Average
BOD = Biochemical oxygen demand
°C = Degrees Celsius
gpd = Gallons per day
max. = Maximum
mg/L = Milligrams per liter
No./100 ml = Number of counts per 100 milliliters
ppt = Parts per thousand
SU = Standard Units
Temp. = Temperature
TRC = Total residual chlorine
TSS = Total suspended solids
≤ = Less than or equal to

TABLE ES-9
ALTERNATIVE 2 - PIPELINE CORRIDOR INFORMATION

Offshore Pipeline Corridor (Oil and Gas) [1]							Onshore Pipeline Corridor [2, 3]			
Water Depth (feet)	**Corridor [4] Length (feet)**	**Estimated [4, 5] Trenching Rate (feet/day)**	**Estimated [5, 6] Trenching Time (days)**	**Estimated [7] Seafloor Area Disturbed (acres)**	**Estimated [4, 5] Volume Excavated (cubic yards)**	**Estimated [8] Construction Costs ($ Million)**	**Pipeline Type**	**Installation Method [9]**	**Line Length [4, 10] (feet)**	**Estimated [8] Construction Costs ($ million)**
0 - 10	12,600	1,000	12.6	2.3	50,400	4.8 - 7.2	Oil	New VSMs along new ROW	50,400	14.3 - 19.1
10 - 20	9,240	600	15.4	9.3	101,600	4.4 - 6.1		New VSMs along existing pipeline and/or road corridor	8,300	2.4 - 3.9
20 - 30	4,840	600	8.1	4.9	59,300	2.8 - 3.7	Gas	New VSMs along new ROW	37,900	10.8 - 14.4
30 - 40	4,800	200	24	4.9	52,800	5.5 - 7.3		New VSMs along existing pipeline and/or road corridor	17,600	5.0 - 8.3
Totals	31,480	N/A	N/A	21.4	264,100	17.5 - 24.3	Totals	N/A	114,200	32.5 - 45.7

Notes:
1 = Offshore freshwater ice road cap (3 inches thick by 100 ft wide) requires 23,500 bbls/mile of pipeline length (31,480 ft requires 140,100 bbls).
2 = Total onshore pipeline corridor length is 76,300 ft (114,200 ft - 37,900 ft).
3 = Onshore freshwater ice road (2 inches thick by 75 ft wide) requires 11,800 bbls/mile of pipeline length (76,300 ft requires 170,600 bbls freshwater).
4 = Source: Hanley, 1997:Attachment 2
5 = Source: BPXA, 1997b:Table 2.4-6
6 = Pipeline trenching would be conducted with three crews working simultaneously.
- Crew 1 would start at the shoreline to a point just outside the barrier island (landfast ice zone).
- Crew 2 would start just outside the barrier islands and continue to a point midway between the barrier islands and Seal Island.
- Crew 3 would begin at a point midway between the barrier islands and continue to Seal Island.

7 = Source: Hanley, 1997:Attachment 2; BPXA, 1997b:Figure 2.4-4
8 = Source: BPXA, 1997a:1
9 = Typical VSM spacing is 55 ft for onshore pipeline construction (76,300 ft ÷ 55 ft = 1,387 VSMs) (Leavitt, 1997:1).
10 = 37,900 ft of pipeline is shared in common onshore corridor.
ROW = Right-of-way   VSMs = Vertical support members   N/A = Not applicable

TABLE ES-10
ALTERNATIVE 3 - PIPELINE CORRIDOR INFORMATION

Offshore Pipeline Corridor (Oil and Gas) [1]							Onshore Pipeline Corridor [2, 3]			
Water Depth (feet)	Corridor [4] Length (feet)	Estimated [4, 5] Trenching Rate (feet/day)	Estimated [5, 6] Trenching Time (days)	Estimated [7] Seafloor Area Disturbed (acres)	Estimated [4, 5] Volume Excavated (cubic yards)	Estimated [8] Construction Costs ($ Million)	Pipeline Type	Installation Method [9]	Line Length [4, 10] (feet)	Estimated[8] Construction Costs ($ million)
0 - 10	12,600	1,000	12.6	2.3	50,400	4.8 - 7.2	Oil	New VSMs along new ROW	35,400	10.0 - 13.4
10 - 20	9,240	600	15.4	9.3	101,600	4.4 - 6.1		New VSMs along existing pipeline and/or road corridor	46,100	13.1 - 21.8
20 - 30	4,840	600	8.1	4.9	59,300	2.8 - 3.7	Gas	New VSMs along new ROW	19,100	5.4 - 7.2
30 - 40	4,800	200	24	4.9	52,800	5.5 - 7.3		New VSMs along existing pipeline and/or road corridor	30,200	8.6 - 14.3
Totals	31,480	N/A	N/A	21.4	264,100	17.5 - 24.3	Totals	N/A	130,800	37.1 - 56.7

Notes:
- 1 = Offshore freshwater ice road cap (3 inches thick by 100 ft wide) requires 23,500 bbls/mile of pipeline length (31,480 ft requires 140,100 bbls).
- 2 = Total onshore pipeline corridor length is 82,570 ft (130,800 ft - 48,230 ft).
- 3 = Onshore freshwater ice road (2 inches thick by 75 ft wide) requires 11,800 bbls/mile of pipeline length (82,570 ft requires 184,600 bbls freshwater).
- 4 = Source: Hanley, 1997:Attachment 2
- 5 = Source: BPXA, 1997b:2.4-6
- 6 = Pipeline trenching would be conducted with three crews working simultaneously.
  - Crew 1 would start at the shoreline to a point just outside the barrier island (landfast ice zone).
  - Crew 2 would start just outside the barrier islands and continue to a point midway between the barrier islands and Seal Island.
  - Crew 3 would begin at a point midway between the barrier islands and continue to Seal Island.
- 7 = Source: Hanley, 1997:Attachment 2; BPXA, 1997b:Figure 2.4-4
- 8 = Source: BPXA, 1997a:1
- 9 = Typical VSM spacing for onshore pipeline construction is 55 ft (82,570 ft □ 55 ft = 1,501 VSMs) (Leavitt, 1997:1).
- 10 = 48,230 ft of onshore pipeline is shared in common onshore corridor.
- ROW = Right-of-way
- VSMs = Vertical support members
- N/A = Not applicable

TABLE ES-11
ONSHORE AND OFFSHORE PIPELINE CORRIDOR COMPARISON

Characteristics	Alternatives				
	1	**2**	**3**	**4**	**5**
Offshore Pipeline Corridor Length (ft)					
0 - 10 ft water depths	0	12,600	12,600	20,600	19,900
10 – 20 ft water depths	0	9,240	9,240	17,470	17,500
20 – 30 ft water depths	0	4,840	4,840	4,840	4,840
>30 ft water depths	0	4,800	4,800	4,800	4,800
Total Offshore Pipeline Length	0	31,480	31,480	47,700	47,000
Estimated Seafloor Area Disturbed (acres)	0	21.4	21.4	31.3	36.7
Estimated Seafloor Volume Excavated (yd^3)	0	264,100	264,100	380,600	377,700
Onshore Oil Pipeline Length (ft)	0	58,700	81,500	63,100	62,200
Onshore Gas Pipeline Length (ft)	0	55,500	49,300	30,800	30,000
Total Onshore and Offshore Pipeline Lengths (ft)	0	145,680	162,280	141,600	139,200
Total Onshore Pipeline Corridor Length (ft)	0	76,300	82,570	64,110	63,270
Estimated Number of VSMs Required (55 ft spacings)	0	1,387	1,501	1,166	1,150
Estimated Barrels of Freshwater for Ice Road Construction	0	310,700	324,700	355,800	350,400

Notes: ft = Feet/foot
yd^3 = Cubic yards
VSMs = Vertical support members

Source: Hanley, 1997:Attachment 2. Estimated seafloor area disturbed value for Alternative 5 has been altered from original BPXA table to include an additional 5.5 acres of gravel fill coverage over seafloor along the widened West Dock causeway.

TABLE ES-11
ONSHORE AND OFFSHORE PIPELINE CORRIDOR COMPARISON

Characteristics	Alternatives				
	1	2	3	4	5
Offshore Pipeline Corridor Length (ft)					
0 - 10 ft water depths	0	12,600	12,600	20,600	19,900
10 – 20 ft water depths	0	9,240	9,240	17,470	17,500
20 – 30 ft water depths	0	4,840	4,840	4,840	4,840
>30 ft water depths	0	4,800	4,800	4,800	4,800
Total Offshore Pipeline Length	0	31,480	31,480	47,700	47,000
Estimated Seafloor Area Disturbed (acres)	0	21.4	21.4	31.3	36.7
Estimated Seafloor Volume Excavated (yd^3)	0	264,100	264,100	380,600	377,700
Onshore Oil Pipeline Length (ft)	0	58,700	81,500	63,100	62,200
Onshore Gas Pipeline Length (ft)	0	55,500	49,300	30,800	30,000
Total Onshore and Offshore Pipeline Lengths (ft)	0	145,680	162,280	141,600	139,200
Total Onshore Pipeline Corridor Length (ft)	0	76,300	82,570	64,110	63,270
Estimated Number of VSMs Required (55 ft spacings)	0	1,387	1,501	1,166	1,150
Estimated Barrels of Freshwater for Ice Road Construction	0	310,700	324,700	355,800	350,400

Notes: ft = Feet/foot
yd^3 = Cubic yards
VSMs = Vertical support members

Source: Hanley, 1997:Attachment 2. Estimated seafloor area disturbed value for Alternative 5 has been altered from original BPXA table to include an additional 5.5 acres of gravel fill coverage over seafloor along the widened West Dock causeway.

TABLE ES-12
ALTERNATIVE 4 - PIPELINE CORRIDOR INFORMATION

Offshore Pipeline Corridor (Oil and Gas) [1]							Onshore Pipeline Corridor [2, 3]			
Water Depth (feet)	**Corridor [4] Length (feet)**	**Estimated [4, 5] Trenching Rate (feet/day)**	**Estimated [5, 6] Trenching Time (days)**	**Estimated [7] Seafloor Area Disturbed (acres)**	**Estimated [4, 5] Volume Excavated (cubic yards)**	**Estimated [8] Construction Costs ($ Million)**	**Pipeline Type**	**Installation Method [9]**	**Line Length [4, 10] (feet)**	**Estimated [8] Construction Costs ($ million)**
0 - 10	20,600	1,000	20.6	3.8	82,400	7.8 - 11.7	Oil	New VSMs along new ROW	18,240	5.2 - 6.8
10 - 20	17,470	600	29.1	17.7	192,200	8.3 - 11.6		New VSMs along existing pipeline and/or road corridor	44,860	12.7 - 21.2
20 - 30	4,840	600	8.1	4.9	53,200	2.8 - 3.7	Gas	New VSMs along new ROW	1,900	0.5 - 0.7
30 - 40	4,800	200	24	4.9	52,800	5.5 - 7.3		New VSMs along existing pipeline and/or road corridor	28,900	8.2 - 13.7
Totals	47,700	N/A	N/A	31.3	380,600	24.4 - 34.3	Totals	N/A	93,900	26.6 - 42.4

Notes:
1 = Offshore freshwater ice road cap (3 inches thick by 100 ft wide) requires 23,500 bbls/mile of pipeline length (47,700 ft requires 212,400 bbls freshwater).
2 = Total onshore pipeline corridor length is 64,110 ft (93,900 ft - 29,790 ft).
3 = Onshore freshwater ice road (2 inches thick by 75 ft wide) requires 11,800 bbls/mile of pipeline length (64,110 ft of ice road requires 143,400 bbls freshwater).
4 = Source: Hanley, 1997:Attachment 2
5 = Source: BPXA, 1997b:2.4-6
6 = Pipeline trenching would be conducted with four crews working simultaneously.
- Crews 1 and 2 would excavate the trench between landfall to the point where the pipeline turns north at the southern boundary of the Northstar Unit.
- Crew 3 would start just outside the barrier island and continue to a point midway between the barrier island and Seal Island.
- Crew 4 would begin at a point midway between the barrier islands and continue to Seal Island.

7 = Source: Hanley, 1997:Attachment 2; BPXA, 1997b:Figure 2.4-4
8 = Source: BPXA, 1997a:1
9 = Typical VSM spacing for onshore pipeline construction is 55 ft (64,110 ft ÷ 55 ft = 1,166 VSMs) (Leavitt, 1997:1)
10 = 29,790 ft of onshore pipeline is shared in common onshore corridor.
N/A = Not applicable
ROW = Right-of-way

VSMs	=	Vertical support members

TABLE ES-12
ALTERNATIVE 4 - PIPELINE CORRIDOR INFORMATION

Offshore Pipeline Corridor (Oil and Gas) [1]							Onshore Pipeline Corridor [2, 3]			
Water Depth (feet)	**Corridor [4] Length (feet)**	**Estimated [4, 5] Trenching Rate (feet/day)**	**Estimated [5, 6] Trenching Time (days)**	**Estimated [7] Seafloor Area Disturbed (acres)**	**Estimated [4, 5] Volume Excavated (cubic yards)**	**Estimated [8] Construction Costs ($ Million)**	**Pipeline Type**	**Installation Method [9]**	**Line Length [4, 10] (feet)**	**Estimated [8] Construction Costs ($ million)**
0 - 10	20,600	1,000	20.6	3.8	82,400	7.8 - 11.7	Oil	New VSMs along new ROW	18,240	5.2 - 6.8
10 - 20	17,470	600	29.1	17.7	192,200	8.3 - 11.6		New VSMs along existing pipeline and/or road corridor	44,860	12.7 - 21.2
20 - 30	4,840	600	8.1	4.9	53,200	2.8 - 3.7	Gas	New VSMs along new ROW	1,900	0.5 - 0.7
30 - 40	4,800	200	24	4.9	52,800	5.5 - 7.3		New VSMs along existing pipeline and/or road corridor	28,900	8.2 - 13.7
Totals	47,700	N/A	N/A	31.3	380,600	24.4 - 34.3	Totals	N/A	93,900	26.6 - 42.4

Notes:
1 = Offshore freshwater ice road cap (3 inches thick by 100 ft wide) requires 23,500 bbls/mile of pipeline length (47,700 ft requires 212,400 bbls freshwater).
2 = Total onshore pipeline corridor length is 64,110 ft (93,900 ft - 29,790 ft).
3 = Onshore freshwater ice road (2 inches thick by 75 ft wide) requires 11,800 bbls/mile of pipeline length (64,110 ft requires 143,400 bbls freshwater).
4 = Source: Hanley, 1997:Attachment 2
5 = Source: BPXA, 1997b:2.4-6
6 = Pipeline trenching would be conducted with four crews working simultaneously.
- Crews 1 and 2 would excavate the trench from landfall to the point where the pipeline turns north at the southern boundary of the Northstar Unit.
- Crew 3 would start just outside the barrier island and continue to a point midway between the barrier island and Seal Island.
- Crew 4 would begin at a point midway between the barrier islands and continue to Seal Island.

7 = Source: Hanley, 1997:Attachment 2; BPXA, 1997b:Figure 2.4-4
8 = Source: BPXA, 1997a:1
9 = Typical VSM spacing for onshore pipeline construction is 55 ft (64,110 ft ÷ 55 ft = 1,166 VSMs) (I. Leavitt – Pers. Comm., 1997:1)
10 = 29,790 ft of onshore pipeline is shared in common onshore corridor.
bbls = Barrels
ft = Feet
N/A = Not applicable
ROW = Right-of-way
VSMs = Vertical support members

TABLE ES-13
ALTERNATIVE 5 - PIPELINE CORRIDOR INFORMATION

Offshore Pipeline Corridor (Oil and Gas) [1]							Onshore Pipeline Corridor [2, 3, 4]			
Water Depth (feet)	**Corridor [5] Length (feet)**	**Estimated [5, 6] Trenching Rate (feet/day)**	**Estimated [6, 7] Trenching Time (days)**	**Estimated [8] Seafloor Area Disturbed (acres)**	**Estimated [5, 6] Volume Excavated (cubic yards)**	**Estimated [9] Construction Costs ($ Million)**	**Pipeline Type**	**Installation Method [10]**	**Line Length [5, 11] (feet)**	**Estimated [9] Construction Costs ($ million)**
0 - 10	19,900	1,000	19.9	9.2	79,500	7.5 - 11.3	Oil	New VSMs along new ROW	16,300	6.9 - 9.2
10 - 20	17,500	600	29.1	17.7	192,200	8.3 - 11.6		New VSMs along existing pipeline and/or road corridor	45,900	13.0 - 21.7
20 - 30	4,840	600	8.1	4.9	53,200	2.8 - 3.7	Gas	New VSMs along new ROW	0	0
30 - 40	4,800	200	24	4.9	52,800	5.5 - 7.3		New VSMs along existing pipeline and/or road corridor	30,000	10.8 - 17.2
Totals	47,000	N/A	N/A	36.7	377,700	24.1 - 33.9	Totals	N/A	92,200	30.6 - 48.1

Notes:
1 = Offshore freshwater ice road cap (3 inches thick by 100 ft wide) requires 23,500 bbls/mile of pipeline length (47,000 ft requires 209,000 bbls freshwater).
2 = Total onshore pipeline corridor length is 63,270 ft (92,200 ft - 28,930 ft).
3 = Onshore freshwater ice road (2 inches thick by 75 ft wide) requires 11,800 bbls/mile of pipeline length (63,220 ft of ice road requires 141,400 bbls freshwater).
4 = Offshore pipeline landfall at Dockhead 2 along West Dock would require the placement of an additional 290,000 to 300,000 cubic yards of gravel fill placed along the west side of West Dock between Dockhead 2 and the West Dock staging pad.
5 = Source: Hanley, 1997b:Attachment 2
6 = Source: BPXA, 1997b:2.4-6
7 = Pipeline trenching would be conducted with four crews working simultaneously.
- Crew 1 and 2 would excavate the trench between West Dock (Dockhead 2) to the point where the pipeline turns north at the southern boundary of the Northstar Unit.
- Crew 3 would start just outside the barrier island and continue to a point midway between the barrier island and Seal Island.
- Crew 4 would begin at a point midway between the barrier islands and continue to Seal Island.

8 = Source: Hanley, 1997b:Attachment 2; BPXA, 1997b:Figure 2.4-4, modified totals to include causeway fill coverage area.
9 = Source: BPXA, 1997a:1
10 = Typical VSM spacing for onshore pipeline construction is 55 ft (63,270 ft ÷ 55 ft = 1,150 VSMs) (I. Leavitt - Pers. Comm., 1997:1).
11 = 28,930 ft of onshore pipeline is shared in common onshore corridor.
ROW = Right-of-way   VSMs = Vertical support members   N/A = Not applicable

TABLE ES-13
ALTERNATIVE 5 - PIPELINE CORRIDOR INFORMATION

Offshore Pipeline Corridor (Oil and Gas) [1]							Onshore Pipeline Corridor [2, 3, 4]			
Water Depth (feet)	**Corridor [5] Length (feet)**	**Estimated [5, 6] Trenching Rate (feet/day)**	**Estimated [6, 7] Trenching Time (days)**	**Estimated [8] Seafloor Area Disturbed (acres)**	**Estimated [5, 6] Volume Excavated (cubic yards)**	**Estimated [9] Construction Costs ($ Million)**	**Pipeline Type**	**Installation Method [10]**	**Line Length [5, 11] (feet)**	**Estimated [9] Construction Costs ($ million)**
0 - 10	19,900	1,000	19.9	9.2	79,500	7.5 - 11.3	Oil	New VSMs along new ROW	16,300	6.9 - 9.2
10 - 20	17,500	600	29.1	17.7	192,200	8.3 - 11.6		New VSMs along existing pipeline and/or road corridor	45,900	13.0 - 21.7
20 - 30	4,840	600	8.1	4.9	53,200	2.8 - 3.7	Gas	New VSMs along new ROW	0	0
30 - 40	4,800	200	24	4.9	52,800	5.5 - 7.3		New VSMs along existing pipeline and/or road corridor	30,000	10.8 - 17.2
Totals	47,000	N/A	N/A	36.7	377,700	24.1 - 33.9	Totals	N/A	92,200	30.6 - 48.1

Notes:
- 1 = Offshore freshwater ice road cap (3 inches thick by 100 ft wide) requires 23,500 bbls/mile of pipeline length (47,000 ft requires 209,000 bbls freshwater).
- 2 = Total onshore pipeline corridor length is 63,270 ft (92,200 ft - 28,930 ft).
- 3 = Onshore freshwater ice road (2 inches thick by 75 ft wide) requires 11,800 bbls/mile of pipeline length (63,220 ft requires 141,400 bbls freshwater).
- 4 = Offshore pipeline landfall at Dockhead 2 along West Dock would require the placement of an additional 290,000 to 300,000 cubic yards of gravel fill placed along the west side of West Dock between Dockhead 2 and the West Dock staging pad.
- 5 = Source: Hanley, 1997:Attachment 2
- 6 = Source: BPXA, 1997b:2.4-6
- 7 = Pipeline trenching would be conducted with four crews working simultaneously.
  - Crew 1 and 2 would excavate the trench from landfall to the point where the pipeline turns north at the southern boundary of the Northstar Unit.
  - Crew 3 would start just outside the barrier island and continue to a point midway between the barrier island and Seal Island.
  - Crew 4 would begin at a point midway between the barrier islands and continue to Seal Island.
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- 10 = Typical VSM spacing for onshore pipeline construction is 55 ft (63,270 ft ÷ 55 ft = 1,150 VSMs) (I. Leavitt - Pers. Comm., 1997:1).
- 11 = 28,930 ft of onshore pipeline is shared in common onshore corridor.
- bbls = Barrels
- ft = Feet
- N/A = Not applicable
- ROW = Right-of-way
- VSMs = Vertical support members

TABLE ES-14
COMPARISON OF PROJECT ALTERNATIVES

Environment/ Resource	Alternative 1 No Action	Alternative 2 Point Storkersen/BPXA Proposal	Alternative 3 Point Storkersen/WDSP	Alternative 4 Point McIntyre/WDSP	Alternative 5 West Dock Causeway
Physical Environment					
Geology and Hydrology - Permafrost	No impact.	Alternatives 2, 3, and 4 all involve comparable impacts associated with potential thaw bulb creation and related subsidence caused within the shoreline permafrost transition zone.			Landfall on causeway and crossing the permafrost transition zone on fill avoids potential thaw bulb creation and related subsidence.
Coastal Erosion	No impact.	Alternatives 2, 3, and 4 all involve comparable impacts associated with potential shoreline erosion and pipe damage hazard caused by construction across a natural shoreline. Potential repeated maintenance of these landfalls could add recurring shoreline impacts.			Landfall on causeway avoids potential shoreline erosion and pipe damage hazard. Maintenance activity is expected to be minimal, and would be comparable to existing maintenance of the causeway.
Spill-related Impacts to Soils and Coastal Erosion	No impact.	Alternatives 2, 3, 4, and 5 could all result in significant oil spill contamination of onshore soils and/or seafloor sediments.			
Biological Environment					
Coastal Vegetation and Invertebrates - Vegetation Impacts	No impact.	Impacts to coastal vegetation at the Point Storkersen and Point McIntyre landfalls would be the same for Alternatives 2, 3, and 4 (impacts would be minor). Periodic maintenance of shoreline landfall may be required.			Coastal vegetation would not be impacted. Periodic maintenance of the landfall would not affect coastal vegetation.
Spill-related Impacts to Invertebrates	No impact.	Alternatives 2, 3, 4, and 5 could all result in significant oil spill mortality of freshwater invertebrates.			
Biological Environment (Cont.)					
Birds - Noise-related Impact	No impact.	Minor disturbance impacts to nesting birds from helicopter inspection overflights would be greater for Alternative 2 than those of Alternative 3 because the Alternative 2 crosses more undisturbed nesting habitat. Approximately 310 and 275 nesting birds (black brant, common eiders,		Minor disturbance impacts to nesting birds from helicopter inspection overflights would be similar for Alternatives 4 and 5, but less than Alternatives 2 and 3 because most of the corridors parallel existing pipeline	

Environment/ Resource	Alternative 1 No Action	Alternative 2 Point Storkersen/BPXA Proposal	Alternative 3 Point Storkersen/WDSP	Alternative 4 Point McIntyre/WDSP	Alternative 5 West Dock Causeway
		oldsquaw, and surf scoters) would be within a 0.25-mile (0.4 km) corridor along Alternative 2 and 3 pipelines, respectively.		and vehicle corridors. Approximately 140 and 127 nesting birds (black brant, common eiders, oldsquaw, and surf scoters) would be within a 0.25-mile (0.4 km) corridor along Alternative 4 and 5 pipelines, respectively.	
		Significant impacts to sea ducks (common eider and oldsquaw) from offshore helicopter overflights during construction only.			
Spill-related Impacts -	No impact.	Because nearshore lagoons could be more easily protected via booms, Alt. 5 would provide more protection to molting, staging, and brood-rearing migratory birds. If a major spill was to occur, direct mortality is expected and could include spectacled and Steller's eiders (threatened species). Reduced populations of several bird species could be evident for several years following the spill.			
Spectacled eiders	No impact.	Minor disturbance impacts from helicopter overflights to spectacled eider nesting pairs within 0.25 miles (0.4 km) of the Alternative 2 and 3 onshore corridor. Total of 6 for each alternative.		Minor disturbance impacts from helicopter overflights to spectacled eider nesting pairs within 0.25 miles (0.4 km) of the Alternative 4 and 5 onshore corridor. Total of 2 for each alternative.	
Terrestrial Mammals Noise-related Impact	No impact.	Minor caribou disturbance from helicopter overflights along 9.55 miles (15.37 km) of pipeline in undeveloped area.	Minor caribou disturbance from helicopter overflights along 6.7 miles (10.8 km) of pipeline in undeveloped area.	Helicopter overflights associated with Alternatives 4 and 5 would occur in an existing industrialized area and would result in minor effects on caribou. Undisturbed habitat is present along 3.4 and 3.1 miles (5.5 and 5 km) of Alternatives 4 and 5, respectively.	
Marine Mammals Noise-related Impacts	No impact.	Alternatives 2, 3, 4, and 5 would have comparable impacts on the bowhead whale, including bowhead whale avoidance of Seal Island and support activity noise, including a 3- to 6-mile (4.8 to 9.6 km) migration path deflection. This behavioral response would not harm individual whales or whale populations, but could affect subsistence harvesting.			
Spill-related Impacts	No impact.	Alternatives 2, 3, 4, and 5 could have comparable spill-related impacts to marine mammals. Depending on the season, size of spill, and response effectiveness, a large oil spill could result in injury and/or mortality of bowhead whales from an oil spill contacting the spring lead system coincident with migration. Other species, such as polar bears, could be adversely affected by ingestion of oil during grooming, consumption of oiled prey, or loss of insulation and subsequent hypothermia.			
Human Environment					
Subsistence - Noise-related Impacts	No impact.	Alternatives 2, 3, 4, and 5 would have comparable impacts on subsistence whaling. This impact is associated with bowhead whale avoidance of noise, which could reduce harvest success or increase safety risk to whalers. If this impact occurs, it would represent a significant adverse effect on subsistence harvest activities by reducing harvest success and increasing whaler safety risk. Decreased harvest could result in changes to IWC harvest quotas.			
Subsistence - Spill-related Impacts	No impact.	Alternatives 2, 3, 4, and 5 would have comparable impacts to subsistence whaling if a major offshore spill was to occur. Depending on the season of spill occurrence and size of spill, a large oil spill could significantly adversely affect whaling vessel operations, response efforts could create noise and activity that could result in whale avoidance behavior and reduced whaling success, and oiling of whales could taint the subsistence harvest. Other subsistence resources also would be significantly affected, including direct mortality and oil tainting of seals, birds, and fish.			

Environment/ Resource	Alternative 1 No Action	Alternative 2 Point Storkersen/BPXA Proposal	Alternative 3 Point Storkersen/WDSP	Alternative 4 Point McIntyre/WDSP	Alternative 5 West Dock Causeway
Cumulative Impacts	No contribution to cumulative impacts.	Alternatives 2, 3, 4, and 5 would have comparable contributions to cumulative impacts to subsistence whaling. Increased offshore industrial activity could cause bowhead whale avoidance and result in longer travel distances, increased safety risk, and reduced harvest success of subsistence whaling activity.			
Land and Water Use	No impact or land use conflicts.	Existing Conservation District policies applicable to offshore and onshore project areas are incompatible with the proposed alternative and required rezoning. This affects the island site and 9.55 miles (15.37 km) of onshore pipeline.	Existing Conservation District policies applicable to offshore and onshore project areas are incompatible with the proposed alternative and required rezoning. This affects the island site and 3.6 miles (5.8 km) of onshore pipeline.	Alternatives 4 and 5 would result in similar land use impacts associated with offshore project elements which are comparable to the offshore impacts described for Alternatives 2 and 3. Alternatives 4 and 5 would not result in onshore land use impacts.	
Cumulative Impacts	Alternative 1 does not contribute to cumulative impacts.	Alternative 2 would contribute to the intensification of industrial development by adding a pipeline across a currently undeveloped area and contributing to Gwydyr Bay development.	Alternative 3 would contribute to the intensification of industrial development by extension of a pipeline corridor closer to Gwydyr Bay and contributing to development in that area.	Alternatives 4 and 5 would contribute less to onshore cumulative impacts than would be contributed by Alternatives 2 and 3. Pipeline routing would mostly follow existing development corridors.	
Socioeconomics - Revenue Impact	No beneficial effect of federal, state, and local revenue generation.	Alternatives 2, 3, 4, and 5 would all result in the generation of revenue for the State of Alaska, including $478.9 million gross state revenues, $306.3 million in federal revenues, $64.3 million in NSB revenues, and $3 million in revenue to the Municipality of Anchorage over 15 years.			
Human Environment (Cont.)					
Development Costs	No development cost to the project proponent, and complete loss of investment in offshore leases and project planning and engineering.	$52.8 to $73.48 million pipeline and ice road construction cost. $405 million total construction cost.	$57.44 to $83.52 million pipeline and ice road construction cost. $415 million total construction cost.	$54.37 to $81.30 million pipeline and ice road construction cost. $413 million total construction cost.	$58.07 to $86.58 million pipeline and ice road construction cost. $418 million total construction cost.
Employment Impacts	No new employment opportunities.	Alternatives 2, 3, 4, and 5 would all result in comparable employment including the creation of approximately 730 construction jobs and 100 facility operations jobs, with a total payroll of $307 million.			
Cumulative Impacts	No contribution to currently declining oil production revenues.	Alternatives 2, 3, 4, and 5 would result in comparable contributions of government revenue to partially offset projected declines. This contribution represents 2.4% of the total North Slope oil production (and related revenues) over the 15-year project life.			
Visual/Aesthetic Characteristics	No impacts.	Project-specific and contribution to cumulative impacts associated with visible lighting offshore and a	Project-specific and contribution to cumulative impacts associated with visible lighting offshore and	Alternatives 4 and 5 would result in the same offshore project-specific and contribution to cumulative offshore visual impacts as discussed in connection with	

Environment/ Resource	Alternative 1 No Action	Alternative 2 Point Storkersen/BPXA Proposal	Alternative 3 Point Storkersen/WDSP	Alternative 4 Point McIntyre/WDSP	Alternative 5 West Dock Causeway
		9.55-mile (15.37 km) long pipeline in an undeveloped area.	a 3.6-mile (5.8 km) long pipeline in an undeveloped area.	Alternatives 2 and 3.	
Oil Spills					
Probability of Spill Occurrence -- Total Project[1]	No project-related risk of spill occurrence.	Any Source - 11% to 24% Pipeline - 4.5% to 19%	Any Source - 12% to 24% Pipeline - 5.6% to 19%	Any Source - 12% to 24% Pipeline - 5.5% to 19%	Any Source - 12% to 24% Pipeline - 5.4% to 19%
Pipeline[2]		Offshore - 1.6% Onshore - 3%	Offshore - 1.6% Onshore - 4.1%	Offshore - 2.4% Onshore - 3.2%	Offshore - 2.4% Onshore - 3.1%
Maximum Potential Pipeline Spill Volume -- Onshore[3]	No potential for any project-related oil spillage.	Pipeline Rupture - 6,400 bbls Chronic Leak - 6,600 bbls	Pipeline Rupture - 8,700 bbls Chronic Leak - 8,900 bbls	Pipeline Rupture - 6,800 bbls Chronic Leak - 7,000 bbls	Pipeline Rupture - 6,700 bbls Chronic Leak - 6,900 bbls
Offshore[3]		Pipeline Rupture - 3,600 bbls Chronic Leak[4] - 6,600 bbls	Pipeline Rupture - 3,600 bbls Chronic Leak[4] - 6,600 bbls	Pipeline Rupture - 5,300 bbls Chronic Leak[4] - 8,200 bbls	Pipeline Rupture - 5,200 bbls Chronic Leak[4] - 8,100 bbls
Oil Spills (Cont.)					
Spill Response Actions -- Onshore	No need for spill response and no response-related impacts.	Spill response access damage associated with 9.55 miles (15.37 km) of pipe in undeveloped area without roadway access.	Spill response access damage associated with 3.6 miles (5.8 km) of pipe in undeveloped area without roadway access.	Alternatives 4 and 5 present small risk of onshore spill response access damage because the onshore pipeline route is accessible from or within 1.5 miles (2.4 km) of existing roadways.	
Offshore		Since spill response equipment would be staged at West Dock, offshore spill responses for Alternatives 2 and 3 would not be as rapid as those for Alternatives 4 and 5.			
Contribution to Cumulative Oil Spill Probability	No contribution to cumulative major spill risk, which would be approximately 93.7% considering other North Slope oil and gas operations from 1997 to 2020.	Alternatives 2, 3, 4, and 5 would all result in a comparable contribution to the overall cumulative spill risk associated with North Slope oil development. Because the Northstar Project represents a relatively small component of the total North Slope development (approximately 2.4% of the total North Slope oil production over the project lifetime), each of these alternatives would result in a 1.5% contribution to the total cumulative spill risk of 95.2% from 1997 to 2020.			

Notes: 1 = Total project spill probabilities are based on CONCAWE and MMS OCS spill statistics for spills from any source (Table 8-6).
2 = Pipeline spill probabilities are based on CONCAWE spill statistics (Table 8-7).
3 = Maximum pipeline spill volumes for a rupture or chronic leak are based on specific calculation assumptions given in Table 8-5. These include: an oil flow rate of 65,000 barrels per day, pipeline lengths between check valves for the different alternatives, and complete drainage of oil from the pipeline. Although drainage of the entire pipeline volume between valves would likely be prevented by seawater intrusion (offshore) and operational measures, it is

		presented as the worst case spill volume.
4	=	Maximum offshore pipeline spill volumes are based on the chronic leak scenario during unstable solid ice conditions, with the detection time assumed to be 35 days.

bbls	=	Barrels
BPXA	=	BP Exploration (Alaska)
gals	=	Gallons
km	=	Kilometers
MMS	=	Minerals Management Service
NSB	=	North Slope Borough
OCS	=	Outer Continental Shelf
%	=	Percent
WDSP	=	West Dock Staging Pad

TABLE ES-15
COMPARISON OF ESTIMATED PIPELINE CONSTRUCTION COSTS BY ALTERNATIVE
(Million $)

Characteristics	Alternatives				
	1	2	3	4	5
Estimated Pipeline Construction Costs [1]					
Onshore	0	32.50 - 45.70	37.10 - 56.70	26.60 - 42.40	30.70 - 48.10
Offshore	0	17.50 - 24.30	17.50 - 24.30	24.40 - 34.30	24.10 - 33.90
Subtotal	0	50.00 - 70.00	54.60 - 81.00	51.00 - 76.70	54.80 - 82.00
Estimated Ice Road Costs Associated with Pipeline Construction [2]					
Onshore	0	0.46 - 0.61	0.50 - 0.65	0.04 - 0.51	0.04 - 0.50
Offshore <8.5 ft	0	0.07 - 0.10	0.07 - 0.10	0.12 - 0.16	0.12 - 0.15
Offshore >8.5 ft	0	2.27 - 2.77	2.27 - 2.77	3.21 - 3.93	3.21 - 3.93
Subtotal	0	2.80 - 3.48	2.84 - 3.52	3.37 - 4.60	3.37 - 4.58
Total Pipeline Construction Costs	0	52.80 - 73.48	57.44 - 83.52	54.37 - 81.30	58.07 - 86.58
Total Estimated Capital Expenditure for Construction of the Northstar Development Project	0	405	415	413	418

Notes:
1 = Source: BPXA, 1997a:1
2 = Source: Rainwater, 1997:1
3 = Includes $5.7 million for widening the causeway.
4 = Estimated from BP (Exploration) Alaska, Inc's. projected capital expenditure of $405 million, assuming that includes the high end of the pipeline cost range.

TABLE ES-15
COMPARISON OF ESTIMATED PIPELINE CONSTRUCTION COSTS BY ALTERNATIVE
(Million $)

Characteristics	**Alternatives**				
	1	**2**	**3**	**4**	**5**
Estimated Pipeline Construction Costs [1]					
Onshore	0	32.50 - 45.70	37.10 - 56.70	26.60 - 42.40	30.70 - 48.10
Offshore	0	17.50 - 24.30	17.50 - 24.30	24.40 - 34.30	24.10 - 33.90
Subtotal	0	50.00 - 70.00	54.60 - 81.00	51.00 - 76.70	54.80 - 82.00
Estimated Ice Road Costs Associated with Pipeline Construction [2]					
Onshore	0	0.46 - 0.61	0.50 - 0.65	0.04 - 0.51	0.04 - 0.50
Offshore <8.5 ft	0	0.07 - 0.10	0.07 - 0.10	0.12 - 0.16	0.12 - 0.15
Offshore >8.5 ft	0	2.27 - 2.77	2.27 - 2.77	3.21 - 3.93	3.21 - 3.93
Subtotal	0	2.80 - 3.48	2.84 - 3.52	3.37 - 4.60	3.37 - 4.58
Total Pipeline Construction Costs	0	52.80 - 73.48	57.44 - 83.52	54.37 - 81.30	58.07 - 86.58
Total Estimated Capital Expenditure for Construction of the Northstar Development Project	0	405	415	413	418

Notes:
1 = Source: BPXA, 1997a:1
2 = Source: Rainwater, 1997:1
3 = Includes $5.7 million for widening the causeway.
4 = Estimated from BP (Exploration) Alaska, Inc□s. projected capital expenditure of $405 million, assuming that includes the high end of the pipeline cost range.

TABLE ES-16
COMPARISON OF POTENTIAL OIL SPILL EVENTS BY ALTERNATIVE

Characteristics	**Alternatives**				
	1	**2**	**3**	**4**	**5**
Probability of 1 or More Releases Occurring Over 15-Year Design Life					
Spill >1,000 barrels (Pipeline)[1]	0	4.5%	5.6%	5.5%	5.4%
Spill >1,000 barrels (Any Source)[2]	0	11%	12%	12%	12%
Maximum Potential Release Volumes (in barrels)					
Blowout	0	225,000	225,000	225,000	225,000
Offshore Pipeline Rupture	0	3,600	3,600	5,300	5,200
Onshore Pipeline Rupture	0	6,400	8,700	6,800	6,700
Offshore Chronic Pipeline Leak	0	6,600	6,600	8,200	8,100
Onshore Chronic Pipeline Leak	0	6,600	8,900	7,000	6,900

Notes:

1	=	CONCAWE pipeline spill statistics used; based on spills exceeding 1,00 barrels
2	=	CONCAWE pipeline and MMS OCS platform spill statistics used.
%	=	Percent
CONCAWE	=	Conservation of Clean Air and Water in Europe
MMS	=	Minerals Management Service
OCS	=	Outer Continental Shelf

Sources: CONCAWE, 1997:2; Anderson and LaBelle, 1994:11