BEAUFORT SEA OIL AND GAS DEVELOPMENT/ NORTHSTAR PROJECT

FINAL ENVIRONMENTAL IMPACT STATEMENT

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LIST OF ACRONYMS AND ABBREVIATIONS

LIST OF ACRONYMS AND ABBREVIATIONS

AAC	Alaska Administrative Code
ACMP	Alaska Coastal Management Program
ACS	Alaska Clean Seas
A.D.	Anno Domini
ADEC	Alaska Department of Environmental Conservation
ADL	Alaska Division of Lands
ADNR	Alaska Department of Natural Resources
AEWC	Alaska Eskimo Whaling Commission
ANCSA	Alaska Native Claims Settlement Act
ANWR	Arctic National Wildlife Refuge
ARCO	Atlantic Richfield Company (or ARCO Alaska, Inc., a subsidiary)
ARRC	Alaska Railroad Corporation
AS	Alaska Statute
BACT	Best Available Control Technology
barrels/day	barrels per day
BLM	Bureau of Land Management (USDOI)
B.P.	Before Present
BPXA	BP Exploration (Alaska) Inc.
Btu/hr	British thermal units per hour
°C	degrees Celsius
CAA	Clean Air Act
CAH	Central Arctic Herd (Caribou)
CCP	Central Compressor Plant
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfs	cubic feet per second
CIDS	Concrete Island Drilling Structure
cm	centimeter(s)
CMP	Coastal Management Plan
CO	carbon monoxide
COFR	Certificate of Financial Responsibility
Corps	U.S. Army Engineer District, Alaska
CRI	Caisson Retained Island
dB	decibel(s)
dBA	A-weighted sound level
DEIS	Draft Environmental Impact Statement
DEW	Distant Early Warning (Line)
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
°F	degrees Fahrenheit

FEIS	Final Environmental Impact Statement
FR	Federal Register
ft	foot, feet
ft^3	cubic feet
ft/yr	feet per year
GCM	Global Climate Model
gpd	gallons per day
Hz	Hertz
INTEC	INTEC Engineering, Inc.
IWC	International Whaling Commission
kHz	kilohertz
km	kilometer(s)
km/hour	kilometers per hour
km^2	square kilometer(s)
liters/day	liters per day
LMRs	land management regulations
m	meter(s)
m^3	cubic meter(s)
m/yr	meters per year
m^3/s	cubic meter(s) per second
mg/L	milligrams per liter
MLLW	mean lower low water
mm	millimeter(s)
MMS	Minerals Management Service (USDOI)
mph	miles per hour
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service (USDOC)
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration (USDOC)
NPDES	National Pollutant Discharge Elimination System
NPRA	National Petroleum Reserve - Alaska (formerly Naval Petroleum Reserve Number 4)
NSB	North Slope Borough
NTU	nephelometric turbidity units
NWI	National Wetlands Inventory
OCS	Outer Continental Shelf
ODCE	Ocean Discharge Criteria Evaluation
ODPCP	Oil Discharge prevention and Contingency Plan
%	percent
pH	potential of Hydrogen (measures the acidity or alkalinity of a substance)
PM1	Point McIntyre No. 1
PM_{10}	particulate matter less than 10 microns in diameter

PM2	Point McIntyre No. 2
PPA	Pressure Point Analysis
ppm	parts per million
ppt	parts per thousand
Put 23	Put 23 Oxbow
PSD	Prevention of Significant Deterioration
ROD	Record of Decision
s	second
SCADA	Supervisory Control and Data Acquisition
sec	second
SHPO	State Historic Preservation Officer (or Office)
SO_2	sulfur dioxide
SPCC	Spill Prevention Containment, and Countermeasure (Plan)
SPL	sound pressure level
SPO	State Pipeline Office
SSDC	Single Steel Drilling Caisson
STP	seawater treatment plant
TAPS	Trans Alaska Pipeline System
TOC	total organic carbon
tpy	tons per year
µg-at/L	microgram atoms per liter
UIC	Underground Injection Control (Permit)
µPa	microPascal
USDOC	U.S. Department of Commerce
USDOI	U.S. Department of the Interior
USFWS	U.S. Fish and Wildlife Service (USDOI)
VOCs	volatile organic compounds
VSMs	vertical support members
yd^3	cubic yard(s)

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CHAPTER 1.0

INTRODUCTION

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1.0 INTRODUCTION

1.1 PROJECT OVERVIEW

BP Exploration (Alaska) Inc. (BPXA) submitted a permit application to the U.S. Army Engineer District, Alaska (Corps) to initiate the review process for BPXA's plans to develop and produce oil and gas from the Northstar Unit. A permit is required by Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act because BPXA proposes to discharge dredged or fill material into United States waters and to do work in navigable waters of the United States.

The Corps determined that issuance of a permit for BPXA’s proposed project constituted a major federal action that may significantly affect the quality of the human environment pursuant to the National Environmental Policy Act (NEPA). In addition, the U.S. Environmental Protection Agency (EPA), upon review of BPXA’s permit application, determined under provisions of the Clean Water Act and 40 CFR Part 6 Subpart F that permitting for BPXA's proposed project constituted a major federal action that may significantly affect the quality of the human environment. As a result, preparation of an Environmental Impact Statement (EIS) under NEPA was undertaken to identify and evaluate a range of reasonable alternatives and evaluate the potential effects the alternatives, including BPXA’s proposed project, may have on the human environment. This information will be used in rendering permit approvals or other action decisions including the authorization of small takes of marine mammals under the Marine Mammal Protection Act by the U.S. Fish and Wildlife Service (USFWS) and National Marine Fisheries Service (NMFS).

Assuming the role of lead federal agency, the Corps initiated a cooperative agreement with four other federal agencies (the Minerals Management Service [MMS], USFWS, NMFS, and the EPA) and the North Slope Borough (NSB). These agencies have regulatory responsibilities applicable to the proposed project. This Alaskan Beaufort Sea Oil and Gas Development/Northstar Project EIS has been prepared by the lead and cooperating agencies, with the assistance of a third-party contractor funded by BPXA.

Figure 1-1, Northstar Unit Location and Project Area, depicts the Northstar project area. This area generally corresponds to the area of consideration for this EIS. However, in some instances, the area of consideration varies due to the nature of the anticipated project effects (e.g. oil spill and cumulative impacts). The Northstar Unit is located between 2 and 8 miles (3.2 and 12.8 kilometers) offshore of Point Storkersen in the Alaskan Beaufort Sea. Oil and gas drilling, processing, and production is proposed to take place at Seal Island, a manmade gravel island originally built by Shell Oil Company to conduct exploratory activities within the Northstar Unit during the 1980s. BPXA’s proposed project includes reconstructing and enlarging Seal Island and directionally drilling production, gas injection, and waste disposal wells from the island. Two pipelines would be constructed for the project. Crude oil produced from the Northstar reservoir would be transported by a buried subsea pipeline from Seal Island to the coastline and subsequently to the Trans Alaska Pipeline System and marine terminal at Valdez, Alaska. From Valdez, oil would be transported by tanker to U.S. west coast and international ports. A second pipeline would be constructed to transport gas from an existing onshore facility to the island to assist with oil recovery. The offshore portion of the pipelines would be buried in a common trench on the seafloor. Crude oil production from the Northstar reservoir is estimated to be 158 million barrels over the anticipated 15-year life of the reservoir. Maximum daily production is estimated to peak at approximately 65,000 barrels of oil per day. A detailed description of BPXA's proposed project is included as Appendix A.

1.2 PURPOSE OF AND NEED FOR ACTION

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 domestic production, including Alaska's contribution, is in decline. This project also will prolong the economic viability of the Trans Alaska Pipeline System.

The NEPA requires the preparation of an 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 making decisions on the project. Because this project represents the first development of Outer Continental Shelf (OCS) oil and gas resources in the Alaskan Beaufort Sea, this EIS addresses a range of potentially applicable technologies and development/production options to provide useful information applicable to evaluate future development proposals.

The proposed development of the Northstar Unit presents several issues which may have significant adverse impacts. The Corps has determined that an EIS is required because:

- The Northstar Project is 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.

- The risks of oil spills from an offshore development/production island and a subsea pipeline system exposed to hazards have not been examined previously.

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

- The effects of long-term, year-round offshore oil and gas development/production activities, particularly noise, on subsistence resources and the subsistence lifestyle of NSB residents should be addressed.

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1.3 AGENCY GOALS FOR THIS EIS

The Corps and the cooperating agencies developed specific goals for this 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 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 1-1).

- 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 in 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, and 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 are appended to this EIS, and rely on this EIS for 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 processes. Agencies have identified to the extent possible preferred alternatives in Section 11.9. Final agency decisions will be made in the Records of Decisions after consideration of the FEIS and all comments received.

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

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- 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.

- 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.

Permits for oil and gas development/production activities from the Northstar Unit will not be issued prior to records of decision being issued by the lead and cooperating agencies. Coordination of EIS preparation with the development of specific permit related information is intended to improve the consistency of multiple agency actions related to this proposal.

1.4 AGENCY RESPONSIBILITIES

In addition to the lead agency decision pursuant to NEPA, several specific federal, state, and local permits and approvals are required prior to development of the Northstar Unit. These approvals are summarized in Table 1-2 and discussed below.

1.4.1 U.S. Army Engineer District, Alaska

Section 404 Permit: To address the Clean Water Act Section 404 requirements, the EIS identifies waters and wetlands within the project area, and describes wetland types and functions. The EIS describes the project components, identifies the type and amount of wetlands and other waters affected by each alternative, describes anticipated impacts, and discusses mitigation measures that have been incorporated to minimize impacts to these resources.

Section 10 Permit: To address requirements of Section 10 of the Rivers and Harbors Act of 1899, the EIS describes navigable waters of the United States within the project area and how structures in, on, or over these waters (e.g., the proposed island and buried pipelines) would affect these waters during construction and operation. The EIS describes the alternatives and compares possible impacts to coastal integrity and navigation from each alternative. It also discusses mitigating measures to minimize these impacts.

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Section 103 Permit: The EIS provides information about dredged material and the substrate at the disposal sites, such as grain size and contaminants, to support agency decisions about disposal of waste material from pipeline trenching. The Corps issues permits for the transportation of dredged material for the purpose of ocean disposal. The EPA must concur with the proposed disposal site.

1.4.2 U.S. Environmental Protection Agency

NPDES Permit and Fact Sheet: The EIS summarizes the present marine water quality, marine life, and human activities in and near the Northstar Unit, including a summary of oceanographic data such as ocean currents and stratification, sea ice, and meteorological conditions. Possible marine discharges associated with either the construction or operation of an offshore development facility are included in the EIS. Descriptions of these discharges include discharge purpose, flow rates, frequency of discharge, and expected pollutants, including concentrations. The EIS also reviews the possible impacts from such discharges and provides both discharge limits and monitoring requirements. In particular, these requirements are stated in the NPDES Permit, while the associated Fact Sheet provides technical justification for these requirements. This justification includes a summary of risk to biota from these possible marine discharges.

Air Quality Permits: The EIS provides an analysis of meteorological factors and air quality baseline conditions and predicts potential impacts to air quality during construction and operations. Prevention of Significant Deterioration (PSD) regulations define major sources as those which have the potential to emit 250 tons (226,798 kilograms) per year or more of any pollutant regulated under the Clean Air Act (CAA). Sources subject to PSD permitting go through pre-construction review and may require collection of meteorological data and modeling of pollutant pathways. A permit under the EPA-approved State of Alaska Title V Operating Permits program will be required for development of the Northstar Unit.

Underground Injection Control: Information is provided in the EIS regarding the use of proposed Class I industrial waste disposal wells, which may be used for disposal of non-hazardous, non-exempt fluids. The EPA reviews applications for Class I industrial waste disposal wells under the Safe Drinking Water Act.

Spill Prevention, Containment, and Countermeasure (SPCC) Plan: The EPA requires an SPCC Plan to be developed by owners and operators of any facility storing in excess of 1,320 gallons (4,997 liters) of fuel in aboveground tanks. The SPCC Plan will describe the location of the fuel storage tank and methods of spill prevention to be implemented at the proposed facility. The SPCC Plan must be developed prior to commencement of oil production. The SPCC Plan is not a part of this EIS.

Council on Environmental Qualities (CEQ): The EPA reviews and evaluates the Draft EIS (DEIS) and Final EIS (FEIS) for compliance with CEQ guidelines, as specified in 40 CFR 1500-1508.

Section 309, Clean Air Act: The CAA (Title III, Section 309), as amended in August 1977, contains guidance that the EPA should review and comment, in writing, on the environmental impact of matters relating to the CAA. This guidance would pertain to the EPA commenting on the DEIS and FEIS for the Northstar Project.

Section 103 Permit: The EPA reviews the ODCE prepared by the Corps for ocean dumping and must concur with the proposed disposal site.

1.4.3 Minerals Management Service

Plans of Operation for Federally Managed Leases: The EIS provides information utilized in developing Exploration Plans, Development and Production Plans, Applications for Permit to Drill, and other applications pertaining to proposed activities located on and under leases managed by the MMS, which must be submitted to and approved by the Regional Supervisor prior to commencement of operations (30 CFR Part 250). Within the Northstar Unit, two leases are federal and five are state. The regulations mandate that the Development and Production Plans meet public review and coastal zone consistency certification (30 CFR 250.34) requirements.

Oil Discharge Prevention and Contingency Plan (ODPCP) and Certificate of Financial Responsibility (COFR): The EIS describes storage and transportation of oil produced from the Northstar Project. This information is used in spill prevention planning and as baseline information for the COFR. In a Letter of Agreement (October 23, 1994), the Director of the MMS, Alaska OCS Region, and the Alaska Department of Environmental Conservation's (ADEC) Director of Air and Water Quality agreed that oil spill response plans approved by ADEC under 18 AAC 75 normally will satisfy federal requirements under the 30 CFR 254 interim regulations. The MMS has jurisdiction over OCS offshore production facilities and will coordinate with the ADEC to resolve or clarify any discrepancies or conflicts between federal and state regulations. Similar to the SPCC Plan, the Oil Discharge Prevention and Contingency Plan and the Certificate of Financial Responsibility must be produced and approved (by the MMS) prior to the commencement of oil production. These documents are not a part of this EIS.

1.4.4 U.S. Fish and Wildlife Service

Endangered Species Act Consultation: To ensure conformance with the requirements of Section 7(a)(2) of the Endangered Species Act of 1973 (ESA), as amended, information was requested from USFWS regarding threatened or endangered species in the area of the proposed project and oil transportation routes. As part of the Section 7 consultation process, a Biological Assessment was prepared by the Corps and submitted to the USFWS separately from the EIS, a copy of which was included in the DEIS as Appendix B. This Biological Assessment combines information on species under both USFWS' and NMFS' jurisdiction to evaluate project impacts.

Fish and Wildlife Coordination Act: The EIS provides baseline and impact information on fish and wildlife resources within the project area for use by the USFWS in its review of the proposed action.

Marine Mammal Protection Act: The EIS provides baseline and impact information on marine mammals within the project area for use by the USFWS in its review of the proposed action.

1.4.5 National Marine Fisheries Service

Endangered Species Act Consultation: The NMFS provided information to the Corps regarding threatened or endangered species in the area of the proposed project and oil transportation routes to ensure conformance with requirements of Section 7(a)(2) of the ESA, as amended. As part of the Section 7 consultation process, a Biological Assessment (Appendix B of the DEIS) was prepared by the Corps and submitted to the NMFS separately from the EIS. This Biological Assessment combines information on species under both NMFS' and USFWS' jurisdiction to evaluate project impacts.

Fish and Wildlife Coordination Act: The EIS provides baseline and impact information on fish and wildlife resources within the project area for use by NMFS in its review of the proposed action.

Marine Mammal Protection Act: The EIS provides baseline and impact information on marine mammals within the project area for use by NMFS in its review of the proposed action.

1.4.6 North Slope Borough

Rezoning and Master Plan Revision: A rezoning recommendation by the NSB Planning Commission and final determination by the NSB Assembly are necessary to convert Northstar Unit tracts presently within the NSB Conservation Zoning District to the Resource Development District. The rezoning must include an associated NSB Master Plan revision. The EIS contains a description of existing NSB zoning districts within the project area and potential impacts of the proposed rezoning to assist with the rezoning process.

Coastal Zone Management Act: The EIS provides a description of the location, type, and operation of the proposed project facilities. This description will assist the State of Alaska and the NSB in their review and determination of BPXA's project consistency with the Alaska Coastal Management Program and NSB Coastal Management Program.

1.4.7 All Federal Agencies

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 (Section 5.3). 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. This information is covered in Section 6.6.

Environmental Justice: Executive Order 12898 requires that federal agencies make achieving Environmental Justice part of their mission by identifying and addressing disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States. The North Slope is defined as an area bounded by the northern foothills of the Brooks Range to the Alaskan Beaufort Sea coastline and from the Chukchi Sea coast to the Canadian border. This development will take place in an area where there exists an indigenous population with a subsistence culture closely tied to the environment. It has been the intent of the lead and cooperating agencies to comply with Executive Order 12898. There is a strong link between Environmental Justice requirements and the use of Traditional Knowledge in the EIS. The cooperating agencies committed to collecting and incorporating Traditional Knowledge, in part, to meet requirements outlined in Executive Order 12898 regarding Environmental Justice.

Preparation of the Beaufort Sea Oil and Gas Development/Northstar Project EIS has taken the following steps to comply with Executive Order 12898 in addressing Environmental Justice and enhancing participation by affected communities.

- Preparation of this EIS has provided many opportunities for community input.

- Project scoping meetings were held in three NSB communities (Barrow, Nuiqsut, and Kaktovik) that have the potential to be affected by the proposed project.

- Translators were used to assist with presentations on the nature of the proposed project and to assist residents expressing their comments regarding the proposed project.

- Additional meetings were held in each of the communities to collect Traditional Knowledge on characteristics of the affected environment and potential environmental consequences.

- Workshops were held in each of the three NSB communities to help residents better understand the EIS content and public review and comment process.

- Formal public hearings were also held to obtain comments on the DEIS and in each of the three NSB communities. Translators were used to assist with public testimony in Kaktovik and Nuiqsut.

- Traditional Knowledge has been used extensively in preparation of the EIS.

- The cooperating agencies, BPXA, the third-party contractors, and residents of affected communities on the North Slope committed to collecting Traditional Knowledge and incorporating it into the EIS.

- Traditional Knowledge was obtained from comments made during scoping meetings, review of past testimony on projects related to oil and gas development on the North Slope, and meetings with whaling captains and other knowledgeable individuals.

- Use of Traditional Knowledge has helped describe the affected environment, assess environmental consequences, enhance public participation, and help develop appropriate mitigation measures to avoid or minimize potential impacts.

- Accumulation, compilation and integration of Traditional Knowledge is described in Chapter 2 (Traditional Knowledge) and used in the description of the affected environment and assessment of environmental consequences presented in Chapters 5 through 9 and the Biological Assessment (Appendix B of the DEIS).

· Topics specified in Executive Order 12898 have been addressed in the Affected Environment sections of Chapters 5 through 9 of the EIS.

- These topics include a description of the socioeconomic characteristics of affected communities, such as ethnic composition of the population and employment and income levels. A description of specific subsistence resources (game and fish utilized by local residents), activities, and harvest and consumption levels of affected communities has been provided.

- Potential adverse and beneficial effects on local residents in the project area have been evaluated (Chapter 7). The analysis of environmental consequences of each of the project alternatives has addressed potential adverse impacts on: fish and wildlife used by local residents for subsistence, subsistence activities and harvest levels, and potential effects on human health. Potential beneficial effects stemming from local employment opportunities and from state and local revenues that are used to provide public facilities and services to communities in the project area also have been addressed.

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 Record of Decisions issued by federal agencies. Traditional Knowledge has been a factor in the EIS and decision-making process in three ways. It has been a factor in reaching conclusions of significant impact (e.g., significant impacts of noise on subsistence whaling harvests). Traditional Knowledge has been incorporated into development of mitigation measures. Finally, Traditional Knowledge has been a factor in project design changes (e.g., the applicant has changed the color of project facilities to avoid disturbance to subsistence whaling harvests). A general summary of where information related to Environmental Justice and Traditional Knowledge can be found in the EIS is presented in Table 1-3. In addition, an index of the location of Traditional Knowledge on specific topics can be found in the EIS.

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As a result of the NSB community meetings and evaluation of Traditional Knowledge, substantive concerns with regard to the Northstar Project were identified. These concerns were focused primarily on potential impacts to subsistence whaling associated with project noise. Oil spill risk and potential widespread environmental damage (including direct impacts to subsistence resources) were additional concerns of the local population. To provide decision-makers and the public with an adequate treatment of these topics, specific EIS chapters are included which address these concerns.

Cultural Resources: The EIS provides information on cultural and archaeological resources in the project area and analysis of the impacts from construction and operation of the project alternatives (Section 7.4). Federal agencies coordinated with the State Historic Preservation Officer for a “no adverse impact” determination or to develop mitigation for adverse impacts during the public review of the DEIS.

1.4.8 Government to Government Coordination

The United States has a unique legal relationship with Indian tribal governments as set forth in the Constitution of the United States, treaties, statutes, Executive Orders, and court decisions. Since the formation of the Union, the United States has recognized Indian tribes as domestic dependent nations under its protection. In treaties, our Nation has guaranteed the right of Indian tribes to self-government. As domestic dependent nations, Indian tribes exercise inherent sovereign powers over their members and territory. The United States continues to work with Indian tribes on a government-to-government basis to address issues concerning Indian tribal self-government, trust resources, and Indian tribal treaty and other rights.

Executive Order 13084 was in part intended 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. Section 3(a) of the executive order states that each agency shall have an effective process to permit elected officials and other representatives of Indian tribal governments to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.

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. During the public comment period each of the federally recognized tribal governments had the opportunity to comment on the DEIS. Representatives of each federally recognized tribal government received, either directly in their capacity as a tribal official, or in some other capacity, notices and newsletters concerning the status and the availability of the DEIS. Likewise, in their capacity as tribal officials, or in some other capacity (e.g. municipal or corporate official, whaling captain, concerned individual), these tribal representatives received copies of the DEIS or its Executive Summary, and attended the public workshop and/or public hearing in their community on the document.

Among the federally recognized tribal governments, the Inupiat Community of the Arctic Slope submitted written comments on the DEIS (see letter F420 in Appendix K), and these were responded to in this FEIS (see response to comments, F420-77 to F420-84 in Appendix L). The Inupiat Community of the Arctic Slope also responded to an offer made to all four federally recognized tribal governments to meet with the lead and cooperating federal agencies to discuss the status of the EIS development process. The meeting was held in Anchorage on October 16, 1998.

Copies of the FEIS will be sent to each of the federally recognized tribal governments and each will have the opportunity to comment during the 30-day public comment period. The federal cooperating agencies will address all comments received and will consult with each federally recognized tribal government regarding their comments.

1.4.9 State of Alaska

Although no state agencies participated in the EIS development or relied directly on the EIS for permit decisions, there was a large overlap between information needs for federal and state regulatory programs. The state and the lead and cooperating agencies coordinated information requests and reviews when possible. The state indirectly relies on the EIS process through certification of federal agency permits that rely on information contained in the EIS. State permits and approvals anticipated for Northstar Unit development are listed in Table 1-2.

1.5 SUMMARY OF THE SCOPING PROCESS AND KEY ISSUES IDENTIFIED

Scoping is the process of identifying both the range of issues to be addressed in the EIS and the significant issues potentially resulting from a proposed action. Scoping includes written comments, statements at public meetings, and consultation with federal, state, and local agency officials, interested groups, and individuals. Scoping occurs early in the EIS process and is designed to be an open, public activity. Comments about the proposed project are communicated to resolve potential conflicts and assist with efficient preparation of an accurate and comprehensive EIS.

A *Notice of Intent* was published in the Federal Register on November 24, 1995, announcing the anticipated 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. A mailing list was compiled and is included as Appendix C to the DEIS. Newsletters were mailed to approximately 5,000 interested parties at various stages during EIS development. Advertisements about scoping meetings were placed in four newspapers throughout the state: the Anchorage Daily News, the Fairbanks Daily News-Miner, the Valdez Vanguard, and the Arctic Sounder. Public announcements were scheduled on KSKA (Anchorage Radio), KBRW (Barrow Radio), Barrow Cable Television, and Kaktovik Television. In addition, poster-sized notices were displayed in communities where public meetings were held.

Written comments on the proposed project have been solicited and received, and seven public scoping meetings were held for communities and agencies on the dates listed below.

- Barrow Public Scoping Meeting - March 25, 1996 (with Inupiaq translator)
- Kaktovik Public Scoping Meeting - March 26, 1996 (with Inupiaq translator)

- Nuiqsut Public Scoping Meeting - March 27, 1996 (postponed[1])
- Fairbanks Public Scoping Meeting - March 28, 1996
- Anchorage Agency Scoping Meeting - April 1, 1996
- Valdez Public Scoping Meeting - April 2, 1996
- Anchorage Public Scoping Meeting - April 3, 1996
- Nuiqsut Public Scoping Meeting - May 7, 1996 (with Inupiaq translator)

(1) Postponed due to weather on March 27 and postponed per community request on March 28. Rescheduled to May 7, 1996.

In addition to the public scoping meetings, smaller, informal public involvement meetings were held. These meetings served the dual purpose of receiving scoping comments and collecting Traditional Knowledge in the region (Chapter 2). Additionally, BPXA held meetings with interested individuals in and around the project area to provide information specific to the proposed project. The public and agencies identified issues of concern with the proposed development, including numerous specific questions regarding the effects of the project.

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 is located in city offices at Barrow, Kaktovik, and Nuiqsut; at the NSB office in Barrow; at the Office of the Alaska Eskimo Whaling Commission in Barrow; and in city libraries at Anchorage, Fairbanks, and Valdez. It 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: Most of the general comments involved concerns regarding cumulative impacts of additional Alaskan Beaufort Sea development, and permitting issues.

- There is the general concern that approval of this development will increase the likelihood of further offshore oil and gas development in the Alaskan Beaufort Sea and the cumulative effects of these potential future developments need to be addressed (Chapter 10).

- Prevention and avoidance of negative whaler/industry interaction needs to be anticipated. Guidelines should be established early in the project to prevent potential conflicts. In addition, there may need to be temporary work stoppages to allow for whale hunting and to minimize disruption during offshore subsistence hunts (Section 7.3).

- Identify steps that can be taken to avoid or mitigate potential impacts to subsistence resources and access, and monitoring programs may need to be established to assess the effectiveness of mitigation measures. The affected communities should have a role in establishing effective mitigation measures based on their experience in dealing with oil and gas activities (Chapter 11).

- The Coastal Standard of the Alaska Coastal Management Program needs to be integrated into the EIS, and all pertinent issues addressed (Section 7.5).

Project Design: Concerns/issues were raised on the design of the production platform/island, subsea pipelines, and resupply. These are summarized below.

· Concerns were raised about the type of armor planned for the proposed island and which type would work best considering ice forces, wave impacts, and storm tide height at the site (Section 4.4).

· The rehabilitation of the island and the reinstatement of the near-shore ecosystem after production ends should be considered and elements incorporated into the project design (Section 4.4).

· Questions were raised about the integrity of the pipeline, its ability to withstand shifting ice, the potential effects of corrosion, permafrost/pipeline interactions, and the need for emergency plans for repairing the pipeline during each season if damage occurs (Sections 3.4.2.7, 4.2.5, 4.3, 5.3, 5.6, and 8.5.3).

· Offshore waste injection needs to be evaluated and how it may differ from onshore injection described (Section 5.3).

· The EIS needs to present a discussion of the alternatives for resupply of the island during periods of the year when surface transportation offshore will not be possible and how they might affect seasonal subsistence activities. Alternate modes of access need to be analyzed, and the EIS should discuss transportation during freeze-up and break-up (Section 4.2).

Physical Environment: Concerns/issues raised on the physical environment centered on sea ice dynamics and oil spill prevention/response as summarized below.

· The EIS needs to analyze and consider ice dynamics, both for heavy, multi-year and "young" ice, particularly in combination with winds and currents (Section 5.6).

· Numerous questions were raised about the oil industry's ability to prevent oil spills and to clean up spilled oil in the Arctic, particularly in broken ice. Cleanup technology must be adequate for response during the Beaufort Sea ice season. The response time for repairing a break in the subsea pipelines needs to be included in spill scenario discussions (Chapter 8).

· Spill planning for a pipeline break is necessary prior to development, and spill cleanup equipment needs to be in place prior to the start of drilling. Lessons learned from the *Exxon Valdez* spill related to oil spill impacts to marine mammals need to be addressed in the EIS. Local people need to be included in oil spill response planning activities (Chapter 8).

Biological Environment: Biological issues/concerns centered mainly around the impacts of offshore development on marine mammals and pipeline impacts to terrestrial ecology, wetlands, and wildlife. These concerns/issues are summarized below.

- Information on the long-term (continuous) versus short-term disturbance of bowhead whales should be evaluated. Impacts on whale migration and possible deflection from the proposed island should be evaluated. Advance planning may be necessary for reducing noise during the fall whale migration. The EIS should describe how noise reduction will be achieved (Chapter 9).

- Impacts to seals should be assessed since there is the potential to create a habitat which could result in increased use of the area by seals (Section 6.5).

- Human/polar bear interactions should be addressed, particularly related to attraction to human activity resulting in bears being killed in defense of life and human injury, as well as construction effects on denning bears. Creation of an artificial lead may attract bears and increase the potential for bears to gain access to the island (Section 6.5).

- Onshore pipeline routing should avoid lakes and high value wetland areas when possible (Section 6.6).

- Concerns related to caribou post-calving and insect relief need to be evaluated (Section 6.8).

- Birds fly through the North Slope area from all over the world. Impacts of an oil spill and impacts to bird populations due to strikes on aboveground pipelines and offshore island structures through the nearshore areas need to be evaluated in the EIS (Chapter 8 and Section 6.7, respectively).

Human Environment: Concerns/issues raised in this category dealt with subsistence, traditional lifestyle and knowledge, cultural resources, and cumulative impacts as summarized below.

- The Inupiat people need to be consulted regarding subsistence resources, and their information needs to be integrated into the EIS. This should include conversations with whaling captains and other community members from Barrow, Kaktovik, and Nuiqsut as a source of information (Section 7.3).
- The importance of subsistence harvests, particularly marine mammals, to the communities of Kaktovik, Nuiqsut, and Barrow needs to be discussed. The EIS should describe fish, wildlife, and marine resources used by affected North Slope communities for subsistence and how the use of these resources might be affected by the project (Section 7.3).

- There are concerns about maintaining long-term access to hunting areas and risks related to food supply following an oil spill (Chapter 8).

- Known archaeological sites within the area affected by the proposed project need to be protected (Section 7.4).

- Traditional Knowledge from elders and whaling captains will be an important source of information in the EIS and should be incorporated. Traditional Knowledge should be an integral part of the EIS decision-making process (Chapters 5 through 9).

A specific listing of issues was developed for each of the physical, biological, and human environments, along with issues specific to effects of oil and effects of noise. Text boxes within each subsection of this document are used to identify information that addresses issues.

Issues Raised That Are Not Addressed in the EIS: Some issues raised during the public scoping process are not addressed in the EIS, as they are deemed to be outside the parameters of relevant issues considered as part of this project. The following is a list of these issues:

- Issues surrounding the purpose and need for revisions of state royalty payments received as a result of oil and gas production from the Northstar Unit.
- Development of oil and gas in the Arctic National Wildlife Refuge as an alternative to offshore development in the Alaskan Beaufort Sea.
- Issues related to Alaska statehood rights and U.S. or Alaska constitutional rights.

1.6 DEIS PUBLIC REVIEW AND COMMENT PERIOD

A Notice of Availability was published in the Federal Register (62 FR 28375) for the 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 comment period was extended from an original 60-day period to continue through August 31, 1998, following requests for an extension to 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 for reference at libraries and city offices in Anchorage, Barrow, Fairbanks, Juneau, Kaktovik, Nuiqsut, and Valdez and the Corps' office 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, municipal, and federally recognized tribal governments, businesses, organizations, and individuals. Public testimony was received from approximately 105 individuals at public hearings. All comments (letters and testimony) were reviewed and, in accordance with NEPA, substantive comments were addressed. 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 the 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. Key issues are presented as questions at the beginning of each chapter and show the section where each topic has been addressed in this EIS. Issue questions appear again in boxes within the technical chapters alongside text that addresses each of them. Issue boxes look like this:

There are also questions to assist in understanding why topics are covered in the EIS. They do not respond directly to a particular issue, but support issues, and are put into boxes that look like this:

The document was constructed to be user-friendly, respond to scoping concerns, and support several approval processes (e.g., 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 in respect to 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 Alaskan Beaufort Sea 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.

Readers may notice repetition of information in this EIS. This was avoided as much as possible; however, in some places it is deliberate. An example is the Traditional Knowledge information which is incorporated within each chapter, but is also repeated in a separate section at the beginning of Chapters 5 through 9. Information on effects of oil and noise on the physical, biological, and human environments may also appear to be repeated. Generally, more detailed discussions on these topics are found in Chapter 8 (Oil) and 9 (Noise), with summary points brought to specific sections of Chapters 5, 6, and 7.

A description of the contents and purpose of EIS chapters is set forth below.

The **Executive Summary** provides an overview of BPXA's proposed project. It summarizes the EIS contents, presents a description of the EIS development process, and explains the EIS structure and supporting rationale. The Executive Summary presents information on the development of project alternatives, impacts assessment, and comparison of project alternatives based on analyses contained in the document.

A list of **Acronyms and Abbreviations** used in this EIS is provided.

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.

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.

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.

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 or population level) 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 or individual level) are described in Chapters 5, 6, and 7. Information is presented (when available) for the species within the project area. 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.

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.

Descriptions of the appendices to the EIS which were developed to provide supplemental technical information and supporting data are provided below.

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, 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, Bureau of Land Management. These 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 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 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 Public 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, 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 preliminary 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. The 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.

Reference Citations are presented within the EIS text in a format that provides information to locate a cited document or communication. Reference citations are provided after or within the first sentence in a paragraph when information in that paragraph is summarized from the same reference. If subsequent sentences in the same paragraph present information from different sources, or different page numbers within the same source, a reference is provided after the first sentence containing information from each new source page(s). If a statement or discussion is supported by more than one reference, all references are listed.

At the end of each chapter a reference listing is provided. References have been arranged in the Modern Language Association format. The reference listing is organized in alphabetical order by the author's last name, then alphabetically by title. Documents authored by companies, government agencies, or other non-person entities are listed alphabetically by their full title the first time they appear in the references. Names are followed by an acronym or abbreviation in parentheses, when necessary, to shorten the reference. (This abbreviated or acronym version is used in the text citation.) For example, a citation from Kinnetic Laboratories, Inc. appears in the text as (KLI, 1992:4). If the author is unknown, the reference is listed alphabetically according to title. This type of reference appears in the text as follows: (Petroleum News Alaska, 1997:1).

Personal communications appear alphabetically and then chronologically in each chapter reference listing. These citations are listed in the document by the person with whom the communication took place, followed by "Pers. Comm.," and the date.

Since Traditional Knowledge has been cited frequently in this EIS, these citations are listed separately in a reference section entitled "Traditional Knowledge" and appear at the end of each chapter, as relevant. Traditional Knowledge references are formatted similarly to those appearing in the regular reference section. There are two forms of Traditional Knowledge citations. Where Traditional Knowledge is contained in previous testimony on oil and gas lease sales or similar documents, each reference lists the person who presented the information, followed by the document in which comments appeared, publication information, and the date. Citations within the text pertaining to Traditional Knowledge list the name of the person presenting the information first, followed by "in" and the author of the document, the date, and page number(s). Where Traditional Knowledge was provided in meetings with whaling captains and other community members, citations list the name of the person presenting the information followed by "Pers. Comm.," the meeting name, location, and date.

1.8 IMPACT EVALUATION CRITERIA

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.

Significant adverse impacts are addressed in the following manner: 1) demonstrating that the impact can be reduced to a minor level by changing the project design, 2) demonstrating that the alternative is acceptable because the risk of the impact is small, or 3) demonstrating that the impact cannot be reduced by changes in design and/or the risk is not small.

The determination of impacts with regard to specific resources and project activities is based upon specific environmental features and significance thresholds related to the resource in question. The impact analysis text presented in Chapters 5 through 10 of this document specifically identifies the significance criteria along with the presentation of each individual analysis.

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

Action	Effects
System Design	
Cathodic protection of offshore pipelines	Reduce potential for 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
Installation of a remotely controlled shut-down valve at pipeline terminus (PS1)	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, storm water, 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 onshore 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 potential contaminant releases from 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 1-1 (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 (1.5m)	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 reduce 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 spill occur
Visual surveillance of pipeline during operation	Rapid detection of oil releases to the environment; minimize the volume spilled should a spill occur
Oil discharge prevention and contingency plan	Reduce the risk of oil spills; minimize volume spilled should a spill occur; expedite cleanup 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

Notes:

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

TABLE 1-2
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. X 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.
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).

TABLE 1-2 (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.)	
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.
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.

TABLE 1-2 (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.)	
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 1-3
SUMMARY OF LOCATION OF ENVIRONMENTAL JUSTICE AND TRADITIONAL KNOWLEDGE TOPICS

Subject	Description	Location In Document
	Environmental Justice	
Agency goals for the EIS	Agency goal for addressing Environmental Justice	Executive Summary Section 1.3
Environmental Justice requirements	Summary of Environmental Justice requirements and description of steps taken to comply with Executive Order 12898	Section 1.4.7
Environmental Justice/ Traditional Knowledge links	Summary of how use of Traditional Knowledge helps meet Environmental Justice requirements	Section 2.7.3.2
	Traditional Knowledge	
Agency goals for the EIS	Agency goal for incorporation of Traditional Knowledge in a way that allows agencies to use these data as part of their decision-making	Executive Summary 1.3, Section 1.3
Summary of EIS use of Traditional Knowledge	Summary of the approach to gathering and incorporating traditional and contemporary knowledge for specific topics addressed by the EIS	Executive Summary Section 2.0
Historic sources of testimony reviewed for Traditional Knowledge	Summary of historic sources of testimony on North Slope oil and gas projects reviewed for Traditional Knowledge	Executive Summary Table ES-3
Coordination/communication on Traditional Knowledge	Summary of coordination and communication with community residents on Traditional Knowledge	Executive Summary Table ES-4
Environmental Justice/ Traditional Knowledge links	Summary of how use of Traditional Knowledge helps meet Environmental Justice requirements	Sections 1.4.7, 2.7.3.2
Scoping and Traditional Knowledge	Scoping issue raised that Traditional Knowledge should be incorporated in and become an integral part of the EIS	Section 1.5
Use of Traditional Knowledge in the EIS	Description of the approach to gathering and incorporating traditional and contemporary knowledge for specific topics addressed by the EIS	Section 2.0
Definition of Traditional Knowledge	Definition of Traditional Knowledge and categories used in the EIS	Section 2.2
Traditional Knowledge workplan	Traditional Knowledge workplan used to guide collection of Traditional Knowledge and incorporation into the EIS	Section 2.7
Historic sources of testimony reviewed for Traditional Knowledge	Summary of historic sources of testimony on North Slope oil and gas projects reviewed for Traditional Knowledge	Section 2.7.1
Traditional Knowledge database	Format of Traditional Knowledge database compiled from review of past testimony	Section 2.7.1
Collection of traditional and contemporary knowledge from individuals	Summary of methodology used, data collection trips made, and individuals contacted to obtain traditional and contemporary knowledge	Section 2.7.2, Table 2-2
Use of Traditional Knowledge in the EIS	Description of categories of Traditional Knowledge collected, and methods for incorporation into the EIS	Section 2.7.3

TABLE 1-3 (Cont.)
SUMMARY OF LOCATION OF ENVIRONMENTAL JUSTICE AND TRADITIONAL KNOWLEDGE TOPICS

Subject	Description	Location In Document
Traditional Knowledge (Cont.)		
Traditional Knowledge related to the Physical Environment	Description of Traditional Knowledge cited in the Physical Environment Section of the EIS	Section 5.2
	Application of Traditional Knowledge in the description of the affected environment and analysis of environmental consequences (see EIS Index for location of Traditional Knowledge on specific topics)	Sections 5.3, 5.4, 5.5, 5.6
Traditional Knowledge related to the Biological Environment	Description of Traditional Knowledge cited in the Biological Environment Section of the EIS	Section 6.2
	Application of Traditional Knowledge in the description of the affected environment and analysis of environmental consequences (see EIS Index for location of Traditional Knowledge on specific topics)	Sections 6.4, 6.5, 6.7, 6.8 6.9
Traditional Knowledge related to the Human Environment	Description of Traditional Knowledge cited in the Human Environment Section of the EIS	Section 7.2
	Application of Traditional Knowledge in the description of the affected environment and analysis of environmental consequences (see EIS Index for location of Traditional Knowledge on specific topics)	Sections 7.3, 7.4, 7.5
Environmental Justice Considerations related to the Human Environment	Evaluation of Environmental Justice considerations related to subsistence	Section 7.3
	Evaluation of Environmental Justice considerations related to socioeconomics	Section 7.6
	Summary of Environmental Justice Considerations	Section 7.10
Traditional Knowledge related to Effects of Oil on the Physical, Biological and Human Environment	Description of Traditional Knowledge cited in the Effects of Oil on the Physical, Biological, and Human Environment Section of the EIS	Section 8.2
	Application of Traditional Knowledge in the description of the affected environment and analysis of environmental consequences (see EIS Index for location of Traditional Knowledge on specific topics)	Sections 8.6, 8.7
Traditional Knowledge related to Effects of Noise on the Biological and Human Environment	Description of Traditional Knowledge cited in the Effects of Noise on the Biological and Human Environment Section of the EIS	Section 9.2
	Application of Traditional Knowledge in the description of the affected environment and analysis of environmental consequences (see EIS Index for location of Traditional Knowledge on specific topics)	Sections 9.5, 9.6, 9.8

Notes: EIS = Environmental Impact Statement

CHAPTER 2.0

TRADITIONAL KNOWLEDGE

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CHAPTER 2.0 TRADITIONAL KNOWLEDGE

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2.0 TRADITIONAL KNOWLEDGE

2.1 INTRODUCTION

This chapter describes the approach to gathering traditional and contemporary knowledge of the Inupiat Eskimo of the North Slope communities of Barrow, Nuiqsut, and Kaktovik as it relates to the proposed development/production activities for the Northstar Unit. It discusses the cultural importance of the Inupiat subsistence lifestyle, Inupiat ties to and intimate knowledge of their environment, the importance of certain roles within the Inupiat subsistence culture, and provides an example of the proven reliability of Inupiat Traditional Knowledge.

Chapter 2 presents the approach to gathering and incorporating traditional and contemporary knowledge for each of the topics covered in Chapters 5 through 9 as a means to help evaluate potential effects of oil and gas development/production activities for the Northstar Unit.

During the past 10 years, biologists have begun to work more with indigenous peoples to integrate Traditional Knowledge into their research (Freeman and Carbyn, 1988:22; Freeman, 1992:11; Hobson, 1992:2; Albert, 1992:25). This interest in Traditional Knowledge is in recognition of the fact that biological studies in the Arctic typically are conducted as intensive, short-term efforts during the brief Arctic summer. In contrast, Traditional Knowledge represents the cumulative observations of people who have lived in the Arctic their entire lives. This knowledge frequently is expressed because of the strong interest Inupiat have in science and resource management (Albert, 1988:18; Albert, 1990:345). John Craighead George, representing the North Slope Borough (NSB) noted: *"There's nothing mysterious about Traditional Knowledge. Wildlife biology is largely an observational science ... the person who has the most number of observational hours has the best data ... and the cumulative hours of observation of the whaling community just dwarfs anything that's been done by the scientific community."* (USDOI, MMS, 1995:25).

Historically, Traditional Knowledge of local indigenous people has not been addressed adequately in environmental assessments or impact statements. Instead, environmental impact statements (EISs) have relied primarily on western scientific knowledge and analysis. In particular, the Inupiat Eskimo people of northern Alaska have been frustrated continually 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 exploration and development projects.

George Ahmaogak, then Mayor of the NSB, summarized the issue of applying Traditional Knowledge in a paper delivered at a 1995 oil and gas workshop:

> *". . . Industry and government agencies must recognize the value of the Traditional Knowledge of local people. We, the 'local people,' the indigenous people of the U.S. Arctic, want our opinions heard, and we want our Traditional Knowledge to be*

respected. Since we have lived here for many centuries, our people have learned much about the ice, snow, ocean currents, wildlife behavior, etc. In the past, there have been many instances where representatives of industry and/or government have come to us with the attitude that they 'know everything' and that our Traditional Knowledge is of little significance. Such an attitude is not only insulting, it is also incorrect. Our knowledge about the environment and its wildlife comes from direct observation over many lifetimes.

Let me also say that we are in favor of well done research to better understand the mysteries of the Arctic, however, we also feel that scientists and managers from government and industry must not neglect the Traditional Knowledge of the indigenous people. Our Traditional Knowledge is important to us in our everyday life, and it can often help all concerned parties to gain a better understanding of matters that are important in the exploitation of Arctic resources." (Ahmaogak, 1995:4-5).

2.2 DEFINITION OF 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 (North Slope is defined as an area bounded by the northern foothills of the Brooks Range to the Alaskan Beaufort Sea coastline, from the Chukchi Sea coast to the Canada border). In a paper on Traditional Knowledge, Martha Johnson, Research Director at the Dene Cultural Institute, wrote:

"Traditional environmental knowledge, or TEK, can generally be defined as a body of knowledge built up by a group of people through generations of living in close contact with nature. It includes a system of classification, a set of empirical observations about the local environment, and a system of self-management that governs resource use. The quantity and quality of traditional environmental knowledge varies among community members, depending upon gender, age, social status, intellectual capability, and profession (hunter, spiritual leader, healer, etc.). With its roots firmly in the past, traditional environmental knowledge is both cumulative and dynamic, building upon the experience of earlier generations and adapting to the new technological and socioeconomic changes of the present" (Johnson, 1992:4).

A Canadian Gwich'in Indian addressed Traditional Knowledge when he said:

"You need to have some faith in the people. They live on the land and know what is happening.... You can't verify or contradict Traditional Knowledge with western science. They are two different perspectives.... Radio collars do not tell you where caribou were twenty years ago." (Personal interview conducted by S. Braund, 1996).

Traditional Knowledge is passed along relatively unchanged from generation to generation, but also adapts to reflect changes in technology and socioeconomic conditions. The term Traditional Knowledge as used in this EIS includes contemporary, indigenous knowledge. 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. As part of this EIS effort, four categories of Traditional Knowledge have been identified based on past testimony and information collected in project-specific community meetings.

· Information on the characteristics of the physical, biological, and human environment.

· Issues and concerns related to oil and gas activities based on Traditional Knowledge.

· Informed views related to the potential impacts of the proposed project based on Traditional Knowledge.

· Observations regarding project design, construction, and operation characteristics based on Traditional Knowledge.

2.3 SUBSISTENCE AS THE FOUNDATION OF TRADITIONAL KNOWLEDGE

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. As Justice Thomas Berger, head of the Alaska Native Review Commission, wrote:

> *"The traditional economy is based on subsistence activities that require special skills and a complex understanding of the local environment that enables the people to live directly from the land. It also involves cultural values and attitudes: mutual respect, sharing, resourcefulness, and an understanding that is both conscious and mystical of the intricate interrelationships that link humans,*

animals, and the environment. To this array of activities and deeply embedded values, we attach the word 'subsistence,' recognizing that no one word can adequately encompass all these related concepts." (SRB&A and PJUCS, 1993:5)

Thus, subsistence is far more than an economic means of production. The economy, social system, and ideology are all oriented around subsistence and integrated in a manner that constitutes a holistic cultural system characterized as subsistence.

2.4 SUBSISTENCE IN BARROW, NUIQSUT, AND KAKTOVIK

Residents of Barrow, Nuiqsut, and Kaktovik (Figure 2-1) maintain a subsistence lifestyle demonstrating a strong reliance on natural resources combined with wage labor employment. In Barrow, 44 percent (%) of households obtained half or more of their meat and fish from subsistence activities. In Nuiqsut and Kaktovik, 62% to 66% of households, respectively, reported that half or more of their meat and fish came from subsistence harvests (Harcharek, 1993: NUI-32, KAK-32, BRW-34). In all three communities, significant amounts of time, energy, and money are spent on subsistence activities, including preparation, hunting, fishing, gathering, processing, storing, consuming, distributing, and celebrating the harvest. Additional information describing the reliance of these communities on wild resources appears in Section 7.3 of this EIS.

2.5 NORTH SLOPE TRADITIONAL KNOWLEDGE

Traditional Knowledge of the project area was gathered from whaling captains and their wives, elders, and other individuals who have spent a great amount of time on the land and sea participating in subsistence activities. Their subsistence experience generates community respect similar to that of advanced academic education in more urban cultures.

FIGURE 2-1 (Pg 1 of 2)

FIGURE 2-1 (Pg 2 of 2)

Whaling captains in particular hold a position of great respect in the community. From early apprenticeship through long training as a crew member, it takes many years to attain knowledge necessary to captain a whaling crew. Few whalers ever become captains. This position requires considerable hunting experience and expertise demonstrated by successful hunts, strong social alliances, and the accumulation of resources necessary to support a whaling crew. The whaling captain is responsible for providing the whaling boat, shoulder gun, darting gun, other whaling equipment, and supplies to sustain the crew throughout the whaling season. A 1983 survey in Alaska Eskimo whaling communities found that 62% of whaling captains and 73% of former whaling captains interviewed were on whaling crews for 15 years or more before they became captains, and 45% of active captains had been on a crew for 20 years or more before becoming captains (ACI and SRB&A, 1984:91).

Whaling captains' wives are their partners in preparing for the hunt, supporting the whalers, processing the animal, and hosting celebrations following a harvest. Wives and other female family members of dedicated hunters generally are very experienced in processing animals brought home from the hunt. Consequently, they are knowledgeable about variations in animal health at different seasons and harvest locations.

Women also participate in hunting, gathering, and fishing, spending considerable time on the land. These individuals are well respected in the community because of their skills, knowledge, and experience. As they grow older and more experienced, they become even more respected. Hence, when a whaling captain, captain's wife, hunter, or elder speaks, their words carry great respect within the community as bearers of collective cultural experience, knowledge, and wisdom. At times, when an elder has spoken on an issue, other members of the community may not make additional comment out of respect for the elder's wisdom, regardless of their personal opinion, as the elder is seen as a spokesperson for the community.

2.6 WESTERN SCIENCE VS. TRADITIONAL KNOWLEDGE - BOWHEAD WHALE ISSUE

Federal and state agencies historically have relied on western scientific research and engineering expertise for decision-making on management and development of resources in the Arctic. In doing so, they often overlook the knowledge of local residents that is based on years, and often generations, of experience and observation. The clearest and most often cited example of the western science of decision-makers coming into conflict with the Traditional Knowledge of local indigenous residents had consequences for the Inupiat people. The case centered on Inupiat estimates of the Bering-Chukchi-Beaufort Seas' bowhead whale population, which conflicted with far lower estimates by western scientists. The outcome of the controversy highlights the value of collecting, using, and attributing due respect to Inupiat knowledge.

In 1977, the International Whaling Commission (IWC) considered the bowhead whale population so low it banned the subsistence harvest of bowhead whales for the 1978 season. This decision had a great effect on the Inupiat and Yu'pik Eskimos of Alaska, who had depended upon subsistence bowhead harvests for thousands of years, and the decision was made without their input. Without notice, the single most important cultural activity and largest source of food for several communities was prohibited by an international commission relying exclusively on western science.

In response to the IWC moratorium, whaling captains from nine Alaskan whaling communities met in Barrow and formed the Alaska Eskimo Whaling Commission (AEWC). The AEWC attended IWC committee meetings and worked with the U.S. delegation to the IWC to build a case for rescinding the moratorium on subsistence whaling. In December 1977, the IWC removed the 1978 ban based on cultural and subsistence dependence on the bowhead by the Alaska Eskimos and implemented a 1978 quota of 12 whales landed or 18 struck, whichever occurred first. This represented the first quota on Alaska Eskimo bowhead whaling. In the view of local whaling captains, the quota was not only inadequate, it was based on erroneous scientific information related to the number of bowheads in the Bering-Chukchi-Beaufort Seas' stock. Local knowledge and observations indicated to whalers that the bowhead population was much larger than the IWC determined. Powerless to do otherwise, the AEWC deferred to western science while the U.S. Government began a bowhead census program.

Western scientific knowledge and Traditional Knowledge were at odds. Traditional Knowledge of indigenous whalers, built from centuries of observation and experience, disagreed with bowhead population estimates used by the western scientists who advised the IWC, a western-style resource management forum. The IWC relied exclusively on western science. Even in rescinding the moratorium, the IWC relied on a report on cultural aspects of aboriginal whaling in North Alaska prepared by an international panel of western social scientists (Bockstoce et al., 1979:1), rather than on any statements from Eskimo whalers themselves.

The government bowhead census, conducted by the National Marine Fisheries Services, consisted mainly of aerial counts of passing bowheads during spring migration. The National Marine Fisheries Services estimated a population of 2,264 animals in 1978. The Inupiat and Yu'pik whalers and elders from the Alaska Eskimo whaling communities maintained there were substantially more bowheads than the count along the shorefast ice indicated. Whalers and elders said there were additional bowheads that migrated further offshore, as well as other bowheads that could not be seen.

The NSB took responsibility for the bowhead census in 1981 and added acoustic techniques. By 1988, the bowhead census yielded a "best estimate" of approximately 7,500 bowheads. The IWC concluded in 1994 that the best available estimate of current bowhead population size for 1993 was approximately 8,000 and by 1996 (using 1993 bowhead census data), the IWC Scientific Committee's best estimate was 8,200. Based on cultural and subsistence needs and on bowhead population data, the IWC gradually has increased the quota through the years from the 1978 IWC quota (for nine recognized whaling communities at the time) of 12 whales landed or 18 struck to the current 4-year block quota (1995-1998) of 204 bowhead whales with between 65 (1998) and 68 (1995) strikes per year for 10 communities. After nearly 20 years and millions of dollars, the AEWC and the NSB were able to document what had been said all along, that the bowhead population was sufficient to sustain an Alaska Eskimo subsistence harvest based on a legitimate cultural dependence on the animals.

In addition to the conflict over different bowhead population estimates, Barrow elders pointed out other examples of Traditional Knowledge either disputed or doubted by western scientists. These examples included that bowheads are not afraid of ice and will swim in ice-covered waters; bowheads pass Point Barrow on a wide front, not confining themselves to the open leads; bowheads can break the ice to breathe; bowheads are sensitive to manmade noise; and some bowheads split from the main population during spring migration and go up the Russian coast, thus not passing the census station at Point Barrow (Albert, 1988:20-21; Albert, 1992:25). Each of these five additional, disputed points has been verified at great cost by western scientists.

2.7 TRADITIONAL KNOWLEDGE WORK PLAN

A Traditional Knowledge work plan was developed to guide the collection of Traditional Knowledge and its incorporation into this EIS. 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 North Slope organizations' and residents' past testimony 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.

2.7.1 Review of Past Testimony

During EIS Scoping Meetings held in the spring of 1996 in the North Slope communities of Barrow, Nuiqsut, and Kaktovik, it was pointed out frequently that residents of the North Slope have been providing testimony and written comments on the same issues and concerns regarding oil and gas leasing and operations for the last 20 years. Residents strongly recommended that previous testimony be reviewed because what would be said on this project had been said many times before. The method used represents an initial effort to extract Traditional Knowledge related to general Alaskan Beaufort Sea oil and gas development from past testimony and from community meetings.

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 utilized for this EIS is shown in Table 2-1. A Traditional Knowledge database was developed to catalogue testimony. The database was organized using the following four general categories of information:

TABLE 2-1

- Source of testimony (project name, date of meeting/hearing, and location).
- Person providing testimony (name and address).
- Subject of testimony (key words for issue/development impact).
- Specific quotes of individual testimony.

The Traditional Knowledge database is organized into three linked tables as listed below.

- Bibliography - transcript document identification, date of testimony, title of report, location of hearing, author, data type (i.e., oral testimony).

- Speaker Information - transcript document identification, speaker’s name, speaker's title or affiliation, speaker's residence, location of hearing.

- Quotes - transcript document identification, speaker’s name, transcript page number, transcript paragraph number, quote text, reader [person entering data], key words, related key words, primary impact, secondary impact.

These tables interconnect through matching subjects or data fields. By connecting fields together, data can be placed into the proper reference for answering questions. These questions are known as “queries.” A query can be as simple as, “*What sea ice issues were raised?”* or as complicated as, “*Which people in Kaktovik were concerned with transportation issues, what did each person have to say, and what is the title or affiliation of each person?”* The database manipulates the data and produces an answer to a query. Answers can then be arranged into an order most useful for the database user.

Information from the database has been incorporated directly into various sections of this EIS to assist in addressing project impacts from a Traditional Knowledge perspective, as well as a western science perspective. The Traditional Knowledge database contains information from selected public testimony for lease sales and related topics on the North Slope since 1979 and testimony (oral and written) collected during the scoping process for this EIS. The Traditional Knowledge database developed from this effort will ultimately be transferred to some appropriate North Slope entity for maintenance and expansion as additional relevant hearing transcripts and other materials become available. To date, the database has been made available to the Barrow Arctic Science Consortium under a contract with the Minerals Management Service.

2.7.2 Collection of Traditional Knowledge Related to the Alaskan Beaufort Sea and Project Area

A special effort was made to collect Traditional Knowledge relevant to this EIS from the affected communities within time and resource constraints. The search focused on aspects of oil and gas development in the Alaskan Beaufort Sea and on BP Exploration (Alaska) Inc.'s (BPXA’s) proposed project. The information obtained does not reflect the more comprehensive range of Traditional Knowledge that residents possess on a variety of subjects. The effort to collect Traditional Knowledge related specifically to the project area involved the four steps described below.

2.7.2.1 Contact with Community Representatives

Phone calls were made and/or letters were sent to community representatives in Barrow, Nuiqsut, and Kaktovik informing them of the purpose of the Traditional Knowledge element of the EIS and plans for village meetings. Communications in Barrow were coordinated through the Barrow Whaling Captains Association. Communication with Nuiqsut was coordinated through the City Vice-Mayor, Kuukpik Corporation, and the Nuiqsut Whaling Captains Association. The Kaktovik representative requested that all EIS communications be coordinated through the Mayor.

2.7.2.2 Preparation of Questions to Obtain Traditional Knowledge

Specific questions were used for Barrow, Nuiqsut, and Kaktovik community meetings to gather Traditional Knowledge on the Alaskan Beaufort Sea and the project. Questions came from three sources. First, questions were prepared by individuals responsible for preparation of this EIS. Second, questions were developed from review of past testimony. Third, BPXA provided questions related to the BPXA proposed project design, construction, and operation.

2.7.2.3 Data Collection Trips to Communities

Traditional Knowledge was collected from the communities as described below. Community residents coordinated and/or communicated with as part of the EIS process are listed in Table 2-2.

Kaktovik - June 19-21, 1996: Discussions were held with representatives of the City of Kaktovik. The intent to use Traditional Knowledge in the EIS was discussed, along with the effort to summarize past testimony on oil and gas development. However, agreement was not reached between the City and the lead and cooperating agencies on the terms of collecting Traditional Knowledge in Kaktovik.

Nuiqsut - July 30-August 1, 1996: An initial trip was made to Nuiqsut to discuss the use of Traditional Knowledge in the EIS, along with discussion on plans to summarize past testimony on oil and gas development. Meetings were held with representatives of the City of Nuiqsut, the Kuukpik Corporation, and the Nuiqsut Whaling Captains Association. These groups requested that the intent and approach to Traditional Knowledge be reviewed in initial meetings, discussed within the community, and that follow-up meetings be scheduled with the whaling captains and other community members to collect Traditional Knowledge and answer questions.

Nuiqsut - August 13-16, 1996: Meetings were scheduled to ask Traditional Knowledge questions of the Nuiqsut whaling captains on August 14 and in a general community meeting on August 15. Seven of the ten community whaling captains attended the August 14 meeting and provided a great deal of information based on their knowledge and experience. This meeting provided valuable information on historical use of the project area, concentrations of fish and wildlife, and experience with oil spill cleanup drills.

Table 2-2 (Pg 1 of 2)

Table 2-2 (Pg 2 of 2)

Barrow - August 27-28, 1996: At the fall meeting of the Barrow Whaling Captains' Association held August 27, 1996, BPXA provided a summary description of its proposed project. Following BPXA's presentation, the goal of integrating Traditional Knowledge into the EIS was explained. Times were scheduled with whaling captains to discuss Traditional Knowledge and BPXA's proposed project the following day and evening. A total of four whaling captains contributed information.

Trip summaries were prepared for each of the data collection community meetings. In some cases, participants allowed meetings to be taped, and information was recorded on maps. Information gathered was incorporated into the Traditional Knowledge database. The majority of information collected in these community meetings concerned sea ice, currents, storms, fish, wildlife, historic use of specific lands and waters, contemporary subsistence activities and use areas, and aspects of project design.

2.7.3 Use of Traditional Knowledge in the EIS

2.7.3.1 Categories of Traditional Knowledge Collected

Information collected was divided into four categories of Traditional Knowledge:

- Information on Characteristics of the Physical, Biological, and Human Environments - 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 specific information about 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 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.

2.7.3.2 Incorporation of Traditional Knowledge into the EIS

Traditional Knowledge from the past testimony database and 1996 community data collection efforts was reviewed for incorporation into the EIS. Information on characteristics of the physical, biological, and human environments, 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 the proposed project were incorporated into discussions of environmental consequences. Observations regarding project design, construction, and operation characteristics also were incorporated into environmental consequences sections.

Specific quotes from individuals were incorporated and cited in some instances. In other cases, an observation or concern may have been shared by several individuals and was paraphrased into a statement followed by a citation of the group representing those individuals.

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 (see Section 1.4.7 of the EIS for Environmental Justice requirements). Interaction with affected communities should require active community participation, recognize community knowledge, and utilize cross-cultural formats and exchanges. The methods used to collect and incorporate Traditional Knowledge into preparation of the EIS help meet these objectives.

The format for incorporating Traditional Knowledge into this EIS was influenced by two major objectives: ease of locating Traditional Knowledge within sections of the EIS and ability to compare Traditional Knowledge with western science. Within Chapter 5 (Physical Environment), Chapter 6 (Biological Environment), Chapter 7 (Human Environment), Chapter 8 (Effects of Oil), and Chapter 9 (Effects of Noise), incorporation of Traditional Knowledge is accomplished through a "stand-alone" section of Traditional Knowledge on specific topics, and general incorporation along with western science information throughout the remainder of the chapter, allowing a comparison of scientific and traditional information. Within Chapter 7 (Human Environment), Traditional Knowledge primarily addresses subsistence resources and activities, and is included with information from the NSB and Alaska Department of Fish and Game research, which rely on Traditional Knowledge. Traditional Knowledge that is directly applicable to Chapter 8 (Effects of Oil) appears to be limited to a few observations regarding historical offshore oil spills in the Alaskan Beaufort Sea. However, knowledge of the local environment is used to describe severe weather conditions that may hinder effective oil spill response and potential effects on fish and wildlife.

A general summary of where information related to Environmental Justice and Traditional Knowledge can be found in the EIS is presented in Table 1-3. In addition, an index of the location of Traditional Knowledge on specific topics can be found at the back of the EIS index.

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George, John Craighead. Testimony *in:* United States. Department of the Interior. Minerals Management Service. Official Transcript, Proceedings of Public Hearing, Draft Environmental Impact Statement for the Proposed Oil and Gas Lease Sale 144 in the Beaufort Sea. Assembly Chambers, Barrow, Alaska, November 8, 1995. Anchorage: Executary Court Reporting, 1995.

TABLE 2-1
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 2-2
COORDINATION/COMMUNICATIONS WITH COMMUNITY RESIDENTS

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 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 2-2 (Cont.)
COORDINATION/COMMUNICATIONS WITH COMMUNITY RESIDENTS

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

CHAPTER 3.0

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

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3.1 INTRODUCTION

Chapter 3.0 presents a broad view of oil and gas technology and options applicable to the development and production of oil and gas in the Alaskan Beaufort Sea. The Northstar project is the first proposal for development and production of oil and gas resources in the Alaskan Outer Continental Shelf (OCS). Oil and gas resources in other areas of the Alaskan Beaufort Sea have been identified, and future development and production activities are likely. Development options and alternatives for this project also may be applicable to development of other OCS resources.

The purpose of this chapter is twofold:

- Provide information for evaluating and selecting specific alternatives for development of the project, as required by the National Environmental Policy Act (NEPA); and

- Present this information in a manner that can be used to evaluate proposals for future OCS oil and gas development in the Alaskan Beaufort Sea.

The following information is presented in this chapter:

- A regional overview of important factors which affect selection of appropriate development technologies and options, including historic oil field development, current operations and facilities, characteristics of potential technologies, and environmental conditions.

- The process used to develop a short list of feasible oil and gas development/production options to be evaluated further in this Environmental Impact Statement (EIS), and applied in Chapter 4.

Chapter 3 addresses the following specific issues/concerns related to the determination of oil and gas development/production options:

Issues/Concerns	Section
· Are existing offshore facilities available for development of new offshore resources?	3.2.2
· Are existing onshore facilities available for shared use or co-location of facilities required for the handling of new oil production?	3.3.2
· What environmental characteristics of the Alaskan Beaufort Sea are important to design and operation of offshore oil and gas facilities?	3.4.1
· What activities are involved in the exploration and development of offshore oil and gas resources?	3.4.2.1
· How does drilling technology affect options for developing oil and gas resources?	3.4.2.3
· What are the characteristics of different offshore oil and gas production structures?	3.4.2.4
· Are different options available for processing produced oil and gas?	3.4.2.6
· What alternatives are available to transport oil?	3.4.2.7
· What happens to industrial facilities at the end of the project life?	3.4.2.8
· How can information about the environment and oil and gas facilities be used (or applied) to identify reasonable project alternatives?	3.5

3.2 OFFSHORE OIL AND GAS ACTIVITIES AND FACILITIES

3.2.1 Oil and Gas Leasing Programs in the Alaskan Beaufort Sea

The Alaska Department of Natural Resources, Division of Oil and Gas regulates oil and gas activities in Alaska, including submerged lands within 3 nautical miles (5.6 kilometers [km]) of the coast. The U.S. Minerals Management Service (MMS) regulates oil and gas exploration and development activities in waters beyond the 3 nautical mile (5.6 km) limit of state ownership within U.S. territorial waters. This federal offshore area is referred to as the OCS. The Bureau of Land Management (BLM) is responsible for oil and gas leasing on federal onshore land such as the National Petroleum Reserve, Alaska (NPRA). The U.S. Fish and Wildlife Service has responsibility for oil and gas leasing within federally designated wildlife refuges such as the Arctic National Wildlife Refuge (ANWR). However, by law, petroleum exploration, leasing, and development are prohibited in ANWR (Section 1003, Alaska National Interests Lands Conservation Act).

Lease sale planning involves a number of state and federal government agencies, industry, and the public. Prior to scheduling a state or federal lease sale, oil companies are asked to nominate geographic areas of interest. A proposed lease sale schedule is developed and released for comment. Additions and revisions are made to the proposed lease schedule based on comments received. The MMS prepares EISs for lease sales as required by the NEPA. The state conducts an environmental review under its own regulations and holds public hearings.

Oil and gas lease sale plans are developed every 5 years by the MMS and the Alaska Division of Oil and Gas, and lease sales are conducted in accordance with these plans. The most recent federal sale in the Alaskan Beaufort Sea was Lease Sale No. 170, held August 5, 1998, and the most recent state sale on the

North Slope was Lease Sale No. 87, held June 24, 1998. A summary of past and proposed Alaskan Beaufort Sea federal and state lease sales is presented in Table 3-1. Federal sales resulted in issuance of 660 federal leases to date. Of the 660 leases issued, 584 have expired or have been relinquished. More than 46 million acres (18 million hectares) have been offered for lease, and approximately 3.1 million acres (1.24 million hectares) have been leased.

Discoveries resulting from the first offshore lease sale, held jointly between the State of Alaska and the Federal Government (December 11-12, 1979), include the Point McIntyre, Niakuk, Endicott, and Northstar reservoirs. The first three were brought into production by directional drilling from land or an island accessed by a causeway to shore. Northstar is the first reservoir to be proposed as an offshore development. Other offshore discoveries from more recent lease sales include Badami, Sandpiper, Tarn (now Liberty), Hammerhead, Kuvlum, and Flaxman reservoirs. Development plans for the Liberty reservoir proposed by BP Exploration (Alaska), Inc. (BPXA) include construction of a new gravel island with a buried subsea pipeline being considered to bring production to shore. The MMS is in the process of preparing an EIS on the proposed Liberty development project.

3.2.2 Existing Offshore Oil and Gas Facilities

An understanding of the existing facilities in the Prudhoe Bay area is important to develop alternatives for offshore development proposals. With regard to the development of new offshore reservoirs, the location of existing offshore facilities such as gravel islands that have been previously used for exploration activities is particularly useful. These facilities may provide opportunities for the development of offshore oil and gas resources if located within reasonable proximity to the reservoir to be produced (Section 3.4.2.3 explains the potential reach of drilling technology). Use of existing sites could allow the development of new petroleum resources while limiting the need to construct new offshore structures.

Seventeen gravel islands have been constructed in the Alaskan Beaufort Sea for exploration drilling since 1975. Most islands remain in some form; however, erosion protection has been removed from a number of them. One, NW Milne Island, was partially removed as its gravel was reused to construct a portion of the new F Pad in the Milne Point Unit. Water depth, year of construction, construction type, and the location of manmade islands in the Alaskan Beaufort Sea are shown on Figure 3-1. These include Seal and Northstar Islands within the Northstar Unit (a unit is a legal designation given to a group of leases which may be owned by multiple parties that are combined to allow the efficient and coordinated development of resources extending across lease boundaries within the unit). Seal and Northstar Islands were abandoned by removal of all equipment and erosion protection.

Table 3-1 (1 page)

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The natural barrier islands also have been used for exploration drilling activities, as temporary camp locations, for gravel storage (Ashford, 1983:205), and as staging areas for other materials such as drill pipe and oil 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, the bottom-founded Concrete Island Drilling Structure (CIDS), is currently located in Camden Bay off the coast of ANWR. The CIDS and other exploration structures may be suitable (Section 3.4.2.4), 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. It usually would be more economical to use existing facilities than to build new ones, especially if they have excess capacity. Because offshore development is likely to connect to or use existing facilities, such as the Trans Alaska Pipeline System (TAPS), the Dalton Highway, and processing facilities, a brief explanation of existing onshore facilities is provided below.

3.3 ONSHORE OIL AND GAS ACTIVITIES AND FACILITIES

3.3.1 Historical Setting

Interest in northern Alaska oil and gas resources began with discovery of oil seeps on the Arctic Coastal Plain in 1904. Land was set aside as a petroleum reserve and exploration drilling was conducted within this area (NPRA) in the 1940s and 1950s (Schindler, 1982:i). Oil and gas discoveries were documented, but not considered commercially viable. Leasing by BLM and the state in the 1950s and 1960s promoted further exploration between the NPRA (to the west) and what is now designated ANWR (on the east) (Figure 2-1). ARCO Alaska, Inc. (ARCO) and Humble Oil discovered the giant Prudhoe Bay reserve in 1968. ARCO initially estimated the Prudhoe Bay discovery at nearly 10 billion barrels of recoverable reserves. The size of the discovery triggered further exploration in the area by British Petroleum, ARCO, and others.

The Prudhoe Bay discovery raised the question of how to get oil from the North Slope to world markets. Options proposed at the time included tankers, railroads, submarines, and pipelines. Railroads and submarines were not seriously considered due to economics. Tanker travel to and from the Alaskan Beaufort Sea was tried in 1969. A single trip through the Northwest Passage suggested that while the trip was possible, tankering could not compete economically or practically with a pipeline. In addition, transport by tankers in the Alaskan Beaufort Sea would be limited by weather and ice, and would increase the risk of oil spills. Ultimately, TAPS was constructed from the North Slope to an oil terminal in Valdez.

Recent discoveries near the NPRA have resulted in a renewed interest in potential leasing of this area. Exploration immediately east of the NPRA border near the Colville River resulted in the discovery of the Alpine Reservoir, estimated to contain 300 to 400 million barrels of oil in place. The northeast portion of NPRA is currently under consideration for oil and gas leasing by the BLM.

3.3.2 Existing Onshore Oil and Gas Facilities

Existing onshore facilities may provide opportunities for shared use or co-location of pipelines and processing facilities required for the handling of oil production from new developments. This sharing or co-location of facilities could reduce the extent of new onshore development or the geographic distribution of industrial facilities in the Prudhoe Bay area. The community of Deadhorse is an example.

Deadhorse is an unincorporated industrial community established in the late 1960s to support the developing North Slope oil industry and related service businesses. Deadhorse has a state operated airport with regular commercial service. It is located on the banks of the Sagavanirktok River, 7.5 miles (12 km) south of Prudhoe Bay. Business occupancy has changed over the years as oil field needs changed; however, services for travelers are growing due to tourism. The population of Deadhorse is highly variable, as most of these people work on the North Slope in shifts and commute from primary residences elsewhere.

Development cost and regulatory requirements result in some oil field facilities being shared between the two main operators on the North Slope, BPXA and ARCO. For example, processing facilities originally constructed to support development of one oil field may be used for nearby developments as additional discoveries are made. Milne Point processing facilities and pipelines are being used to process oil from the Cascade and West Sak oil fields. The seawater treatment plant (STP) on the northern end of the West Dock causeway supports secondary oil and gas recovery in the east (ARCO operated) and west (BPXA operated) portions of the Prudhoe Bay reservoir and the Milne Point (BPXA operated) reservoir. The STP currently processes 390,000 barrels per day (barrels/day) of water, and has the capacity to process 1.2 million barrels/day treated seawater (Rainwater - Pers. Comm., 1997:1). The West Dock causeway has several owners and is shared for loading/unloading vessels, supporting offshore exploration, and as a production drillsite for the Point McIntyre reservoir.

Pipelines that carry oil between units require a state right-of-way permit and are designated as common carrier pipelines. Common carrier pipelines can be accessed by companies other than the operator to transport oil to Pump Station No. 1 at the beginning of the TAPS. The TAPS is also a common carrier pipeline. Processing and pipeline transport fees are negotiated between the controlling operator and the purchaser.

The TAPS Pump Station No. 1 lies just to the south of the oil field units and is the collecting point for all oil products entering the approximately 800-mile (1,288 km) long TAPS. The facility, covering approximately 112 acres (45 hectares) currently handles about 1.45 million barrels/day of oil, but has a capacity for up to 2.2 million barrels/day. To date, more than 12.5 billion barrels of oil have been transported from the North Slope to the marine terminal at Valdez through the TAPS.

In addition to the shared use of processing facilities and pipelines, oil spill response capabilities have been developed under cooperative agreements among several operating companies. BPXA, ARCO, and the Alyeska Pipeline Service Company have established a mutual aid agreement to assist each other with response equipment and personnel in the event of an oil spill or mutual aid drill. These companies and

Exxon Company USA are members of Alaska Clean Seas (ACS), a non-profit oil spill response cooperative. ACS is a full response organization and currently functions as the focal point for spill response and training for member companies. ACS provides equipment, training, and personnel for oil spill response preparedness, response, and cleanup. The ACS administration offices, response command center, central communications system, and main warehouse are located in Deadhorse. During the open water season, ACS stages response equipment (including vessels) at West Dock and East Dock in Prudhoe Bay and additional equipment at the confluence of the east and west channels of the Sagavanirktok River. Additional resources currently available in the event of a spill include: trained village response teams, Cook Inlet Spill Response and Prevention Incorporated, Alyeska Pipeline Service Company Ship Escort/Response Vessel System in Prince William Sound, the U.S. Coast Guard Strike Team, and the U.S. Navy Supervisor of Salvage response equipment inventory.

Current and proposed oil and gas facilities on the North Slope include those at the Alpine, Kuparuk, Tarn, West Sak, Milne Point, Prudhoe Bay, Point McIntyre, Lisburne, Niakuk, Endicott, Badami, and Cascade reservoirs (Figure 3-2 a through c). The facilities associated with these developments are described below and summarized in Table 3-2. The design and operating capacities for these onshore facilities are summarized in Table 3-3.

Alpine: Plans to develop ARCO's Alpine Unit, located 34 miles (55 km) west of Kuparuk in the western Colville River Delta, were announced October 2, 1996 (ARCO, 1996:1-4). Original oil in place is estimated at 800 million to 1 billion barrels, with 250 to 300 million barrels potentially recoverable using current technology (Nelson, 1996:30). Six wells, four side-track wells (a well drilled from an existing wellbore that is directionally drilled to another point), and a three-dimensional seismic survey indicate that the reservoir is approximately 10 miles (16 km) long, covering approximately 40,000 acres (16,188 hectares). Development is proposed from two gravel pads connected by 3 miles (4.8 km) of gravel road. One gravel pad, Alpine Pad 1, is approximately 85 acres (34.4 hectares) in size and will be used for the central oil processing facility, employee accommodations, maintenance facilities, and some drilling equipment. The second gravel pad, Alpine Pad 2, will be used for wellheads. A 34-mile (55 km) long pipeline will connect Alpine production to the Kuparuk pipeline, and TAPS. Daily production is expected to peak between 50,000 and 80,000 barrels/day oil, and production could start as early as the year 2000 (ARCO et al., October 1996:2-1). The right-of-way was granted by the Alaska Department of Natural Resources on December 15, 1998. In addition, a seawater pipeline will transport water for waterflood from Oliktok Point to water injection wells.

Kuparuk Reservoir Facilities and Pipelines: The Kuparuk reservoir was discovered in 1969 and began production in 1981. There are an estimated 5.9 billion barrels of original oil in place and 2.8 trillion standard cubic feet of original gas in place (BPXA, 1997:18). The Kuparuk facilities are operated by ARCO. Kuparuk road and well pads extend to or near the coastline at several points. There currently are 462 oil production

Table 3-2 (1 page)

Figure 3-2a (page 1 of 2)

Figure 3-2a (page 2 of 2)

Figure 3-2b (page 1 of 2)

Figure 3-2b (page 2 of 2)

Figure 3-2c (page 1 of 2)

Figure 3-2c (page 2 of 2)

Table 3-3 (1 page)

wells, 300 gas injection wells, and 162 water injection wells. The Kuparuk oil pipeline to TAPS is a common carrier pipeline.

Tarn Reservoir Facilities and Pipelines: The Tarn discovery was announced in March 1997, and plans to develop were announced by ARCO and BPXA in April 1997. The field is located 10 miles (16 km) west of Kuparuk and covers approximately 161,000 acres (65,157 hectares). Tarn is estimated to contain approximately 65 million barrels of recoverable reserves. The discovery well test flowed 2,000 barrels of 38° API gravity oil from a reservoir depth of approximately 5,200 feet (ft) (1,585 meters [m]). Gravel placement started in December of 1997. First Production from Pad 2N occurred in July 1998 and Pad 2L began producing in December of 1998. The initial phase of construction is complete, but additional facilities are required to fully develop the reservoir. The initial facilities include a road, flow line, injection line, and power line back to the existing Kuparuk infrastructure, approximately ten miles. The reservoir is being developed from two well pads with slots for up to 40 production and injection development wells. There are currently 16 oil production wells and 6 gas injection wells. Some additional work is planned for 1999 but the pace of the next phase has been slowed due to low oil prices.

West Sak Reservoir Facilities and Pipelines: West Sak, owned by ARCO, is shallow, low-temperature, heavy oil accumulation that overlies the Kuparuk formation. Discovered in 1969, it is estimated by ARCO to hold 3 million barrels of original oil in place, with 300 to 500 million barrels of recoverable oil. Delineation of the reservoir began in 1971 and continued through 1982. An experimental development program undertaken by ARCO from 1983 to 1986 yielded approximately 760,000 barrels of oil before it was abandoned. Production is expected to resume in late 1998, with oil sent to the Kuparuk processing facilities. Phase One of the development (fall of 1998) will have 25 production wells and 25 water injection wells. Production will be about 7,500 barrels/day. Development drilling will continue intermittently for approximately 12 years and may result in 500 wells. Production is expected to be approximately 60,000 barrels/day (Jones, 1996: C-8). Development may require several drilling pads because of the shallow reservoir (about 3,500 ft [1,067 m]). The majority of the oil is heavy and thick, requiring a relatively long time period to deplete the reservoir. Waterflood or miscible gas injection may be required to assist oil flow to the wells (Thomas et al., 1993: xiii). Half the wells will be drilled for oil production and the other half for water or miscible gas injection.

Milne Point Reservoir Facilities and Pipelines: Milne Point reservoir was discovered in 1969 and began production in 1985. The reservoir contained an estimated 3.3 billion barrels of original oil in place. Production is expected to increase from current levels (Table 3-3) with additional oil from the Cascade reservoir, additional oil production wells installed within the Milne Point reservoir, and the planned expansion of more than 500 new wells over the next 12 years for the West Sak reservoir (BPXA, 1997:22; White, 1998:F1). The Milne facilities are operated by BPXA.

Milne Point facilities are located northeast of the Kuparuk reservoir and several roads and pads extend to or near the coastline. Currently, there are 140 oil production wells and 63 water injection wells. Milne Point recently expanded F-Pad into Simpson Lagoon to allow additional wells to be drilled. The Milne Point common carrier pipeline joins the Kuparuk common carrier pipeline about 11 miles (17.7 km) south of the Milne Point facilities and continues on to the TAPS.

Prudhoe Bay Reservoir Facilities and Pipelines: The Prudhoe Bay reservoir was discovered in 1968 and began production in June 1977. Original in place reserves are currently estimated to be 25 billion barrels of oil, and 47 trillion cubic feet of gas (BPXA, 1997:20). Recoverable reserves are estimated at 12 to 13 billion barrels of oil. Production is declining at a rate of about 10 percent (%) per year (BPXA, 1997:17). The Western Operating Area of the Prudhoe Bay Unit is operated by BPXA, and the Eastern Operating Area is operated by ARCO. These facilities are shown on Figure 3-2b.

Prudhoe Bay facilities include six oil processing facilities that are operating at full capacity for gas and water. Facilities would need to be expanded to handle additional gas or water from other reservoirs. Currently, there are 1,079 oil production wells, 36 gas injection wells, and 182 water injection wells, with projected increases to 1,180 oil production wells and 300 water injection wells (BPXA, 1997:17).

The West Dock causeway is a manmade, solid-fill gravel structure with a 650-ft (198 m) bridge span between Dock Head 2 and Dock Head 3, and a 50-ft (15.2 m) bridge span seaward of Dock Head 3. West Dock extends into water depths of approximately 12 ft (3.6 m). The 50-ft (15.2 m) opening is filled with gravel and no longer allows flow of water. An STP located at the end of West Dock provides a water source to support a waterflood program for the Point McIntyre reservoir. The causeway is owned by BPXA, ARCO, and other companies of the Prudhoe Bay Unit. It is used for mooring and unloading small vessels and barges, providing access to the STP, and housing the Point McIntyre 2 (PM2) drill pad. Multiple pipelines and cables to and from the STP and drill pad PM2 run along and within the causeway.

East Dock, the first dock built during development of the Prudhoe Bay oil fields, is a solid-fill gravel structure, extending approximately 80 ft (24.4 m) into the water along the eastern shore of Prudhoe Bay. Only small, shallow draft vessels can use East Dock because of the shallow 6 ft (1.8 m) water depth. Most docking and mooring activities were moved to West Dock after it was constructed into deeper water.

Point McIntyre Reservoir Facilities and Pipelines: The Point McIntyre reservoir was discovered in 1989 and began production in 1993. The reservoir contains an estimated 800 million barrels of original oil in place and 0.9 trillion standard cubic feet of original gas in place. Recoverable reserves are estimated at 400 million barrels of oil. Point McIntyre facilities are operated by ARCO.

The Point McIntyre 1 drill pad is located approximately 250 ft (76 m) inland from the coast; drill pad PM2 is located approximately 2 miles (3.2 km) offshore along the West Dock causeway. Currently, there are 48 oil production wells, 1 gas injection well, and 14 water injection wells. All wells have been directionally drilled from these two sites to reach reserves in the nearshore region. Projections are for an additional 23 oil production wells, 1 gas injection well, and 3 water injection wells in the near future. Three-phase fluids (combination of oil, gas, and water) from Point McIntyre are routed to Lisburne facilities for separation and transport to the TAPS.

Lisburne Reservoir Facilities and Pipelines: The Lisburne reservoir was discovered in 1968 and began production in 1986. There are an estimated 2 billion barrels of original oil in place, and recoverable reserves are estimated at 300 million barrels of oil. The Lisburne facilities are operated by ARCO.

The Lisburne processing facilities are located near the southeast shoreline of Prudhoe Bay. The Lisburne Processing Center is a shared production facility, processing fluids from Lisburne, Point McIntyre, North Prudhoe Bay State, and Niakuk reservoirs (BPXA, 1997:21). Lisburne currently has 78 oil production wells, and 4 gas injection wells. Two additional oil production wells are planned. The Lisburne crude oil pipeline to the TAPS is a common carrier pipeline.

Niakuk Facilities and Pipelines: The Niakuk reservoir was discovered in 1985 and began production in 1994. The reservoir contains an estimated 200 million barrels of original oil in place and 130 billion standard cubic feet of original gas in place. Recoverable reserves of oil and gas liquids are estimated at 75 million barrels. The field is operated by BPXA.

The Niakuk reservoir is accessed from a drill pad at Heald Point. Currently, there are 12 oil production wells and 4 water injection wells, which are projected to increase to 14 and 7, respectively (BPXA, 1997:23). Produced fluids are processed at the Lisburne Production Center and transported to the TAPS via the Lisburne common carrier pipeline.

Endicott Reservoir Facilities and Pipelines: The Endicott reservoir was discovered in 1978 and began production in 1987. There is an estimated 1.1 billion barrels of original oil in place and 1.4 trillion standard cubic feet of original gas in place. Recoverable reserves are estimated at 660 million barrels of oil. Endicott is operated by BPXA.

The Endicott development is located on two manmade gravel islands linked to the mainland by a breached gravel causeway approximately 5 miles (8 km) long. One island houses wells and gathering pipelines, and the second island includes living quarters and processing facilities. Currently, there are 74 oil production wells, 5 gas injection wells, and 28 water injection wells. Oil production wells are expected to increase by 20, and water injection wells will increase by 2 in the near future. The Endicott oil pipeline is a common carrier pipeline to the TAPS and could be used to transport processed crude from future development to the east. Up to 35,000 barrels/day oil from Badami was routed through the Endicott pipeline beginning in 1998.

Badami Reservoir Facilities and Pipelines: The Badami reservoir was discovered in 1990 and began production in late 1998. The Badami reservoir is located 25 miles (40.2 km) east of the Prudhoe Bay reservoir. Recoverable reserves are estimated at 150 million barrels of oil (BPXA, 1995a:1-1). The Badami Unit is operated by BPXA.

Two drilling pads and up to 50 wells are expected to fully develop this field. The wells will be directionally drilled to the reservoir from the gravel pad. An approximate 35-mile (56 km) long common carrier pipeline corridor from Badami ties into the Endicott common carrier pipeline for transport to the TAPS.

Cascade: Cascade is an onshore discovery located east of and is considered part of the Milne Point Unit with estimated potential reserves of 12 million barrels of oil. Initial production began in 1997. Cascade routes oil to the Milne Point processing facility and produces an estimated 8,000 barrels of oil per day. Development includes the construction of a 7-mile (11.2 km) pipeline to existing processing facilities, gravel well pad, gathering pipelines, and 8 oil production wells.

3.4 ANALYSIS OF OIL AND GAS DEVELOPMENT OPTIONS FOR THE ALASKAN BEAUFORT SEA

3.4.1 General Characteristics of Alaska's Beaufort Sea and Arctic Coastal Plain Environments

The following discussion about the physical, biological, and human environment of Alaska's Arctic Coastal Plain and Beaufort Sea is intended to provide information pertinent to considering options for working in this area. The technical and logistical methods required to develop oil and gas resources in the Arctic are determined in part by environmental conditions. The following discussions present a cursory overview of environmental conditions without specific reference to cited literature; additional information can be found in Chapters 5, 6, and 7 and in literature cited within those chapters.

3.4.1.1 Physical Environment

Offshore: The Beaufort Sea comprises the southern part of the Arctic Ocean, extending 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 generally are less than 600 ft (183 m). Characteristically, bottom sediments are composed of sands and silt. An exception is the area near the Sagavanirktok River Delta where a collection of boulders and cobble (the Boulder Patch) have been identified. This unusual hard substrate provides habitat diversity which supports a biological community uncommon in the Alaskan Beaufort Sea. As a consequence, this substrate is of particular interest to resource agencies. Recent surveys suggest that rocky substrates are more widespread than previously believed; however, the majority of the seabottom is fine-grained material. 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.

Nearshore currents primarily are wind-driven between the Alaskan Beaufort Sea coastline and the barrier islands during the open water season (Section 5.5.1). Currents usually flow parallel to the coast (east-west) at speeds between 0.1 to 0.3 miles per hour (mph) (0.2 to 0.5 km/hour) during summer. Currents beneath the ice are much slower than wind-driven currents and generally are less than 0.1 mph (0.2 km/hour).

Zones of sea ice found in the Alaskan Beaufort Sea include: the landfast zone, stamukhi (shear) zone, and the pack-ice zone (Section 5.6). The landfast ice zone usually extends from shore to water depths of approximately 65 ft (20 m) in winter, with ice thickness of 4 to 7 ft (1.2 to 2.1 m). 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 within 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 pack-ice or 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. Offshore ice roads are typically constructed using seawater with a freshwater ice cap. The springtime broken ice season extends from mid-May to mid-July. Another broken ice season occurs during fall freezeup from mid-September to November. During broken ice seasons, access to offshore structures is by helicopter. Boats can be used during the open water and light ice season from mid-July to mid-September.

Sea ice also affects the seafloor topography. Landfast sea ice adjacent to river deltas becomes flooded during early stages of breakup (mid-May to early June) with meltwater from inland drainages that thaw before coastal areas. 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. Strudel scour depressions as large as 5.7 ft (1.7 m) in depth and 90 ft (27 m) in diameter have been documented (Section 5.6). Erosion caused by strudel scour must be considered in the design of offshore structures or pipelines in the landfast ice zone.

Portions of the Alaskan Beaufort seafloor are marked by long linear depressions from ice gouging. Ice gouging is caused by grounding and movement of large pieces of ice in response to winds and currents. Ice gouging along the seafloor is most common in water depths of approximately 50 to 66 ft (15.2 to 20 m). At a 32.5 ft (9.9 m) water depth, ice gouges of up to 2 ft (0.6 m) deep have been recorded. Recorded seafloor depressions from ice gouging in the Alaskan Beaufort Sea ranged up to 8.5 ft (2.6 m) in depth, and occurred in 125 ft (38 m) of water (Section 5.6). Risk of damage to structures or pipelines from ice gouging varies with water depth and pack ice dynamics.

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. Much of the Arctic Coastal Plain is covered by shallow thaw-lake basins, ponds, and deeper lakes. Topographical features are related to permafrost (e.g., pingos, polygons) and river drainages. Several large rivers transect the coastal plain, forming deltas along the shoreline of the Alaskan Beaufort Sea. The coastline consists of beach bluffs, bays, spits, and bars characteristic of dynamic shorelines.

The Arctic Coastal Plain has a mean annual temperature of 11 degrees Fahrenheit (-12.2 degrees Celsius). Average annual precipitation ranges from 4.8 inches (12.2 centimeters [cm]) at Barrow to 6.5 inches (17.0 cm) at Barter Island and occurs mostly as rain in summer. Annual average precipitation recorded at

Prudhoe Bay from 1983 and 1993 indicate 7.0 inches (17.8 cm) of rain/snow fall. The annual average wind speed at Deadhorse Airport is 13.3 mph (21.4 km/hour). Dominant wind direction is from the east during May through December and from the west during January through April. Although some oil and gas activities are possible during summer, the majority of construction in the Arctic is done during winter because frozen ground and frozen sea ice provide solid surfaces for access to work sites without construction of permanent roads. Work is discontinued in extreme wind and cold, but vertical support member (VSM) installation, pipeline construction, excavation of gravel from mine sites, placement of gravel for roads and pads, and movement of large modules or drill rigs over roads or over ice are routinely conducted in sub-zero temperatures. Fog develops along the coast during the open water season (mid-June through mid-September) and frequently limits air travel. Boat travel also can be limited by ice incursion into the nearshore area during summer.

Permafrost is frozen ground that remains at below freezing temperatures continuously from one winter to the next (Section 5.3). It is believed to be continuous throughout the Arctic Coastal Plain to depths of approximately 2,200 ft (671 m). The existence and thickness of subsea permafrost depends on seawater temperature and salinity, extent of shorefast ice in winter, proximity to large rivers, and large-scale sea level fluctuations that occurred during late Pleistocene and Holocene times (less than 17,000 years before present). Construction activities on permafrost can cause thawing and settlement of the previously frozen soils, resulting in damage to structures. Common practices in the Arctic include insulating soils to prevent thawing, and winter construction to minimize impacts to the surface. Winter construction also avoids working on the seasonally thawed soils at the surface which are saturated with water. 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 soil is frozen to a depth of 12 inches (31 cm); this depth of frost usually occurs by December and lasts through May.

3.4.1.2 Biological Environment

Coastal and Offshore Ecosystem: The Beaufort Sea is dominated by ice. In coastal areas, ice covers the water for 9 months or more each year, except for occasional open water leads. Sea ice along the shoreline frozen to the seafloor essentially becomes an extension of the land and provides a solid substrate for year-round inhabitants, including polar bears and seals. Coastal areas, including lagoons inside the barrier islands, have open water earlier in summer than areas further offshore (Section 5.6.1). Islands provide important habitat and protection from terrestrial predators for nesting common eiders, glaucous gulls, and Arctic terns (Section 6.7). The lagoon systems provide a protected, low salinity corridor for movements and feeding of fish and for feeding, resting, and molting water birds.

Jaegers, gulls, and terns usually are present in coastal areas during summer, while tundra-nesting waterfowl (e.g., eiders, oldsquaw, geese) and shorebirds (e.g., phalaropes) may appear on lagoon and protected nearshore waters in large molting and post-breeding flocks later in summer. Feeding in marine areas may be critical for these birds throughout the summer. The marine invertebrates and fish the birds feed on prepare them for breeding and migration. For some loons, marine waters are the source of fish which adults feed to young, although the young remain on freshwater ponds until they can fly.

Marine fish generally remain in higher salinity marine waters deeper than 12 to 15 ft (3.7 to 4.6 m), except for Arctic cod, which also may be found in nearshore waters during summer. Arctic cod are an important food resource for larger fish and seals (Section 6.4). Char, Arctic cisco, least cisco, and broad whitefish move from rivers into nearshore waters, particularly the lagoons inside of the barrier islands during summer, when freshwater discharge from rivers creates a zone of relatively warm, low salinity water along the coast (Section 6.4). These species are an important subsistence resource across the North Slope and for a commercial fishery on the Colville River Delta (Sections 6.4 and 7.3).

Large animals of the offshore ecosystem include polar bears; ringed, bearded, and spotted seals; and bowhead and beluga whales. Polar bears and ringed and bearded seals are year-round inhabitants and are closely tied to the sea ice (Section 6.5). Because seals are the primary food of polar bears, the bears usually follow the seals. Bowhead whales are migratory, moving eastward in spring through the offshore leads of the Alaskan Beaufort Sea and westward in fall closer to shore (Section 6.9). Like bowheads, beluga whales are migratory and are not dependent on sea ice, but are often associated with sea ice in the Alaskan Beaufort Sea. Open water leads and ice thickness are important factors for these marine mammals. Local residents rely on these species to a varying extent for subsistence, with bowhead whales and seals being the most important in terms of volume of food harvested (Section 7.3). The Beaufort Sea polar bear population currently contains about 1,800 animals (Amstrup, 1995: 187-188). The mean Alaskan subsistence harvest for the Beaufort Sea is 36 bears per year, and the overall (Canada and United States) subsistence harvest is 62 bears per year, but could approach the maximum sustainable harvest rate (80 bears). Polar bears are closely tied to the movement of sea ice in the Beaufort Sea (Canada and Alaska). They usually reach the coastal areas near Kaktovik and Barrow in September and October and may be present in these areas until they leave with the receding ice during April and May. Polar bears move along the coast to search for mates or carcasses, move between feeding locations, and search for denning areas in the fall. Polar bears also use the barrier islands to rest, den, and provide access to other feeding locations.

The proposed Northstar project occurs within the range of known polar bear denning (Amstrup, 1995:259; USDOI, FWS, 1995: Figures A-36 and A-38). Although there are no documented dens in the Northstar Unit, or along the coastal areas between the Kuparuk and Putuligayuk Rivers, potential denning habitat occurs on Long Island, and along or on coastal and riverine bluffs. Current levels of industrial activity and disturbances in the area preclude the use of some areas by denning females. Polar bears represent an important subsistence and cultural resource for local residents.

Onshore Ecosystem: Common vegetation communities range from dry tundras to moist to aquatic tundra, with grasses and sedges dominating the species composition of most communities. Small variations in topography due to permafrost polygon formation (Section 5.3.1), pingos, or river banks create microhabitats supporting small woody shrubs and lichens which favor the drier, higher areas. Habitats considered high value include: ponds with *Arctophila fulva* (an emergent grass), which is heavily used by waterfowl during the 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 (greater than 6 ft [1.8 m]) to remain unfrozen during winter, which are essential overwintering habitats for resident and anadromous fish.

Most birds on the Arctic Coastal Plain are migratory, traveling from as far away as South America to breed during the brief Arctic summer. Seasonal abundance varies from an occasional raven, ptarmigan, gull, or snowy owl in winter, to an influx of hundreds of thousands of waterfowl and shorebirds from May through September (Section 6.7). Waterbirds, such as snow geese, tundra swans, and loons, are the most conspicuous. King eiders, spectacled eiders (a threatened species), and oldsquaw nest on the tundra, and then congregate in coastal waters for molt and migration. Although waterfowl and shorebirds occur in low densities across the tundra during the nesting season, large numbers congregate or stage in relatively small areas during migration, which makes them vulnerable to a single disturbance event. Birds are major consumers of energy and are important links in arctic foods webs. Waterfowl are also a food resource for humans, providing an important subsistence role for local residents (Section 7.3).

Caribou are year-round inhabitants of the Arctic Coastal Plain although most winter in the Brooks Range. Pregnant cows move from the Brooks Range foothills to spring calving grounds near the coast to avoid predators during the vulnerable calving period. The remainder of the herd moves toward the coast in late spring. Warm temperatures in midsummer result in mosquito and oestrid fly hatching; caribou are so harassed by mosquitoes and flies that the relief provided by coastal winds and cooler temperatures is considered critical to their health (Section 6.8). Grizzly bears appear in small numbers on the coastal plain in late spring, preying on Arctic ground squirrels and caribou calves, as well as consuming various roots and berries. Arctic and red foxes are major predators on bird eggs and lemmings. Both bears and foxes are attracted to human activities, and may scavenge garbage as an additional food source. Many of these mammals are taken by local residents, with caribou serving as a major food item (Section 7.3).

3.4.1.3 Human Environment

The North Slope Borough (NSB) is the largest, northernmost, home rule municipal government 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 home to approximately 3,900 residents and is located just southwest of Point Barrow on the Chukchi Sea coast. 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, home to approximately 400 residents, and Kaktovik, located on Barter Island in the eastern Alaskan Beaufort Sea, home to approximately 225 residents. There is no permanent road access to these 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 Alaskan Beaufort Sea and adjacent land area have been the home of the Inupiat people for thousands of years. Numerous cultural and historical resource sites on barrier islands and along the coastline and rivers of the North Slope are evidence of the Inupiat's long-term, continuous use of the region. Local residents of the North Slope have retained a largely traditional, subsistence-based lifestyle. They participate in the harvest of subsistence resources and related cultural activities throughout the year (Section 7.3). Harvesting, processing, and distributing bowhead whale is particularly important to the Inupiat culture. Subsistence activities are a significant part of the overall North Slope economy. The cash economy is derived to a great extent from taxation of oil industry facilities by the NSB, and by employment in government services. The majority of wage-earning North Slope residents are employed by the NSB, the NSB School District, village governments, regional and village corporations created by the Alaska Native Claims Settlement Act, or the oil industry.

The James B. Dalton Highway (Haul Road) connecting Deadhorse to Fairbanks, is the only road to the North Slope. It was constructed as an industrial service road, but has recently been opened to travel by the general public. Regularly scheduled commercial air service is the primary means of passenger and cargo transportation to and within the NSB. Barrow and Deadhorse airports and the airstrip maintained by ARCO within the Prudhoe Bay oil field 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.

3.4.2 Technological Options Applicable to Offshore Oil and Gas Operations

3.4.2.1 Overview of Oil and Gas Activities

The identification and development of offshore oil and gas resources involve a series of distinct activities. These activities are generally categorized into two phases, exploration and development/production. Specific activities include those summarized below.

Exploration:

· Seismic Surveys - Exploratory seismic surveys are conducted to collect data used to interpret subsurface geology. (These surveys often occur during production also.)

· Exploration Drilling - Once promising geologic structures are identified, exploration drilling is conducted to confirm the presence of recoverable oil and gas resources, and to evaluate the potential volume of oil that could be produced. Several wells are typically required to confirm a discovery and provide sufficient data to prepare a development/production plan.

Development/Production:

· Development/Production Drilling - This activity typically involves the installation of several oil production wells. In addition, reservoir development may require water or gas injection wells. Several wells may be drilled from a single location using directional drilling technology. Operation of production wells involves routine well maintenance procedures, some of which require a workover rig (a type of drilling).

· Oil and Gas Processing - Processing facilities may be located at the production site if sufficient space is available, or they may be located at a distant site. Sometimes the produced fluids are only partially separated into oil, gas, and produced water components at the production site prior to transport to offsite processing facilities for final separation.

· Transportation of Produced Fluids - Produced fluids (oil, gas, and water) may be transported from offshore sites by pipeline, marine tankers, or barges during open water, and pipelines or trucks during winter. Pipelines, railroads, and trucks may be used year-round at onshore locations. Existing offshore drilling and production facilities in the Prudhoe Bay area are connected to shore by gravel causeways which protect pipelines from sea ice hazards. Buried subsea pipelines have never been used in the Alaskan Beaufort Sea, but a buried subsea pipeline was installed once in the Drake gas field in the Canadian Arctic (Section 3.4.2.7).

· Facility Decommissioning and Abandonment - When a production facility is no longer economically viable, it is decommissioned. Wells are plugged and surface structures may be removed. Facilities may be reused in place, transported for use at another location, removed for salvage or disposal, or cleaned and prepared for abandonment in place.

In addition to the development of oil and gas facilities, construction and operation of these facilities frequently results in the need for development of gravel mines, freshwater sources, roadways, airstrips/heliports, and waste collection and disposal systems.

A brief description of oil and gas technologies and facilities that may be applicable to development in the Alaskan Beaufort Sea is presented below.

3.4.2.2 Seismic Surveys

Seismic surveys are conducted to collect subsurface geologic data. Although primarily associated with exploration, seismic surveys are sometimes conducted in producing fields to provide data used to refine field development plans. In the Arctic, offshore seismic surveys are conducted during open water periods (typically August and September) or winter time (February through April). Open water surveys are conducted by a survey vessel equipped with an air gun and a towed array of hydrophones. The air gun uses compressed air to create a sound wave that penetrates the seafloor and is reflected by different rock layers. Hydrophones record these reflected sound waves, and the data collected is used to develop a "picture" of the geologic formation under the seafloor. Support vessels are often used for logistical support and ice management activities.

During the winter (February through April), seismic surveys are conducted from the ice surface. The sound source for these surveys is a large vibrating plate which is mounted on a wheeled vehicle. Geophones are placed on the ice surface and record reflected sound waves in the same manner as the hydrophones used during open water season surveys. There are no further seismic activities currently planned for the Northstar Unit; therefore, this EIS does not address seismic activities specific to the Northstar Unit.

3.4.2.3 Oil and Gas Drilling Methods

Characteristics such as water depth, distance from shore, reservoir depth below the seafloor, reservoir thickness, degree of faulting, reservoir permeability and porosity, and the overall areal extent of the reservoir determine the drilling options for oil and gas development. There are two categories of drilling methods for recovering oil and gas reserves: 1) conventional vertical drilling in which the well is drilled straight down, and 2) directional drilling in which the well is drilled at an angle. As directional drilling techniques are improved to make longer horizontal divergences from the top to the bottom of the well possible, the term “extended reach” drilling is sometimes used. For convenience, “directional drilling” in this document will include all angled, extended reach, or stepped out drilling methods.

Reservoir production from a conventional vertical well is limited to the portion of the reservoir located beneath the wellhead. Multiple surface locations would be required to develop a reservoir that has a large areal extent using conventional vertical drilling. In contrast, direction drilling allows for access to multiple bottom hole locations from a single surface facility. A directional well can produce more than a vertical well because it intersects a greater portion of the reservoir as it passes through the producing formation at an angle. For an offshore reservoir, many surface structures are not practical for cost, logistical, safety, and environmental reasons. Conventional vertical drilling is not preferred onshore or offshore in the Alaskan Arctic.

Directional wells typically cost approximately two to three times more than a conventional vertical well. Much of the additional cost is associated with the equipment and data verification required to ensure that directional wells intersect the desired target locations within the reservoir. Directional wells also take more time to drill because they are often much longer than vertical wells.

The horizontal reach of a directional well may be limited by the substrate and borehole angle required to reach the intended location. The longest directional well drilled on the North Slope is approximately 3.9 miles (6.3 km) at the Niakuk field (Nelson, 1996:11). The vertical portion of the well was drilled to a depth of 1.8 miles (2.9 km) and a departure from vertical was drilled for 3.4 miles (5.5 km). The longest directional well drilled in the world to date is approximately 5 miles (8 km) at Wytch Farm in the United Kingdom (Headden, 1995:40[2]). In this case, the vertical depth was 1 mile (1.6 km) and the horizontal departure was 4.2 miles (6.8 km). Advances in drilling technology have resulted in the progressive increase of the reach of directional drilling over time (ADNR, 1997:5-9). The ability to "reach" extended distances from the surface drill site varies from one project to another. Reservoir geology and depth may limit the well "reach" to distances much less than 4 miles (6.4 km) in some cases.

The location and characteristics of the oil and gas reservoir and directional drilling technology limit the range of potential surface drilling sites. The range of locations for surface facilities may include onshore, on existing offshore islands (natural or manmade), or a new offshore location.

3.4.2.4 Offshore Production Structures

Selection of drilling and/or production structure(s) is based on the site-specific environment of the offshore reservoir and project economics. In addition, oil recovery and processing methods (Sections 3.4.2.5 and 3.4.2.6), options for transportation of product (Section 3.4.2.7), and relationships between onshore and offshore facilities influence structure location. This section presents a brief description of components that may be a part of a drilling and/or production facility, and a comparison of the following factors for drilling and production structure options:

- Depth of water in which it can be used.
- Structural stability to withstand ice forces known to occur at the offshore site.
- Durability.
- Noise propagation characteristics.
- Space available for facilities needed.
- Cost.

Components of Production Facilities:

<u>Drilling Rig and Associated Equipment</u>: The drilling rig contains power generation units, a drilling mud system (tanks, cuttings removal screens, pumps), a cementing system, and a storage area for drill pipe.

Additional storage space is required for drilling mud, cement, and well casing.

Oil/Gas/Water Separator System: Usually one to three multi-phase bulk oil separators are used to decrease the pressure of produced fluids and remove natural gas and water to produce stabilized sales quality crude oil. Separators are located on the offshore structure and/or onshore sites, depending on how much processing is done at the offshore production site.

Water Treatment and Injection System: Water produced with the oil is routed to a clarification system consisting of a series of vessels that separate oil from water by gravity, electrical, or centrifugal force. Clarified water is pumped to a disposal well, injection well, or to a pipeline for transport to another location.

Gas Dehydration and Compression System: Gas removed from produced reservoir fluids is routed to coolers that use air and/or seawater for cooling. Cooled gas flows into vessels that separate the remaining water from the gas. Natural gas liquids also may be separated in this process. Low pressure gases are compressed by a series of turbine-driven and/or electric-driven compressors, and further dehydrated with chemicals that absorb water remaining in the gas. The gas may be injected to the reservoir (for gas cycling or gas lift), used on site as fuel, or transported by pipeline to another location.

Seawater Systems: Seawater is used for fire suppression, for waterflood, and to supply potable water. Seawater for waterflood may require deaeration and chemical treatment to match the characteristics of the naturally-occurring reservoir water prior to injection into the reservoir. Seawater is also sometimes used to cool processing equipment. Outfalls for wastewater discharges may be required.

Emergency Flare: Flares are tall structures with a small stream of gas feeding a continuous pilot flame. This safety system protects processing systems during startups and shutdowns, as well as provides emergency gas pressure relief. The flare burns gas to prevent its release to the atmosphere.

Chemical Treatments: Chemical storage systems include tanks and small electric-driven pumps to inject chemicals such as emulsion breakers, corrosion inhibitors, biocides, and anti-foaming agents into producing wells and pipelines.

Electric Power Generation: Electricity is provided by at least one main and one standby emergency generator.

Fire Suppression: The main components of the fire suppression system are a water storage tank, pump, and distribution piping.

Other facilities that would be located on a manned production structure include: offices and a control room, a potable water system, a wastewater treatment system, heating and cooling systems, storage and shop areas, and living quarters. Ship docking facilities and a helicopter landing area are likely to be needed for either a manned, or unmanned structure.

Islands: Because a natural island modified to support drilling and/or production facilities would function similar to an artificial island, differentiation will not be made here. Ice islands and floating structures are discussed together because of their similar seasonal limitations.

Manmade gravel islands are constructed by placing gravel on the seafloor until the mounded gravel is above sea level. After an island is created, slope protection may be used to prevent erosion by waves and moving ice. Historically, the practical limit of water depth for a manmade gravel island appears to be about 65 ft (20 m) (Figure 3-1) because of the logistical and economic constraints related to the amount of gravel required to create an island in deeper water (Masterson, 1991:17). However, in theory, the water depth for gravel islands is not limited. The location of the source material for the island and hauling time/distance greatly influence its cost. Re-use of an existing island would reduce the amount of material even if additional material is needed to enlarge the island or repair damage caused by erosion. Usually at least some of the material would be brought from a site on land because sediments dredged from the seafloor tend to be too soft to support facilities. However, some areas of the Alaskan Beaufort Sea floor do have appropriate material for island construction. Material from an abandoned (or natural) island also could be moved to the desired location. A recent example is the reuse of approximately 45,250 cubic yards (34,600 cubic meters) of gravel from NW Milne Island to enlarge F Pad (Milne Point unit) into marine waters. When the distance to a material source is too great and the cost of hauling is too high, another type of structure would be considered.

Gravel islands typically have side slope ratios of approximately 1:3 (vertical:horizontal), with the island surface 10 to 23 ft (3 to 7 m) above sea level (Masterson et al., 1991:23). Some islands were constructed with side slopes as flat as 1:20, resulting in a beach-like slope structure that can be washed away without affecting the integrity of the island's working surface. Sandbags, interlocking concrete blocks or mats, or steel walls may be used to help protect island slopes from wave and ice erosion. Slope protection is likely to be required for all long-term use of islands. In contrast to other structures (see below), gravel islands are relatively easy and inexpensive to repair by replacing or reshaping gravel and slope protection, as necessary. Gravel islands can withstand ice movements because they are an extension of the seafloor and the base area is larger than the working surface. This provides resistance to sliding (lateral movement) greater than other structures. Construction costs for gravel islands typically range from $10 to $40 million, depending on size of the island and water depth (Masterson et al., 1991:25).

Gravel, sand, and other earthen materials absorb sounds and particularly dampen higher frequency noise. As discussed in Chapter 9, sounds from an island are transmitted by structural vibrations through the island material into the water. Measurement of noise of industrial activities on a gravel island in the Alaskan Beaufort Sea demonstrated greater attenuation of noise relative to other types of structures (Davis et al., 1985; Johnson et al., 1986; Richardson et al., 1995). Although sound propagation is site specific, gravel islands are generally expected to dampen more noise than other types of structures.

A gravel island structure:

- Is economically and logistically limited to about 65 ft (20 m) water depths.
- Can withstand high lateral ice forces without movement or damage.
- Is subject to erosion, but is easily repairable.

- Is expected to have the greatest noise dampening of all structure types.
- Is almost unlimited in design size and flexibility of shape.
- In most cases, is less expensive than other structures.

Mobile Bottom-Founded Structures: Mobile, bottom-founded structures are those that rest on the seafloor, but can be floated and towed to different locations. Designs for mobile, bottom-founded structures were developed to conduct offshore exploratory drilling in the Arctic during the 1980s. Several different one-of-a-kind structures of this type were used and remain in Arctic or northern waters. These are described below.

Caisson Islands: One-of-a-kind structures, such as the Caisson Retained Island (CRI) and the concrete caisson island (Tarsiut), were designed to increase slope protection and decrease gravel fill requirements over a conventional gravel island. This is particularly important when material is unavailable, unsuitable, or haul distances are long. The CRI was constructed in 1982 and consists of eight steel caissons linked together by cables forming a ring 384 ft (117 m) across the bottom with 302 ft (92 m) of working deck width at the top. The caissons are subdivided into 10 ballast tanks, two fuel tanks, machinery spaces, and a control room (Arctic Transportation Ltd., 1995:4). The CRI is ballasted with seawater to rest on the seafloor or a prepared gravel pad. The inner ring is filled with sand or gravel. The CRI is designed to operate in water depths between 11.5 and 66 ft (3.5 to 20.1 m). In more than 20 ft (6 m) of water depth, a gravel pad or berm is needed. Equipment located on the CRI likely would include: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, blowout preventor system and associated manifolds, diesel-powered generators, air compressors, a domestic water treatment system, and facilities to accommodate staff.

The CRI was used for oil and gas exploration and it is not designed for production activities. The CRI does not have space for numerous wells and equipment needed for production.

The Tarsiut Caisson Island, built in 1986 for use in the Canadian Beaufort Sea, is constructed of four concrete caissons and installed on a submerged berm in water 70 ft (21.3 m) deep (Han-Padron, 1985:5-11). The hexagonal center core is filled with sand or gravel and the working deck area is approximately 330 ft (101 m) across. Relocating the Tarsiut would require removing, resetting, and connecting the caissons at a new site. This has never been attempted and would be difficult because the caissons are ballasted with sand, rather than water (Masterson et al., 1991:11). Equipment located on the Tarsiut likely would include: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, blowout preventor system and associated manifolds, diesel powered generators, air compressors, a domestic water treatment system, and facilities to accommodate staff.

The caisson island designs:

- Are limited to 11.5- to 70-ft (3.5 to 21 m) water depths.
- Have demonstrated stability in heavy ice.
- Have demonstrated durability and currently are in good condition.
- Have a fixed size working area that would need to be restructured to accommodate production facilities and a larger number of wells.

- Would reduce gravel costs, but would require extensive modifications to accommodate the needs of a long-term development/production program.

Concrete Island Drilling Structure (CIDS): The CIDS consists of a steel base that rests on the seafloor and a concrete unit that extends through the surface water/ice zone (Figure 3-3). The CIDS has drilled four exploration wells in the Alaskan Beaufort Sea. None of these wells were drilled in the project area shown on Figure 3-1. Three wells were drilled off of Cape Halkett, approximately 80 miles (128.7 km) west of the Northstar Unit (one in 1984 in 49 ft [15 m] of water, another in 1985 in 49 ft [15 m] of water, and a third in 1985 in 50 ft [15.2 m] of water). A well was drilled in 1997 in approximately 50 ft (15.2 m) of water in Camden Bay, approximately 75 miles (120.6 km) east of the Northstar Unit (D. Choromanski-Pers. Comm., 1998). Operational water depths for the CIDS range from 35 to 55 ft (10.7 to 16.8 m). The working deck area measures 291 by 274 ft (88.6 by 83.5 m), and the base is 312 by 295 ft (95 by 90 m). Equipment located on the CIDS includes: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, a blow-out preventor system and associated manifolds, diesel-powered electric generators, cranes, air compressors, a domestic water treatment system, and facilities to accommodate up to 94 staff.

The CIDS was not designed for oil and gas development/production activities; however, the owners have proposed to modify CIDS to accommodate such facilities. Proposed modifications include reconstructing the current drilling equipment layout, adding production equipment, allowing space for 22 wells, and an additional deck for a maximum of 35 wells (Global, 1995: Section 9:1). Limits on production capacity were not provided by the vendor. Long-term maintenance requirements are unknown, but may require transport to dry dock facilities away from the oil production area.

The CIDS:

- Is limited to 35- to 55-ft (10.7 to 16.8 m) water depths.
- Has demonstrated stability in heavy ice.
- Has demonstrated durability and currently is in good condition.
- Has a fixed size working area that could be restructured to accommodate production facilities and 22 to 35 wells.
- Requires modifications in dry dock costing approximately $70-75 million.

Mobile Arctic Caisson (Molikpaq): The Molikpaq is an eight-sided steel caisson constructed as a continuous ring, creating a hollow center which is filled with sand or gravel and a working top deck (Figure 3-4). The caisson has outer dimensions of approximately 366 ft (111.5 m) per side at the base and approximately 241 ft (73.4 m) per side on the working deck. The caisson is divided into 12 ballast compartments filled with seawater.

The Molikpaq began operations in 1984 and has drilled 10 wells in the Canadian Beaufort Sea (Gulf, 1995:1). It is designed to drill in water depths ranging between 30 and 130 ft (9 to 39.6 m) (BPXA, 1996:6-4). For water depths over 69 ft (21 m) it requires a pad to raise the bottom surface. Equipment located on the Molikpaq includes: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, a blow-out preventor system and associated manifolds, diesel-powered electric generators, cranes, air compressors, a domestic water treatment system, and facilities to accommodate 104 staff.

The Molikpaq was not designed to support oil and gas development/production activities. However, the owners have proposed to modify the Molikpaq to accommodate such facilities. Modifications that have been proposed would be to reconstruct the current drilling equipment layout to add the necessary production equipment and allow space for 24 to 40 wells. Production capacity would range from 65,000 to 120,000 barrels/day oil, 110 to 180 million standard cubic feet per day of natural gas, and 100,000 to 180,000 barrels/day water. Maintenance requirements are unknown.

The Molikpaq:

- Is limited to 30- to 130-ft (9 to 39.6 m) water depths.
- Has demonstrated stability in heavy ice.
- Has demonstrated durability and is in good condition.
- Has a fixed size working area that could be restructured to accommodate production facilities and 40 wells.
- Requires modifications to accommodate a long-term development/production program with modification costs expected to be between $85 and 112 million.

Single Steel Drilling Caisson (SSDC): The SSDC is a modified, very large crude oil carrier (super tanker) that conducts exploratory drilling operations in open water and ice (Figure 3-5). The SSDC has been previously used to drill exploration wells in the Alaskan Beaufort Sea; however, only one location is in the project area shown on Figure 3-1. Other locations where the SSDC has been used in the Alaskan Beaufort Sea outside the project area include two wells drilled off Cape Halkett, approximately 80 miles (128.7 km) west of the Northstar Unit. One of these was drilled in 1990 in 50 ft (15.2 m) of water, and another was drilled in 1991 in 55 ft (16.7 m) of water. Additionally, one well was drilled in 1987 in 66 ft (20 m) of water offshore of the Beaufort Lagoon, approximately 150 miles (241 km) east of the Northstar Unit (D. Choromanski-Pers. Comm., 1998). Operational water depths initially ranged from 25 to 70 ft (7.6 to 21.3 m); however, a steel platform was added in 1985 which allows the structure to operate in water depths to 100 ft (30.5 m) (CANMAR, 1994:4). Drilling in 80 to 100 ft (24.3 to 30.5 m) of water requires construction of a gravel berm in addition to the steel platform. The working deck of the SSDC is approximately 664 ft (202.4 m) long by 174 ft (53 m) wide.

Figure 3-3 (page 1 of 2)

Figure 3-3 (page 2 of 2)

Figure 3-4 (page 1 of 2)

Figure 3-4 (page 2 of 2)

Figure 3-5 (page 1 of 2)

Figure 3-5 (page 2 of 2)

The SSDC began exploratory drilling in the Alaskan Beaufort Sea in the winter of 1982/1983. Two exploratory wells were drilled from a prepared gravel berm in 100 ft (30.5 m) of water outside the landfast ice zone (Masterson et al., 1991:9). Equipment located on the SSDC includes: a rotary table drilling rig, drilling mud pumps and mud mixing equipment, a cementing unit, a blowout preventor system and associated manifolds, diesel-powered electric generators, an extended flow well test separator, crude oil storage capacity of approximately 700,000 barrels, cranes, air compressors, a domestic water treatment system, and facilities to accommodate 93 staff.

The SSDC was not designed for oil and gas development/production activities; however, the owners proposed to modify the SSDC to accommodate drilling and production facilities. Proposed modifications include reconstructing the current drilling equipment layout to add production equipment and allow space for 30 to 40 wells. Production capacity ranges from 40,000 to 50,000 barrels/day oil, 1 to 4 million standard cubic feet per day of natural gas, 20,000 barrels/day water, and an oil storage capacity of 625,000 barrels of crude in the steel platform (CANMAR, 1995:31-34). Long-term maintenance requirements are unknown.

The SSDC:

- Is limited to 25- to 100-ft (7.6 to 30.5 m) water depths.
- Has demonstrated stability in heavy ice.
- Has demonstrated durability and currently is in good condition.
- Has a fixed size working area that could be restructured to accommodate production facilities and 40 wells.
- Would require modifications to accommodate a long-term development/production program, with modification costs estimated to be approximately $113 million.

These bottom-founded structures or others that could be designed and constructed to meet specific project needs are feasible options within the limits discussed for drilling and production structures in the Alaskan Beaufort Sea. The structures have a record of success in withstanding sea ice and other cold weather operating conditions.

Subsea and Subterranean Structures: In areas where ice movements or gouging of the seafloor would endanger an exposed structure, facilities could be placed deep enough below the seafloor to prevent damage. Construction of such facilities would be expensive, and would generally require a large reservoir or special site conditions to justify this expense.

A subsea cavern is similar in design to an underground mine. A cavern would likely have an access tunnel from land which would also be used for removal of excavated material and for transport of produced oil and gas to shore. Considerations for using a subsea cavern structure include distance of the reservoir from shore (i.e., length of the tunnel), heat transfer to the surrounding permafrost, disposal of excavated soils, ventilation of hazardous and flammable gases, and emergency evacuation of personnel.

Subsea silos, similar in concept to underground missile silos, have been considered to develop the Kuvlum reservoir in the Alaskan Beaufort Sea. The Kuvlum reservoir is located in the shear ice zone about 12 miles (19.3 km) offshore in approximately 105 ft (32 m) of water. The conceptual design includes produced oil and gas reaching shore through a trenched pipeline. The silo design depth is approximately 40 ft (12 m) below the seafloor and 20 to 24 ft (6 to 7.3 m) in diameter to allow well servicing and maintenance (MBC, 1996:26). The Kuvlum design includes a cover plate over each silo near the seafloor surface for additional protection of wellheads and production equipment from ice. Plans for this development or other silos in the Alaskan Beaufort Sea are not anticipated in the near future.

A subsea cavern or silo:

- Can be constructed in water depths as great as 200 ft (61 m).
- Could be protected from ice damage.
- Would not be subjected to erosion or other damage.
- Could be designed for any size working area.
- Would have very high costs.

Subsea Templates: Seafloor templates, which rest on the surface of the seafloor, are used in many offshore regions as a drilling guide and to house wellheads. Drilling equipment is positioned over a template and wells are drilled and brought into production using pipelines or flexible, steel-reinforced (umbilical) hoses to connect the template to oil and gas processing facilities. These pipelines carry produced fluids from the wellheads to processing facilities. Templates are used in deep water with nearby floating production and drilling structures. A seafloor template with multiple wells is more economical than single well templates, but also increases the size of the structure that rests on the seafloor. The largest operating multi-well seafloor template is in the Gulf of Mexico; it measures approximately 118 by 75 by 56 ft (36 by 23 by 17 m) (length by width by height) and houses 10 well slots (Abbott et al., 1995:314 and 315).

A variation on the conventional subsea template has been used off the east coast of Russia near Sakhalin Island in a severe ice environment. A four well template was placed in a seafloor excavation and protected by 36 ft (11 m) high steel caissons and a lid buried in the seafloor. This subsea caisson production system was developed for gas production. A buried subsea pipeline transports produced gas from the subsea caisson production system to onshore facilities for processing and distribution (J.P. Kenny, 1992:1-4).

Seafloor templates could be used in water depths greater than 200 ft (61 m) in the Alaskan Beaufort Sea, where ice grounding or gouging do not occur. At these depths, a floating vessel would be used to drill the wells. It may take a full 2- to 3-month summer season to drill a single well. In deep water situations, this combination may be feasible for development/production in the Alaskan Beaufort Sea.

A subsea template system:

- Could be used in water depths greater than 200 ft (61 m).
- Design would not have to consider ice forces on the bottom.
- Would not be subjected to erosion or other damage.
- Would be a fairly quiet facility, but would transmit noise directly to the water.
- Size could be adjusted to meet a wide range of production objectives.

· Would have moderate to high costs.

Floating Drilling Structures (Seasonal Use Structures): Floating drilling structures have limited usefulness in the Arctic unless conventional designs are modified for ice protection. Even with modifications, a floating structure is not considered suitable for year-round development/production activities because it could be moved and/or damaged by ice. Seasonal drilling and workover activities in combination with a seafloor template or subsea silo enclosed template are potential production-related uses of floating drilling structures. These could be used during open water periods and in over-ice applications when used in conjunction with ice islands. In general, floating structures are not suitable for year-round use as a development and production facility.

Jackup Drilling Platform: Conventional jackup drilling platforms are towed and positioned over a specific drilling location. Three legs are lowered to the sea floor to stabilize the superstructure, which is then raised out of the water. Jackup platforms have been used to support exploratory drilling activities in waters less than 100 ft (30.5 m) deep in open water conditions.

Semi-Submersible Drilling Vessels: Semi-submersible drilling vessels are self-powered or towed steel-hulled platforms that are positioned over a specific drilling location. Their position in the water is controlled either by a dynamic positioning system or by an anchor mooring system. Semi-submersibles can operate in waters between 100 and 1,000 ft (30.5 and 305 m) deep in open water conditions.

Ice Islands: Ice islands are created by pumping seawater onto the frozen sea ice sheet. The water freezes in layers until the ice is grounded onto the seafloor or is thick enough to accommodate the weight of a drilling rig and associated equipment. Ice islands would be used for exploration drilling for only one winter because they melt and lose structural integrity in spring and summer months when ambient air temperatures are above freezing.

Drillships: Conventional drillships are self-powered, steel-hulled platforms that are positioned over a specific drilling location. Their position in the water is controlled either by a dynamic positioning system or by an anchor mooring system. Drillships have been supporting exploratory drilling operations in waters of the Alaskan Beaufort Sea since 1976. Drillships can operate in waters between 100 and 1,000 ft (30.5 and 305 m) deep in open water conditions.

Conical Drilling Unit (Kulluk): The Kulluk is a one-of-a-kind floating exploration drilling vessel designed for extended season arctic operations in light to moderate ice conditions. It is towed to and positioned over a drilling location. The double-walled, inward-sloping hull is in the form of an inverted cone, 265 ft (80.8 m) in diameter. The cone flares at the bottom, causing light to moderate ice to break downward and away from the hull. The Kulluk is held in position by 12 radially-deployed mooring lines in water depths of 60 to 600 ft (18 to 183 m) (CANMAR, 1994:18). The Kulluk has drilled one exploration well in the Alaskan Beaufort Sea. The operating range of the Kulluk is considered practical in up to 328 ft (100 m) water depths (Masterson et al., 1991:12).

Except for ice islands, these structures are not designed to operate in sea ice and are limited to open water or light ice conditions during the summer; ice islands are usable only during winter. These structures are not suitable for long-term development/production activities in the Beaufort Sea; however, they could be used for drilling on a seasonal basis as drilling support facilities for a seafloor or silo template installation. Because they are steel-hulled structures (except ice islands), these are expected to transmit more drilling and operational noise than other types of structures. The amount of noise would increase if ice-breaking vessels were used as part of an ice management program to protect the drilling structure in moderate ice conditions to extend the drilling season.

3.4.2.5 Oil and Gas Recovery

A variety of technologies, ranging from those relatively unchanged for more than a century to modern state-of-the-art technologies, are used for oil and gas recovery. These technologies are usually referred to as primary, secondary, or enhanced (tertiary) recovery.

Primary Recovery: Primary recovery uses only the reservoir's natural pressure to force crude oil from the underground reservoir to the surface. As the reservoir is depleted, the reservoir's pressure drops, resulting in a decline in crude oil recovery rates. Primary recovery was used with the earliest oil wells and is still used today when reservoir pressures are sufficient to force reservoir fluids to the surface. Primary recovery by itself results in an average recovery of only 5% to 20% of a reservoir. Some reservoir developments employ primary recovery during early reservoir development/production, then add a secondary recovery method for continued production.

Primary recovery is a reasonable option for oil and gas development/production in some situations in the Alaskan Beaufort Sea. For a fairly large reservoir, or one that would have too many difficulties in implementing pressure enhancement, this could be the best option. A deep water site could be developed with sea floor templates and primary recovery using a minimal investment in facilities.

Secondary Recovery: Secondary recovery options are designed to improve oil recovery from the reservoir. This is accomplished by boosting or maintaining reservoir pressure or by lifting fluids in individual wells. Secondary recovery options include injecting gas or water into the reservoir to maintain reservoir pressure as oil, gas, and water are produced. These secondary recovery methods include gas lift, reservoir maintenance with gas (gas cycling), reservoir maintenance with water injection, and waterflood. Use of secondary oil recovery options depends upon individual reservoir characteristics, such as pressures, water and gas volumes, geometry, depth, fluid properties, formation permeability, and porosity.

Availability of water or gas from another source is a factor in choosing an appropriate secondary oil recovery technology. A combination of recovery methods may be used, depending upon reservoir characteristics. Therefore, each reservoir development is evaluated individually for the best application of secondary oil recovery technology.

<u>Gas Lift</u>: Gas lift involves injecting natural gas at high pressure, usually several thousand pounds per square inch, to introduce small bubbles into the oil/water column in the well. The gas bubbles lighten well fluids, allowing them to rise to the surface easily. Gas lift is effective particularly if the reservoir

contains heavy, thick oil or if it has high water content. Gas lift requires a gas supply, either from the producing reservoir or an external gas source. The amount of gas needed is small relative to gas cycling (below) and usually can be supplied by the producing reservoir. Gas compression, cooling, and dehydration are required to implement gas lift.

Gas lift:

- Is useful for heavy, viscous oils, or oils with high water content.
- Is applicable on a single well basis.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Requires gas compression and dehydration.
- Requires air coolers or a cooling water source (may have subsequent warm water discharge).

Reservoir Pressure Maintenance with Gas (Gas Cycling): Gas cycling involves reinjecting natural gas through dedicated injection wells into a reservoir's overlying gas layer (the reservoir's gas cap) or into the oil producing zone. The reinjected gas preserves or enhances reservoir pressure, which then allows greater volumes of oil to be recovered. The gas supply requires compression, cooling, and dehydration. The pressure of the gas reinjected into the reservoir must be higher than the existing reservoir pressure, typically 3,500 to 5,000 pounds per square inch.

Gas cycling is effective in reservoirs that have a natural gas cap or that can produce a substantial amount of gas. Because gas cycling requires 1 to 1.5 times the amount of gas normally produced daily, an external, supplemental natural gas source must be available. Typical reserve recovery rates range from 45% to 65%.

Gas cycling:

- Is useful in reservoirs with a natural gas cap or with a large volume of gas.
- Is applicable on a reservoir-wide basis via dedicated injection wells.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Is useful for light oils that flow easily.
- Requires a natural gas cap or substantial amounts of gas in the crude oil.
- Requires gas compression and dehydration equipment.
- Requires supplemental gas supply.
- Requires air coolers or a cooling water source (may have subsequent warm water discharge).

Reservoir Pressure Maintenance with Water Injection: Many oil/gas reservoirs have aquifers beneath the oil reservoir and water injected into the underlying aquifer causes upward pressure on the oil layer. This pressure forces the oil to continue flowing to production wells. Some of the water injected may be produced water (i.e., water separated from reservoir fluids). Generally, one to two times the amount of fluid produced from the reservoir is required for water injection. Water from another source, such as seawater, can be treated and injected along with produced water to maintain reservoir pressure. Water is injected at pressures above existing reservoir pressure through dedicated water injection wells.

Poor water quality can damage an injection well, resulting in the need for extensive repair and maintenance. Treatment of produced water and seawater may consist of separation of oil from water, addition of chemicals, removal of air and solids, and compression. Typical water injection recovery rates are 35% to 45% of reserves.

Water injection:

- Is useful when large aquifers are present beneath the oil reservoir.
- Is applicable on a reservoir-wide basis via dedicated injection wells.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Requires treatment of produced water and/or seawater.
- Can damage injection wells if water quality is poor.
- May require large turbine-driven or multi-stage pump systems.

<u>Waterflood</u>: Waterflooding involves injecting treated produced water or seawater directly into the oil reservoir through dedicated injection wells. Water is injected in a specific pattern, to flush oil toward oil production wells. Injection wells are located in geometrical patterns around producing wells or injected at the boundary of the reservoir. Uniform reservoir permeability is essential for a successful waterflood.

During the start of a waterflood program, water use would be approximately two barrels of water per barrel of oil produced. Ultimately, the volume of water is in the range of 150% to 170% of the total produced fluids. If available, seawater is the best choice for initial waterflooding until formation water is produced at a rate high enough to supply a long-term waterflood program. Seawater also can be used as the sole supply.

Poor water quality can damage an injection well irreparably or result in expensive workover costs. Treatment and injection equipment requirements for waterflood are similar to water injection. The size and quantity of treatment and injection equipment depends upon the amount of oil/water produced and treated for injection, and the characteristics of the reservoir. Typical reserve recovery rates range from 40% to 50% of the original oil in place.

Waterflood:

- Is applicable on a reservoir-wide basis via dedicated injection wells.
- Can be integrated with other secondary or enhanced oil recovery methods.
- Requires uniform or well known reservoir permeability.
- Requires treatment of produced water and/or seawater.
- Can damage injection wells if water quality is poor.
- May require large turbine driven or multi-stage pump systems.
- Requires an ocean discharge from water treatment processes.

All of these secondary recovery methods have been used in the North Slope oil reservoirs and remain as options under the specific reservoir conditions identified above. Environmental issues differ little between these methods. Differences are primarily related to the specific ancillary facilities required (water supply, gas pipelines, etc.) and STP discharges.

Enhanced (Tertiary) Recovery: Enhanced or tertiary recovery options can be employed on reservoirs once secondary recovery options are no longer effective. Enhanced oil recovery methods include chemical flooding, miscible flooding, and thermal techniques. Chemical flooding methods (e.g., polymer, surfactant, and alkaline flooding) are characterized by the addition of chemicals to improve the flow of oil through the reservoir. Miscible flooding uses carbon dioxide, nitrogen, or hydrocarbons as a solvent, and thermal processes add heat to the reservoir to improve oil flow. Enhanced recovery methods are not considered until development/production from secondary recovery methods decline dramatically, typically many years into the production life of the reservoir. Only miscible flooding with hydrocarbons as enhanced recovery has been used on the North Slope.

3.4.2.6 Oil and Gas Processing

Produced reservoir fluids (a mixture of oil, water, and gas) are processed by separating crude oil, produced water, and gas. The processing facilities for an offshore reservoir may be located entirely offshore, entirely onshore, or with parts in either location. Processing requirements depend upon reservoir characteristics, production rates, and the types of secondary oil recovery methods. These requirements also may differ depending upon a reservoir's distance to shore and its proximity to existing oil and gas processing facilities. Offshore oil and gas processing options can be used with one or more secondary recovery methods.

Considerations for determining an appropriate oil and gas processing option include:

- Distance of the development/production structure to existing processing facilities.
- Method for transporting oil and/or gas (tankers or pipelines).
- Size of development/production structure required to support the processing facilities.

Fluids produced at the wellhead contain oil, gas, and water and are called “three-phase fluids.” Partial processing removes much of the gas and some of the water from the oil, leaving a three-phase mixture that still contains small amounts of gas, some water, and oil. Pipelines can be used to transport unprocessed, partially-processed, or fully-processed crude oil. Pipelines carrying three-phase fluids are not technically feasible for distances greater than about 12 miles (19.3 km) because inconsistent mixtures at the wellhead make pumping difficult over long distances. Non-pressurized tankers and barges are unable to transport three-phase fluids. Fully processing reservoir fluids to remove water and separate the oil and gas results in a uniform, consistent crude oil product which can be transported by a variety of vessel types, and a uniform consistent gas product which can be reused on site for secondary recovery or transported by pipeline for use or sale at another location.

The size and location of the reservoir, as well as the reservoir characteristics, are important factors for determining processing facility needs. Because of the cost of processing equipment, a small reservoir alone may not support an independent processing facility; however, in combination with others, it may be economical to develop small reservoirs. Offshore reservoirs within the 12-mile (19.3 km) range of a three-phase fluid pipeline could be developed by connecting to existing processing facilities (onshore or offshore) with excess capacity for handling produced fluids. If excess capacity is not available, the distance is too long, or transport of mixed-phase fluids is to be avoided, partial or full processing can be done at a new offshore site. Processing on site allows for reuse of products in secondary recovery which may not be possible if processing is completed at a different site. Since the equipment types and size are similar for partial and full processing, the impacts of these options are expected to be about the same. These impacts include the footprint of the structure used for processing, noise of equipment in operation, noise from transportation of supplies and people, discharges of wastes, and accidental release of hydrocarbons or other toxic materials. Impacts can be reduced if no processing occurs at the reservoir site; however, the impacts would occur at the alternative processing site and may have similar or greater effects there. If processing cannot be done at the reservoir site, such as when a permanent structure cannot be maintained, the offsite option would be the only one available.

Site-specific concerns about processing impacts may influence selection of a processing site, but the more likely factors are economics of the reservoir and transportation of the products. In water depths less than about 100 ft (30.5 m) in the Alaskan Beaufort Sea, where a stable structure can be placed and protected from ice forces, full processing at the offshore reservoir site is expected to be proposed because it avoids three-phase and two-phase fluid transportation problems. In deeper water, other alternatives may be considered; however, since none have been seriously considered, it is difficult to predict what technology may be developed and proposed in the future.

3.4.2.7 Transportation of Product

Transportation of oil and gas products from the Alaskan Beaufort Sea to world markets could be accomplished by a variety of methods, such as vessels, pipelines, railroad, or trucks. It is expected that the existing TAPS pipeline and Dalton Highway would be used rather than developing duplicate facilities for the onshore portion of transportation. For the offshore area, there are no existing pipelines, ports, fuel storage, or shipping facilities. Thus new systems would be required for offshore development. Listed below are transportation options and a summary of their associated limitations.

Offshore transportation:

- Tankers to market – petroleum product must be processed to crude oil, icebreaker support required, seasonal shipping.

- Barges to coastline – same as tankers; in addition, shoreline transfer and onshore transportation facilities required.

- Pipeline to shoreline – three-phase, gas, or crude oil transport possible; new pipeline required as none exist in Alaskan Beaufort Sea; year-round operation.

Onshore transportation:

- Railroad – product must be processed to crude oil, new railroad system required as none exist north of Fairbanks, year-round operation.

· Trucks – product must be processed to crude oil, year-round operation on existing roads.

· Pipeline – three-phase, gas or crude oil transport possible; use of new or existing pipelines, including existing common carrier pipelines and the TAPS; year-round operation.

Railroad and truck transportation of crude oil is unlikely to occur because of the existence of the TAPS and a perceived need to find additional oil to keep the TAPS in operation as Prudhoe Bay production declines. Rail and truck transportation also have higher spill risk than pipelines because of increased transfers between vessels and tanks. For these reasons, use of either railroad or truck transport of crude oil from the North Slope is considered unlikely. Use of tankers, barges, and pipelines are discussed below.

Tankers: If an offshore production facility can provide full processing of the crude oil, tankers could carry the oil directly to world markets. Such a system would require a mooring and loading system (possibly with vapor recovery), and a large capacity crude oil storage site to hold products between tanker callings. Small and super tankers require a minimum of 60 ft (18.3 m) and at least 120 ft (36.6 m) of water depth, respectively. Therefore, a channel for tanker access must be dredged in shallower waters. Alternatively, a pipeline from the development/production facility to a tanker loading site located in deeper water could be constructed. Ice management would be required to keep tankers operating for much of the year. In some areas, ice conditions would prohibit safe transportation by tankers. Tankers also present an increased risk for oil spills to occur during tanker loading/unloading activities.

The use of tankers to transport crude oil from the Alaskan Beaufort Sea was attempted in 1969. However, it was determined that tankering crude oil from the Alaskan Beaufort Sea could not compete economically with an onshore pipeline system from the North Slope. Offshore reservoir development proposals may reopen the question of tankering from the Alaskan Beaufort Sea. Under certain circumstances, this may be a feasible or preferred option for transportation of products.

Barges: If an offshore production facility can provide full processing of the crude oil, barges could be used to transport crude oil between an offshore site and the shoreline without the dredging requirement of tankers. A dock, such as existing facilities at Oliktok Point, West Dock, East Dock, and Badami may be used to reach the required water depth of 6 to 8 ft (1.8 to 2.4 m) for barge operation. Occasional or frequent dredging may be required to maintain these depths at the shoreline unloading site, depending on sediment transport at the site (Section 5.3). Barges usually can operate between late-July and mid-September in the Alaskan Beaufort Sea; however, icebreaker support would be required to extend the shipping season into winter months. Barge transport of crude oil to the Alaskan Beaufort Sea coastline would also require construction of a loading/unloading facility connected by pipeline to the TAPS. Barges also present an increased risk for oil spills to occur during barge loading/unloading activities.

Under certain conditions, barging crude oil to the shoreline for transport through the TAPS may be feasible. When a pipeline cannot be constructed, barging may be the only remaining option; however, this is likely to result in only seasonal production from the offshore site.

Pipelines: Pipelines could transport three-phase fluids or crude oil to the Alaskan Beaufort Sea coastline and on to existing oil and gas facilities or to the TAPS. Pipeline installation from offshore development/production structures to the Alaskan Beaufort Sea coastline may occur on gravel-filled causeways, elevated pile-supported structures, the seafloor, or buried or drilled beneath the seafloor. A combination of these methods may be used to cross different types of seafloor conditions.

Once pipelines reach the coastline, onshore pipelines constructed on elevated VSMs or other types of pipelines would continue to carry the fluids to their destination. Depending on the landfall site, pipelines may join existing routes, tie-in to a common carrier pipeline, or be the first pipeline in the area.

Onshore Pipeline Corridor: Onshore pipelines installed on elevated VSMs are currently the conventional method of oil and gas transportation on the North Slope. Selection of an onshore pipeline route would consider environmental issues, project cost, and access to the pipeline. These factors may include:

- Maximizing the use of existing disturbed area, such as pipeline corridors and roadways.
- Avoiding high value fish and wildlife habitat.
- Minimizing total pipeline length and expense.
- Avoiding conflicting land uses such as native allotment, federal reserve lands, and cultural/ archaeological sites.

In some cases, reasonable alternatives may not satisfy all the considerations identified above. A range of alternative routes would be considered to allow comparison of alternatives which satisfy concerns in different ways.

Gravel-filled Causeway: A gravel causeway is a manmade structure that connects an offshore development/ production facility to the mainland. It is constructed by placing gravel onto the seafloor until it extends above water. Pipelines are installed on top of, or within, the causeway. The causeway protects the pipeline from waves and ice, and provides access for maintenance and repairs. Gravel-filled causeways can be continuous or broken by openings called “breaches” that allow small vessels, coastal water, and marine organisms to pass beneath bridged pipeline sections.

Causeway construction is most practical when the offshore facility is located in shallow water and relatively close to shore (e.g., the Endicott development). Existing causeways in the Alaskan Beaufort Sea are 3 to 5 miles (5 to 8 km) in length and extend to water depths of 12 to 14 ft (3.7 to 4.3 m). Impacts of causeways on coastal circulation and fish movements preclude their use along some portions of the coastline. The presence of a relatively continuous band of low salinity water along the coastline during July and August (Section 5.5) is critical for feeding and distribution of some anadromous fish species (Section 6.4). The low salinity water is created by river runoff and summer wind patterns. Causeways constructed perpendicular to the shoreline disrupt the coastal band of water and may induce local upwelling of high salinity water near the shoreline. Either the physical presence of the causeway or the break in the low salinity corridor, can delay or stop movement of some fish, particularly broad whitefish and young-of-the-year Arctic cisco, which are two important subsistence fish species (Section 7.3). A causeway proposed for an area where water and fish movements are a concern would be unacceptable unless it has adequate breaching, particularly near the coastline to allow water and fish movement. This concern would be evaluated on a site specific basis.

Elevated Pile-Supported Structure: A pile-supported pipeline would extend above sea level to allow water and fish to pass unimpeded; however, this could present an impediment to navigation. Since a pile-supported structure in the Alaskan Beaufort Sea would be exposed to winds, wave action, and ice forces, it is most suited for offshore development/production facilities close to the shore. Even in the bottomfast ice zone (water depths less than 6 ft [1.8 m]), the pipeline would be at risk of damage from moving ice during breakup and freezeup. Since current directional drilling technology has a horizontal "reach" of approximately 4 miles (6.4 km) (Section 3.4.2.3), elevated, pile-supported causeways would not be practical for accessing reservoirs that are less than 4 miles (6.4 km) from shore because they can be reached from an onshore drilling location. Due to the costs of building pile-supported structures and the limited distance they could be used offshore, this option is not considered reasonable for use in the Alaskan Beaufort Sea.

Installed on the Seafloor: Pipelines from offshore oil and gas development/production facilities to onshore facilities are laid directly onto the seafloor in many regions of the world. In the Alaskan Beaufort Sea, bottom-fast ice, ice gouging, and strudel scour occur from the coastline out to depths of about 200 ft (61 m) (Section 5.6). Ice and sediment movements would likely rupture or damage pipelines installed on the seafloor. In water deeper than 200 ft (61 m) pipelines could be laid on the seafloor. Facility options and the means of drilling in greater than 200 ft (61 m) of water are fairly limited.

Buried Beneath the Seafloor: The only other arctic subsea buried pipeline connecting offshore and onshore facilities was constructed at the Drake gas field in the Canadian Beaufort Sea in 1978. The following paragraphs present a brief discussion of this buried subsea pipeline, as presented in Brown (1996:1-9), Palmer et al. (1979:765-772), and Watts and Masterson (1979:755-764).

The pipeline extended into the McClure Strait in Canada, located off the Sabine Peninsula of Melville Island in the Northwest Territories, approximately 800 miles (1,287 km) east of the Alaska/Canada border. The pipeline was built by Panarctic Oils Ltd. to test technologies that could potentially be useful in the development of hydrocarbons in high arctic regions. This specifically included the ability to work off the ice sheet, as well as several other aspects related to pipeline installation and performance.

The pipeline was approximately 3,050 ft (929.6 m) in length and extended from the shoreline to the wellhead, located in 181 ft (55 m) of water. The 820 ft (250 m) nearshore portion of the subsea pipeline was trenched approximately 5 ft (1.5 m) beneath the seafloor using a plowing technique. This was deemed necessary to avoid potentially damaging effects from floating multi-year ice that was assumed to have seafloor effects down to water depths of approximately 65 ft (19.8 m), primarily during periods of breakup. The portion of pipeline in water depths greater than 65 ft (19.8 m) was installed on the seafloor.

The pipeline was tested by allowing a limited quantity of gas to flow from the well, but the well was never placed into operational service. The pipeline was intended to become part of a larger hydrocarbon transportation scheme, but related transportation facilities needed for long-term operation of the well and pipeline were never built. The project was undertaken at a time when crude oil prices were $50 per barrel and hydrocarbon prices were projected to continue to increase. However, hydrocarbon prices began a decline shortly after the pipeline was installed that has continued to this day. The costs to transport hydrocarbons from the area exceeded the economic return at these lower prices.

Since the pipeline was not placed into service, there was no program of monitoring, research, or maintenance. The pipeline was officially abandoned in 1996-97, approximately 18 years after it was constructed. As part of abandonment, a limited survey of the condition of the pipeline was undertaken which showed no apparent damage. The well remains plugged and abandoned.

Pipelines buried beneath the seafloor in the Alaskan Beaufort Sea could avoid damaging effects from ice in waters less than 200 ft (61 m) deep. To accomplish this, pipeline burial depths would have to be determined based on anticipated depths of ice gouge and related stresses and strudel scour events. Methods for installing pipelines beneath the seafloor by trenching include:

· Plowing - a device similar to a farmer's plow is pulled along the seafloor by a vessel (effective in water depths up to 200 ft [61 m]).

· Jet sledding - high pressure water jets are towed along the seafloor by a vessel (effective in all water depths).

· Trenching - Conventional or modified hydraulic excavators and mechanical pipeline trenching machines may be used through the ice in water depths dependent on specific equipment limitations.

Selection of a buried pipeline trench excavation method in the Alaskan Beaufort Sea would depend upon water depth, time of year, length of pipeline, seafloor sediments, equipment availability, and pipeline depth.

When a pipeline cannot be buried deeply enough, another option would be to directionally drill and then pull pipe through the tunnel created. Directionally drilled pipelines have been installed beneath large rivers and barrier islands. A small diameter pilot hole is drilled, and a reamer attached and pulled back through the hole to increase the diameter. A single pipe or several pipes bundled together can be pulled through the hole. This method is limited to distances of approximately 1.25 miles (2 km) due to the weight of the drillstring and the pipeline. Its use may also be limited by the substrate. Loose, unconsolidated soils are difficult to drill through because they tend to collapse. The drilling depth may be adjusted, or special techniques used, to avoid problem areas.

<u>Offshore Buried Pipelines: Single- versus Double-walled</u>: A description of the single-walled pipeline is described in detail in Appendix A and in the Technical Notes, Appendix E. In this EIS, a double-walled pipe is defined as an oil carrier pipe inside of an external pipe. This configuration may be designated as pipe-in-pipe, cased pipe, or pull tube depending on the actual pipeline design. Conceptually, a double-walled pipe design could be used at locations susceptible to adverse environmental conditions. In

conceptual design and in limited field applications (testing, but not operational) such a pipeline design could increase pipeline integrity, provide oil spill containment, and enhance leak detection. The determination of the actual benefits versus costs and risks associated with single and double-walled pipeline alternatives require a project specific analysis based on the most current available knowledge.

Pipe-in-pipe designs are currently used offshore for some insulated pipelines and to bundle multiple smaller pipelines together. In the Gulf of Mexico, it is used in some deep-water applications to physically protect pipeline insulation from damage during construction and operations. Building multiple pipes in a single, larger pipeline keeps the pipelines together and simplifies the installation process. In the Northstar application, pipe insulation is unnecessary to retain heat and prevent hydrate or wax formation inside the pipeline nor is it necessary to ease installation.

Although double-walled pipes have not historically been used on the North Slope for transportation of oil and gas, two developments have incorporated features of a doublewall configuration into their pipeline designs. First, BPXA has proposed installation of a pull tube for the Liberty development during construction of the island. This would allow subsequent installation of the pipeline bundle the following year without excavation of part of the island. Second, ARCO's Alpine development will use a cased pipeline configuration for the Colville River crossing. ARCO's 4,300-foot cased pipeline underground crossing of the Colville River was designed to minimize the possibilities of a pipeline leak, provide secondary containment, provide redundant structural integrity, and to accommodate portions of the external loads that would normally be carried by the carrier pipe (ARCO, 1997:2-14, 2-19, 2-20).

The Alpine Colville River crossing "pipeline-within-a-pipeline" for the above cited functions combined with horizontal directional drilling approach remains unique in pipeline river crossings within the North Slope of Alaska. In construction of the Colville River crossing, operations begin by drilling a small pilot hole. Once the pilot hole is completed, it is enlarged by making multiple passes with a reamer. The carrier and casing pipe strings are then fabricated, welded, non-destructively examined with radiographic and/or ultrasonic techniques, hydrotested (carrier pipe only), and the pipe joints coated. The carrier pipe is then installed within the casing and the combined assembles are then pulled through the enlarged hole. Simultaneous failure of both the carrier oil pipeline (0.438-inch wall thickness) and the casing pipeline (0-5-inch wall thickness) is unlikely. If oil leaked from the carrier pipeline, it would be captured within the spaces between the outer wall of the carrier pipeline and the inner wall of the high-strength casing pipe, rather than reaching the subsurface river environment. This design is analogous to secondary containment provided as a spill prevention technique for storage tanks. The casing performs a second function in that it is designed to accommodate portions of the external loads that would normally be carried by the carrier pipe (ARCO, 1997:2-28). One load exerted on the casing and not on the inner carrier pipeline is the external pressure due to the surrounding soil. In addition, the casing will initially absorb bending due to thaw settlement because the carrier pipelines will be supported within the casings by loose fitting casing isolators. Since the carrier pipeline is smaller than that of the casing, its bending resistance will be much smaller than that of the casing. And, since the carrier pipeline will not be rigidly attached to the casing and there will be gaps between the isolators and casings, it is possible for the casing to bend without bending the carrier pipeline. Thus the curvature of the carrier pipeline will always be less than the curvature in the casing at the same location. However, once the carrier pipeline has started to bend, the bending resistance of the composite (casing and carrier pipelines) is essentially the sum of the two bending resistances (Baker, 1998).

To prevent external corrosion, all the casing pipes and carrier pipes are protected by a mechanically tough state-of-the-art fusion-bonded epoxy coating. In addition, an 8-inch pipe parallel to and near the casing pipes provides the anode portion of an impressed cathodic protection system to address corrosion of the casing pipes. ARCO has included various spill detection techniques to provide early warning of potential problems (ARCO, 1997:2-28). One is a Pressure Point Analysis (PPA) system, a computerized leak detection system. The PPA system depends upon sampling frequency and the speed of sound in the liquid to compare instantaneous pressure data to trended pressure data using a computer algorithm to determine if there is evidence of a leak. The current trend data are also compared with data sets that characterize leak profiles. The PPA system is also supplemented with the traditional mass balance leak detection system used in current advanced pipelines. Although the mass balance detection system is effective, it is also limited in detecting small quantity leaks based on the accuracy of the flow meters. ARCO will also install an independent hydrocarbon sensor to monitor below current threshold leak detection limits in the space between the cased pipeline and carrier pipeline. The sensor system is a fiber optic based system capable of distinguishing between hydrocarbons, salt water, and fresh water (Fowler - Pers. Comm., 1999:1).

The extent of applicability or feasibility of transferring a 4,300-foot doubled-walled pipeline river crossing technique to multi-mile subsea Arctic oil pipeline requires detailed information and analysis which is currently not available. There remains a degree of uncertainty that could affect structural integrity and pipeline safety. The practicability, applicability, and current technological limitations or constraints associated with the use of a multi-mile double-walled pipeline in a subsea Arctic environment are currently unknown.

Some influencing or constraining factors are expected in the construction, installation, and operation of a multi-mile doubled-walled pipeline configuration compared to a single pipeline configuration. The use of horizontal directional drilling technology, as used in Alpine, is not considered as a practicable installation technique for the subsea pipeline. Subsea installation difficulties could result from increased pipeline buoyancy associated with annular spaces between the external and carrier pipes. Depending on the design and operational conditions, the resultant buoyancy of the pipelines could cause the assembly to shift or even migrate (float) upwards. Other installation difficulties associated with a double-walled pipe compared to a single-walled pipe configuration could include: summer time construction requirements; increased weight and stiffness of the pipeline; need for heavier pipe handling equipment; and additional time requirements for fabrication (primarily welding), quality control, and installation of the pipeline. Double-walled pipes could be at a higher risk from some types of pipeline failure, such as trauma from ice gouging that was not a factor for the Alpine cased pipeline feasibility determination. It is also possible that external trauma causing failure to the exterior pipe could also breach the inner carrier pipe defeating the secondary containment function of the double-walled pipeline. On the other hand, if a small leak occurs in the carrier pipeline, it could be contained in the double-wall pipeline configuration with the potential of providing an increased detection and containment before reaching the environment. The same can not be said for a single-walled pipeline design. Repair of a damaged doubled-walled pipeline would be more difficult than repairing a single-walled pipeline.

Offshore Buried Pipelines, Landfall Location Alternatives: The point where an offshore buried pipeline intersects the coastline and begins an onshore transition is called a pipeline landfall location. Pipeline landfall locations may require onshore gravel pads to accommodate pipeline valves and leak detection equipment. Equipment at these landfall locations would also require vehicular access by gravel road, or a helipad to accommodate access by helicopter. Environmental and engineering concerns which may be considered when identifying potential pipeline landfall locations include:

- Avoid large river delta systems to reduce strudel scour hazard.
- Avoid coastal areas with near-surface permafrost to minimize thaw subsidence.
- Avoid rapidly eroding shorelines to reduce the need for pipeline protective structures.
- Avoid high value fish and wildlife habitats.
- Avoid cultural or archaeological sites.
- Avoid areas where historical subsistence use is high.
- Allow access/connection to existing onshore oil and gas facilities.
- Minimize offshore and overland route lengths.

In some cases, reasonable alternatives may not satisfy all the considerations identified above. A range of alternative landfall locations should be considered to allow comparison of alternatives which satisfy concerns in different ways.

Offshore Buried Pipelines, Corridor Alignments: The determination of offshore pipeline alignments connecting an offshore oil and gas development/production facility with a pipeline landfall location may consider environmental issues, construction cost, construction feasibility, and obvious hazards, such as:

- Limit offshore pipeline length in water depths greater than 20 ft (6.1 m) because it requires special excavation equipment or open water dredging.

- Limit offshore pipeline length in water depths greater than 6 ft (1.8 m) because working on floating ice is slower and more difficult than working on bottomfast ice.

- Minimize pipeline fabricated bends to reduce construction costs and improve reliability.

- Avoid proximity to river deltas to minimize potential impacts from strudel scour events.

- Avoid high value fish and wildlife habitat, such as the Boulder Patch.

- Avoid areas of near surface subsea permafrost to minimize thaw subsidence.

In some cases, reasonable alternatives may not satisfy all the considerations identified above. A range of alternative routes should be considered to allow comparison of alternatives which satisfy concerns in different ways.

3.4.2.8 Development/Production Facilities Abandonment/Reuse Potential

When production from a reservoir ceases, oil and gas facilities would be abandoned in accordance with terms of individual lease agreements. Abandonment could range from complete removal of all facilities including pipelines, VSMs, and the production structure, to a shut down mode with most facilities left intact for future use. Requirements are decided at the time when the field is abandoned because of the unknown possibilities for future uses. For example, the lease agreements for the Northstar Unit state: "At the option of the state, all improvements such as roads, pads, and wells must either be abandoned and the sites rehabilitated by the lessee to the satisfaction of the state, or be left intact and the lessee absolved of all further responsibility as to their maintenance, repair, and eventual abandonment and rehabilitation." Possible uses of an island structure include other oil and gas projects, a deepwater port facility, scientific research projects, or a shelter for travelers ranging from subsistence hunters to tourists. A mobile production structure could be relocated for use at another reservoir. Pipelines are likely to be reused only if oil and gas production continues, or possibly to supply fuel for activities or housing. Housing facilities on an island may be of interest to local government, businesses, or individuals.

If no future uses for the facilities can be identified, structures may be removed. Removal is likely to involve similar activities to construction. Mobile production structures would be the easiest to remove, with gravel islands and pipelines the most difficult. Some facilities, (e.g., buried or drilled pipelines) could be abandoned in place, provided that safety and environmental regulations are met.

3.5 SUMMARY OF REASONABLE DEVELOPMENT OPTIONS AND PROCESS FOR THE DETERMINATION OF PROJECT ALTERNATIVES

As indicated in Section 3.4, the determination of appropriate alternatives for development of offshore oil and gas resources requires consideration of a variety of environmental factors and technical options. The preceding discussion identified several technical options which should be eliminated from further consideration due to environmental conditions in the Alaskan Beaufort Sea (Table 3-4). Options which merit further consideration are summarized in Table 3-5. Refining this list of options to identify reasonable alternatives for a specific development proposal requires consideration of general criteria, such as those listed for pipeline route selection, site-specific conditions, and technical factors. Economic factors and compatibility with the existing industrial support infrastructure are also important.

The location of the oil and gas reservoir and technical limitations to drilling are the primary factors defining the geographic area suitable for location of drilling facilities. As indicated in Section 3.4.2.3, current directional drilling technology requires a drillsite to be within approximately 4 miles (6.4 km) of the desired bottom-hole location. In some cases, the characteristics of the oil and gas reservoir may limit the reach of directional drilling to lesser distances, although future advances in drilling technology also could extend the reach. For this reason, this factor should be evaluated specifically for each oil and gas development proposal. Once a geographic area of potential drilling locations is determined, environmental conditions and existing facilities within this area should be considered to select offshore production structure(s) suitable for the development proposed. Related activities, such as oil and gas processing and transportation methods, can then be evaluated in relation to the existing industrial infrastructure.

Figure 3-6 illustrates a simple process that incorporates the information presented in Section 3.4 into the selection of offshore production facility alternatives for a specific development proposal. The process shown is focused on selecting alternatives which are suitable to develop the resource, and are compatible with the environmental conditions of the site. This process presumes that development from an onshore site or an existing offshore structure is generally preferable to installation of new offshore structures. By answering the questions on Figure 3-6, a short-list of reasonable alternatives can be developed. This process is intended to illustrate the reasoning used for selection of alternatives to be evaluated in this EIS. The process eliminates alternatives which are clearly unsuitable or would involve substantially greater environmental impact and/or expense. However, specific project proposals that would not otherwise be identified using this process could still be evaluated in response to an applicant's request.

Table 3-4 (page 1 of 1)

Figure 3-6 (page 1 of 2)

Figure 3-6 (page 2 of 2)

Table 3-5 (page 1 of 3)

Table 3-5 (page 2 of 3)

Table 3-5 (page 3 of 3)

Once the locations and types of offshore structures have been selected, alternatives for other components and facilities can be developed. This requires consideration of options for each major project component, including: oil and gas recovery techniques, onshore or offshore gas processing, oil transportation methods, offshore pipeline routes (if applicable), pipeline landfall locations, and onshore pipeline routes. To avoid unnecessary evaluation of an unreasonably long list of alternatives with only subtle differences, environmental information collected early in the NEPA process should be applied to determine appropriate development/production options as described in Section 3.4. This process will lead to identification of alternatives which are distinctly different from one another.

Each of these alternatives may then be considered as representative of a particular "type" of alternative. For example, alternatives involving pipeline landfall locations on a natural shoreline and an existing manmade causeway allow comparison of these options without addressing all possible landfalls of each type. The use of the information in Section 3.4 also allows the consideration of technical and economic factors to avoid the evaluation of unreasonable alternatives.

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TABLE 3-1
PAST AND PROPOSED ALASKAN BEAUFORT SEA
FEDERAL AND STATE LEASE SALES SUMMARY

Lease Sale Number	Sale Date	Acres Offered
Federal		
Sale #71	October 13, 1982	1,825,770
Sale #87	August 22, 1984	7,773,447
Sale #97	March 16, 1988	18,227,806
Sale #124	June 26, 1991	18,556,976
Sale #144	September 18, 1996	2,947,247
Sale #170	August 5, 1998	1,900,000
Future Sale: Sale #176	2000	12,200,000
State		
Sale #30	December 12, 1979	341,140
Sale #36	May 26, 1982	56,682
Sale #43	May 22, 1984	298,074
Sale #48A	February 25, 1986	42,053
Sale #50	June 30, 1987	118,147
Sale #55	September 28, 1988	201,707
Sale #52	January 24, 1989	175,981
Sale #65	June 4, 1991	491,091
Sale #68	June 2, 1992 (no bids placed)	153,445
Sale #86A	October 1, 1996	15,484
Sale #86	November 18, 1997	365,398
Sale #87	June 24, 1998	Areawide
Future Sales: Beaufort Sea Areawide 1999	October 1999	2,000,000
Joint Federal and State Sale		
BF	December 11, 1979	173,423

Sources: ADNR, 1995:76-77
USDOI, MMS, 1996:I-5

TABLE 3-2
SUMMARY OF CURRENT ONSHORE OIL AND GAS FACILITIES [1]

Facilities	Alpine	Kuparuk	Tarn	West Sak	Milne Point[5]	Prudhoe Bay WOA/EOA	Point McIntyre	Lisburne	Niakuk	Endicott	Badami[2]
Operator	ARCO	ARCO	ARCO	ARCO	BPXA	BPXA/ARCO	ARCO	ARCO	BPXA	BPXA	BPXA
Well Pads/Drill Sites	2	43	2	--	12	38	2	6	1	2	1
Wells: Oil/Producers	46	462	16	25	140	1,079	48	78	12	74	1
Gas Injectors	2	300[3]	6	--	--	36	1	4	0	5	0
Water Injectors	44	162	--	25	63	182	14	0	4	28	--
Central Compression Plant	1	--	--	--	--	1	--	--	--	--	--
Central Gas Facility	1	1	--	--	--	1	--	--	--	--	--
Central Oil/Gas Separation Plant	1	3	--	--	1	6	--	1	--	1	1
Central Power Station	1	1	--	--	--	1	--	--	--	--	--
Crude Oil Topping Unit	--	1	--	--	--	1	--	--	--	--	--
Personnel Living Quarters	1	3	--	--	1	5	--	--	--	1	1
Seawater Injection Plant	--	1	--	--	--	--	--	--	--	1	--
Seawater Treatment Plant	--	--	--	--	--	1	--	--	--	1	--
Airstrip	1	1	--	--	--	1	--	--	--	--	1
Helipad	--	--	--	--	--	2	--	--	--	--	--
Dock	--	1	--	--	--	2	--	--	--	1	1
Gravel Mine Site/Water Reservoir	1[4]	4	1	--	1	2	--	--	--	1	1
Gathering Pipeline (miles)	3	97	--	--	30	145	12	50	5	3	--
Common Carrier Pipeline (miles)	40	37	10	--	10	--	--	--	--	26	27
Roads (miles)	3	19		--	10	110	3	10	1	10	4.5

Notes:
1 = As of December 31, 1997
2 = Includes both oil and gas pipelines in a common corridor
3 = Alternating gas and water injection
4 = Lake with fish only
5 = Includes Cascade

ARCO = Arco Alaska, Inc.
BPXA = BP Exploration (Alaska) Inc.
EOA = Eastern Operating Area
WOA = Western Operating Area
-- = Not applicable

Source: Hanley, 1997:Attachment 6; USDOI, BLM, 1998:Table IV, A.5-5; Thomas et al., 1993:xiii

TABLE 3-3
DESIGN AND OPERATING CAPACITY FOR NORTH SLOPE ONSHORE OIL AND GAS FACILITIES

Reservoir [1]	Design			Operating			Comments
	Oil (MBPD)	Gas (MMSCFD)	Water (MBPD)	Oil (MBPD)	Gas (MMSCFD)	Water (MBPD)	
Badami	35	22	31	NA	NA	NA	
Prudhoe Bay Unit							
GC1	350	2,500	190	160	2,500	105	Facilities are gas limited.
GC2	350	1,100	320	110	1,100	280	
GC3	320	1,100	250	70	1,100	150	
FS1	350	2,700	120	140	2,700	129	
FS2	350	1,300	700	90	1,350	700	
FS3	350	1,350	240	82	1,350	116	
CCP/CGF	NA	7,600	NA	NA	7,600	NA	Miscible Injection Expansion (MIX) will increase capacity to 8,200 MMSCFD.
West Dock STP	NA	NA	2,300	NA	NA	300	Point McIntyre is the only user.
Endicott	120	480	200	60	480	180	Facility is gas limited.
Kuparuk	340	540	800	270	540	790	Excludes Alpine Projections.
Milne Point	75	42	40	57	38	38	
Lisburne	220	450	180	188	340	96 [2]	
Point McIntyre	NA	NA	NA	NA	NA	NA	Runs through Lisburne Production Center
Niakuk	NA	NA	NA	NA	NA	NA	Runs through Lisburne Production Center

Notes:
1 = Location of facilities shown on Figures 3-2a through 3-2c.
2 = Limited by ability of injection wells to accept injected fluids.
CCP = Central Compressor Plant
CGF = Central Gas Facility
FS = Flow Station
GC = Gathering Center
MBPD = Thousand barrels per day
MMSCFD = Million standard cubic feet per day
NA = Not applicable
STP = Seawater Treatment Plant

Source: Campbell - Pers. Comm., 1998:1

TABLE 3-4
OPTIONS ELIMINATED FROM FURTHER EVALUATION
FOR DEVELOPMENT/PRODUCTION IN THE ALASKAN BEAUFORT SEA

Development/Production Components	Options	Reason for Elimination
Oil and Gas Drilling Methods (Section 3.4.2.3)	Vertical Drilling Technology	XOnly accesses portions of a reservoir directly beneath the surface drilling location. XMultiple drilling structures at multiple drilling locations increases overall development/production costs and creates an increase in potential environmental concerns.
Offshore Production Structures (Section 3.4.2.4)	XFloating Structures - Jackup Drilling Platforms	XNot designed to operate in an ice environment or to support long-term development/production activities.
	- Semi-Submersible Drilling Vessels	XNot designed to operate in an ice environment or to support long-term development/production activities.
	- Conventional Drillships	XNot designed to operate in an ice environment or to support long-term development/production activities.
	- Conical Drilling Unit (Kulluk)	XNot designed to operate in an ice environment or to support long-term development/production activities.
	- Ice Islands	XMelt in summer when ambient air temperatures are above freezing.
	XIsland Structures - Caisson Retained Island (CRI) Designs and Tarsiut Island (Concrete CRI)	XRelocation expected to be very difficult because the caissons are ballasted with sand, rather than water. X Redesign and construction of a new caisson structure would create a purpose-built structure and would be expected to be very costly compared to other options.
	XSubsea and Subterranean Structures - Subsea Cavern	XUnproven concept not yet demonstrated as technically or economically feasible. XSafety concerns related to gas build-up, fire/explosions, evacuation, blowouts, etc. XWould create a large volume of excavated material that would require disposal. XPermafrost stability concerns around the cavern and entrance to the cavern.
Oil and Gas Recovery (Section 3.4.2.5)	XEnhanced (Tertiary) Recovery	XNot considered in this Environmental Impact Statement because options are unknown.
Transportation of Product (Section 3.4.2.7)	XPipeline Elevated Pile-supported Structure	XWould be exposed to winds, wave action, and ice forces and would be difficult to design for this exposure. XStructure could impede passage of vessels/barges beneath or through it as a result of pile spacing and elevation above the sea surface.

Notes: ft = Foot or feet m = Meter(s) % = Percent

CHAPTER 4.0

NORTHSTAR UNIT DEVELOPMENT/PRODUCTION ALTERNATIVES

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4.0 NORTHSTAR UNIT DEVELOPMENT/PRODUCTION ALTERNATIVES

4.1 INTRODUCTION

Chapter 4 of this Environmental Impact Statement (EIS) addresses National Environmental Policy Act requirements to identify reasonable alternatives, including the No Action Alternative, for further analysis. Reasonable alternatives are developed in Section 4.2 by applying the process discussed in Section 3.5. Section 4.3 identifies the alternatives considered but eliminated from detailed analysis in this EIS. Section 4.4 presents a detailed discussion of the alternatives selected for further evaluation in this EIS. The No Action Alternative is discussed first, and provides a basis for comparison of impacts associated with the action alternatives. BP Exploration (Alaska) Inc.'s (BPXA) proposed action is presented next, followed by the other action alternatives. Sections 4.5 and 4.6 discuss the agency preferred alternative and the environmentally preferred alternative, respectively.

Issues and Concerns: Chapter 4 addresses the following questions concerning alternatives for Northstar Unit development:

Issues/Concerns	Section
· What characteristics of the Northstar Unit and reservoir affect the determination of alternatives?	4.2
· What development/production location and structure type is reasonable for the Northstar Unit?	4.2
· What alternatives were identified, but eliminated from detailed analysis, and why were they eliminated?	4.3
· What are reasonable alternatives for development of the Northstar Unit?	4.4
· What is the environmentally preferable action alternative?	4.5
· What is the preferred action alternative?	4.6

4.2 DEVELOPMENT OF POTENTIAL ALTERNATIVES

4.2.1 Overview

The process for selecting reasonable alternatives to be considered for further evaluation in this EIS, and eliminating alternatives which are unsuitable or would involve substantially greater environmental impact and/or expense, was presented in Section 3.5. This process presumes that development/production from an onshore site or an existing offshore structure is generally preferable to the installation of new offshore structures because new structures would add to cumulative impacts. An exception to this general case would occur if the existing site or facility involved a special environmental or technical issue. The general approach and special considerations involved in selecting the development/production location and structure type are outlined on Figure 3-6, and are applied to the specific characteristics of the Northstar Unit in Section 4.2.2. Other components of development/production are reviewed through similar reasoning to select: oil and gas recovery techniques, oil and gas processing facility options, product transportation options, gravel source options, spoils disposal options (required due to consideration of buried pipelines), and construction schedule options (winter versus summer season). Each of these facility and support requirements are discussed in the following sections.

4.2.2 Determination of Drilling/Production Facility Alternatives

4.2.2.1 Northstar Unit Reservoir and Site Characteristics

The Northstar Unit is located between 2 and 8 miles (3 and 13 kilometers [km]) offshore of Point Storkersen in the Alaskan Beaufort Sea, and covers approximately 60 square miles (155 square km) (Figure 4-1). The northeastern portion of the unit lies in federal waters and consists of two federal oil and gas leases (Outer Continental Shelf Y-0179 and Y-0181). The remainder of the unit lies in state waters and consists of five state oil and gas leases (Alaska Division of Lands [ADL] 312798, ADL 312799, ADL 312808, ADL 312809, and ADL 355001). The portion of the Northstar Unit within state waters also lies within the jurisdiction of the North Slope Borough (NSB) coastal management program and land management regulations.

A portion of Long Island, one in a series of natural barrier islands paralleling the coastline 3 to 5 miles (5 to 8 km) offshore, is located in the southwest corner of the Northstar Unit. Two manmade gravel islands, Seal and Northstar Islands, were built within the Northstar Unit to support previous oil and gas exploration activities. Northstar Island, in the northwest corner of the unit in 43 feet (ft) (13.1 meters [m]) of water, has since eroded to below sea level and has become the Northstar Island shoal, while portions of Seal Island, centrally located in the unit in 39 ft (12 m) of water, remain above the sea surface. Water depths over the Northstar Unit range from 0 ft along the shoreline of Long Island to depths approaching 45 ft (13.7 m) near the Unit's northern boundary.

Bottomfast ice occurs over portions of the Northstar Unit where water depths are less than approximately 5 ft (1.5 m). The remaining portions of the Northstar Unit are within the relatively stable, floating landfast ice zone. The more dynamic stamukhi or shear ice zone, begins in approximately 65 ft (20 m) of water, occurring approximately 3 to 5 miles (5 to 8 km) further offshore than the Northstar Unit.

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Northstar Unit Exploration History: The two federal and four state leases were acquired by Amerada Hess Corporation, Amoco Production Company, Murphy Oil USA, Inc., Shell Western Exploration & Production Inc., and Texas Eastern Corporation as a result of successful bidding in the 1979 joint State/Federal BF Lease Sale. A fifth state lease (ADL 355001) was acquired by these companies in 1982 through State Lease Sale No. 36. These leases now comprise the Northstar Unit.

Six exploration wells were drilled within the Northstar Unit between 1983 and 1986 from two manmade gravel islands, Seal and Northstar Islands, constructed specifically for exploratory drilling activities (Figure 4-2). Seal Island, constructed in 1982, was used for drilling three wells which located hydrocarbons in the Ivishak formation, and a fourth well which was dry. Northstar Island, constructed in 1985, was used for drilling two wells; one confirmed the extension of hydrocarbons in the Ivishak formation, and the second was abandoned because of mechanical difficulties downhole. A seventh well, a dry hole, was drilled in 1994 from Long Island. Four of the seven exploratory wells were deemed capable of producing hydrocarbons in commercial quantities: Northstar No.1 drilled from Northstar Island; and Seal Island Nos. 1, 2, and 3 drilled from Seal Island. All seven exploration wells were plugged and abandoned in accordance with state and federal regulations.

In 1989, a Northstar Unit Agreement was entered into among the U.S. Minerals Management Service (MMS), Alaska Department of Natural Resources (ADNR), and the original leaseholders named above. A Unit Agreement is a mechanism through which multiple leases, contiguous to one another, are administratively combined and managed as a single lease under a single operator to promote more effective and efficient management of oil and gas reservoirs. The Northstar Unit Agreement defines how costs, liabilities, and benefits incurred in maintaining or conducting operations are apportioned and assumed among the owners. The Unit Agreement also discusses procedures for exploration, development, and production activities within the Unit.

The original leaseholders abandoned Seal and Northstar Islands in 1994 under plans approved by state and federal agencies. BPXA entered into discussions with the original leaseholders for acquisition of a working interest and operatorship of the Northstar Unit, and developed conceptual engineering designs for reservoir development. By the end of February 1995, agreements were reached for BPXA's purchase of the Northstar Unit. BPXA became 98 percent (%) owner of the Unit and Murphy Oil USA, Inc. retained 2% interest. The Unit Agreement was transferred to BPXA in 1995 and amended in 1996 to reflect changes in royalty payments.

Northstar Reservoir Characteristics: The Northstar reservoir is approximately 2 miles (3.2 km) wide and 8 miles (13 km) long, oriented in a northwest-southeast direction with the central axis of the reservoir generally located beneath Seal and Northstar Islands (Figure 4-2). Figures 4-3 and 4-4 represent cross-sections through the reservoir that show reservoir thickness beneath Seal and Northstar Islands. As depicted, these reservoir cross-sections suggest that the Seal Island location is over the center of the reservoir’s thickest and most promising area in terms of potential oil recovery.

Results of seismic investigations and previous exploration drilling show the Northstar reservoir lies between 10,839 and 11,100 ft (3,304 and 3,383 m) below the sea floor. The Northstar reservoir is within the Prudhoe Bay member of the Ivishak Formation of the Sadlerochit Group, the same geologic unit that occurs onshore and which has, to date, produced more than 12.5 billion barrels of oil. The producing formation or "pay zone" is approximately 260 ft (79.2 m) thick, with an oil/water contact estimated to be at 11,100 ft (3,383 m) below the seafloor and a predicted gas/oil contact at 10,839 ft (3,304 m) below the sea floor. Sediments within the Northstar reservoir are coarser grained and more cemented, and the rock has a lower porosity and permeability than the adjacent onshore reservoir formations.

The Northstar reservoir contains an estimated 260 million barrels of original oil in place. Well tests conducted during the exploration phase, coupled with results of detailed reservoir studies, indicate that reservoir fluids from producing wells will be a combination of oil, water, and gas. Recoverable reserves are estimated to be 158 million barrels. The operational design life of the reservoir is expected to be approximately 15 years.

Oil within the Northstar reservoir is very light (42° API gravity) with a low viscosity. The oil is higher quality than the heavier oils (approximately 26° API gravity) found in adjacent onshore reservoirs. Reservoir temperature is 246 degrees Fahrenheit (119 degrees Celsius). Fluids are at high pressure (estimated in the range of 5,300 pounds per square inch) and the wells are expected to flow easily (Appendix A). Northstar Unit crude oil composition is presented in Table 4-1.

Northstar Unit Lease Stipulations: The U.S. Department of Interior (through the Bureau of Land Management and now the MMS) and the State of Alaska Division of Minerals and Energy Management (currently the ADNR Division of Oil and Gas) issued leases containing stipulations governing oil and gas exploration and development activities within the Northstar Unit.

Lease stipulations issued by the MMS pertain to oil and gas activities on the two federal leases located in the northeastern portion of the Northstar Unit. Lease stipulations issued by state agencies pertain to activities within the five lease tracts located in state waters. A summary of the state and federal lease stipulations that influence selection of alternatives for Northstar Unit development/production activities are presented below.

- Minimize the impact of industrial development on wetlands, waterfowl, and shorebirds, including restricting siting of certain facilities to the least environmentally sensitive portions of wetlands.

- Pipelines are required if a right-of-way can be identified and is technically feasible.

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- Archaeological and historical sites within the area affected by the activity must be preserved and protected.

- Areas of special biological significance must be identified, preserved, and protected.

- Gravel mining sites are restricted to the minimum number of onshore or approved offshore sites needed to develop the field efficiently with minimal environmental damage.

- Onshore pipelines should be consolidated and constructed to allow for the safe passage of caribou.

The state and federal Northstar Unit lease stipulations and restrictions for plans of operation and other terms of sale are summarized in Appendix D.

4.2.2.2 Selection of a Development/Production Location and Structure Type

Figure 4-5 illustrates the process for selecting the development/production location and structure type for the Northstar Unit. This process is described in Section 3.5. The process is applied, in conjunction with the Northstar Unit resource and site characteristics described above, in the following paragraphs.

Section 3.4 identified the current limits of directional drilling in northern Alaska as approximately 4 miles (6.4 km) from a specific surface location. Therefore, the area for potential drill sites is within an approximate 4-mile (6.4 km) radius of the most productive portion of the reservoir. Section 4.2.2.1 identified this location to be the central-southeast portion of the Northstar reservoir (Figure 4-6).

There are no onshore locations within a 4-mile (6.4 km) radius of the most-productive portion of the Northstar reservoir (Figure 4-6). Therefore, an onshore location for a development/production structure is not suitable for the Northstar Unit.

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There also are no offshore structures in useable condition (i.e., not requiring modification) within a 4-mile (6.4 km) radius of the most-productive portion of the Northstar reservoir.

A portion of Long Island, a natural barrier island, as well as the submerged remains of Northstar Island (Northstar Island shoal) and the remains of Seal Island (both man-made gravel islands) are within a 4-mile (6.4 km) radius of the most-productive portion of the Northstar reservoir (Figure 4-6). In addition, mobile bottom-founded structures, such as the Concrete Island Drilling Structure (CIDS), Molikpaq, Caisson Retained Island, and Single Steel Drilling Caisson (SSDC), could be moved to an appropriate location over the reservoir. As previously discussed in Section 3.4.2.4, all of these have served as structures to support past oil and gas exploration activities in the Alaskan Beaufort Sea. However, each of these existing offshore structures would require extensive modifications in order to serve as a long-term development/production structure.

Long Island is located in the southwest corner of the Northstar Unit and is the nearest barrier island to the Northstar reservoir (Figure 4-1). Long Island was previously used for exploratory drilling within the Northstar Unit during winter 1993/1994 (Figure 4-2). A development/production structure located on Long Island could reach only approximately 75% of the reservoir using current directional drilling technology (Figure 4-6). Moreover, Long Island is an important nesting site for common eiders, Arctic terns, and glaucous gulls (Section 6.7.1).

The Northstar Island shoal is located in the northwest corner of the Northstar Unit in approximately 43 ft (13.1 m) of water (Figure 4-1). This location has a greater exposure to dynamic ice conditions than the Seal Island location (Sections 3.4.1 and 5.6.1). If Northstar Island shoal was rebuilt to serve as a development/production structure, existing directional drilling technology could access only about 70% of the areal extent of the Northstar reservoir (Figure 4-6). In addition, directional drilling activities from this location could not reach a large part of the most productive portion of the reservoir (Figure 4-6).

Seal Island is located over the south-central portion of the Northstar reservoir, the most productive portion of the reservoir based on exploration well results (Figure 4-6). Seal Island is closer to the mainland than Northstar Island and in the floating ice zone, distant from the shear ice zone (Sections 3.4.1 and 5.6.1). If Seal Island was rebuilt to serve as a development/production structure, approximately 90% of the Northstar reservoir could be accessed using existing directional drilling technology.

The mobile, bottom-founded structures could be located 1 mile (1.6 km) northwest of Seal Island, the optimal location for reservoir access, where directional drilling could reach nearly 100% of the reservoir. Water depth at this location is approximately 40 ft (12.1 m) and it is within the floating ice zone where ice dynamics are similar to those at Seal Island. Although any of the structures, when modified, could be used in this water depth, or a new one constructed, the CIDS is the most likely candidate because of lower costs to modify it for production and less noise transmission than a steel structure (Molikpaq, SSDC).

Considering the moderate ice regime over most of the Northstar Unit, any of the island or mobile structures could be provided with adequate protection from ice impact or override. They also could all be designed to provide adequate space for drilling and production needs. Environmental concerns are raised by use of Long Island because it would mean the loss of relatively rare nesting habitat for eiders, terns, and gulls. A second environmental concern would be the higher noise levels from a steel structure. Since there are few environmental concerns about construction of a gravel island offshore, one of the gravel structures would be preferable and Long Island should be avoided. Considering cost and maximizing recovery of oil, a location at or northwest of Seal Island is most logical. The flexibility and cost savings of using a reconstructed Seal Island outweigh the benefits of locating a structure 1 mile (1.6 km) away that could reach more of the reservoir. In addition, advances in directional drilling may result in the ability to reach the entire reservoir from Seal Island within the expected lifetime of the Northstar project.

A reconstructed Seal Island, modified for ice protection and enlarged to accommodate drilling and production, will be evaluated for all alternatives for Northstar Unit development/production. Use of the CIDS or a gravel and concrete structure for additional space would be acceptable because they could be designed to withstand ice movements and because of their noise dampening characteristics. Use of the CIDS was not carried forward as a potential option for Northstar Unit development because potential benefits associated with its use would not be offset by limiting factors related to engineering and production. These factors include a relatively limited working area that would not accommodate full offshore processing of produced fluids and potential long-term maintenance requirements that would require transport of the production facilities to dry dock facilities away from the oil production area. Additionally, drilling and production operations from steel structures would result in greater transmission of sound to the environment than would occur from similar activities on a gravel island. Therefore, steel structures are not being considered as alternatives for Northstar Unit development/ production in this EIS.

4.2.3 Selection of Oil and Gas Recovery Options

Oil and gas recovery options that are available for use in the Alaskan Beaufort Sea include primary recovery, gas lift, gas cycling, waterflood, and water injection. Each of these is evaluated in the context of Northstar reservoir characteristics (Section 4.2.2.1) to determine the suitable method(s) to support oil and gas development/production activities from the Northstar Unit.

Primary Recovery: Oil and gas production through primary recovery occurs as a result of internal reservoir pressures forcing reservoir fluids to the surface (Section 3.4.2). The information presented in Sections 3.4.2 and 4.2.2, suggests that primary recovery would recover between 5% and 20% (13 million and 53 million barrels) of the estimated 260 million barrels of oil in place in the Northstar reservoir.

Gas Lift: Gas lift is most effective if a reservoir contains heavy, thick oil or if the reservoir has a high water content (Section 3.4.2). Reservoir tests conducted during the exploration phase indicate that oil within the Northstar reservoir is very light and has a low viscosity (Section 4.2.2).

Reservoir Pressure Maintenance Using Gas Cycling: Gas cycling is an effective option for oil and gas recovery from reservoirs that have a natural gas cap or that are expected to produce substantial amounts of gas, such as the Northstar reservoir (Sections 3.4.2 and 4.2.2). Based upon the results of exploration activities and reservoir modeling studies conducted by BPXA, gas cycling is expected to recover 158 million barrels (61%) of the estimated 260 million barrels of oil in place from the Northstar reservoir. Modeling shows that gas cycling would maximize recovery of oil and gas from the Northstar reservoir and makes Northstar Unit development/production economically feasible.

Reservoir Pressure Maintenance Using Waterflood: Waterflood is widely used in onshore reservoirs on the North Slope. The source of water for waterflood can be treated seawater from an intake system on Seal Island, or can be treated seawater from an existing seawater treatment plant (STP). The STP at the end of West Dock has the capacity to provide treated water to the Northstar Unit (Section 3.2.2). This would require construction of a seawater pipeline from West Dock to Seal Island.

Based upon the result of exploration activities and reservoir modeling studies conducted by BPXA, recoverable oil reserves using waterflood would be expected to be between 132 and 159 million barrels (51% and 61%) of the estimated 260 million barrels of oil from the Northstar reservoir. This is a large enough volume to make waterflood a viable recovery method for the Northstar reservoir and, if implemented, could allow the Northstar Unit development/production to be economically feasible.

Reservoir Pressure Maintenance Using Water Injection: Similar to waterflood, the source of water for water injection can be treated seawater from an intake system on Seal Island, or can be treated seawater from an existing STP. Recoverable oil reserves using water injection are expected to be between 91 and 117 million barrels (35% and 45%) of the estimated 260 million barrels of oil in place in the Northstar reservoir (Section 3.4.2). Water injection would not recover as much oil as gas cycling or waterflood and would not be as economically feasible as these two options.

Differences in environmental impacts from recovery methods are more subtle than those for other project components. There may be variations in air emissions, consumption of fuel, and wastes produced. The most obvious difference in the options discussed above, is that some require a water source and discharge and others do not. Since seawater can be used as this water source, and discharge is only backwash from the seawater intake filters, environmental impacts are likely to be minor. The major decision factors for recovery options, therefore, are cost and maximum potential recovery. Based on the discussions above, gas cycling and waterflood, which are projected to recover approximately the same amount of oil, are viable options to carry forward; however, gas cycling would be less costly, more efficient, and result in fewer environmental impacts than waterflood. Gas lift is not useful for the type of oil present, and primary recovery and water injection have recovery potentials too low to justify building the project.

4.2.4 Selection of Oil and Gas Processing Method

Oil and gas processing options that are available for use in the Alaskan Beaufort Sea include full offshore processing, partial offshore processing coupled with partial onshore processing, and full onshore processing (Section 3.4.2). These are discussed below to identify reasonable options for the Northstar Unit.

Full Offshore Processing: Full offshore processing would separate produced reservoir fluids into three product streams (sales quality crude, produced water, and natural gas). Necessary oil and gas processing equipment would be located on the gravel island and no onshore support for this activity would be required. Full offshore processing would require an island of a few acres in size to accommodate the infrastructure necessary for offshore processing. Portions of the separated gas stream could be used as a source of fuel on the island, and the remaining portion could be re-injected to support gas cycling as a method of oil recovery (Section 4.2.3). The separated water stream could be disposed of via an injection well installed on the offshore island. The crude oil could then be transported to shore without the need for further processing.

Partial Offshore Processing and Partial Onshore Processing: Partial offshore processing and partial onshore processing involve separating most of the gas and some of the water from produced reservoir fluids on the island and transporting the remaining mixture to shore for final processing. However, as indicated in Section 3.3.2, none of the onshore facilities have the capacity to fully process the volume of partially processed reservoir fluids projected to be transported from the Northstar Unit. Therefore, new processing facilities, or modifications to existing facilities, would have to be constructed to accommodate partial onshore processing of fluids produced from the Northstar reservoir. Partial offshore and partial onshore processing would require essentially the same gravel island size and the same type and amount of processing equipment, compressors, treatment facilities, pumps, and an injection well on the offshore gravel island as would the full offshore processing option.

Full Onshore Processing: Full onshore processing requires Northstar reservoir fluids to be transported by a three-phase (mixture of oil, water, and gas) pipeline to onshore facilities for processing. No processing would occur on Seal Island. However, as indicated in Section 3.3.2, none of the onshore facilities have the capacity to fully process the volume of reservoir fluids projected to be transported from the Northstar Unit. Therefore, new processing facilities, or modifications to existing facilities, would have to be constructed to accommodate the full onshore processing of fluids produced from the Northstar reservoir. Full onshore processing would require a smaller gravel island size and no processing equipment, compressors, treatment facilities, or an injection well (for produced water) on the offshore gravel island.

In summary, the partial and full onshore processing options do not appear to have environmental, technical, or cost benefits in comparison to the full offshore processing option. Although the gravel island could be smaller if all processing is done onshore, impacts to wetlands, wildlife, and hydrology from onshore expansion of facilities would be greater than impacts at an offshore site. Full processing offshore also results in an oil product that can be transported from the island by pipeline, tanker, or barge. For these reasons, full offshore processing will be carried forward as the method to be evaluated for all alternatives in this EIS.

4.2.5 Selection of Product Transportation Methods

Offshore Transportation Options: Offshore product transportation options that are suitable for use in the Alaskan Beaufort Sea were discussed in Section 3.4.2.7 and include tankers, barges, pipelines installed on gravel causeways, pipelines installed on the seafloor, and pipelines buried beneath the seafloor. Each of these are evaluated in the context of Northstar reservoir characteristics (Section 4.2.2.1) to determine the suitable methods for transporting oil from the Northstar Unit to onshore facilities.

Tankers: Oil tankers do not currently operate in the Alaskan Beaufort Sea, and no tanker facilities currently exist along the coastline to berth, load, and/or unload tankers. Seal Island is located in water depths less than 60 ft (18.3 m) and would require a dredged channel for tanker access or a pipeline from Seal Island to a tanker loading system located in water depths greater than 60 ft (18.3 m). An integrated ice management system would be required for safe transport of crude oil by tanker approximately 9 months out of the year when ice is present. If an integrated ice management system could not be successfully implemented, crude oil transportation by tanker would be limited to times of open water or very light ice conditions when tankers could operate safely. The relatively small volume of recoverable reserves from the Northstar reservoir (158 million barrels) could not economically support new facilities to accommodate tanker transport, ice management systems, or partial-year production/transport of oil.

Barges: Barge transport of crude oil from Seal Island to the Alaskan Beaufort Sea coastline would require a dredged shipping channel for barge access to the coastline, and a coastal crude oil loading/unloading facility. This would require an integrated ice management program to ensure safe transport. If an integrated ice management system could not be implemented, crude oil transport from Seal Island to the Alaskan Beaufort Sea coastline would be limited to times of open water or very light ice conditions when barges could operate safely. The relatively small volume of recoverable reserves from the Northstar reservoir (158 million barrels) could not economically support new facilities to accommodate barge transport, ice management systems, or partial-year production/transport of oil.

Pipelines Installed on Gravel Causeways: A gravel-filled causeway from the shoreline to Seal Island would extend a minimum distance of approximately 6 miles (9.6 km) offshore in water depths up to 39 ft (11.9 m). It is estimated that approximately 2 million cubic yards (yd^3) (1.5 million cubic meters [m^3]) of gravel would be necessary to construct a gravel causeway from Point Storkersen to Seal Island, and would affect approximately 95 acres (38.4 hectares) of seafloor. The causeway would be subject to erosion from ice movement and would have to be built several feet above sea level to withstand significant wave forces from severe storm events. A gravel-filled causeway of this length along this portion of the Alaskan Beaufort Sea coastline would impede nearshore water circulation patterns, nearshore sediment transport, and interfere with coastal migration of fish (Sections 5.3.1 and 6.4.1). It also would impede vessel movements associated with subsistence and commerce activities in the area. It is estimated that a gravel causeway would cost between \$40 and \$50 million (exclusive of any bridges) and require several months to construct.

Pipelines Installed on the Seafloor: Pipelines installed on the surface of the seafloor between Seal Island and the Alaskan Beaufort Sea coastline would be in water depths between 0 and 39 ft (0 and 11.9 m). They would be exposed to ice gouge and strudel scour events on a yearly basis during breakup. These events could rupture or damage the pipeline (Section 3.4.2.7) and cause oil spills.

Pipelines Buried Beneath the Seafloor: Pipelines must be buried to adequate depths to be protected from the effects of ice gouge and strudel scour. The project area inside the barrier islands, as well as between the barrier islands and Seal Island, is considered to be of low ice gouge intensity (Norton and Weller, 1984:202). Ice gouge survey data collected during the summer of 1995 in the project area indicated a maximum gouge depth of 2 ft (0.6 m) in water depths of 32.5 ft (9.9 m) (Leidersdorf and Gadd, 1996:1). Estimates of 100-year event ice gouge depths in the project area indicate potential gouges to depths of approximately 3.5 ft (1.1 m) (INTEC, 1997a:18-19). Surveys conducted by Leidersdorf and Gadd (1996:3) in 1995 and 1996 in the project area detected strudel scours in water depths of 6 to 20 ft (1.8 to 6 m), with maximum horizontal dimensions in the range of 20 to 70 ft (6 to 21.3 m), and a maximum depth of 4.4 ft (1.3 m). Based upon these data, offshore pipelines in the project area must be buried to depths of no less than 7 ft (2.1 m) below the seafloor (2 times the 100-year predicted ice gouge depth [Section 5.6]).

Unlike strudel scour and ice gouging, which are natural occurrences, upheaval buckling is caused by pipeline expansion, generally due to either high temperatures or pressure from within the pipeline itself. Under these circumstances, the pipeline would be subject to axial compressive loads. To relieve these loads, segments of the pipeline may shift vertically (upheaval buckling) in the trench if it is not covered sufficiently. The proposed pipeline depths, as required for protection against strudel scour and ice gouging, provide for a safety factor against upheaval buckling (INTEC, 1997b:7).

Conventional backhoe and related excavation equipment could be used from the sea ice during the winter to bury pipelines below the seafloor in water depths less than 40 ft (13 m) (Section 3.4.2.7). They also could be installed during the open water season using equipment deployed from vessels and/or barges.

<u>Double-walled Offshore Buried Pipelines</u>: The three most likely causes of a leak in a pipeline without valves and flanges (such as that proposed for the Northstar Unit) would be construction defects, corrosion, and external trauma. Control of construction defects and prevention of corrosion would be more complex for a double-walled pipeline than for a single-walled pipeline. A double-walled pipeline configuration would also require a more complex design than a single-walled pipeline and would likely present a greater chance of operational problems. A failure of the external double-walled pipeline without breaching the carrier pipe would flood the annulus with seawater. Removal of the seawater would be difficult. On the operational side, monitoring of the pipeline annulus to detect leaks would be difficult due to the length of the proposed Northstar's pipeline and associated volumes. There is currently no data available on the reliability or complexities of maintaining hydrocarbon sensors in the annulus of such a long pipeline. Based on existing information it remains unclear to what extent and to what significance these complexities and uncertainties would affect construction, installation, repair and preventative maintenance concerns. Although a double-walled pipe configuration may increase the complexity of construction, installation, and repair, a thorough analysis of the benefits and costs associated with this design alternative have not been conducted.

In determining the appropriateness and practicability of a doubled-walled pipeline alternative there remains a degree of uncertainty surrounding the issues of reliability and structural integrity. Although a cased pipeline was designed and is currently under construction for the Alpine Colville River crossing, there are significant differences in its application to subsea pipelines in an Arctic environment. Best available information is not sufficient to indicate that this (pipe-in-pipe) technology is as good or better than the proposed design for the Northstar carrier pipeline. However, the design appears to have merit in at least some specifications and warrants further consideration and analysis in future potential applications.

In summary, for cost, environmental, and safety reasons, as well as their limited season of usefulness, transport by tankers or barges does not appear to be a desirable option. Risks to the environment from oil spills would be greater, with no advantages in reduced impacts elsewhere. However, a pipeline could not simply be installed on the surface of the seafloor. Protection by burial would be necessary for the entire distance between Seal Island and the shoreline. Burial within a gravel-filled causeway would be acceptable only if enough breaches were included to provide for water circulation and fish and boat passage. Because the structure would need to cross Gwydyr Bay, which is used by both fish and birds, bridges may be needed for up to half of the causeway length. This would be expensive, in addition to the cost of the gravel. One-time burial of a pipeline would have fewer adverse impacts than repeated dredging of a shipping channel or placement and maintenance of a causeway. Therefore, for both cost and environmental reasons, burial beneath the seafloor appears to be the best option. Burial depths and other pipeline design features must consider ice gouging, strudel scour, and thawing and subsidence in the permafrost transition zone (Sections 5.3 and 5.6) to ensure that the pipeline is stable and safe. A variety of buried pipeline routes between Seal Island and the shoreline will be evaluated as alternatives for Northstar Unit development/production (see below).

Pipeline Landfall Options and Offshore Pipeline Corridor Alignments: The use of pipelines to transport oil from Seal Island to the Alaskan Beaufort Sea coastline requires that the offshore pipeline transition from beneath the seafloor to land at the coastline. Pipeline landfalls can be located along a natural coastline or at an existing manmade facility. The criteria for determining suitable landfall location(s) are discussed in Section 3.4.2.7. Pipeline landfall locations must be selected in conjunction with selecting the offshore pipeline corridors between Seal Island and the coastline. Criteria for determining offshore pipeline alignments also are discussed in Section 3.4.2.7.

Application of these criteria to the Northstar project area determined that there is no single landfall and offshore pipeline corridor combination that best satisfies all items in the lists of criteria. Offshore pipeline corridor and landfall locations that best satisfy their respective criteria are discussed in Section 3.4.2.7. Those options that represent a reasonable range of options for transporting crude oil from Seal Island to a landfall location and gas from a landfall location to Seal Island are shown on Figure 4-7 and are identified as follows:

- An offshore pipeline corridor extending south from Seal Island to landfall at Point Storkersen. This offshore corridor and landfall option has the shortest possible offshore pipeline corridor length, avoids high value habitat, avoids known cultural or archaeological sites, and minimizes pipeline bends (Alternatives 2 and 3).

- An offshore pipeline corridor extending south from Seal Island until it intersects the southern boundary of the Northstar Unit. The corridor then turns southeast toward West Dock, staying north of Stump Island. At the southeast end of Stump Island, the corridor turns southwest, making landfall along the coastline between Point McIntyre 1 (PM1) and the West Dock causeway. This offshore corridor and landfall option avoids proximity to river deltas, which minimizes potential impacts from strudel scour, avoids high value habitat, avoids cultural or archaeological sites, and allows access/connection to existing onshore oil and gas facilities (Alternative 4).

- An offshore pipeline corridor extending south from Seal Island until it intersects the southern boundary of the Northstar Unit. The corridor then turns southeast toward West Dock, staying north of Stump Island and continuing eastward until it intersects the West Dock causeway. Landfall is shown at Dock Head 2, just landward of the 650-ft (198 m) breach; however, this site should be considered representational of any West Dock causeway landfall. A landfall seaward of the breach would require placing Northstar pipeline(s) on the causeway bridge, which may increase costs. A landfall further landward of Dock Head 2 would increase the subsea length of buried pipe, but would decrease the length of required causeway widening (see Section 4.4.5). This offshore corridor and landfall option avoids proximity to river deltas, high value habitat, near surface subsea permafrost, eroding shoreline, and cultural or archaeological sites. It also allows access/connection to existing onshore oil and gas facilities (Alternative 5).

Onshore Pipeline Corridor Alignments: Once the offshore pipelines from Seal Island reach landfall, they transition to onshore pipelines. Onshore pipelines would be elevated along vertical support members (VSMs) and would cross undeveloped tundra or follow established pipeline corridor(s) to the Central Compressor Plant (CCP) (gas line) and Pump Station No. 1 (oil line). The criteria for identifying new onshore pipeline corridors that cross undeveloped tundra are presented in Section 3.4.2.7.

There is no single onshore pipeline corridor that satisfies all of the criteria described in Section 3.4.2.7. Onshore pipeline corridors that best satisfy these criteria and that represent a reasonable range of options for connecting the landfall locations to Pump Station No. 1 and the CCP are shown on Figure 4-7 and described as follows:

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- A new oil and gas pipeline corridor from the Point Storkersen landfall continues south to a point where the gas pipeline turns east and follows existing road and pipeline corridors to the CCP. The oil pipeline continues south along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 2) minimizes total pipeline length and costs, avoids high value fish and wildlife habitat (although less so than the other alternatives), and avoids conflicting land uses.

- A new oil and gas pipeline corridor from the Point Storkersen landfall turns east until it intersects the existing pipeline corridor between PM1 and the West Dock Staging Pad. From that intersection, the oil and gas pipelines parallel existing pipeline corridor to the West Dock Staging Pad, then turn south following an existing pipeline and roadway corridor to the CCP, where the gas pipeline terminates. The oil pipeline continues in a southwesterly direction along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 3) avoids high value fish and wildlife habitat and avoids conflicting land uses.

- The oil and gas pipeline corridor continues from a landfall location midway between PM1 and the West Dock Staging Pad where it parallels an existing pipeline corridor to the West Dock Staging Pad. From the West Dock Staging Pad, the oil and gas pipelines turn south, paralleling existing roadway and pipeline corridors to the CCP, where the gas pipeline terminates. The oil pipeline continues in a southwesterly direction along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 4) maximizes use of existing disturbed areas, avoids conflicting land uses, and avoids high value fish and wildlife habitat.

- The oil and gas pipeline corridor continues from the landfall on the West Dock causeway, paralleling the causeway to the West Dock Staging Pad. The oil and gas pipelines then parallel existing pipeline and roadway corridors from the West Dock Staging Pad south to the CCP, where the gas pipeline terminates. The oil pipeline continues in a southwesterly direction along a combination of new and existing pipeline corridors, crosses the Putuligayuk River, and connects to Pump Station No. 1. This alignment (Alternative 5) maximizes use of existing disturbed areas, avoids conflicting land uses, and avoids high value fish and wildlife habitat.

4.2.6 Gravel Source Options

Gravel would be necessary for gravel island reconstruction, gravel pads, as an aggregate material for concrete, and as backfill material for pipeline installation at landfall locations. In addition, gravel may be required for new roads, causeway widening, and construction of caribou and road crossings. The largest volume would be several hundred thousand cubic yards for reconstruction of Seal Island for use as a development/production structure.

Existing gravel at Seal Island should be re-used to the extent practical to minimize additional mining impacts as well as hauling costs. Additional gravel to support construction needs could be obtained from other offshore gravel sources, such as abandoned manmade gravel islands, barrier islands, or from suitable seafloor deposits. Gravel also could be obtained from active onshore gravel mine sites, or from a newly developed gravel source.

Offshore gravel sources, such as other existing manmade gravel islands or gravel/rocky seafloor deposits, may provide valuable substrate for marine organisms. These sources would require excavation and transport to the new location which may result in increased turbidity during excavation, and noise impacts (vessel movement and loading, dredging) which could affect wildlife and fisheries resources in the area. Northstar Island shoal is the only known offshore source of gravel in the area. Summertime excavation and relocation of this gravel from Northstar Island shoal to Seal Island could be disruptive to both whale migration and subsistence hunting due to its location near the migration corridor. Winter removal of gravel from Northstar Island shoal would require that dredging operations be conducted from the ice surface. This activity would be time consuming and costly.

Offshore barrier islands in the Northstar Unit area are long and narrow and have low elevations, typically less than 10 ft (3 m). Many of these islands provide a limited type of nesting habitat for migratory birds, and gravel removal from these islands could adversely impact this habitat. It also could prove difficult to develop a gravel mine pit on a barrier island that extends below sea level, since the pit may fill with seawater. In addition, blasting frozen gravel, if required, would adversely affect fish and birds during spring and summer and could also create a deep pit in shallow water which could trap fish over the winter.

There are seven active onshore gravel mine sites in the North Slope oil fields (Figure 4-8). The closest active gravel mine to Seal Island is the Kuparuk Deadarm mine site, located in the Prudhoe Bay Unit. Mining several hundred cubic yards of gravel from this site would require removal of approximately 625,000 yd^3 (477,800 m^3) of tundra overburden (BPXA, 1997b:7.6-1). Additional, smaller quantities of gravel also could be obtained from the existing, permitted Put 23 Oxbow (Put 23) mine site near the mouth of the Putuligayuk River (Figure 4-8). These sites could be used as a primary gravel source in the event that a new gravel source for island construction could not be permitted or was determined to be inadequate. These two sites also could be used as a gravel source for island maintenance after it is constructed.

As an alternative to using existing onshore mine sites, a new site may be identified, especially if haul distances to existing sites are long. A new gravel mine site near the mouth of the Kuparuk River is proposed by BPXA as a source of gravel to reconstruct Seal Island. The site is close to Seal Island in a region of riverine barrens and floodplain alluvium (BPXA, 1997b:7.2-1) with little overburden. Winter mining and hauling activities would not interfere with either the spring or fall bowhead whale migration offshore of the project area. 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. The general quality of the gravel is not as well known as that from an existing source. This location would require construction of an onshore ice road for approximately 2 miles (3.2 km) on the river from the mine site to the river mouth. Because the ice road would be used only one winter, no permanent road would be necessary. An advantage of the single winter

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season use is that rehabilitation work would be completed quickly. In contrast, other large existing mine sites may be in use for 10 to 20 years before decommissioning and rehabilitation..

Considering the adverse impacts of mining either a natural barrier island or an abandoned, manmade island, onshore gravel sources appear to be preferable. Among the onshore sites, any of the active mine sites (e.g., Put 23 Oxbow, Kuparuk Deadarm) are available, and their use during winter would result in little negative impact. The proposed new mine site in the Kuparuk River delta is preferable for economic reasons and because rehabilitation work would return the site to usable habitat more quickly than would occur at other mine sites.

4.2.7 Spoils Disposal Options

Installation of pipelines between Seal Island and onshore facilities would necessitate burying the pipe beneath the seafloor to sufficient depths to avoid ice gouging and strudel scour damage. Pipeline burial requires digging a trench into the seafloor and placing pipe into the trench; then refilling the trench with previously removed sediment. However, not all removed sediment would be returned to the trench, particularly where the trench is excavated through bottomfast ice. In these areas, the trench walls are vertical (like the slot cut through the ice) and the return of all the removed sediments would create a mound higher than the original bathymetric contours. In shallow waters, this could adversely impede water circulation, fish movements, and boat operations. Although this mound would be expected to be smoothed and redistributed by natural ice and oceanographic processes over several years, the risk of short-term adverse impacts can be reduced by disposing some of the sediments at other locations.

In the landfast ice zone, in water depths greater than about 6 ft (1.8 m) (floating-fast ice), seabed sediments remain unfrozen. Trenches in these water depths will have sloped walls due to sloughing. Excavated material refilling these sections could also create a temporary mound over the pipeline trench. Because the water is deep, this mound would not adversely impede water circulation, fish migration, or boat operations. Ocean currents and ice activity would disperse these spoils relatively quickly.

In both cases, sediments not returned to the pipeline trench are termed excess spoils and must be disposed in an acceptable manner. Approximately 5,000 yd^3 (3,823 m^3) of excess spoil would need to be disposed for a buried pipeline between Seal Island and the shoreline. Disposal options for such material include:

- Onshore disposal.
- Offshore disposal in the bottomfast ice zone.
- Offshore disposal in the floating-fast ice zone.

For the onshore disposal option, excess spoil material would be salty and of little or no use for revegetation purposes. Because it is mostly fine material, it is also not of value as construction fill. It could also contaminate areas outside the disposal site if salt leaches into surrounding areas. Therefore, onshore disposal of excess spoil material is not a reasonable option.

Although disposal of spoils on bottomfast ice provides a more stable surface for trucking and handling of excavated material, water depth is insufficient to provide adequate dispersion of the spoils over a large area as the ice breaks up in the spring. In Gwydyr Bay and other nearshore lagoons, weaker currents inhibit soil dispersion making these areas unsuitable for spoil disposal.

Disposal in waters with floating-fast ice provides enough water depth for dispersion of the spoils as the ice melts, although some ice thickening may be required for haul road stabilities. Moreover, if the disposal area is beyond the barrier islands, stronger currents are available to further disperse the excess spoils as the ice breaks up in the spring. The offshore location(s) should be selected away from sensitive habitats (e.g., the Boulder Patch). In addition, location(s) that would reduce distance should be used, if possible. Disposal in areas with water depths greater than 65 ft (19.8 m) is impracticable due to the long haul distances. This area is also likely to contain ice ridges, making travel difficult and unsafe.

The preferred excess spoils disposal area(s) are regions of floating-fast ice either outside the barrier islands or along the thickened area adjacent to the ice slot (Section 4.4.2.2). Regardless of the option(s) selected, spreading of the excess spoil material to not more than 1 to 2 ft (0.3 to 0.6 m) thick over the ice would prevent large piles of material from being deposited on the seafloor once breakup occurs.

4.2.8 Construction Schedule Options

Alaska's Arctic Coastal Plain and Beaufort Sea environments are harsh, with extreme cold and a period of continuous darkness during the winter. Summers are warmer, with periods of continuous daylight. These seasonal variations can influence the nature and severity of impacts associated with construction of oil and gas development/production facilities in this area.

Gravel mining in the river channels and/or floodplain in the winter when rivers are frozen avoids disturbances to fish and their habitat, which could occur during the warmer summer months. Use of onshore ice roads for gravel hauling and pipeline installation during the winter months also minimizes impacts to tundra habitats, compared to the construction of permanent gravel roads. Offshore vessel activities and related noise impacts during open water season may impact bowhead whales and migratory birds. For these reasons, the winter season is the preferred alternative (when compared to the summer season) for conducting gravel mining, hauling, and placement for island construction, as well as onshore and offshore pipeline installation.

Some island construction activities, such as island slope grading and installation of island slope protection, would be done during the open water season because sea ice would hinder the efficiency and safety of these activities. In addition, gas compression and process modules and other equipment, which are too heavy for safe transport over offshore ice roads, would require transport to Seal Island by barge and/or vessel during the open water season.

Offshore construction activities, when conducted during the open water season, should be conducted in a manner that minimizes disturbance to the bowhead whale migration that occurs through the project area during the spring and fall.

4.3 ALTERNATIVES CONSIDERED BUT ELIMINATED FROM DETAILED ANALYSIS

Oil and gas technologies applicable to development/ production in the Alaskan Beaufort Sea, based on the discussion in Chapter 3, were evaluated in Chapter 4 to identify those appropriate for the Northstar Unit. Options for project components that were eliminated from further evaluation, and the reason(s) for elimination, are identified below.

Development/Production Location and Structure Type (Section 4.2.2.2):

- 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 the Northstar reservoir.
  - Cost cannot be justified by additional oil reached (versus Seal Island location).
  - Likelihood for extending current limits of directional drilling from Seal Island in future.
- Molikpaq, CIDS and SSDC.
  - 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 (Section 4.2.3):

- 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.
  - STP required.
  - Marine discharges of filtrate.

Oil and Gas Processing Options (Section 4.2.4):

- 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 transport three-phase fluids.

Product Transportation Options (Section 4.2.5):

- 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 a 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 pipeline would be more difficult than repairing a single-walled pipeline.

Offshore Pipeline Route and Landfall Options (Section 4.2.5):

- 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 (Section 4.2.5):

- 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 (Section 4.2.6):

- 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 (Section 4.2.7):

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

Construction Schedule Options (Section 4.2.8):

- 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.

4.4 ALTERNATIVES SELECTED FOR EVALUATION IN THIS EIS

A broad range of oil and gas technological options were evaluated to identify those that are applicable for long-term development/production in the Alaskan Beaufort Sea (Chapter 3). Technological options identified were then evaluated in Section 4.2 to determine which are applicable for the Northstar Unit. Selected project components are listed below, along with the most important criteria used for selection.

Oil and Gas Drilling Methods (Section 3.4.2.3):

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

Development/Production Location and Structure Type (Section 4.2.2.2):

- 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 (Section 4.2.3):

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

Oil and Gas Processing Options (Section 4.2.4):

- 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 (Section 4.2.5):

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

Offshore Pipeline Route and Landfall Options (Section 4.2.5):

- 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 (Section 4.2.5):

- 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 (Section 4.2.6):

- 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 (Section 4.2.7):

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

Construction Schedule Options (Section 4.2.8):

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

The selected options were combined to describe four action alternatives for the Northstar Project. A No Action alternative is also considered for comparing and evaluating potential impacts of the action alternatives in Chapters 5 through 9. The alternatives discussed in the following sections are:

- 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

4.4.1 Alternative 1 - No Action

Northstar Unit development/production would not occur at this time or by the proposed methods under the No Action Alternative. The remains of Seal Island would not be reconstructed and would continue to erode in accordance with approved abandonment plans. Onshore and offshore pipelines between Seal Island, Pump Station No. 1, and the CCP would also not be constructed, and a nominally estimated 158 million barrels of recoverable reserves from the Northstar reservoir would remain in place. The offshore and onshore environments (Figure 4-9) would be expected to continue to experience fluctuations in population and habitat quality in a manner similar to that which has occurred in previous years.

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

4.4.2.1 Overview of Proposed Action

The Applicant's preferred alternative (BPXA's proposed action) includes a self-contained offshore development/production facility in 39 ft (11.8 m) of water approximately 6 miles (9.6 km) offshore of Point Storkersen in the Alaskan Beaufort Sea. The facility would be located on a gravel island constructed over the remains of Seal Island.

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Seal Island's reconstructed working surface (top) dimensions would be 465 by 421 ft (141.7 by 128.3 m) to accommodate drilling, processing equipment and facilities, a personnel camp, and supporting infrastructure. The island would have a sheet pile perimeter wall surrounding the island work surface to protect the island from natural forces. A 315-ft (96 m) long barge dock is planned for the south side of the island to allow access onto the island surface for the drilling rig, processing equipment, and supplies. A submerged gravel berm 50 to 100 ft (15.2 to 30.5 m) wide would be placed around the west, north, and east sides of the island. The surface of the submerged berm would be at 15 ft (4.6 m) below mean lower low water (MLLW). This submerged berm would break large incoming waves, reduce the force of waves against the sheet pile wall, and minimize wave overtopping. This submerged berm would also help prevent thick, multi-year ice floes and ridges from contacting the concrete mat armor on the island slopes. The submerged berm may erode or be damaged during major storm events. It would be inspected and maintained as needed. The total sea bottom footprint acreage of the proposed island would be approximately 18.1 acres (7.3 hectares); however, this acreage may increase to about 20 acres (8 hectares) as a result of side slope and/or submerged berm material being redistributed by current, wave, and ice forces.

Gas cycling is the preferred oil recovery method for depleting the Northstar reservoir. The reinjected gas allows a greater volume of oil to be produced. Approximately 100 million standard cubic feet (2.83 million m^3) per day of natural gas would be sent via a subsea pipeline from the CCP located onshore in the Prudhoe Bay Unit to Seal Island to assist with the gas cycling process.

Two pipelines between Seal Island and existing onshore facilities would be constructed. These pipelines would follow onshore and offshore pipeline alignments identified in Section 4.2.5, and are described below.

- One 10-inch (25 centimeter [cm]) common carrier pipeline from Seal Island to Pump Station No. 1 to transport sales quality oil that meets delivery specifications for delivery to the Trans Alaska Pipeline System.

- One 10-inch (25 cm) common carrier gas pipeline from the CCP located onshore in the Prudhoe Bay Unit to Seal Island to transport high-pressure gas to the island to assist with the gas cycling process.

These pipelines would be buried in a trench approximately 6 ft (1.8 m) below the seafloor between the coastline and the barrier islands and from 7 to 9 ft (2.1 to 2.7 m) below the seafloor between the barrier islands and Seal Island. More detailed pipeline corridor information for this alternative is presented in Table 4-2. The offshore and onshore pipeline alignment is shown on Figure 4-10.

4.4.2.2 Proposed Construction Activities

Freshwater Sources for Ice Road Construction: Permitted freshwater sources in the project area are shown on Figure 4-8. Many of these sources are not useable during the winter because they are too shallow and either freeze, or nearly freeze, solid. The Kuparuk Deadarm mine site (Permit No. ADL

75979), located approximately 5 to 6 miles (8 to 9.7 km) up the Kuparuk River, would be the most probable source of

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freshwater for ice road construction associated with the Northstar Development Project. The Kuparuk Deadarm mine site 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.

Ice Road Construction: An ice road would be constructed over sea ice from the West Dock causeway to the mouth of the Kuparuk River, and then up the Kuparuk River approximately 2 miles (3.2 km) to the proposed gravel mine site. A second ice road would be constructed from the mine site to Seal Island (Figure 4-11). Gravel from the new gravel mine site would be used to reconstruct Seal Island. Additional ice roads paralleling the onshore pipeline alignment and along existing onshore pipelines would be constructed for onshore pipeline construction activities.

The offshore ice roads would be built as approximately 200-ft (61 m) wide ice platforms. Construction would start in early December and occur 24 hours a day, 7 days a week. Work would stop only during unsafe conditions, such as high winds or extremely low temperatures. In water deeper than 10 ft (3 m) the ice needs to be approximately 8 ft (2.4 m) thick to support construction equipment. 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. Following construction, ice roads would be maintained using graders with snow wings and blowers. Ice road travel is usually not safe after the first part of May. Ice road construction crews would be housed at existing facilities in the Prudhoe Bay area and transported by bus to the work site for each shift.

Onshore pipeline construction activities would be performed from the surface of existing gravel roads/pads, frozen lakes, and/or ice roads and pads. Ice roads would be built approximately 130 ft (39.6 m) wide and would be constructed with sufficient thickness to protect the tundra. Ice pads would be made by the use of snow and spraying freshwater over the surface of the frozen tundra and would be large enough for construction vehicle traffic. Construction of the ice roads and pads would take place in January and February. Figure 4-12 provides details of a typical cross-section of an onshore ice road on which the construction activities will be performed.

Reconstruction of the Existing Seal Island: A plan view of the reconstructed Seal Island is shown on Figure 4-13, and two cross-sections, one looking east and another looking north, are shown on Figures 4-14 and 4-15, respectively. The reconstructed gravel island would be designed to accommodate the following oceanographic parameters:

- Water level fluctuations of 4 ft (1.2 m) above MLLW.
- Significant wave heights of 20 ft (6 m).
- A maximum of 7.5 ft (2.3 m) thick, rafted and ridged first-year ice.
- Surface currents of 4 knots (7.4 km per hour) as a result of storm-generated sustained winds of 60 knots (111 km per hour).

A more detailed presentation of the oceanographic design criteria and wave and ice force considerations is provided in Tables 4-3, 4-4, and 4-5.

Gravel Mine Pit Development: Gravel for reconstruction of the island would be hauled from a new gravel mine site to be developed near the mouth of the Kuparuk River (Figures 4-11 and 4-16). On completion of mining activities, an approximately 6-ft (1.8 m) deep breach would be constructed at the eastern end of the pit to connect the mine site to the Kuparuk River. The bottom of the breach would be excavated to a level approximately 2 ft (0.6 m) below the mean low water line of the river. During spring, the Kuparuk River would begin breakup in its headwaters and flow would proceed down river. As the melt water reaches the sea ice, it would begin to backup and flood the lower reaches of the river. This back flow would begin to fill the excavated mine site. As breakup continues, the flooded mine site water elevation would reach a point of equilibrium with the Kuparuk River. It is anticipated that this would occur sometime during the first spring and summer following mine site closure.

Completion of the mining and rehabilitation plan would create an approximately 30-acre (12 hectare) combination shallow water/deep water lake with approximately 4 acres (1.6 hectares) of shallow littoral area along the south side of the site. Shallow littoral areas would be approximately 6 ft (1.8 m) deep with the rehabilitated mine site's deepest point being approximately 40 ft (12 m) deep.

Due to its proximity to Gwydyr Bay, the rehabilitated mine site would become brackish. It is anticipated to be useful as anadromous fish habitat. Fish access to the pit would be provided by the breach excavated at the northern end of the pit.

Under a single season construction schedule, all gravel (for island, valve pads, and pipe placement at the landfall) would be obtained from the new mine site. The pit would be mined on a one-time basis during the winter of project construction and would serve as the primary source of construction material for the island. Gravel needed for summer construction activities would be obtained from either the Put 23 mine site or the Kuparuk Deadarm mine site. These include small volumes for placement of the oil and gas pipelines within existing caribou and road crossings, or for maintenance and repairs.

Under a two season construction schedule, only gravel for the island would be obtained from the new mine site, since the new mine site would be flooded at first season breakup and therefore would not be available for future use. Gravel for two new valve pads (one at the landfall and one adjacent to the CCP) and for the Point Storkersen pipeline approach, would be obtained from either the Put 23 or the Kuparuk Deadarm mine site. Gravel would also be obtained from these sources, if necessary, for placement of the pipelines within existing caribou and road crossings during the summer prior to pipeline construction.

Gravel Haul and Placement: Approximately 400,000 to 500,000 yd^3 (306,000 to 382,000 m^3) of existing gravel remains at Seal Island. Approximately 700,000 to 800,000 yd^3 (535,185 to 612,640 m^3) of additional gravel would be excavated from the gravel mine site and 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

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inside the barrier islands on bottomfast ice (Figure 4-11). This staging area would be necessary because lighter dump trucks must be used to transport gravel to Seal Island over the floating landfast ice. The dump trucks would deposit loads on the existing Seal Island surface.

Island Construction: The working surface of the island would be a rectangle surrounded on all four sides by sheet piling. The sheet pile wall would be designed to carry the loads of the gravel and water behind it, and surface loads placed on top of the gravel (loads up to 600 pounds per square ft of area). On the west side of the island where storms are most intense, the wall will rise to an elevation of 27 ft (8.2 m) above MLLW. On the east side of the island, the wall will rise to an elevation of 21 ft (6.4 m) above MLLW. Open-cell sheet pile construction would be used on the south side of the island for the dock area. The top elevation of the sheet piles along a section of the dock face would be 7 ft (2.1 m) above MLLW to allow barge docking and roll-off of loads onto the island. The sheet pile wall would be installed between March and May, before the submerged gravel berm is shaped and the concrete mats are placed. The sheet pile perimeter wall surrounding the island work surface would be untreated steel that would weather to a natural rust color. Island slopes would be graded and contoured to the general shape shown on Figure 4-17 during the subsequent open water season prior to installation of a linked concrete mat armor island slope protection system. The linked concrete-mat armor would consist of a series of concrete blocks approximately 4 by 4 ft by 9 inches (1.2 m by 1.2 m by 23 cm) thick with 1 inch (2.5 cm) integral spacers. The blocks will be both square (approximately 9,500 total) and corner trapezoids (approximately 5,800 total). Figure 4-18 provides details of a typical square block layout.

A block plant would be set up in a Deadhorse yard for fabrication of these blocks. Cement and required additives would be trucked from Anchorage. The concrete aggregates would be mined in the Put 23 mine site on the North Slope. Water would be obtained from permitted sources shown on Figure 4-8. The blocks would be stored outside until they are transported to Seal Island via ice road or barge.

Prior to concrete mat placement, a highly permeable fabric liner would be placed on the island's gravel slope down to the -20-ft (-6 m) MLLW depth to help prevent erosion of fine sediments into the water column following island construction. Cranes would be utilized for setting concrete mats below the water surface. Divers would adjoin mat sections. The concrete armor would be connected to the sheet pile wall with shackles, chain linked to steel angle iron welded to the base of the sheet pile wall. Blocks which are damaged during the construction phase would be hauled back to shore for disposal in an approved disposal site.

The heaviest loads to be supported on the island are the process and the gas compression, personnel accommodation, and warehouse modules. The drilling rig provides its own foundation support through its own substructure. Concrete foundation footings would be installed on the island surface to provide sufficient foundation support for these modules.

During island construction, a 15-ft (4.6 m) wide trench leading from the south side of the island would be built with additional sheet piling to assist with pipeline installation on the island. A seawater intake structure would be installed below the water line along the island's dock face during island construction (Figure 4-19). The intake structure would be designed to withstand impact from rubble ice and configured to limit flow velocities to acceptable levels.

Installation of Island Facilities: The process and gas compression modules would be constructed at the Port of Anchorage, transported via ocean-going barges, and installed on Seal Island. These modules would be the facilities where produced oil, water, and gas are separated and power for the island is generated. In addition to these modules, a permanent quarters module, other operations support facilities, and drilling-related equipment would be installed on the island. Drilling-related equipment includes a dedicated drilling rig. Operations support facilities include a module which contains the potable water system, emergency power generation, and wastewater management facility. A pre-fabricated, modular tank farm would also be installed that would be comprised of two insulated tanks, one 2,100-barrel potable water tank, and one 2,800-barrel diesel storage tank. All of these modules and equipment would be transported to Seal Island by barge during the ice-free season (August to September). Module walls, buildings, and storage containers would be painted beige, and exposed module steel would be painted gray.

A 55- by 62-ft (16.8 by 19 m) platform located on the southwest corner at the island would be designated for landing helicopters (Figure 4-13). It would be capable of handling up to a Sikorsky 76A or Bell 212 helicopter.

A 215-ft (65.5 m) high cantilevered flare tower would be located in the northwest corner of the island. The flare tower would have both low pressure and high pressure flare tips. The flare would combust natural gas releases that may result during oil processing (e. g., safety purges of equipment) and from equipment being started-up/shutdown due to maintenance. The smokeless flare 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 will operate continuously through pilot and feed gas to the system. The flame would be smokeless and yellow to light orange in color. Low luminosity would be expected because the flame should be virtually transparent. The high pressure flare would operate only as required, and for short periods. Flaring would not be expected more than 30 days per year. Pilot and purge gas would be provided continuously to the flare tip. While flaring, the flame would be smokeless, virtually transparent, and light yellow and blue in color.

Offshore Pipeline Construction: 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 bottom-fast ice adjacent to the pipeline corridor. 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 pipeline route using ice trenchers and large trenching equipment (ditch witches). Blocks of ice would be removed by backhoes, and front end loaders would move the ice away from the work site (Figure 4-20). A trench to allow a 6 ft (1.8 m) depth of cover over the pipeline, and 8 ft (2.4 m) wide at the bottom, would be excavated in the nearshore zone between the shoreline and the barrier islands (Figure 4-21). A trench to allow for 7 to 9 ft (2.1 to 2.7 m) depth of cover over the pipeline, and approximately 10 to 12 ft (3 to 3.7 m) wide at the bottom, would be excavated in deeper, offshore water north of the barrier islands to Seal Island (Figure 4-22). The bottom of the trench would be cut to the desired final

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grade by use of a hydraulic excavator, which discharges the excavated spoils back into the trench (Figure 4-23). Tracked equipment would tow pipeline strings to the side of the trench, where tie-in welds to the previously laid strings would be made and non-destructive testing performed on welds. Tracked equipment on one side of the ice slot would control the position of the pipelines while they are lowered through the opening into the seafloor trench. Backfilling would be performed concurrently with pipe laying activities. Pipelines would be pressure tested with a glycol/water mix prior to use.

Excess trench spoils associated with offshore pipeline installation would be disposed of immediately north of the barrier islands in water depths greater than 5 ft (1.5 m) in a 1,200- by 2,700-ft (365.8 by 823 m) area. The volume of trench spoils disposed of in this area may increase if adverse weather or ice conditions dictate the abandonment of operations prior to completion of pipeline installation activities. Material stored in this disposal area would be leveled to an average height of 1-ft (0.3 m) in any 100- by 100-ft (30.5 by 30.5 m) area. Maximum height of individual features would not exceed 2 ft (0.6 m). Some residual trenched material, less than 3 ft (0.9 m) deep may also be disposed in an area along the west side of the offshore trench where water depths are greater than 5 ft (1.5 m).

Onshore Pipeline Construction: Construction of the onshore pipelines would be accomplished using equipment and methods which have been used in the Arctic region for many years. Typical onshore pipeline construction activities are discussed below and shown on Figure 4-12.

<u>VSM and Pipeline Installation</u>: The pipe laying process would commence in January by surveyors staking positions where VSMs would be installed. VSM holes would be drilled and the tailings cleared. The average spacing for VSMs is approximately 55 ft (16.7 m). The tailings from VSM installation would be disposed of at the Put 23 mine site or the newly opened Kuparuk River Delta Northstar mine site. VSMs would be strung along the pipeline alignment together with the support beams. The VSM assemblies would be set in holes approximately 6 ft (1.8 m) deep, which are typically filled with sand slurry or foam.

Upon completion of VSM installation on a segment 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. Each weld produced in the field would be examined by non-destructive testing methods. The pipeline strings would then be lifted onto the VSMs, and tie-in welds performed and examined. Applying insulation to the tie-in welds would conclude the pipe-laying activities. The horizontal bar which supports the oil and gas pipeline across the top of the VSMs would be a minimum of 5 ft (1.5 m) above the ground to allow passage of caribou beneath the onshore pipeline alignment.

Completed segments of the pipelines would be hydrotested with a glycol/water mix after they are installed to satisfy applicable regulations and codes. The test fluid would be pumped into the pipeline and the pressure would be increased until the desired test pressure (1.25 times the maximum allowable operating pressure) has been reached. This pressure would be maintained for a minimum of 8 hours. The pressure would then be gradually reduced to atmospheric pressure and the fluid transferred to another segment of the pipeline. These activities would require approximately 10 days to complete (in mid-April). To reduce the volume of fluid required, the pipelines would be tested one after the other by transferring the testing fluid from one to another. Hydrostatic test fluids would either be stored for future work, injected into an approved disposal well, or sent back to the supplier for recycling.

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: The pipelines would have automated quick closure valves located at Seal Island. A remotely controlled shut-down valve would be located at the end of the oil pipeline at Pump Station No. 1. A manually operated isolation valve would also be placed on each side of the Putuligayuk River crossing. They would be installed in line and would be situated close to supporting VSMs on either side of the river. These valves would be protected from cold weather conditions by standard North Slope insulating jackets and not enclosed in buildings. The use of gravel pads for these valves is not expected to be required. Access to the Putuligayuk River valves would be from the service road via existing catwalks located between the road and the oil pipeline.

The pipelines would also be provided with automated, quick closure valves at the shore approach where the pipelines transition from buried subsea pipelines to aboveground onshore pipelines. At this location, an onshore gravel valve pad would be constructed to support the transition from buried to aboveground pipeline segments. The valve pad would be set back approximately 110 ft (33.5 m) from the shoreline bluff to help protect it from coastal erosion and potential storm surge and ice override events (Figure 4-24). A gravel berm will be constructed around the north and west sides of the pad in the vicinity of the valve enclosure, gas-fired generator, and controls building to help further protect these facilities from potential ice override events. This construction activity would include an 8-ft (2.4 m) wide trench through the transition zone to the 70- by 135-ft (21.3 by 41 m) gravel pad (Figure 4-25).

The trench in this transition area would be backfilled with select material and the onshore portion would be finished with a layer of soil and revegetated. Excess material obtained from excavation of the shore approach trench would be transported to the Put 23 mine site or the proposed new mine site in the Kuparuk River for disposal. A permanent access road to the gravel pad is not planned; the pad would be sized to accommodate a helipad for year-round access.

The gas-fired generator 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 is sized to provide 15 days of power, should the generator be off-line. Power from the batteries would energize a solenoid valve which would keep the valve open. A loss of power at the shore crossing would cause the valves to close.

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Pig Launching/Receiving Facilities: Pig launching and receiving facilities would be provided for the oil and gas pipelines. At the island, these facilities would be incorporated within the process module and would be permanent. The pig launcher for the gas pipeline would be installed on a gravel pad approximately 170 ft (51.8 m) long and 85 ft (25.9 m) wide on the south side of the CCP facility (Figures 2.4-20 and 2.4-21, Appendix A). The pig launcher at Pump Station No. 1 would be adjacent to the facility and would not require construction of a new gravel pad.

Construction-Related Wastes/Discharges: Sanitary, domestic, and construction related wastes generated during winter construction activities (ice road construction, gravel hauling, and placement) would be collected and backhauled to existing waste injection and/or approved disposal facilities onshore. Wastes generated during island construction activities during the broken ice and/or open water seasons (island slope protection and facilities installation and hookup) would be consolidated and stored onsite until transportation to shore and disposal at an approved disposal facility could be safely accomplished. Treated domestic and sanitary wastewater may be discharged through Outfall 001 following its installation. Upon completion of the Class I industrial waste disposal well, such wastewater would be disposed of in the well.

Construction of the seawater intake structure and marine outfall lines at the island would require a dewatering discharge to the marine environment. This discharge results as seawater seeps through subsea gravels into a construction trench as the pipelines are installed from the subsea environment to the island's surface. These waters are pumped from the construction area back into the Alaskan Beaufort Sea. It is anticipated that this construction-related discharge would occur discontinuously during an approximate 2- to 4-week time frame during early spring (April to May). The expected flow rate for this discharge is 1 million gallons per day (gpd) (3.7 million liters per day [liters/day]), but could approach 2 million gpd (7.6 million liters/day). Other characteristics associated with this discharge are shown in Table 4-6. Additional information regarding this discharge is presented in a draft National Pollutant Discharge Elimination System Permit and Fact Sheet (Appendices F and G). For the Preliminary Final National Pollutant Discharge Elimination System Permit being proposed by the U.S. Environmental Protection Agency see Appendix O.

Construction Schedule: BPXA is considering both a single winter season and a two winter season program associated with island construction and onshore and offshore pipeline installation activities. BPXA's preferred program is to conduct these construction activities in two seasons, separating island construction from pipeline installation. This reduces logistical problems and work schedules can be accommodated more efficiently. However, a single season may be required as a result of permit scheduling and/or other factors external to the project. It should be noted that BPXA would not haul gravel for island construction or install pipelines during the summer open water season as part of either construction program.

A likely scenario for a single-season construction schedule is presented in Table 4-7. All major construction activities, including island construction, onshore and offshore pipeline installation, and island infrastructure and module installation and 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. For a single-season construction schedule, the drill rig would be transported via barge during September and set up

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on the island. Drilling would commence in late September using fuel gas provided by the gas pipeline. A barge would be used to transport a 4-month supply of drilling consumables during September to provide sufficient quantities until an ice road is again built the following January. With the exception of the gravel island and associated sheet pile wall and slope protection, which is scheduled to begin in March 1999, the applicant has elected a one year construction hiatus to the present schedule based on a business decision driven by low oil prices and the need to reduce capital expenditures in 1999.

A likely scenario for a two-season construction schedule is presented in Table 4-8. Under this scenario, all work associated with the road and caribou crossings and construction of the island would occur within the first season. Based on the decision by the applicant to delay, installation of the onshore and offshore pipelines, facilities installation, and drilling would occur during the following years. For both schedules, the initial phase of development drilling would be completed approximately 21 months later.

4.4.2.3 Proposed Drilling Activities

Well Drilling Program: Seal Island facilities would be designed to accommodate a maximum of 37 wells. Initially, 23 wells would be drilled: 15 oil producers, 7 gas injectors, and 1 Class I industrial waste disposal well. The additional 14 well slots could be used for infill drilling and an additional waste injection 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.

Since freshwater would not be available in sufficient quantities, drilling muds and well completion brines would be formulated using seawater, which differs from current onshore North Slope drilling practices.

Well Control: There would be three types of development wells (oil producers, Class I industrial waste disposal, and gas injectors). All wells would have subsurface safety valves in the completion string and wellhead controls and valving consisting of:

- Master valve (manual).
- Surface safety valve (actuated).
- Wing valve (manual).
- Swab valve (manual).

The well cellars for all wells would be lined with an 8-ft (2.4 m) diameter culvert set in the gravel pad, then 6 inches (15.2 cm) of concrete would be poured in the base.

The Northstar reservoir pressures are very similar to those originally found in the Prudhoe Bay field. In the seven exploration and appraisal wells drilled to date into the structure, there have been no well control incidents or indications of shallow gas accumulations. However, 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.

Drilling-Related Wastes/Discharges: 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 I industrial waste disposal well has been drilled and completed, and a cuttings grind and inject unit 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.

4.4.2.4 Proposed Operation/Maintenance Activities

Oil Recovery and Transport: Gas cycling is the preferred oil recovery method for depleting the Northstar reservoir because reservoir tests and modeling results suggest this method of oil and gas recovery will produce more oil than other recovery methods. Target locations for oil producers, gas injectors, and Class I industrial waste disposal wells to support the gas cycling program are shown on Figure 4-26. Approximately 100 million standard cubic feet (2.83 million m^3) per day of natural gas would be sent via a subsea pipeline from the CCP located onshore in the Prudhoe Bay Unit to Seal Island to assist with the gas cycling process. A simplified process flow diagram using gas cycling as the method for oil and gas recovery is presented on Figure 4-27. A production curve for gas cycling over the proposed 15-year life of the Northstar reservoir is presented on Figure 4-28.

Approximately 700 to 800 tanker trips per year leaving the Valdez marine terminal are 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 would be required over the life of the project to accommodate Northstar reservoir production (the average capacity of tankers calling at the Valdez Marine Terminal is approximately 800,000 barrels) (Table 4-9). At peak production, tanker trip requirements would increase over current levels. Thirty tanker trips per year during peak production years 2,3, and 4 would be required, a 4.3% increase over current levels. After production has peaked, additional tanker movements decrease to one by the 14th year of production. These estimates do not include North Slope decreases in field production or possible increases in production from additional developments. However, decreases in oil production overall may offset the need for increased tanker trips that would result from Northstar production.

Island Surface Management: The island surface would be regraded to the design contours on an annual basis following spring breakup. Once barge access to the island is available, earthmoving equipment would be mobilized to the island to blade and compact the surface, and the existing gravel would be reshaped to comply with the grading plan. Should additional material be required, it would be mined at the Put 23 mine site,

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hauled to West Dock, then transported via barge to the island. Some surface subsidence is expected during the first few years. The majority of subsidence is expected near the wellheads (1 to 2 ft [0.3 to 0.6 m]) immediately next to well cellars, and would pose no safety problems. Localized subsidence around the island surface should be less than 6 inches (15 cm) and would be corrected by regrading. If necessary, the island would again be graded just prior to freezeup each year.

Island Operation/Maintenance - Bench Maintenance and Repair: The entire slope-protection system would be inspected annually, both above and below waterline, during the open water season to document the condition of the armor. The inspection would involve visual observation of the concrete mats and linkage hardware. The annual inspection would also include profiling of the bench and below water slopes to detect changes in configuration.

During initial block production for construction, maintenance replacement blocks would be produced. These blocks would be stockpiled in Deadhorse and would be available for immediate repairs identified by the inspection team. Filter fabric also would be stockpiled in Deadhorse.

The frequency of repairs to the Seal Island slope-protection system would depend on the severity of the wave and ice conditions to which it is subjected. When repairs are required, a tracked crane would be mobilized to the island, along with a small crew of divers and equipment operators. The repair work would be conducted from the bench on the outside of the sheet-pile wall. The crane would work from wood crane mats to avoid damage to the bench surface concrete mats. Divers would map the damaged area and detach the linkages of the blocks as required. If necessary, the damaged area would be regraded and filter fabric would be installed by crane. Replacement mats would be made up on the bench surface and lowered via crane to replace the damaged section. The damaged blocks would be transported to shore for disposal.

The sacrificial gravel berm at the toe of the slope has been designed to reduce damage to the concrete mat due to wave and ice impacts. This berm would not be slope-protected and, therefore, would be subject to erosion and relocation during major storm and/or ice events. Previous surveys of eroded gravel islands in the Alaskan Beaufort Sea (e.g, Seal Island, Mukluk Island) indicated a predominant migration of eroded gravel from the east to the west, in response to the prevailing northeasterly winds and waves during the open water season. It is anticipated that the direction of gravel transport would reverse direction under the influence of major, yet less frequent, westerly storms. It is expected that the northeast corner of the island (where the surface width of the berm is 100 ft [30.5 m]) would erode, with the resulting gravel loss moving to the west and south. It is not possible to predict the frequency of gravel berm replenishment. Should major storm events occur, gravel berm replenishment could be necessary on an annual basis.

The repair gravel may be delivered from an onshore mine site in either winter (via ice road) or in summer (via barge). Under these circumstances, gravel placement would require bulldozing the gravel through a slot in the wintertime ice sheet, or clamming or bulldozing the gravel off a barge during summer.

If berm erosion and gravel displacement is minor, berm replenishment may be accomplished by “backpassing,” or relocating the gravel from areas of deposition back to eroded areas. A clamshell operation would be required to retrieve the gravel. The work platform for the clamshell would either be the 100-ft (30.5 m) wide island bench during winter or summer, or a floating barge in summer. Because this method of replacement would not require new gravel deliveries to the island, it would be the preferred choice for berm maintenance.

Snow Removal: During the winter months, snow removal activities would be conducted on an ongoing basis. Snow would be cleared to maintain a safe operating surface and to prevent snow from contacting any contamination sources. Equipment and personnel on the island would be adequate to handle the continual snow removal requirements. All snow would be visually inspected for contamination before removal. Snow dumping would occur around the entire perimeter, wherever access is available. It is likely that access would be most available on the south side of the island. Uncontaminated snow would be dumped off the edge of the island onto the bench or onto the sea ice, where it would be allowed to melt and run off into the ocean during breakup. Any snow found to contain contamination would be melted and injected in the Class I industrial waste disposal well.

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

Instrumentation and Controls: Instrumentation and controls would follow current industry practices for remote facilities and include:

- Local and remote monitoring of well, process, and safety data.
- Pipeline leak detection.
- Automatic alarms that report operating conditions outside of programmed parameters.
- Security systems to prevent unauthorized modifications.
- Remote terminal units for pipeline monitoring and transmitting data.
- Standardized instrumentation for modules and equipment.
- Unit shutdown and emergency shutdown system capabilities.

Operator consoles would be located in a central control room. The operating system would display process conditions and equipment status, including alarms, trip conditions, and fire/gas detection status. Alarms would be relayed to the operator on a real-time basis, allowing the operator to make rounds through the plant. Emergency shutdown devices could be activated either manually or remotely via the Supervisory Control and Data Acquisition (SCADA) System.

Operations-Related Wastes/Discharges: Operation of Seal Island facilities associated with the development/ production of the Northstar Unit would require several marine discharges. These proposed operational discharges are summarized below by outfall identifier, and include:

- Outfall 001(a) - Continuous flush system.

- Outfall 001(b) - Brine effluent associated with the potable water system.

· Outfall 001(c) - Effluent from the domestic/sanitary wastewater treatment system (temporary marine discharge during periods when the Class I industrial waste disposal well is not available).

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

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. The seawater intake system is anticipated to take in an average 40,500 gpd (153,309 liters/day), which would be diverted to the potable water system, continuous flush system, and the drilling muds and cuttings grind and inject equipment. Seawater used for annual testing of the fire suppression system would also be provided through this intake system. Figure 4-29 illustrates the flow of seawater collected by this intake system through various facility systems terminating with Outfalls 001(a-c) and 002 and the Class I industrial waste disposal well. As shown on Figure 4-29, dechlorinators would be used to ensure marine discharges satisfy Alaska Water Quality Standards. Figure 4-30 presents a cross-section of Outfalls 001(a-c) at Seal Island.

Outfall 001 would consist of up to three commingled streams: continuous flush (Outfall 001a), brine effluent (Outfall 001b), and treated domestic/sanitary wastewater effluent (Outfall 001c). The continuous flush system would be designed to prevent ice formation and biofouling. The desalination brine would be a byproduct of the potable water system that renders freshwater from seawater. The freshwater produced would be utilized for both human and operational activities. Domestic/sanitary wastewater, following an activated sludge and ultraviolet treatment, would generally be discharged through the Class I industrial waste disposal well, but may occasionally be discharged via Outfall 001. This domestic/sanitary wastewater stream would result almost exclusively from human activities, such as food preparation, consumption, and bathing, and would not contain any fluids related to the oil production/processing systems. As noted above, collectively these three streams are referred to as Outfall 001. This outfall would have an average flow rate of 27,928 gpd (105,719 liters/day), with a maximum flow rate of 49,020 gpd (185,560 liters/day).

The fire water test discharge (Outfall 002) would be an annual discharge required for testing the island's principal fire suppression system. During a test, seawater would be pumped through selected monitors to ensure adequate pressure and supply is available in the event of fire or explosion. This outfall is expected to discharge up to 88,200 gallons (333,872 liters) annually during its 30-minute test duration.

Table 4-6 provides additional details for the above outfalls, including: flowrates, temperatures, pH, salinity, biological oxygen demand, total suspended solids, total residual chlorine, turbidity, sediments, toxics, and fecal coliforms.

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Pipeline Leak Detection: Daily operation of the pipeline would be monitored on a continuous basis by the SCADA system, which provides operating personnel with real-time information on pipeline status. In order to help ensure the proper operation of the system, regular checks would be conducted on the equipment employed, including the hardware and associated software.

In addition to the valves discussed above, the equipment involved in the leak detection system would include the following:

- Flow meters installed at the inlet and outlet of the pipelines.

- Pressure and temperature indicators at each flow meter location (to improve the response time of the system, an additional set of pressure and temperature indicators will be installed at the shore approach location).

- A communication link with the SCADA system, capable of updating the information as required by the leak detection system.

Information on pipeline condition, both with regard to vertical and horizontal position in the trench, and condition of the wall thickness would be obtained by means of pigging devices that would be run at predetermined intervals. After reviewing the results from these inspection runs, the necessary preventative and/or corrective actions would be identified and implemented, if required.

Visual inspection 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, ice cover would hamper aerial surveys of the offshore pipeline by hiding the oil from view. A through-the-ice surveillance program of the offshore pipeline would be performed every 30 days in the winter during solid ice conditions. Holes would be drilled through the ice at regular intervals along the pipeline route to search for evidence of hydrocarbons that could have entered the marine environment through a pipeline leak. The effectiveness of this oil spill detection technique is discussed in Section 8.5.1.

Pigging: Pigging would be performed to measure wall thickness; 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.

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Pipeline Repair: Repairs to the onshore facilities would be accomplished from existing roads running along the alignment of the pipelines, by using all-terrain vehicles, or from winter ice roads built specifically to access a location. Access also would be achieved by employing a helicopter to move personnel and equipment. Typically, minor repairs would require only hand tools and, possibly, welding equipment. Major repairs might require the use of earth-moving equipment, cranes and lifting equipment, and specialized tools and materials. Equipment, materials, and personnel to conduct minor and major pipeline repairs are generally available in the Deadhorse service area on a year-round basis.

Spare parts and replacement materials would be maintained at both Seal Island and onshore to provide quick response to minor emergencies and perform repairs to pipeline flow and leak detection facilities. These repairs would be performed by personnel employed as part of routine facility operations. Personnel from the production island could be mobilized by helicopter to the valve pad if required.

The complexity of repairs to the offshore pipelines increases with water depth. Pipeline damage caused by internal or external corrosion or external forces would require pipeline excavation. Damaged pipeline sections would either be replaced, or repaired using an external pipeline shrink sleeve. Regardless of the season, underwater divers and excavation, welding, and pressure testing equipment would be required for offshore pipeline repairs. Specialist contractors and equipment may be needed to perform activities such as blocking flow inside a pipeline by creating an internal ice plug. 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 periods due to the unsafe conditions for personnel. In this situation, the damaged pipeline would be closed by isolation valves until repairs could be made.

4.4.2.5 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 375 personnel. Estimated average monthly manpower requirements to support a two season construction program would peak at approximately 285 personnel. The distribution of personnel by month are broken down by specific work activity for each of these two construction scenarios in Tables 4-11 and 4-12.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of operation.

4.4.2.6 Transportation Requirements

The method (bus, barge, boat, helicopter, and truck) and estimated number of trips required to support construction, drilling, and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-13 and 4-14, respectively.

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As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, helicopter, and truck requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation between August and November. In addition, the single season construction schedule will require 7 more barge trips and 80 fewer truck trips to support the drilling program than the two season construction schedule.

4.4.2.7 Development/Production Facilities Abandonment/Reuse Potential

BPXA would be required to develop a Northstar Unit development/production facilities Abandonment Plan when the reservoir is depleted. An abandonment plan would require approval by the U.S. Army Engineer District, Alaska, MMS, and ADNR 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.

Requirements for Abandonment of Facilities: The Northstar reservoir is anticipated to produce oil in economic quantities for approximately 15 years after production commences. Once production ceases and facilities are no longer needed, oil and gas facilities would be abandoned in accordance with the approved abandonment plan, terms of individual lease agreements, terms of the Northstar Unit Agreement, and applicable state and federal statutes and regulations.

Abandonment With the Removal of All Development/Production Facilities: Abandonment with the removal of all development/production facilities would include the removal of Seal Island armor protection, all island infrastructure, and the abandonment of the onshore and offshore pipelines. Under this scenario, all production, injection, and Class I industrial waste disposal wells would be plugged and abandoned in accordance with state and federal requirements.

The development/production infrastructure located on the island would be dismantled, removed, and transported from the island over ice roads during winter months. Larger, heavier components, such as the process and compressor modules, may have to be transported from the island by barge during the open water season. These facilities would be reused at other development/production locations, stored for possible future use, salvaged as scrap material, or removed for disposal.

Buried offshore pipelines would be emptied and removed or abandoned in place. Abandoning pipelines in place would require removing all hydrocarbons and filling pipelines with seawater. Pipelines would not require excavation; eventually, buried pipelines would decay and become a component of the marine sediment. The onshore gravel valve station pad would be dismantled and removed for disposal. Gravel would be removed to the extent feasible and stored for reuse or transported back to an active gravel mine. The disturbed area would be rehabilitated and revegetated. VSMs that support onshore pipelines would be cut off below the land surface and removed. Onshore pipelines would be cut into pieces and reused to the extent feasible, salvaged as scrap material, or removed for disposal. This activity would take place during winter months and would require construction of ice roads to access the onshore gravel valve pad and onshore pipeline alignments.

The linked concrete armor around Seal Island would be dismantled, removed, and transported onshore by barge for disposal. This activity would take place during the open water season. The gravel island would be left unprotected and exposed to wave and ice erosion; with time, Seal Island would erode below the sea surface, similar to the current status of Northstar Island shoal (Section 4.2.2.1).

Abandonment of Development/Production Facilities With Seal Island Remaining: Abandonment with Seal Island remaining would require the removal of all development/production infrastructure, including onshore and offshore pipelines. Seal Island and the protective linked concrete armor around it would remain. Under this scenario, all production, injection, and waste injection wells would be plugged and abandoned in accordance with state and federal requirements.

The development/production infrastructure on the island would be dismantled, removed, and transported from the island over ice roads during winter months. Larger, heavier components, such as the process and compressor modules, may have to be transported from the island via barge during the open water season. These facilities would be reused at other development/production locations, stored for possible future use, salvaged as scrap material, or removed for disposal.

Seal Island would remain in place as it has been designed. The island would require routine inspection and maintenance and may require periodic repairs as a result of continued exposure to wave and ice forces.

The onshore gravel valve station pad would be dismantled and removed for disposal. Gravel would be removed to the extent feasible, stored for reuse elsewhere, or transported back to an active gravel mine. The disturbed area would be rehabilitated and revegetated. VSMs that support onshore pipelines would be cut off below the land surface and removed. Onshore pipelines would be cut into pieces and reused to the extent feasible, salvaged as scrap material, or removed for disposal. This activity would take place during winter months and would require construction of ice roads to access the onshore gravel valve pad and onshore pipeline alignments.

Facility Reuse Potential: Alternative uses have been considered for this project in relation to abandonment and/or reuse of Northstar Unit development/production facilities after production has ceased. If maintained properly, Seal Island and its buried subsea pipelines could be used for future offshore oil and gas development (such as the Sandpiper Unit discussed in Chapter 10). This would eliminate the need for additional pipelines to existing onshore facilities.

Seal Island also could be utilized by non-oil and gas industries once the leases are relinquished to the state. Seal Island could serve as a staging camp for local NSB residents to assist with subsistence hunting activities (e.g., seals and bowhead whales). Seal Island could also serve as a base for Alaskan Beaufort Sea research facilities or become part of the expanding North Slope tourism industry.

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

4.4.3.1 Overview of Alternative

The principal difference between Alternative 3 and Alternative 2 (previously described in detail in Section 4.4.2) is a variation in the onshore oil and gas pipeline alignment and valve pad location. The oil and gas pipelines associated with Alternative 3 follow the same offshore corridor from Seal Island to Point Storkersen as Alternative 2. The buried subsea pipelines would transition to aboveground pipelines in a similar 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 pipeline transition from subsea to aboveground at Point Storkersen. However, once onshore, the oil and gas pipeline corridor would turn east until it intersected the existing pipeline corridor between PM1 and the West Dock Staging Pad. A check valve would be placed in the oil line at the shore crossing, and a small gravel valve pad approximately 75 by 75 ft (23 by 23 m) in size would be constructed adjacent to the point of intersection with the existing pipeline corridor between PM1 and the West Dock Staging Pad. Valves and instrumentation at this pad would be powered by electricity from the existing onshore power grid.

From that intersection, the oil and gas pipelines 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, where the gas pipeline terminates. The oil pipeline continues from the CCP to Pump Station No. 1 via a combination of existing and new pipeline and/or roadway corridors.

A more detailed description of pipeline alignment information for this alternative is presented in Table 4-15. The offshore and onshore pipeline alignment for this alternative is shown on Figure 4-31.

Onshore oil and gas pipeline alignments locations and lengths differ with this Alternative than that described for Alternative 2. The onshore pipeline alignments would also require that onshore ice road lengths and locations differ from those presented for Alternative 2 (they would parallel the new pipeline alignments). The amount of freshwater needed for ice road construction differs from Alternative 2 (see footnote in Table 4-15). Since the onshore pipelines are longer, construction manpower and related equipment needs would increase over those presented for Alternative 2 in order to complete these construction activities within the 5-month (January through May) time frame as shown. These requirements are presented below. Because the offshore structure, gravel mine site, pipeline construction methods, and operations/maintenance and abandonment activities would be the same as Alternative 2, these will not be described again.

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4.4.3.2 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 410 personnel. Estimated average monthly manpower requirements to support a two season construction program also would peak at approximately 410 personnel. The distribution of personnel by month are broken down by specific work activity for each of these construction season scenarios on Tables 4-16 and 4-17.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of the operation.

4.4.3.3 Transportation Requirements

The method (bus, barge, boat, helicopter and truck) and estimated number of trips required to support construction, drilling and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-18 and 4-19, respectively.

As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, truck, and helicopter requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation between August and November. In addition, the single season construction schedule will require 7 more barge trips and 80 fewer truck trips to support the drilling program than the two season construction schedule.

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

4.4.4.1 Overview of Alternative

The principal differences between Alternative 4 and Alternatives 2 and 3 (previously discussed in Sections 4.4.2 and 4.4.3, respectively) is a variation in the landfall location and the corresponding onshore and offshore pipeline corridor alignments. The oil and gas pipelines associated with Alternative 4 follow the same offshore corridor from Seal Island toward Point Storkersen as does Alternative 2 until it reached the southern boundary
of the Northstar Unit. The offshore corridor then would turn southeast toward West Dock, staying north of Stump Island in water depths between 5 and 12 ft (1.5 and 3.7 m). As the corridor approached West Dock at the east end of Stump Island, it would turn in a southwest direction, making landfall approximately midway between PM1 and the West Dock Staging Pad. A gravel valve pad approximately 75 by 75 ft (23 by 23 m) in size would be constructed at this landfall location to accommodate the buried subsea pipeline transition to aboveground. This transition would be conducted in a manner similar to that previously described for Alternatives 2 and 3. 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 existing

pipeline corridor to the West Dock

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Staging Pad. From the West Dock Staging Pad, the pipelines would be 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 4-20. The offshore and onshore pipeline alignment for this alternative is shown on Figure 4-32.

As discussed above, onshore and offshore oil and gas pipeline alignments and landfall and valve pad location differ with this alternative from those described for Alternatives 2 and 3. 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). The amount of freshwater needed for ice road construction differs from Alternatives 2 and 3 (see footnote in Table 4-20). In addition, offshore pipeline staging areas would be relocated along the offshore pipeline alignment.

Since the offshore and onshore pipeline alignments are different, construction manpower and related equipment needs would differ from those presented for Alternatives 2 and 3. These requirements are presented below. Because the offshore structure, gravel mine site, pipeline construction methods, and operation/maintenance and abandonment activities would be the same as Alternatives 2 and 3, these will not be described again.

4.4.4.2 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 420 personnel. Estimated average monthly manpower requirements to support a two season construction program would peak at approximately 330 personnel. The distribution of personnel by month are broken down by specific work activity for each of these construction season scenarios in Tables 4-21 and 4-22.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of the operation.

4.4.4.3 Transportation Requirements

The method (bus, barge, boat, helicopter and truck) and estimated number of trips required to support construction, drilling and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-23 and 4-24, respectively.

As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, truck, and helicopter requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation

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Figure 4-32 (page 1 of 2)

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between August and November. In addition, the single season construction schedule will require 7 more barge trips and 80 fewer truck trips to support the drilling program than the two season construction schedule.

4.4.5 Alternative 5 - West Dock Landfall

4.4.5.1 Overview of Alternative

The principal differences between Alternative 5 and Alternatives 2, 3, and 4 (previously described in Sections 4.4.2, 4.4.3, and 4.4.4, respectively) is another variation in the landfall location, with resulting changes in the onshore and offshore pipeline alignments. The oil and gas pipelines associated with Alternative 5 would follow the same offshore corridor from Seal Island south toward Point Storkersen as Alternatives 2 through 4, until it reached the southern boundary of the Northstar Unit. The offshore corridor would then turn southeast toward West Dock following the same corridor as Alternative 4, staying north of Stump Island in water depths greater than 5 ft (1.5 m). At the east end of Stump Island, the corridor would continue eastward until it intersected the West Dock causeway. The oil and gas pipelines would then transition from buried subsea to aboveground approximately 40 to 50 ft (12.1 to 15.2 m) from the edge of the causeway, then parallel the causeway to the West Dock Staging Pad. From the West Dock Staging Pad, the pipelines would be routed to the CCP and on to Pump Station No. 1 as described for Alternative 3.

Another aspect of this alternative that is different from other alternatives is that approximately 290,000 to 300,000 yd^3 (221,700 to 229,400 m^3) of gravel fill material would be placed along the west side of West Dock causeway to widen it by approximately 50 ft (15.2 m) between Dock Head 2 and the West Dock Staging Pad, a distance of approximately 0.9 miles (1.5 km). This fill would accommodate a valve pad area approximately 75 by 75 ft (23 by 23 m) in size, and VSMs for the oil and gas pipelines. Alternate landfalls on West Dock would result in larger or smaller volumes of gravel required for widening the causeway.

This additional width is necessary because:

- Extending the existing VSMs to the west would interfere with access to the existing buried water pipelines along the west side of West Dock.

- Stacking the pipelines vertically on the existing VSMs would interfere with maintenance access to the existing pipeline.

- Installing new VSMs along the west side of the buried water pipelines would prevent access to the water lines unless the new VSMs are installed to the west of the existing access road.

- The existing VSMs could be extended to the east, over the power cables which are presently buried between the VSMs and the roadway. This would increase the loading on the VSMs and limit maintenance access to the buried cables.

More detailed pipeline corridor information for this alternative is presented in Table 4-25. The offshore and onshore pipeline alignment for this alternative is shown on Figure 4-33.

As discussed above, onshore and offshore oil and gas pipeline alignments, landfall, and valve pad location differ with Alternative 5 from those described for Alternatives 2, 3, and 4. This landfall location does not require the 110-ft (33.5 m) setback from the shoreline, helipad, pipeline bedding backfill at the landfall, or revegetation of disturbed tundra. The valve pad at the landfall location would have power provided from the local onshore power grid.

The onshore and offshore pipeline alignments would require different ice road lengths and locations from Alternatives 2, 3, and 4 (they would parallel the new onshore and offshore pipeline alignments). The amount of freshwater needed for ice road construction differs from Alternatives 2, 3, and 4 (see footnote in Table 4-25). In addition, offshore pipeline staging areas would be relocated along the offshore pipeline alignments.

Since the onshore and offshore pipeline alignments are different, construction manpower and related equipment needs would differ from those presented for Alternatives 2, 3, and 4. These requirements are presented below. Because the offshore structure, gravel mine site, pipeline construction methods, and operation/ maintenance and abandonment activities would be the same as for Alternatives 2, 3, and 4, these will not be described again.

4.4.5.2 Manpower Requirements

Estimated average monthly manpower requirements to support a single season construction program would peak at approximately 420 personnel. Estimated average monthly manpower requirements to support a two season construction program would peak at approximately 330 personnel. The distribution of personnel by month are broken down by specific work activity for each of these construction season scenarios on Tables 4-26 and 4-27.

An operational workforce of approximately 100 would be employed at the Seal Island facilities and onshore facilities following completion of drilling and through the 15-year life of the operation.

4.4.5.3 Transportation Requirements

The method (bus, barge, boat, helicopter and truck) and estimated number of trips required to support construction, drilling and operations/maintenance activities for both a single season and a two season construction program are summarized below and presented in more detail in Tables 4-28 and 4-29, respectively.

As shown on these tables, the primary differences between the single season and two season construction requirements for this alternative are associated with differences between bus, barge, truck, and helicopter requirements. The single season construction schedule will require 150 fewer bus trips, 4 fewer barge trips, and 240 more helicopter trips than the two season construction schedule for process facilities installation between August and November. In addition, the single season construction schedule will require 7 more barge

Figure 4-33 (page 1 of 2)

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trips and 80 fewer truck trips to support the drilling program than the two season construction schedule. In addition, this alternative would require approximately 6,600 to 6,900 additional truck trips associated with gravel hauling for widening a portion of the West Dock causeway.

4.5 THE AGENCY PREFERRED ALTERNATIVE

As discussed in Chapter 1, one of the agency goals for this EIS is to support a consensus decision among the federal agencies and the NSB on the project that will go forward for development and production of the Northstar Unit. Because there are numerous components of the project, and many agencies with management and regulatory roles, there are many decisions to be made (Section 1.4). The components of the project under the jurisdiction of the lead and cooperating agencies are assessed in this chapter (Chapter 4) to develop the five alternatives described. As shown throughout this chapter, the differences in the action alternatives (2, 3, 4, and 5) are the route of the offshore pipeline, the landfall location, and the route of the onshore pipeline. Consensus was reached on specific alternatives to other project components (e.g., use of gravel island, island location, transportation by buried subsea pipeline) and on sets of alternatives from which the project developer can choose the appropriate action as further refinement is made to the project plan (e.g., gravel mined from the Kuparuk Delta site or the Kuparuk Deadarm site). For further discussion of agency preferred alternatives, see Section 11.9.1.

4.6 THE ENVIRONMENTALLY PREFERRED ALTERNATIVE

The environmentally preferred alternative has been identified by the lead and cooperating federal agencies, with the exception of the MMS, as Alternative 5 - West Dock Landfall. The MMS has identified Alternatives 2 and 3 (Section 11.9.2).

4.7 REFERENCES

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TABLE 4-1
COMPOSITION OF NORTHSTAR CRUDE

COMPONENT	MOLE [1] %
Hydrogen sulfide	--
Carbon dioxide	5.43
Nitrogen	0.61
Methane	56.88
Ethane	7.12
Propane	4.94
Iso-butane	0.97
N-butane	2.26
Iso-pentane	0.94
N-pentane	1.14
Hexanes	1.79
Heptanes plus[2]	17.92

Notes: 1 = Percent of total given in moles, which are equal to 6.02×10^{23} (Avogadro's number) molecules of the substances.
2 = Heptane plus specific gravity (60EF) is 0.83; molecular weight is 187.
-- = Not Applicable

Source: BPXA, 1997b:Table 3.3-1

TABLE 4-2
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, 1997b: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, 1997b: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) (I. Leavitt - Pers. Comm., 1997:1).
10 = 37,900 ft of pipeline is shared in common onshore corridor.
bbls = Barrels N/A = Not applicable VSMs = Vertical support members
ft = Feet ROW = Right-of-way

TABLE 4-3
SUMMARY OF OCEANOGRAPHIC DESIGN CRITERIA

Parameter	1-Year Return Period (Typical Period)	100-Year Return Period
Surface Currents	2 knots (2.3 mph) (east or west)	3 to 4 knots (3.4 to 4.6 mph) (east or west)
Water Level Elevation	East wind set-down = -1 foot MLLW West wind set-up = +2 feet MLLW	-2 feet MLLW +4 feet MLLW (offshore) +6 feet MLLW (nearshore)
Waves Offshore	H_S = 8 feet T_{Peak} = 7 seconds	H_S = 20 feet T_{Peak} = 11 seconds
Waves Nearshore	H_S, T_{Peak} vary with water depth	H_S, T_{Peak} vary with water depth

Notes:
H_S = Significant wave height
MLLW = Mean lower low water
T_{Peak} = Peak wave period

Source: BPXA, 1997b:Table 2.1-2

TABLE 4-4
EXTREME WAVE PREDICTION AT SEAL ISLAND

Return Event (Years)	Westerly Storm		Easterly Storm	
	H_S (Feet)	T_{peak} (Seconds)	H_S (Feet)	T_{peak} (Seconds)
1	7.1	6.8	7.6	7.0
5	8.3	7.8	8.3	7.5
10	10.8	8.3	9.7	7.8
25	14.6	5.1	11.1	9.9
50	18.4	9.9	11.8	10.7
100	19.9	10.9	12.8	12.3

Notes: H_S = Significant wave height
T_{Peak} = Peak wave period

Based on Beaufort Sea Hindcast Study

Source: BPXA, 1997b:Table 2.1-3

TABLE 4-5
DESIGN BASIS ICE ENVIRONMENT CRITERIA FOR NORTHSTAR

Ice Condition or Parameter	Average or Typical Values	Design or Extreme Values
Ice Type	First-Year Ice	Multi-year ice
Ice Zone	Landfast Ice	Summer multi-year invasions Freeze-up multi-year invasions
Ice Season		
Freeze-up	October 7	3rd week in September to the 4th week in October
Breakup	July 4	4th week in June to the 2nd week in July
First Open Water	mid-July	N/A
Ice Season Duration	290 ± 8 days	N/A
Total Open Water	75 ± 10 days	N/A
Summer Ice Invasion	--	2-3 times during summer
Max. Sheet Ice Thickness	6 feet	7.5 feet
Multi-Year Ice Parameters		
Presence	1 in 2 years during summer 1 in 3 to 4 years during freeze-up	N/A N/A
Multi-Year Ice Concentration	0.5 to 1.0 tenth	2 to 3 tenths
Floe Diameter	1,000 to 1,500 feet	4,000 to 5,000 feet
Floe Thickness - Nearshore	23 to 26 feet	Water-depth-limited
Floe Thickness - Pack	13 to17 feet	30 to 33 feet
Keel Depth	30 to 33 feet	Water-depth-limited
Ice Crushing Pressure	100 to 175 psi	200-250 psi
Ice Speed in 20 to 40 feet (6 to 12 meters) of water		
Summer	0.2 to 0.4 knots	3 to 4 knots
Freeze-up	0.3 to 0.6 knots	3 to 4 knots

TABLE 4-5 (Cont.)
DESIGN BASIS ICE ENVIRONMENT CRITERIA FOR NORTHSTAR

Ice Condition or Parameter	Average or Typical Values	Design or Extreme Values
Ice Gouge Depths		
Simpson Lagoon	<1 foot[1]	<3 feet[1]
0- to 16-foot Water Depth	<1 foot[1]	<3.5 feet[1]
16- to 34-foot Water Depth	<2 feet[1]	<3.5 to 6 feet[1]
Strudel Scours		
Depth	<4 feet[1] □	< 4.4 feet
Width	<50 feet[1] □	90 to 110 feet in diameter
Population	40 to 50 per year	75 to 100 per year
Density	5 to 10 per square mile	20 to 25 per square mile

Notes: 1 = Based on pipeline route surveys conducted in the Seal Island region (Coastal Frontiers, 1996:1 through 6.
< = Less than
N/A = Not applicable
psi = pounds per square inch

Source: BPXA, 1997b:Table 2.1-5

TABLE 4-6
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 4-9
NORTHSTAR PRODUCTION AND ESTIMATED ADDITIONAL TANKER TRIPS [1]

Production Year[2]	Oil Recovery Using Gas Cycling	
	Barrels of Oil/Day	Annual Tankers Trips[3]
1	32,065	15
2	65,000	30
3	65,000	30
4	65,000	30
5	61,935	28
6	43,700	20
7	30,834	14
8	21,755	10
9	15,350	7
10	10,831	5
11	7,642	3
12	5,392	2
13	3,804	2
14	2,684	1
15	1,894	1
Total		198

Notes:
1 = Per year leaving the Valdez Marine Terminal
2 = Production life of reservoir is anticipated to be 15 years.
3 = Average tanker capacity leaving Valdez Marine Terminal is 800,000 barrels. Annual tankers trips are rounded to nearest full tanker.

Source: Hanley, 1997a

TABLE 4-10
PIG RUN SCHEDULE

Activity	Schedule
Wall Thickness Measurement - performed early in the winter, such that, if required, repairs can be carried out in the same winter season.	• Start-up • Every 2 years thereafter.
Pipeline Geometry - only proposed for the oil pipeline.	• Start-up • Once every year for the first 5 years. • Additional geometry runs will be carried out if severe ice gouges or strudel scours are observed and suspected to have occurred.
Mechanical Damage	• Start-up (Prior to initial wall thickness or geometry pig survey). • Prior to every wall thickness or geometry pig run.
Cleaning - pigging interval to be determined after commencement of operations.	• Start-up (this will be carried out as part of pipeline commissioning). • For removal of sediment in an oil pipeline, cleaning pigs are typically run once a month. • For removal of water or liquid hydrocarbons in a gas pipeline, the frequency is dependent upon the gas properties. No liquids are expected for the design gas dew points, composition, and operating conditions.
Inhibitor Distribution	• If the gas line requires treatment with corrosion inhibitors, it can be distributed around the internal diameter of the pipeline using pigs. Typically, this is carried out on the same cycle as the cleaning pigging, in this case it will be every month.

Source: BPXA, 1997b:Table 3.4-1

TABLE 4-11
ALTERNATIVE 2 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, SINGLE SEASON CONSTRUCTION[1]

Work Activity/ People Housed	3Q			4Q			1Q			2Q			3Q			4Q			1Q			2Q		
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Island Construction: Deadhorse					30	40	40	90	100	100	60	50	50	50	5									
Onshore Pipeline Installation: Deadhorse	20	30	20	13	30	10	120	140	145	150	60													
Offshore Pipeline Installation: Deadhorse						65	130	145	125	120	10													
Facilities Installation and Hookup: Deadhorse													20	20	11	48								
Island														40	109	72	50							
Drilling: Island															25	50	50	50	50	50	50	50	50	50
Operations/ Maintenance[2]: Island														2	8	20	25	25	25	25	25	25	25	25
Total Manpower: Deadhorse	20	30	20	13	60	115	290	375	370	370	130	50	70	70	16	48	0	0	0	0	0	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	42	142	142	125	75	75	75	75	75	75	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.
2 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.
Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-12
ALTERNATIVE 2 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, TWO SEASON CONSTRUCTION [1]

Work Activity/ People Housed	4Q			1Q			2Q			3Q			4Q			1Q			2Q			3Q			4Q		
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Island Construction: Deadhorse		30	40	40	90	100	100	60	50	50	50	5															
Onshore Pipeline Installation: Deadhorse										20	30	20	13	30	10	120	140	145	150	60							
Offshore Pipeline Installation: Deadhorse															65	130	145	125	120	10							
Camp/Piperack/ Flare Installation: Deadhorse											60	60															
Facilities Installation And Hookup: Deadhorse																								36			
Island																						20	60	84	70	50	
Drilling: Island																		25	25	50	50	50	50	50	50	50	50
Operations/ Maintenance [2]: Island																							2	8	20	25	25
Total Manpower: Deadhorse	0	30	40	40	90	100	100	60	50	70	140	85	13	30	75	250	285	270	270	70	0	0	0	36	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	50	50	70	112	142	140	125	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.

2 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.

Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-13
ALTERNATIVE 2 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Island Construction							
Manufacture Concrete Mats	Personnel, Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	Personnel, Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies.
Island Construction	Personnel, Gravel, Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 cy of gravel per day from mine site to Seal Island.
Install Island Piling	Personnel, Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	Personnel, Concrete Blocks, Filter Fabric, Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily, via boat during bad weather. Barge supplies in July to August from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge.
Pipeline Installation							
Install Road and Caribou Crossings	Personnel, Materials, Heavy Equipment	100				64	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Offshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	650				254	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Onshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	900				820	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Module Installation							
Infrastructure Installation	Personnel, Heavy Equipment, Consumables/Tools, Construction Materials, Fuel/Start-up Materials	90	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. Infrastructure installation will require 2 local barge trips and 1 barge trip from Anchorage. Barges will transport materials between Anchorage and/or West Dock and Seal Island.

TABLE 4-13 (Cont.)
ALTERNATIVE 2 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	**Transported Items**	**Transportation Method [1] (by number of round trips)**					**Comments**
		Bus	**Barge**	**Boat**	**Helicopter**	**Truck**	
Module Installation (Cont.)							
Process Facilities Installation	Personnel, Modules, Fuel/ Start-up Fluids	240	2	20	480		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for infrastructure installation and will require 2 barges from Anchorage.
Drilling							
Drilling Mobilization	Personnel, Drill Rig, Drilling Materials and Supplies		21		30		Assume one helicopter trip per day for drilling personnel. Drill rig and associated buildings require 5 to 6 local barge trips. Approx. 4 months of supplies will require 15 to 16 local barge trips.
Drilling Resupply	Personnel, Drilling Materials and Supplies		1			200	Personnel already housed on island. Approx. 4 months of supplies will require 150 to 200 truck trips. Subsequent biannual resupply (Feb to April by ice road, Aug to Sept by barge). During the first year of drilling, diesel fuel would be obtained via trucks from Prudhoe Bay, or from other instate refineries via trucks and/or barges or from Canada via barges.
Operations/Maintenance Activities							
Ice Road Construction	Personnel, Heavy Equipment	30				50	Mobilize personnel from Deadhorse. Water haul and blade to condition road.
Operations Staff, Pipeline Recon, and Rotating Equipment Maintenance	Personnel, Commodities, Supplies	60	50	50	84		Transportation of staff and consumables via bus over ice road during winter and by helicopter and/or barge/boat during open water season.
Logistics Resupply	Heavy Equipment, Chemicals, Parts, Materials		3			50	Annual re-supply by barge during open water season and by truck during winter over ice road.
Island Grading and Slope Protection Maintenance	Graders, Tractors, Cranes		3				Heavy equipment to re-grade island and potentially add gravel.

Notes: 1 = Transportation methods reflect maximum total estimated round trips during noted period.
cy = Cubic yards

Source: Hanley, 1997b:Attachment 4

TABLE 4-14
ALTERNATIVE 2 - ESTIMATED TRANSPORTATION REQUIREMENTS, TWO SEASONS

Project Activity	Transported Items	Transportation Method [1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Island Construction							
Manufacture Concrete Mats	Personnel, Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	Personnel, Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies.
Island Construction	Personnel, Gravel, Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 cubic yards of gravel per day from mine site to Seal Island.
Install Island Piling	Personnel, Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize Personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	Personnel, Concrete Blocks, Filter Fabric, Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily, via boat during bad weather. Barge supplies in July to August from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge.
Pipeline Installation							
Install Road and Caribou Crossings	Personnel, Materials, Heavy Equipment	100				64	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Offshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	650				254	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Onshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	900				820	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Module Installation							
Infrastructure Installation	Personnel, Heavy Equipment, Consumables/Tools, Construction Materials, Fuel/Start-up Materials	360	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. Infrastructure installation will require 2 local barge trips and 1 barge trip from Anchorage. Barges will transport materials between Anchorage and/or West Dock and Seal Island.

TABLE 4-14 (Cont.)
ALTERNATIVE 2 - ESTIMATED TRANSPORTATION REQUIREMENTS, TWO SEASONS

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Module Installation (Cont.)							
Process Facilities Installation	Personnel, Modules, Fuel/ Start-up Fluids	120	6	20	240		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for infrastructure installation and will require 2 barges from Anchorage.
Drilling							
Drilling Mobilization	Personnel, Drill Rig, Drilling Materials and Supplies				30	280	Assume one helicopter trip per day for drilling personnel. Drill rig and associated buildings require 5 to 6 local barge trips. Approx. 4 months of supplies will require 15 to 16 local barge trips.
Drilling Resupply	Personnel, Drilling Materials and Supplies		15				Personnel already housed on island. Approx. 4 months of supplies will require 150 to 200 truck trips. Subsequent biannual resupply (Feb to April by ice road, Aug to Sept by barge). During the first year of drilling, diesel fuel would be obtained via trucks from Prudhoe Bay, or from other instate refineries via truck and/or barges, or from Canada via barges.
Operations/Maintenance Activities							
Ice Road Construction	Personnel, Heavy Equipment	30				50	Mobilize personnel from Deadhorse. Water haul and blade to condition road.
Operations Staff, Pipeline Recon, and Rotating Equipment Maintenance	Personnel, Commodities, Supplies	60	50	50	84		Transportation of staff and consumables via bus over ice road during winter and by helicopter and/or barge/boat during open water season.
Logistics Resupply	Heavy Equipment, Chemicals, Parts, Materials		3			50	Annual re-supply by barge during open water season and by truck during winter over ice road.
Island Grading and Slope Protection Maintenance	Graders, Tractors, Cranes		3				Heavy equipment to re-grade island and potentially add gravel.

Notes: 1 = Transportation methods reflect maximum total estimated round trips during noted period.
cy = Cubic yards

Source: Hanley, 1997b:Attachment 4

TABLE 4-15
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, 1997b: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, 1997b: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) (I. Leavitt - Pers. Comm., 1997:1).
10 = 48,230 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 4-16
ALTERNATIVE 3 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, SINGLE SEASON CONSTRUCTION [1]

Work Activity/ People Housed	3Q			4Q			1Q			2Q			3Q			4Q			1Q			2Q		
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Island Construction: Deadhorse					30	40	40	90	100	100	60	50	50	50	5									
Onshore Pipeline Installation[2]: Deadhorse	25	38	25	16	38	13	150	175	180	190	70													
Offshore Pipeline Installation: Deadhorse						65	130	145	125	120	10													
Facilities Installation and Hookup: Deadhorse													20	20	11	48								
Island														40	109	72	50							
Drilling: Island															25	50	50	50	50	50	50	50	50	50
Operations/ Maintenance[3]: Island														2	8	20	25	25	25	25	25	25	25	25
Total Manpower: Deadhorse	25	38	25	16	68	118	320	410	405	410	140	50	70	70	16	48	0	0	0	0	0	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	42	142	142	125	75	75	75	75	75	75	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.
2 = Revised manpower forecast prorated from Alternative 2.
3 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.
Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-17
ALTERNATIVE 3 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, TWO SEASON CONSTRUCTION[1]

Work Activity/ People Housed	4Q			1Q			2Q			3Q			4Q			1Q			2Q			3Q			4Q		
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Island Construction: Deadhorse		30	40	40	90	100	100	60	50	50	50	5															
Onshore Pipeline Installation[2]: Deadhorse										25	38	25	16	38	13	150	175	180	190	70							
Offshore Pipeline Installation: Deadhorse															65	130	145	125	120	10							
Camp/Piperack/ Flare Installation: Deadhorse											60	60															
Facilities Installation and Hookup: Deadhorse																								36			
Island																						20	60	84	70	50	
Drilling: Island																		25	25	50	50	50	50	50	50	50	50
Operations/ Maintenance[3]: Island																							2	8	20	25	25
Total Manpower: Deadhorse	0	30	40	40	90	100	100	60	50	75	148	90	16	38	78	280	320	305	410	80	0	0	0	36	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	50	50	70	112	142	140	125	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.
2 = Revised manpower forecast prorated from Alternative 2.
3 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.
Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-18
ALTERNATIVE 3 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	Transported Items	Transportation Method [1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Island Construction							
Manufacture Concrete Mats	Personnel, Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	Personnel, Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies.
Island Construction	Personnel, Gravel, Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 cy of gravel per day from mine site to Seal Island.
Install Island Piling	Personnel, Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	Personnel, Concrete Blocks, Filter Fabric, Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily, via boat during bad weather. Barge supplies in July to August from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge.
Pipeline Installation							
Install Road and Caribou Crossings	Personnel, Materials, Heavy Equipment	100				64	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Offshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	650				254	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Onshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	1,125				1,025	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Module Installation							
Infrastructure Installation	Personnel, Heavy Equipment, Consumables/Tools, Construction Materials, Fuel/Start-up Materials	90	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. Infrastructure installation will require 2 local barge trips and 1 barge trip from Anchorage. Barges will transport materials between Anchorage and/or West Dock and Seal Island.

TABLE 4-18 (Cont.)
ALTERNATIVE 3 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	Transported Items	Transportation Method [1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Module Installation (Cont.)							
Process Facilities Installation	Personnel, Modules, Fuel/ Start-up Fluids	240	2	20	480		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for infrastructure installation and will require 2 barges from Anchorage.
Drilling							
Drilling Mobilization	Personnel, Drill Rig, Drilling Materials and Supplies		21		30		Assume one helicopter trip per day for drilling personnel. Drill rig and associated buildings require 5 to 6 local barge trips. Approx. 4 months of supplies will require 15 to 16 local barge trips.
Drilling Resupply	Personnel, Drilling Materials and Supplies		1			200	Personnel already housed on island. Approx. 4 months of supplies will require 150 to 200 truck trips. Subsequent biannual resupply (Feb to April by ice road, Aug to Sept by barge). During the first year of drilling, diesel fuel would be obtained via trucks from Prudhoe Bay, or from other instate refineries via trucks and/or barges or from Canada via barges.
Operations/Maintenance Activities							
Ice Road Construction	Personnel, Heavy Equipment	30				50	Mobilize personnel from Deadhorse. Water haul and blade to condition road.
Operations Staff, Pipeline Recon, and Rotating Equipment Maintenance	Personnel, Commodities, Supplies	60	50	50	84		Transportation of staff and consumables via bus over ice road during winter and by helicopter and/or barge/boat during open water season.
Logistics Resupply	Heavy Equipment, Chemicals, Parts, Materials		3			50	Annual re-supply by barge during open water season and by truck during winter over ice road.
Island Grading and Slope Protection Maintenance	Graders, Tractors, Cranes		3				Heavy equipment to re-grade island and potentially add gravel.

Notes: 1 = Transportation methods reflect maximum total estimated round trips during noted period.
cy = Cubic yards

Source: Hanley, 1997b:Attachment 4

TABLE 4-19
ALTERNATIVE 3 - ESTIMATED TRANSPORTATION REQUIREMENTS, TWO SEASONS

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Island Construction							
Manufacture Concrete Mats	Personnel, Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	Personnel, Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies.
Island Construction	Personnel, Gravel, Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 cy of gravel per day from mine site to Seal Island.
Install Island Piling	Personnel, Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize Personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	Personnel, Concrete Blocks, Filter Fabric, Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily, via boat during bad weather. Barge supplies in July to August from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge.
Pipeline Installation							
Install Road and Caribou Crossings	Personnel, Materials, Heavy Equipment	100				64	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Offshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	650				254	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Onshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	1,125				1,025	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Module Installation							
Infrastructure Installation	Personnel, Heavy Equipment, Consumables/Tools, Construction Materials, Fuel/Start-up Materials	360	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. Infrastructure installation will require 2 local barge trips and 1 barge trip from Anchorage. Barges will transport materials between Anchorage and/or West Dock and Seal Island.

TABLE 4-19 (Cont.)
ALTERNATIVE 3 - ESTIMATED TRANSPORTATION REQUIREMENTS, TWO SEASONS

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Module Installation (Cont.)							
Process Facilities Installation	Personnel, Modules, Fuel/ Start-up Fluids	120	6	20	240		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for infrastructure installation and will require 2 barges from Anchorage.
Drilling							
Drilling Mobilization	Personnel, Drill Rig, Drilling Materials and Supplies				30	280	Assume one helicopter trip per day for drilling personnel. Drill rig and associated buildings require 5 to 6 local barge trips. Approx. 4 months of supplies will require 15 to 16 local barge trips.
Drilling Resupply	Personnel, Drilling Materials and Supplies		15				Personnel already housed on island. Approx. 4 months of supplies will require 150 to 200 truck trips. Subsequent biannual resupply (Feb to April by ice road, Aug to Sept by barge). During the first year of drilling, diesel fuel would be obtained via trucks from Prudhoe Bay, or from other instate refineries via trucks and/or barges or from Canada via barges.
Operations/Maintenance Activities							
Ice Road Construction	Personnel, Heavy Equipment	30				50	Mobilize personnel from Deadhorse. Water haul and blade to condition road.
Operations Staff, Pipeline Recon, and Rotating Equipment Maintenance	Personnel, Commodities, Supplies	60	50	50	84		Transportation of staff and consumables via bus over ice road during winter and by helicopter and/or barge/boat during open water season.
Logistics Resupply	Heavy Equipment, Chemicals, Parts, Materials		3			50	Annual re-supply by barge during open water season and by truck during winter over ice road.
Island Grading and Slope Protection Maintenance	Graders, Tractors, Cranes		3				Heavy equipment to re-grade island and potentially add gravel.

Notes: 1 = Transportation methods reflect maximum total estimated round trips during noted period.
cy = Cubic yards

Source: Hanley, 1997b:Attachment 4

TABLE 4-20
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	4,804	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 of freshwater).
4 = Source: Hanley, 1997b: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, 1997b: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) (A. 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 4-21
ALTERNATIVE 4 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, SINGLE SEASON CONSTRUCTION [1]

Work Activity/ People Housed	3Q			4Q			1Q			2Q			3Q			4Q			1Q			2Q		
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Island Construction: Deadhorse					30	40	40	90	100	100	60	50	50	50	5									
Onshore Pipeline Installation[2]: Deadhorse	17	28	17	12	28	9	110	130	135	140	55													
Offshore Pipeline Installation[2]: Deadhorse						85	180	200	175	170	15													
Facilities Installation and Hookup: Deadhorse													20	20	11	48								
Island														40	109	72	50							
Drilling: Island															25	50	50	50	50	50	50	50	50	50
Operations/ Maintenance [3]: Island														2	8	20	25	25	25	25	25	25	25	25
Total Manpower: Deadhorse	17	28	17	12	58	134	330	420	410	410	130	50	70	70	16	48	0	0	0	0	0	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	42	142	142	125	75	75	75	75	75	75	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.
2 = Revised manpower forecast prorated from Alternative 2.
3 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.
Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-22
ALTERNATIVE 4 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, TWO SEASON CONSTRUCTION [1]

Work Activity/ People Housed	4Q			1Q			2Q			3Q			4Q			1Q			2Q			3Q			4Q		
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Island Construction: Deadhorse		30	40	40	90	100	100	60	50	50	50	5															
Onshore Pipeline Installation[2]: Deadhorse										17	28	17	12	28	9	110	130	135	140	55							
Offshore Pipeline Installation [2]: Deadhorse															85	180	200	175	170	15							
Camp/Piperack/ Flare Installation: Deadhorse											60	60															
Facilities Installation and Hookup: Deadhorse																								36			
Island																						20	60	84	70	50	
Drilling: Island																		25	25	50	50	50	50	50	50	50	50
Operations/ Maintenance [3]: Island																							2	8	20	25	25
Total Manpower: Deadhorse	0	30	40	40	90	100	100	60	50	67	138	82	12	28	94	290	330	310	310	70	0	0	0	36	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	50	50	70	112	142	140	125	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.
2 = Revised manpower forecast prorated from Alternative 2.
3 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.
Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-23
ALTERNATIVE 4 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Island Construction							
Manufacture Concrete Mats	Personnel, Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	Personnel, Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies.
Island Construction	Personnel, Gravel, Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 cy of gravel per day from mine site to Seal Island.
Install Island Piling	Personnel, Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	Personnel, Concrete Blocks, Filter Fabric, Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily, via boat during bad weather. Barge supplies in July to August from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge.
Pipeline Installation							
Install Road and Caribou Crossings	Personnel, Materials, Heavy Equipment	100				64	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Offshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	985				384	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Onshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	837				762	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Module Installation							
Infrastructure Installation	Personnel, Heavy Equipment, Consumables/Tools, Construction Materials, Fuel/Start-up Materials	90	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. Infrastructure installation will require 2 local barge trips and 1 barge trip from Anchorage. Barges will transport materials between Anchroage and/or West Dock and Seal Island.

TABLE 4-23 (Cont.)
ALTERNATIVE 4 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Module Installation (Cont.)							
Process Facilities Installation	Personnel, Modules, Fuel/ Start-up Fluids	240	2	20	480		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for infrastructure installation and will require 2 barges from Anchorage.
Drilling							
Drilling Mobilization	Personnel, Drill Rig, Drilling Materials and Supplies		21		30		Assume one helicopter trip per day for drilling personnel. Drill rig and associated buildings require 5 to 6 local barge trips. Approx. 4 months of supplies will require 15 to 16 local barge trips.
Drilling Resupply	Personnel, Drilling Materials and Supplies					200	Personnel already housed on island. Approx. 4 months of supplies will require 150 to 200 truck trips. Subsequent biannual resupply (Feb to April by ice road, Aug to Sept by barge). During the first year of drilling, diesel fuel would be obtained via trucks from Prudhoe Bay, or from other instate refineries via trucks and/or barges or from Canada via barges.
Operations/Maintenance Activities							
Ice Road Construction	Personnel, Heavy Equipment	30				50	Mobilize personnel from Deadhorse. Water haul and blade to condition road.
Operations Staff, Pipeline Recon, and Rotating Equipment Maintenance	Personnel, Commodities, Supplies	60	50	50	84		Transportation of staff and consumables via bus over ice road during winter and by helicopter and/or barge/boat during open water season.
Logistics Resupply	Heavy Equipment, Chemicals, Parts, Materials		3			50	Annual re-supply by barge during open water season and by truck during winter over ice road.
Island Grading and Slope Protection Maintenance	Graders, Tractors, Cranes		3				Heavy equipment to re-grade island and potentially add gravel.

Notes: 1 = Transportation methods reflect maximum total estimated round trips during noted period.
cy = Cubic yards

Source: Hanley, 1997b:Attachment 4

TABLE 4-24
ALTERNATIVE 4 - ESTIMATED TRANSPORTATION REQUIREMENTS, TWO SEASONS

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
				Island Construction			
Manufacture Concrete Mats	Personnel, Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	Personnel, Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies.
Island Construction	Personnel, Gravel, Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 cy of gravel per day from mine site to Seal Island.
Install Island Piling	Personnel, Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize Personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	Personnel, Concrete Blocks, Filter Fabric, Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily, via boat during bad weather. Barge supplies in July to August from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge.
				Pipeline Installation			
Install Road and Caribou Crossings	Personnel, Materials, Heavy Equipment	100				64	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Offshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	985				384	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Onshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	837				762	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
				Module Installation			
Infrastructure Installation	Personnel, Heavy Equipment, Consumables/Tools, Construction Materials, Fuel/Start-up Materials	360	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. Infrastructure installation will require 2 local barge trips and 1 barge trip from Anchorage. Barges will transport materials between Anchroage and/or West Dock and Seal Island.

TABLE 4-24 (Cont.)
ALTERNATIVE 4 - ESTIMATED TRANSPORTATION REQUIREMENTS, TWO SEASONS

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Module Installation (Cont.)							
Process Facilities Installation	Personnel, Modules, Fuel/ Start-up Fluids	120	6	20	240		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for infrastructure installation and will require 2 barges from Anchorage.
Drilling							
Drilling Mobilization	Personnel, Drill Rig, Drilling Materials and Supplies				30	280	Assume one helicopter trip per day for drilling personnel. Drill rig and associated buildings require 5 to 6 local barge trips. Approx. 4 months of supplies will require 15 to 16 local barge trips.
Drilling Resupply	Personnel, Drilling Materials and Supplies		15				Personnel already housed on island. Approx. 4 months of supplies will require 150 to 200 truck trips. Subsequent biannual resupply (Feb to April by ice road, Aug to Sept by barge). During the first year of drilling, diesel fuel would be obtained via trucks from Prudhoe Bay, or from other instate refineries via trucks and/or barges or from Canada via barges.
Operations/Maintenance Activities							
Ice Road Construction	Personnel, Heavy Equipment	30				50	Mobilize personnel from Deadhorse. Water haul and blade to condition road.
Operations Staff, Pipeline Recon, and Rotating Equipment Maintenance	Personnel, Commodities, Supplies	60	50	50	84		Transportation of staff and consumables via bus over ice road during winter and by helicopter and/or barge/boat during open water season.
Logistics Resupply	Heavy Equipment, Chemicals, Parts, Materials		3			50	Annual resupply by barge during open water season and by truck during winter over ice road.
Island Grading and Slope Protection Maintenance	Graders, Tractors, Cranes		3				Heavy equipment to re-grade island and potentially add gravel.

Notes: 1 = Transportation methods reflect maximum total estimated round trips during noted period.
cy = Cubic yards

Source: Hanley, 1997b:Attachment 4

TABLE 4-25
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 of 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.
- 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.

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.

bbls = Barrels; N/A = Not applicable; VSMs = Vertical support members
ft = Feet; ROW = Right-of-way

TABLE 4-26
ALTERNATIVE 5 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, SINGLE SEASON CONSTRUCTION[1]

Work Activity/ People Housed	3Q			4Q			1Q			2Q			3Q			4Q			1Q			2Q		
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Island Construction: Deadhorse					30	40	40	90	100	100	60	50	50	50	5									
Onshore Pipeline Installation[2]: Deadhorse	17	73	62	12	28	9	110	130	135	140	55													
Offshore Pipeline Installation[2]: Deadhorse						85	180	200	175	170	15													
Facilities Installation and Hookup: Deadhorse													20	20	11	48								
Island														40	109	72	50							
Drilling: Island															25	50	50	50	50	50	50	50	50	50
Operations/ Maintenance[3]: Island														2	8	20	25	25	25	25	25	25	25	25
Total Manpower: Deadhorse	17	73	62	12	58	134	330	420	410	410	130	50	70	70	16	48	0	0	0	0	0	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	42	142	142	125	75	75	75	75	75	75	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.
2 = Revised manpower forecast prorated from Alternative 2.
3 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.
Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-27
ALTERNATIVE 5 - ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST, TWO SEASON CONSTRUCTION [1]

Work Activity/ People Housed	4Q			1Q			2Q			3Q			4Q			1Q			2Q			3Q			4Q		
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Island Construction: Deadhorse		30	40	40	90	100	100	60	50	50	50	5															
Onshore Pipeline Installation[2]: Deadhorse										17	73	62	12	28	9	110	130	135	140	55							
Offshore Pipeline Installation [2]: Deadhorse															85	180	200	175	170	15							
Camp/Piperack/ Flare Installation: Deadhorse											60	60															
Facilities Installation and Hookup: Deadhorse																								36			
Island																						20	60	84	70	50	
Drilling: Island																		25	25	50	50	50	50	50	50	50	50
Operations/ Maintenance [3]: Island																							2	8	20	25	25
Total Manpower: Deadhorse	0	30	40	40	90	100	100	60	50	67	183	127	12	28	94	290	330	310	310	70	0	0	0	36	0	0	0
Island	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	50	50	70	112	142	140	125	75

Notes: 1 = The living quarters and utilities modules are sealifted to the island, installed and operational by October. These numbers reflect the estimated average manpower per month.
2 = Revised manpower forecast prorated from Alternative 2.
3 = Once drilling activities conclude, the estimated monthly average manpower loading for routine island operations/maintenance activities is estimated to be approximately 25 personnel; an additional 75 personnel will provide support during the life of the project.
Q = Quarter

Source: Hanley, 1997b:Attachment 3

TABLE 4-28
ALTERNATIVE 5 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Island Construction							
Manufacture Concrete Mats	Personnel, Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	Personnel, Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies.
Island Construction	Personnel, Gravel, Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 cy of gravel per day from mine site to Seal Island.
Install Island Piling	Personnel, Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	Personnel, Concrete Blocks, Filter Fabric, Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily, via boat during bad weather. Barge supplies in July to August from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge.
Pipeline Installation							
Install Road and Caribou Crossings	Personnel, Materials, Heavy Equipment	100				64	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Offshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	969				379	Mobilize personnel via bus to/from the job site. Truck trips required for transporting equipment and supplies to/from the job site.
Install Onshore Pipelines	Personnel, Materials, Heavy Equipment, Consumables	957				7,691	Mobilize personnel via bus to/from the job site. Includes 291,000 cy gravel for West Dock expansion at 42 cy per truck.
Module Installation							
Infrastructure Installation	Personnel, Heavy Equipment, Consumables/Tools, Construction Materials, Fuel/Start-up Materials	90	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. Infrastructure installation will require 2 local barge trips and 1 barge trip from Anchorage. Barges will transport materials between Anchorage and/or West Dock and Seal Island.

TABLE 4-28 (Cont.)
ALTERNATIVE 5 - ESTIMATED TRANSPORTATION REQUIREMENTS, SINGLE SEASON

Project Activity	Transported Items	Transportation Method[1] (by number of round trips)					Comments
		Bus	Barge	Boat	Helicopter	Truck	
Module Installation (Cont.)							
Process Facilities Installation	Personnel, Modules, Fuel/ Start-up Fluids	240	2	20	480		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for Infrastructure installation and will require 2 barges from Anchorage.
Drilling							
Drilling Mobilization	Personnel, Drill Rig, Drilling Materials and Supplies		21		30		Assume 1 helicopter trip per day for drilling personnel. Drill rig and associated buildings require 5 to 6 local barge trips. Approx. 4 months of supplies will require 15 to 16 local barge trips.
Drilling Resupply	Personnel, Drilling Materials and Supplies		1			200	Personnel already housed on island. Approx. 4 months of supplies will require 150 to 200 truck trips. Subsequent biannual resupply (Feb to April by ice road, Aug to Sept by barge). During the first year of drilling, diesel fuel would be obtained via trucks from Prudhoe Bay, or from other instate refineries via trucks and/or barges or from Canada via barges.
Operations/Maintenance Activities							
Ice Road Construction	Personnel, Heavy Equipment	30				50	Mobilize personnel from Deadhorse. Water haul and blade to condition road.
Operations Staff, Pipeline Recon, and Rotating Equipment Maintenance	Personnel, Commodities, Supplies	60	50	50	84		Transportation of staff and consumables via bus over ice road during winter and by helicopter and/or barge/boat during open water season.
Logistics Resupply	Heavy Equipment, Chemicals, Parts, Materials		3			50	Annual resupply by barge during open water season and by truck during winter over ice road.
Island Grading and Slope Protection Maintenance	Graders, Tractors, Cranes		3				Heavy equipment to re-grade island and potentially add gravel.

Notes: 1 = Transportation methods reflect maximum total estimated round trips during noted period.
cy = Cubic yards

Source: Hanley, 1997b:Attachment 4