HILCORP ALASKA, LLC

LIBERTY DEVELOPMENT PROJECT

DEVELOPMENT AND PRODUCTION PLAN

Revision 1

(Public)

Submitted December 30, 2014

Revised September 8, 2015

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SUBMITTED TO:

Bureau of Ocean Energy Management
Alaska OCS Region
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TABLE OF CONTENTS

APPENDICES

LIST OF TABLES

LIST OF FIGURES

ACRONYMS

°F	Degrees Fahrenheit
°T	Degrees True North
1Q	First quarter
2Q	Second quarter
3D	Three-dimensional
3Q	Third quarter
4Q	Fourth quarter
AAC	Alaska Administrative Code
ACPH	Air changes per hour
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
AEWC	Alaska Eskimo Whaling Commission
AIMS	Alaska Incident Management System
AMS	American Meteorological Society
ANCSA	Alaska Native Claims Settlement Act
ANSI	American National Standards Institute
AOGCC	Alaska Oil and Gas Conservation Commission
APD	Application for Permit to Drill
APDES	Alaska Pollutant Discharge Elimination System
API	American Petroleum Institute
AQIA	Air Quality Impact Analysis
ARRC	Alaska Railroad Corporation
AS	Alaska Statute
ASH	Alaska Safety Handbook
ASME	American Society of Mechanical Engineers
ASOS	Automated Surface Observing System
BACT	Best available control technology
bbl	Barrel(s)
BHL	Bottom Hole Location
BMP	Best management practices
BO	Biological Opinion
B_o	Formation volume factor - oil
BOEM	Bureau of Ocean and Energy Management
BOP	Blowout preventer
BOPD	Barrels of oil per day
BOPE	Blowout preventer equipment
BPCS	Basic Process Control Systems
BPXA	BP Exploration (Alaska) Inc.
BS&W	Basic sediment and water
BSEE	Bureau of Safety and Environmental Enforcement

BWPD	Barrels of water per day
CAA	Conflict Avoidance Agreement
CFR	Code of Federal Regulations
CIP	Cleaning in Place
CO	Carbon monoxide
cP	CentiPoises
CVA	Certified Verification Agent
cy	cubic yard
dB	Decibel
DCS	Distributed Control System
DMLW	Division of Mining, Land, and Water
DOC	Depth of Cover
DOG	Division of Oil and Gas
DOT	U.S. Department of Transportation
DPP	Development and Production Plan
E&P	Exploration and production
EA	Environmental Assessment
ECA	Engineering Critical Analysis
EFH	Essential Fish Habitat
EH&S	Environmental Health and Safety
EIA	Environmental Impact Analysis
EIS	Environmental Impact Statement
EOFL	End of Field Life
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ER	Electrical Resistance
ESA	Endangered Species Act
ESD	Emergency shutdown
ESS	Emergency Support System
EU	Emission unit
F&G	Fire and Gas
FEIS	Final Environmental Impact Statement
FLIR	Forward-looking infrared
FOC	Fiber optic cable
FONSI	Findings of No Significant Impact
fps	Feet per second
FPS	Floating Production System
FRP	Facility Response Plan
FSD	Full Shutdown
ft	Feet
ft-lbs	Foot-pounds
G&G	Geological and geophysical
G&I	Grind and Inject Facility
gal	Gallons(s)

GIS	Geographical information system
GNOME	General NOAA Operational Modeling Environment
GOR	Gas-oil ratio
GPB	Greater Prudhoe Bay
gpd	Gallons per day
gph	Gallons per hour
GPS	Global Positioning System
GPY	Gallons per year
H_2S	Hydrogen sulfide
HAK	Hilcorp Alaska, LLC
HAZOP	Hazards and Operability Analysis
HAZWOPER	Hazardous Waste Operations (training)
HDDT	Heavy-Duty Diesel Truck
HDPE	High-density polyethylene
HMI	Human machine interface
hp	Horsepower
HRZ	Highly radioactive zone
HSE	Health, Safety, and Environment
HVAC	Heating, ventilating, and air conditioning
I&E	Instrument and electronics
I:W	Injection to withdrawal ratio
IAPMO	International Association of Plumbing and Mechanical Officials
IBOP	Inside blowout preventer
IC	Incident Commander
ICAS	Inupiat Community of the Arctic Slope
ICC	International Code Council
ICP	Incident Command Post
IHA	Incidental Harassment Authorization
IHLC	Inupiat History, Language, and Culture
ILI	In-Line Inspection
IMT	Incident Management Team
IP	Improvement Plan
IPS	Instrumented Protective Systems
ISB	In-situ burning
ISO	International Standards Organization
JSA	Job Safety Analyses
kip	1,000 pounds force
KOH	Potassium hydroxide
kW	Kilowatt
lb/hr	Pound(s) per hour
lbs	Pounds
LCU	Lower Cretaceous Unconformity
LDPI	Liberty Drilling and Production Island
LEDPA	Least environmentally damaging practicable alternative

LOA	Letter of Authorization
LWD	Logging while drilling
MBOD	Thousand barrels of oil per day
MBR	Membrane Bio Reactors
mD	Millidarcy
mg/L	Milligram per liter
MIC	Microbiological influenced corrosion
MLLW	Mean Low Low Water
mm	Millimeter
MMBO	Million barrels of oil
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MMscf/day	Million standard cubic feet per day
MMscf/hr	Million standard cubic feet per hour
MMscf/yr	Million standard cubic feet per year
MOC	Management of Change
mph	Miles per hour
MPI	Main Production Island (at Endicott)
MPMS	Manual of Petroleum Measurement Standards
MW	Megawatt
MWD	Measurement while drilling
NA	Not applicable
NACE	National Association of Corrosion Engineers
NaCl	Sodium chloride
NAD	North American Datum
NaOH	Sodium hydroxide
NEC	National Electric Code
NEPA	National Environmental Policy Act
NIMS	National Incident Management System
NMFS	National Marine Fisheries Service
NO_2	Nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NO_X	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSB	North Slope Borough
NSSRT	North Slope Spill Response Team
NSTC	North Slope Training Cooperative
NTL	Notice to Lessees
NWS	National Weather Service
O&M	Operations and Maintenance
OCS	Outer Continental Shelf
ODPCP	Oil Discharge Prevention and Contingency Plan
OEM	Original equipment manufacturer OSD Operational Shutdown
OSHA	Occupational Safety and Health Administration

OSRB	Oil Spill Response Barge
OSRO	Oil Spill Removal Organization
OSRP	Oil Spill Response Plan
OSRV	Oil Spill Response Vessel
P&IDs	Piping and Instrument Diagrams
PHMSA	Pipeline and Hazardous Material Safety Administration
PIP	Pipe-in-pipe
PLC	Programmable Logic Controllers
PLQ	permanent living quarters
PM	Particulate Matter
PM_{10}	Particulate matter with aerodynamic diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Very fine particulate matter
ppb	Parts per billion
PPE	Personal protective equipment
ppg	Pounds per gallon
ppm	Parts per million
PREP	Preparedness for Response Exercise Program
Psat	Saturation pressure
PSD	Process Shutdown
psf	Pounds per square foot
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PSL	Pressure Safety Low
PVT	Pressure volume temperature
PWD	Pressure while drilling
QI	Qualified Individual
RB	Reservoir volume barrel
RCRA	Resource Conservation and Recovery Act
RICE	Reciprocating internal combustion engines
ROD	Record of Decision
Rs	Solution gas-oil ratio
RS/FO	Regional Supervisor, Field Operations
RTU	Remote Terminal Unit
SCADA	Supervisory control and data acquisition
SCF	Standard cubic feet
SDI	Satellite Drilling Island
SDV	Shut-down valve
SEMS	Safety and Environmental Management System
sf	Square feet
SHL	Surface Hole Location
SIS	Safety Integrated System
So	Oil Saturation
SO_2	Sulphur dioxide

SOP	Suspension of Operations
SPCC	Spill Prevention, Control, and Countermeasures
SPCO	State Pipeline Coordinator's Office
SSSV	Subsurface safety valves
SSV	Surface safety valves
STB	Stock tank barrel
STP	Seawater Treatment Plant
SWPPP	Stormwater Pollution Prevention Plan
TAPS	Trans-Alaska Pipeline System
TEG	Thermoelectric generators
TES	Threatened and endangered species
TLP	Tension-Leg Platforms
TLUI	Traditional Land Use Inventory
TPY	Tons per Year
TSS	Total suspended solids
TVA	Tuned Vibration Absorbers
TVD	True vertical depth
TVDSS	Total vertical depth subsea
uERD	Ultra-extended-reach drilling
UL	Underwriters Laboratories Inc.
ULSD	Ultra-low sulfur diesel
UOP	Unified Operating Procedures
UPC	Uniform Plumbing Code
USACE	U.S. Army Corps of Engineers
USCG	U.S. Coast Guard
USD	Unit Shutdown
USDOI	U.S. Department of the Interior
USFWS	U.S. Fish and Wildlife Service
UW	Universal waste
VOC	Volatile organic compounds
VSM	Vertical support member(s)
WCCP	Well Control Contingency Plan
WCD	Worst-case discharge
YR	Year

1 EXECUTIVE SUMMARY

Hilcorp Alaska, LLC (HAK) as the Liberty Operator submits this Development and Production Plan (DPP) to the U.S. Department of the Interior (USDOI) Bureau of Ocean Energy Management (BOEM) as directed by the USDOI Bureau of Safety and Environmental Enforcement (BSEE) in the Suspension of Production dated December 31, 2012. If developed, this would be the first field to produce hydrocarbons from a reservoir located entirely from federal leases of the Outer Continental Shelf (OCS) of the U.S. Arctic Ocean. HAK is proposing to initiate commercial production of the Liberty Reservoir in the Alaskan Beaufort Sea within 3 years of regulatory approvals and financial sanction.

This DPP describes the subsurface depletion plan, all construction phases of the proposed project, important safety features and practices, and provides an Environmental Impact Analysis (EIA) of the project included as Appendix A. The Liberty Operator proposes to efficiently and safely develop the reservoir, using technology proven at similar developments. This project will take advantage of learnings gathered from the four prior island developments in Alaska State waters of the Beaufort Sea: Endicott, Northstar, Oooguruk, and Nikaitchuq.

The Liberty Reservoir is the largest delineated but undeveloped light oil reservoir on the North Slope. It is projected to deliver a peak production rate of between 60,000 and 70,000 barrels of oil per day (BOPD) within 2 years of initial production. Total recovery over an estimated field life of 15 to 20 years is predicted to be in the range of 80 to 150 million stock tank barrels of oil.

The proposed Liberty Development will:

- Provide economic benefits to the federal, state, and local population and governments;
- Increase domestic production of oil; and
- Contribute to the throughput and efficiency of the Trans-Alaska Pipeline System (TAPS).

The proposed Liberty Development includes the Liberty Drilling and Production Island (LDPI), which will be constructed of reinforced gravel in 19 feet of water about 5 miles offshore in Foggy Island Bay of the Beaufort Sea OCS, as depicted in the 3-D rendering shown in Figure 1-1. Process facilities on the island will separate crude oil from produced water and gas. Gas and water will be injected into the reservoir to provide pressure support and increase recovery from the field. A single-phase subsea pipe-in-pipe pipeline will transport sales-quality crude from the LDPI to shore, where an above-ground pipeline will transport crude to the existing Badami pipeline. From there, crude is transported to the Endicott Sales Oil Pipeline, which ties into Pump Station 1 of the TAPS for eventual delivery to a refinery.

The reservoir depletion plan is based on five producers and four injectors. The well row arrangement on the island is designed to accommodate up to 16 wells in case additional wells are required to increase reserves recovery or account for wells that need replacement. The rock and fluid properties are excellent. This fact allows for conventional wells to be drilled from an artificial island that is optimally located over the reservoir. Once the drilling unit is commissioned, drilling operations will continue uninterrupted for approximately 2 years. Drilling through the reservoir section will be limited to the summer open-water season and the winter frozen ice season, as prescribed in the Oil Spill Response Plan (OSRP).

This DPP, the EIA, and the OSRP address the relevant requirements of Title 30 Code of Federal Regulations (30 CFR) Part 550, Sections 241-262. The submittal of these documents begins the review process to secure federal approvals to allow the development of the Liberty Field. A cross reference of this DPP to the relevant requirements of 30 CFR 550.241-262 is shown in Table 2-1.

Figure 1-1. Conceptual 3-D Rendering of Proposed Liberty Island

2 INTRODUCTION

As the Liberty Operator[1], Hilcorp Alaska, LLC (HAK) proposes to develop the Liberty Oil Field, located on the Outer Continental Shelf (OCS), in Foggy Island Bay (Figure 2-1). Liberty is located on two leases, OCS-Y-1650 and OCS-Y-1585 (Figure 2-2), which constitutes the Liberty Unit.

In accordance with the requirements of Title 30 Code of Federal Regulations (30 CFR) Part 550, Sections 241-262, this Development and Production Plan (DPP) is being submitted to the Bureau of Ocean Energy Management (BOEM) to initiate the permitting process and National Environmental Policy Act (NEPA) review. This DPP describes the full scope and impacts of activity associated with construction, drilling, and production operations.

The Liberty Development project design has evolved from an offshore standalone island, as described in the 2002 *Liberty Development and Production Plan Final Environmental Impact Statement,* to the use of ultra-extended-reach drilling (uERD) technology, as proposed in the April 2007 Liberty Development and Production Plan, back to the original concept of a gravel island with producer wells, injector wells, and three-phase processing, as described in this document. The proposed project represents over 20 years of experience at this location, as well as experiences of similar island developments in the Beaufort Sea. The result is a project that develops the reservoir in a sound manner while minimizing the impacts to the surrounding environment.

2.1 Liberty Project History

The Liberty Reservoir was first discovered by Shell Oil Company which, between 1982 to 1987, drilled four wells to evaluate the potential of the Kekiktuk Formation in Foggy Island Bay. Three of the wells (Tern Island wells 1A, 2A, and 3) were drilled from Tern Island, which Shell constructed in 1981-1982. The fourth well was drilled from Goose Island, located southeast of Tern Island. In September 1996, BP Exploration Alaska (BPXA) acquired Tract OCS-Y1650 in OCS Lease Sale 144, and initiated exploration permitting activity for the Liberty No. 1 Exploration Well. The surface location for this well was located on a gravel and ice structure on top of the abandoned Tern Island on Tract OCS-Y1585 (Lease Sale 124), with the bottomhole location in Tract OCS-Yl650. All five wells are shown along with lease boundaries and offset wells in the map shown in Figure 2-2.

Drilling of the Liberty No. 1 well began in February 1997, followed by well testing in March 1997. The drilling operation was demobilized in April 1997. Based on interpretations of geologic data, seismic data, and well tests, on May 1, 1997, BPXA confirmed the discovery of an estimated 120 million barrels of recoverable reserves from the Liberty prospect. Since then the plans to develop the field have progressed through three stages, as described below.

2.1.1 1996 – 2002 Plans

BPXA initiated conceptual engineering in 1996. This effort was based on assumed exploratory success and focused on identification and screening of project development alternatives. Factors considered in the evaluation of alternatives included reservoir development and recovery, environmental impacts, costs, technical complexity, and logistical practicalities. The project goal was to identify the best development option that balanced resource recovery and environmental stewardship, as well as short-term and full-cycle costs.

[1] On November 3, 2014, BP Exploration (Alaska) Inc. (BPXA) filed forms BOEM-0150 to assign 50% ownership to HAK in Leases OCS-Y1585 and OCS-Y1650. On November 12, 2014, BPXA filed form BOEM-1123 naming HAK as the Liberty Unit operator for said leases.

Figure 2-1. Liberty Location on Alaska North Slope

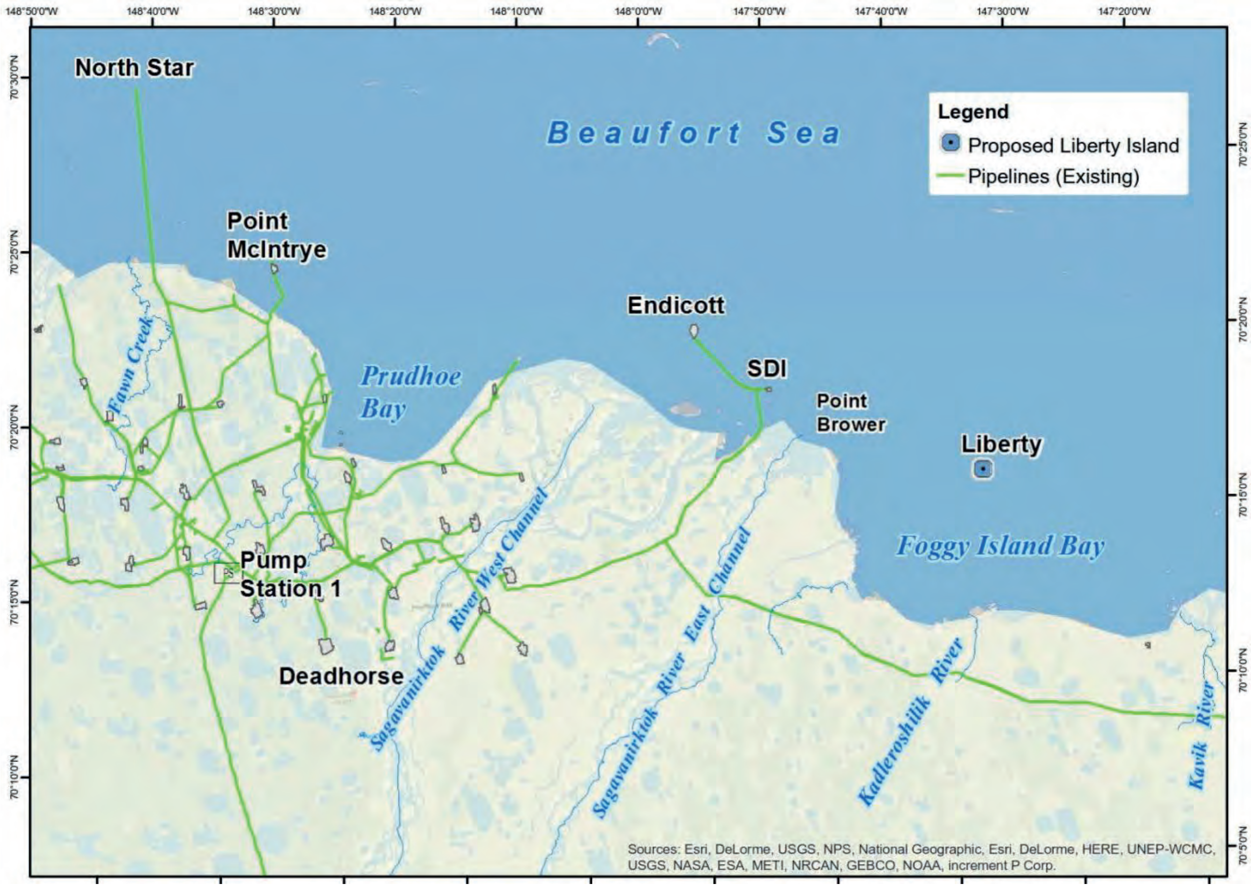
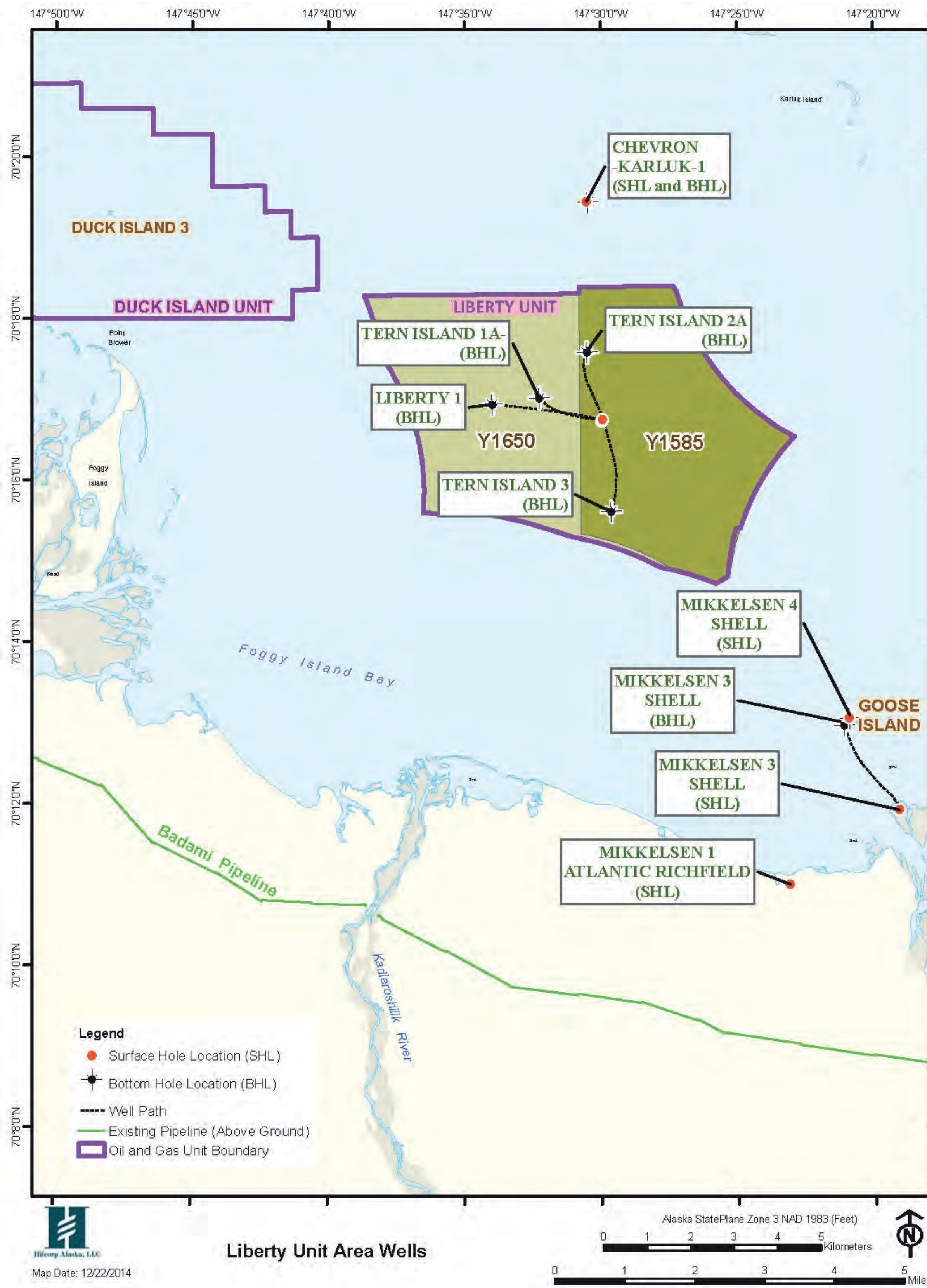


Figure 2-2. Liberty Locator Map with Area Wells, Lease Boundaries



By May 1997, a proposed Liberty development case had been prepared, which included a man-made offshore gravel island with full processing facilities, a subsea pipeline, and associated support infrastructure. In May 1997, BPXA formed an industry alliance of contractors to conduct preliminary engineering to provide the basis for permit applications to federal, state, and local agencies. On February 17, 1998, BPXA submitted a DPP to Minerals Management Service (MMS) for review and approval of a development project based on a manmade gravel island with three-phase process facilities and a buried subsea pipeline to shore and tie-in to the Badami pipeline. In 2001, prior to a Record of Decision (ROD), BPXA requested that the project be placed on hold in order to re-evaluate the project and study the lessons learned at Northstar. A Suspension of Production (SOP) was requested on July 10, 2001, and granted on July 19, 2001. MMS continued the NEPA review and in May 2002[2] issued a final environmental impact statement (FEIS) on the offshore project.

2.1.2 2002 – 2012 Plans

From 2002 to 2005, BPXA evaluated alternative ways to develop the oil accumulation at the Liberty site. In August 2005, BPXA announced that it would pursue use of ultra-extended-reach drilling (uERD) from an onshore location from the satellite drilling island (SDI) on the Endicott causeway. Recent advancements in drilling technology were thought to have made such a project feasible. The proposed land-based project was intended to eliminate the offshore impacts of an island and subsea pipeline construction, which mitigated impacts related to the Boulder Patch, marine mammals, and concerns related to subsistence whaling. It also made issues related to construction impacts and risk of an offshore pipeline design moot. This was the project described in the April 2007 Liberty DPP, which was approved by the MMS in January 2008.

Following approval of this plan, BPXA expanded the Endicott SDI and constructed and positioned a drilling rig to drill the proposed wells. The uERD project was cancelled in 2012 as further evaluations indicated that there were development alternatives that were safer and more technically sound. An SOP was requested and granted in December 2012, with the stipulation that an actionable DPP be submitted by December 31, 2014.

The Liberty Unit is currently under the December 31, 2012, SOP. BSEE specified the current SOP would expire December 31, 2014, unless a complete, timely, and actionable DPP is submitted. Based on discussions with BSEE on September 24, 2014, the December 31, 2012, SOP has been extended until such time as BOEM renders a decision on the DPP. Assuming the SOP will be in effect for 5 years as allowed by 30 CFR 250.10 (c) and (e) an SOP issued in the 1st quarter of 2015 could extend to planned commencement of operations in the first quarter of 2019. One additional SOP may be required depending on exactly when the SOP is issued after the DPP is deemed submitted and subsequent schedule changes.

2.1.3 2012 – 2014 Plans

Beginning in 2012, BPXA conducted a re-evaluation of ways to develop the reservoir with an island over the reservoir and conventional drilling technology. Several options on how to process fluids and deliver sales quality crude to TAPS were investigated. One option included a drilling-only island with onshore processing at Endicott. Another option that was evaluated included the concept that was proposed in the 2000 DPP and the subject of the FEIS published in May 2002. This plan was based on full processing on the island and a subsea sales quality pipeline to the south, where it would come ashore and tie in to the Badami Pipeline.

In April 2014, BPXA announced the sale of several North Slope assets to HAK including Northstar, Endicott, Milne Point, and Liberty. In the case of Liberty, 50% ownership and full operatorship of the

[2] Liberty Development and Production Plan, Final Environmental Impact Statement. OCS EIS/EA. MMS 2002-019 May 2002.

field was to be transferred from BPXA to HAK upon closing the sale in late 2014. In June of 2014, it was determined that the plan as outlined in the 2000 DPP and subject of the 2002 FEIS represented the most sound, practical, and expedient way to develop the Liberty reservoir while minimizing impacts to the environment.

This Liberty Development and Production Plan was originally submitted on December 30, 2014. After responding to questions posed by BOEM, this revision is filed September 8, 2015.

2.2 Project Overview

The Liberty Development will be a self-contained offshore drilling and production facility located on an artificial gravel island with a pipeline to shore. The island will be built about 5 miles offshore in Foggy Island Bay of the Beaufort Sea OCS in approximately 19 feet of water, about 2 miles west of the Tern Island shoal.

Infrastructure and facilities necessary to drill wells and process and export approximately 60,000 to 70,000 BOPD to shore will be installed on the island. There will be slots for 16 wells, which include accommodations for 5-8 producing wells, 4-6 water and/or gas injection wells, and up to two disposal wells at surface wellhead spacing of 15 feet between wellheads. Produced gas will be used for fuel gas, artificial lift, and re-injection into the reservoir. Seawater will be treated and used to waterflood the Liberty reservoir. Following waterflood breakthrough, produced water will be commingled with seawater and re-injected for reservoir support. A nominal 12 inch sales oil pipeline inside 16 inch outer pipe will transport crude oil to the Badami Sales Oil Pipeline. The offshore portion of the pipeline will be approximately 5.6 miles long, and the overland portion will be approximately 1.5 miles long to the Badami pipeline tie-in point.

Associated onshore facilities to support the project will include use of permitted water sources, construction of gravel pads to support the pipeline tie-in location and Badami ice road crossing, ice roads and ice pad construction, hovercraft shelter, small boat dock, and development of a gravel mine site west of the Kadleroshilik River. In addition, existing North Slope infrastructure will be used to support this project.

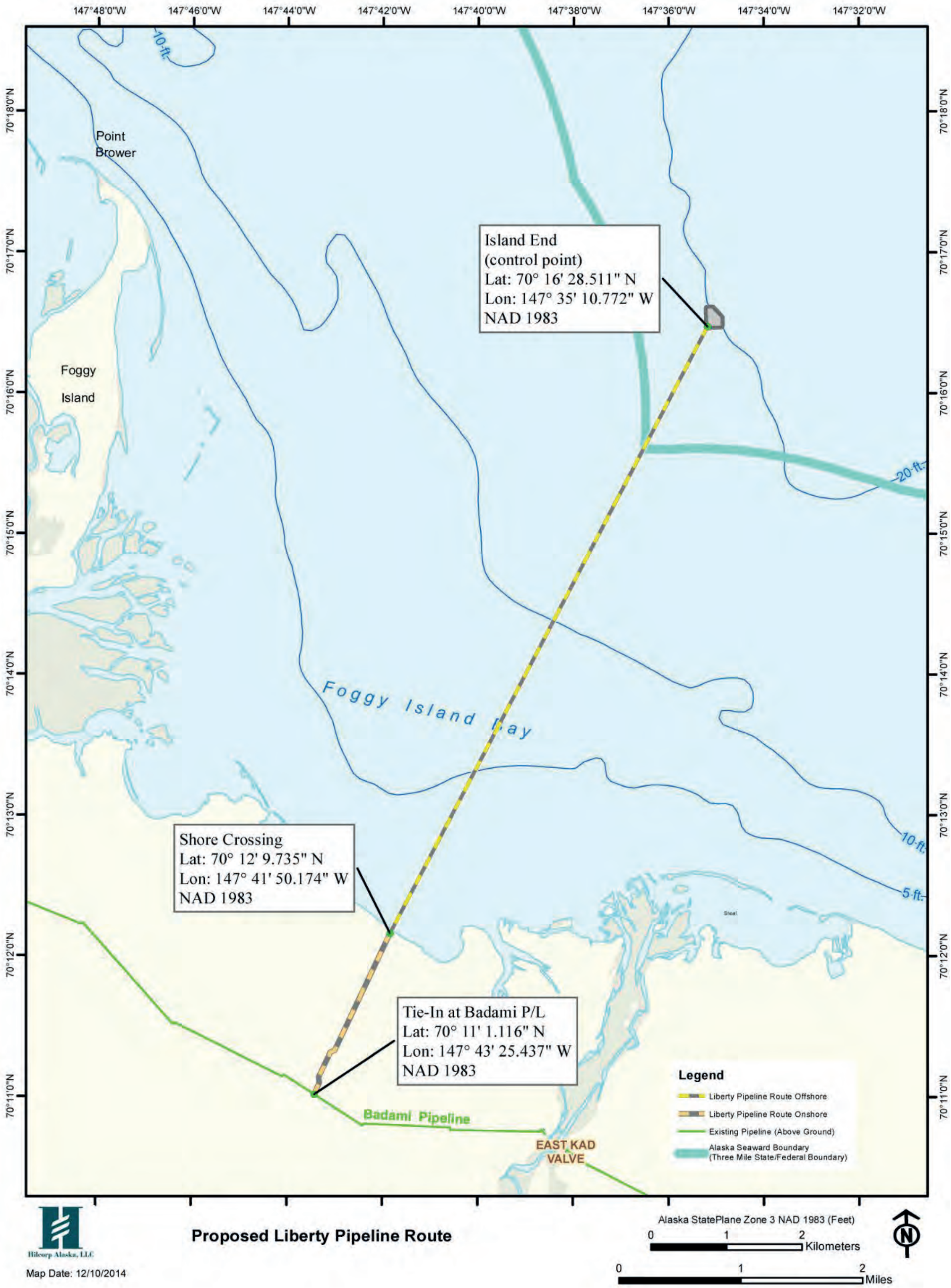
2.3 Location

The Liberty Drilling and Production Island (LDPI) will be constructed to recover reserves from two federal leases (OCS-Y1650 and OCS-Y1585) in Foggy Island Bay in the Beaufort Sea, northeast of the Prudhoe Bay Unit, and east of the Duck Island Unit.

The LDPI will be located approximately 5 miles north of the Kadleroshilik River and 7.3 miles southeast of the SDI. The LDPI will be built in approximately 19 feet of water; elevation of the top of the LDPI will be +15 feet (ft) Mean Lower Low Water (MLLW). The LDPI location is shown in Figure 2-3.

The LDPI coordinates are: 70°16’28.511” N, 147°35’10.772” W, AKSP3, NAD83.

Figure 2-3. Proposed Location for Liberty Drilling and Production Island



2.4 Project Objectives

A principal goal of the project is to optimize the balance between resource development and environmental impacts. Decisions about well count, island size, schedule, and emissions sources must consider each of these priorities and tradeoffs. The proposed development is intended to meet the following objectives:

- Produce hydrocarbons from the offshore Liberty Reservoir, maximizing oil and gas recovery while utilizing safe, efficient, and environmentally sound principles and practices.
- Reduce the impact of offshore infrastructure and operations to the extent practicable.
- Comply with applicable laws, regulations, lease stipulations, and permit requirements.
- Increase domestic oil production and help offset the decline in TAPS throughput.

2.5 Permits and Approvals

The Liberty development is subject to the federal, state, and local approvals as described in Section 15 of this document. This DPP provides a comprehensive description of the proposed project, including all the information required per 30 CFR 550.241-262. The DPP incorporates several additional documents submitted as Appendices, including the Environmental Impact Analysis (EIA) Report. Table 2-1 provides a cross reference between this document and the requirements of 30 CFR 550.241-262.

Table 2-1. Cross Reference Table: 30 CFR 550.241-262 Requirements versus this Liberty DPP

BUREAU OF OCEAN ENERGY MANAGEMENT 30 CFR PART 550 REQUIREMENT		SECTION OF DPP
30 CFR 550.241	What must the DPP include: PLAN CONTENTS	
30 CFR 550.241 (a)	Description, objectives and schedule of development	2.2-Project Overview 2.4-Project Objectives 3-Schedule
30 CFR 550.241 (b)	Location	2.3
30 CFR 550.241 (c)	Drilling Unit	8.3, 8.3.4, 8.3.5, Table 8-2, 8.3.6
30 CFR 550.241 (d)	Production Facilities	6, 7, 9, 10
30 CFR 550.241 (e)	Service fee	$4,238 per well proposed
30 CFR 550.242	What information must accompany the DPP	
30 CFR 550.242 (a)	General information required by 550.243	See details below
30 CFR 550.242 (b)	Geological and geophysical information required by 550.244	See details below
30 CFR 550.242 (c)	Hydrogen sulfide information required by 550.245	See details below
30 CFR 550.242 (d)	Mineral resource conservation information required by 550.246	See details below
30 CFR 550.242 (e)	Biological, physical, and socioeconomic information required by 550.247	See details below
30 CFR 550.242 (f)	Solid and liquid wastes and discharges information and cooling water intake information required by 550.248	See details below
30 CFR 550.242 (g)	Air emissions information required by 550.249	See details below
30 CFR 550.242 (h)	Oil and hazardous substance spills information required by 550.250	See details below
30 CFR 550.242 (i)	Alaska planning information required by 550.251	See details below

Table 2-1. Cross Reference Table: 30 CFR 550.241-262 Requirements versus this Liberty DPP

BUREAU OF OCEAN ENERGY MANAGEMENT 30 CFR PART 550 REQUIREMENT		SECTION OF DPP
30 CFR 550.242 (j) by 550.252	Environmental monitoring information required	See details below
30 CFR 550.242 (k) 550.253	Lease stipulations information required by	See details below
30 CFR 550.242 (l) 550.254	Mitigation measures information required by	See details below
30 CFR 550.242 (m) 550.255	Decommissioning information required by	See details below
30 CFR 550.242 (n) required by 550.256	Related facilities and operations information	See details below
30 CFR 550.242 (o) by 550.257	Support vessel and aircraft information required	See details below
30 CFR 550.242 (p) by 550.258	Onshore support facilities information required	See details below
30 CFR 550.242 (q) 550.259	Sulphur operations information required by	N/A
30 CFR 550.242 (r) by 550.260	Coastal Zone Management information required	See details below
30 CFR 550.242 (s) required by 550.261	Environmental impact analysis information	See details below
30 CFR 550.242 (t)	Administrative information required by 550.262	See details below
30 CFR 550.243 GENERAL INFORMATION		
30 CFR 550.243 (a)	Applications and permits	15.4, Table 15-1, Table 15-2, Table 15-3
30 CFR 550.243 (b)	Drilling fluids	8.4.3, Table 8-4
30 CFR 550.243 (c)	Production Information	4.4, Figure 4-10, Table 4-2
30 CFR 550.243 (d)	Chemical products and storage	8.4.1, Table 8-3, 9.3.13, Table 9-7, Table 10-1
30 CFR 550.243 (e)	New or unusual technology	9.7
30 CFR 550.243 (f) control statements	Bonds, oil spill financial responsibility, and well	16.10
30 CFR 550.243 (g)	Suspensions of production or operations	Table 15-4
30 CFR 550.243 (h)	Blowout scenario	14, 14.3, Table 14-3
30 CFR 550.243 (i)	Contact information	20
30 CFR 550.244 GEOLOGICAL AND GEOPHYSICAL INFORMATION		
30 CFR 550.244 (a)	Geological description	4.2
30 CFR 550.244 (b)	Structure contour maps	4.2, Figure 4-3
30 CFR 550.244 (c) (3-D) seismic lines	Two-dimensional (2-D) and three-dimensional	4.2, Figure 4-1 through Figure 4-10
30 CFR 550.244 (d)	Geological cross-sections	4.2, Figure 4-5, Figure 4-6, Figure 4-7, Figure 4-8
30 CFR 550.244 (e)	Shallow hazards report	4.5
30 CFR 550.244 (f)	Shallow hazards assessment	4.5

Table 2-1. Cross Reference Table: 30 CFR 550.241-262 Requirements versus this Liberty DPP

BUREAU OF OCEAN ENERGY MANAGEMENT 30 CFR PART 550 REQUIREMENT		SECTION OF DPP
30 CFR 550.244 (g)	High resolution seismic lines	Appendix B
30 CFR 550.244 (h)	Stratigraphic column	4.2, Figure 4-2
30 CFR 550.244 (i)	Time-versus-depth chart	4.1.2, Figure 4-1
30 CFR 550.244 (j)	Geochemical information	Appendix C – Proprietary Copy
30 CFR 550.244 (k)	Future G&G activities	4.3
30 CFR 550.245 HYDROGEN SULFIDE INFORMATION		
30 CFR 550.245 (a)	Concentration	11.7
30 CFR 550.245 (b)	Classification	11.7.1
30 CFR 550.245 (c)	H2S contingency plan	11.7.2
30 CFR 550.245 (d)	Modeling report	11.7.3
30 CFR 550.246 MINERAL RESOURCE CONSERVATION		
30 CFR 550.246 (a)	Technology and reservoir engineering practices and procedures	4.3
30 CFR 550.246 (b)	Technology and recovery practices and procedures	4.3
30 CFR 550.246 (c)	Reservoir development	4.2, 8.3.2, 8.4
30 CFR 550.247 BIOLOGICAL, PHYSICAL, AND SOCIOECONOMIC INFORMATION		
30 CFR 550.247 (a)	Biological environment reports	Appendix A
30 CFR 550.247 (b)	Physical environment reports	Appendix A
30 CFR 550.247 (c)	Socioeconomic study reports	Appendix A
30 CFR 550.248 SOLID AND LIQUID WASTES AND DISCHARGES INFORMATION AND COOLING WATER INTAKE		
30 CFR 550.248 (a)	Projected wastes	11.12, Table 11-1
30 CFR 550.248 (b)	Projected ocean discharges	Table 11-1, Table 11-2, Table 11-3, Table 11-4, Table 11-5
30 CFR 550.248 (c)	NPDES permit	Appendix E
30 CFR 550.248 (d)	Modeling report	N/A
30 CFR 550.248 (e)	Projected cooling water intake	9.2.6.1
30 CFR 550.249 AIR EMISSIONS		
30 CFR 550.249 (a)	Projected emissions	9.4.1
30 CFR 550.249 (b)	Emission reduction measures	9.4.2, Appendix F
30 CFR 550.249 (c)	Processes, equipment, fuels, and combustibles	9.4.3, Table 9-8, Table 9-12
30 CFR 550.249 (d)	Distance to shore	9.4.4
30 CFR 550.249 (e)	Non-exempt facilities	9.4.5
30 CFR 550.249 (f)	Modeling report	9.4.6
30 CFR 550.250 OIL AND HAZARDOUS SUBSTANCE SPILLS		
30 CFR 550.250 (a)	Oil spill response planning	14
30 CFR 550.250 (b)	Modeling report	14.3.2.1 and Figure 14-3
30 CFR 550.251 ALASKA PLANNING INFORMATION		
30 CFR 550.251 (a)	Emergency plans	8.7, 11.6, 14.3.1 (Winter), 14.3.2 (Summer) and Appendix H WCCP Outline

Table 2-1. Cross Reference Table: 30 CFR 550.241-262 Requirements versus this Liberty DPP

BUREAU OF OCEAN ENERGY MANAGEMENT 30 CFR PART 550 REQUIREMENT		SECTION OF DPP
30 CFR 550.251 (b)	Critical operations and curtailment procedures	8.7, 11.6, 14
30 CFR 550.252	ENVIRONMENTAL MONITORING	
30 CFR 550.252 (a)	Monitoring systems	12.5.1
30 CFR 550.252 (b)	Incidental takes	12.5.2
30 CFR 550.252 (c)	Flower Garden Banks National Marine Sanctuary	N/A
30 CFR 550.253	LEASE STIPULATIONS	16
30 CFR 550.254	MITIGATION MEASURES	
30 CFR 550.254 (a)	Proposed Measures	13.2
30 CFR 550.254 (b)	Protected Species	13.3
30 CFR 550.255	DECOMMISSIONING	19
30 CFR 550.256	RELATED FACILITIES AND OPERATIONS	
30 CFR 550.256 (a)	OCS facilities and operations	7, 7.8, 9
30 CFR 550.256 (b)	Transportation system	7
30 CFR 550.257	SUPPORT VESSEL AND AIRCRAFT	
30 CFR 550.257 (a)	General information	5
30 CFR 550.257 (b)	Air emissions	5.2, Tables 5-8 through 5-14
30 CFR 550.257 (c)	Drilling fluids and chemical products transportation	5, Table 8-4, Table 9-7
30 CFR 550.257 (d)	Solid and liquid wastes transportation	Table 11-1 through Table 11-5
30 CFR 550.257 (e)	Vicinity map	Figure 5-1, Figure 5-3
30 CFR 550.258	ONSHORE SUPPORT FACILITIES	
30 CFR 550.258 (a)	General information	3.1.2, 10
30 CFR 550.258 (b)	Air emissions	10.6, Table 10-2
30 CFR 550.258 (c)	Unusual solid and liquid wastes	11.11
30 CFR 550.258 (d)	Waste disposal	11.11, Table 11-1, Table 11-2, Table 11-3, Table 11-4, Table 11-5
30 CFR 550.260	COASTAL ZONE MANAGEMENT	
30 CFR 550.260 (a)	Consistency certification	Tables 15-1, 15-2, 15-3
30 CFR 550.260 (b)	Other information	Tables 15-1, 15-2, 15-3
30 CFR 550.261	ENVIRONMENTAL IMPACT ANALYSIS (EIA)	Appendix A
30 CFR 550.262	ADMINISTRATIVE INFORMATION	
30 CFR 550.262 (a)	Exempted information	21.1
30 CFR 550.262 (b)	Bibliography of previously submitted information	21.2

3 SCHEDULE

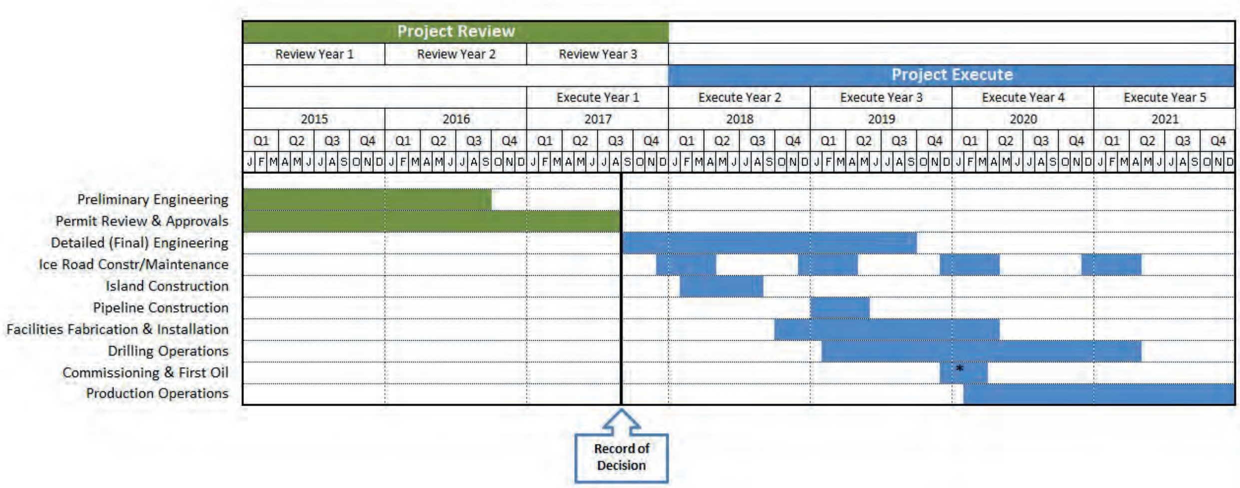
If treated as one continuous project, the Liberty project can be broken into nine distinct but overlapping phases as listed below:

- Preliminary Engineering
- Permit Review and Approvals
- Detailed (Final) Engineering
- Island Construction (including ice roads and mine site development)
- Pipeline Installation (including ice roads)
- Facilities Fabrication and Installation
- Drilling Operations
- Production Operations
- Decommissioning and Abandonment

However, due to seasonal constraints and the fact that the start of project execution depends on the month when all regulatory and owner approvals are secured, it is necessary to break the project into two major phases: "Project Review" (including approvals), and "Project Execution." Also, in order to de-couple the two phases and not assume when project approvals will be secured, the use of Review Year 1, Review Year 2, etc., and Execute Year 1, Execute Year 2, etc. is utilized in place of calendar year (2015, 2016, etc.). Schedules with different review and approval durations are shown and described below.

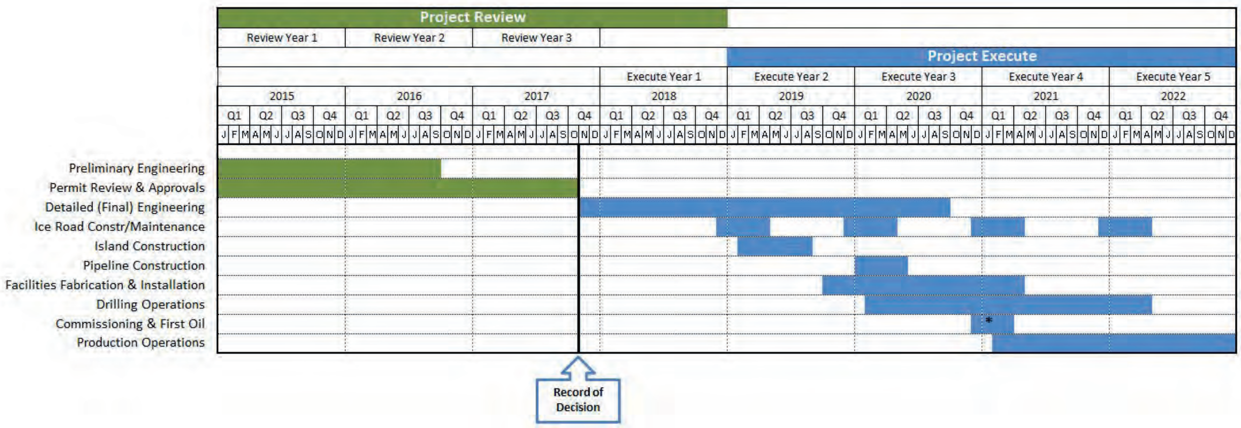
If permits and sanction are secured prior to September 1 of a calendar year, then construction could begin the same year. For example, if the ROD is posted on July 1, 2017, and financial sanction is secured by August 15, 2017, then construction could begin in 4Q of the same year and 2017 would be defined as Execute Year 1. Figure 3-1 is the proposed project schedule, assuming approvals are secured before September 1, 2017.

Figure 3-1. Liberty Project Schedule, Sanction Secured Prior to September 1



If permits and sanction are secured after September 1 of calendar year 2017, construction would be delayed to the next winter season and Execute Year 1 would be the following calendar year (2018). Figure 3-2 is the proposed project schedule that represents Execute Year 1 as 2018.

Figure 3-2. Liberty Project Schedule, Sanction Secured After September 1

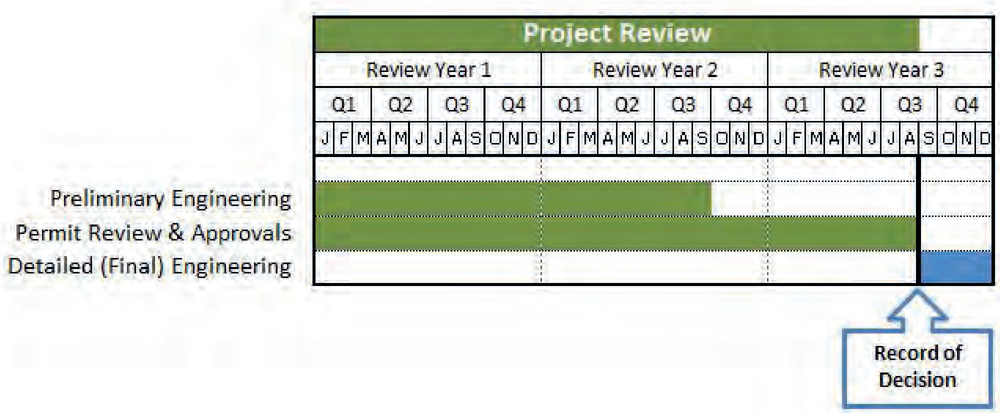


Either schedule is possible, depending on when approvals are secured. However, the time of the year that execution can begin will not change, since island construction can only begin when it is cold enough to build ice roads to access the mine site.

3.1 Project Review Phase

Even though the development project has been studied for over 15 years, for the sake of this discussion, the Project Review and Approval phase is shown to begin in 2015 and will continue until the ROD is posted and financial sanction is secured. The Project Execution period begins as soon as the project has been sanctioned by the owners. The Project Review period includes preliminary engineering, project permit submittals, review and approvals by governing bodies, and investor sanction to initiate project execution (Figure 3-3).

Figure 3-3. Liberty Schedule – Project Review Phase



3.1.1 Preliminary Engineering

This project has been studied for many years, so considerable volumes of data have been gathered, and an extensive amount of engineering analyses, environmental investigation, and planning has been completed and documented. In addition to the work specific to the Liberty location, there are hundreds of lessons that have been learned from four prior island developments in the Beaufort Sea. All of this information has been incorporated into the proposed project.

HAK began its preliminary engineering work in 2014 with a review of alternative ways to develop the field and a determination of the pros and cons of each alternative. This analysis confirmed that a standalone island and a southern pipeline route is the best approach, both from an environmental impact and project constructability standpoint. HAK then initiated additional engineering work to refine the concept. Factored into this effort were the results of environmental investigations and impact mitigation studies. In addition, HAK has sought input from a number of experts, including residents of the North Slope, to improve the design and refine the construction techniques and schedule to minimize effects to surrounding resources.

3.1.2 Permit Review and Approvals, Project Sanction

Beginning with the submission of the DPP, EIA, and pre-decisional OSRP in late December 2014, the NEPA review process will start, which is expected to culminate in a ROD. Concurrent with the NEPA review will be a parallel effort to prepare and submit additional federal, state, and local permit applications (as outlined in Section 15) to seek approvals to construct the project as described herein. HAK, as operator, will work with the lead and supporting agencies to review the project and provide additional information, so that a thorough evaluation of the impacts can be conducted and authorizations secured in a timely manner.

Following the ROD and review of all permit stipulations, the owners will review the project in light of new information and determine whether the project is a prudent investment and should proceed. Project sanction generally requires at least 2 to 6 months of re-evaluation, following a review of all stipulations attached to the permits.

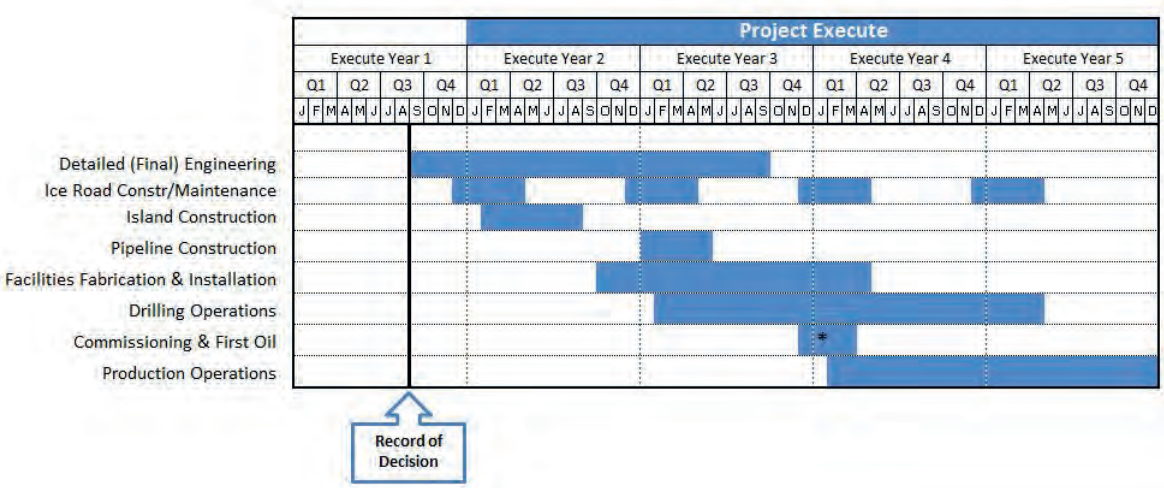
No land will be acquired to support the Liberty Project. Rights-of-way (ROW) will be needed prior to construction. The ROW application process has a mandated period to allow public notice, lease drafting, and public hearings. These mandated time periods total 104 days. HAK has scheduled permit acquisition to be completed by the end of August 2017. Permit acquisition discussions commenced, including ROW acquisition, in April 2014. This time period allows adequate time for permit and application consultation permit review, and mandated permit review time periods.

It should be noted that because financial commitments to proceed cannot be obtained until all federal, state, and local authorizations are secured, permit reviews and approvals are on the critical path to the date of first oil. HAK recognizes that it is difficult to predict when governmental evaluations will be completed and authorizations will be granted. Given the fact that this area has been extensively studied and a FEIS has been issued on a project that is nearly identical to the one described in this DPP, the operator and its partners are hopeful that authorizations can be secured in time to initiate gravel island construction activities in the proposed Execute Year 1 of 2017. As noted above, if permit approvals and project sanction extend beyond September of 2017, then start of construction would be delayed until the next winter season after September 1 in the year in which final approvals and project sanctions occur.

3.2 Project Execution Phase

Once all governmental agencies have approved the project, stipulations have been reviewed, and financial funding is secured, the project would progress to the execution phase as summarized in Figure 3-4. The Project Execution phase includes all construction activities, beginning with detailed and final engineering. A description of the duration and seasonal windows of each major activity is given below.

Figure 3-4. Liberty Schedule - Execution Phase



3.2.1 Detailed Engineering

In order to calculate and describe the exact details of process facilities, pipeline dimensions, and civil structures including the island, an additional level of data gathering, engineering analyses, and drafting of drawings will be required before equipment can be ordered. For example, additional data about the composition of the soil under the proposed island and along the pipeline route will need be gathered and analyzed for sediment strength characteristics. This data will be used to finalize the design of the island and pipeline construction techniques. A winter geotechnical survey is planned for early 2015, and a summer survey of the pipeline route is planned for mid-year 2015. Final engineering is expected to continue through Execute Year 3, when fabrication quality drawings of all process facilities will be completed.

It should be noted that wherever possible, pre-engineered modules will be utilized to expedite the overall final engineering and construction schedule. Many of these modules will be very similar to modules built and installed in other cold weather regions, including Canada. Therefore, the engineering timeline for this project will be much shorter than would be required if large sea-lift modules were used for processing.

3.2.2 Ice Road Construction

Ice road construction and equipment mobilization will commence in 4Q Execute Year 1 when the environmental conditions allow travel on the tundra and on the sea ice. Ice roads will be constructed in 4Q Execute Year 1 and 1Q Execute Year 2 to support transportation from existing North Slope roads to the proposed mine site, and from the mine site to the proposed LDPI location in the Beaufort Sea. The ramp up in activity will depend on weather and will proceed faster when temperatures drop below 0° F. Typically, ice road construction can be initiated in mid to late December, and ice roads can be maintained until mid-April of the following year.

Ice roads will be reconstructed in 4Q Execute Year 2 and 1Q Execute Year 3 to support the pipeline installation, including the offshore section from the shore crossing to LDPI, and the onshore portion that includes the tie into the Badami pipeline. Both sections of the pipeline will require access via an ice road system for construction.

Additional ice roads from Endicott SDI will be constructed in Execute Years 2 through 5 to allow additional materials and equipment to be mobilized to support island, pipeline, and facility construction activities.

3.2.3 Mine Site Development

Development of the Liberty mine site, located to the west of the Kadleroshilik River, will be completed in one season. Mining activities will begin in 1Q Execute Year 2 and continue through 3Q of Execute Year 2. The general sequence of activities for mine site development includes removal of snow and ice, removal and stockpiling of unusable overburden material, pit excavation, and gravel hauling, backfill of unusable material into the pit breach construction, and flooding to reclaim the pit. Additional reclamation activities will be conducted after the pit is flooded. A Mining and Reclamation Plan will be submitted under separate cover to the State of Alaska, Department of Natural Resources, Division of Land, for review and approval. Additional description of the mine site and gravel mining techniques is provided in Section 10.3 of this plan.

3.2.4 Island Construction

The overall construction strategy for the Liberty project is to use the winter season to its maximum advantage for island and pipeline construction, allowing for the use of conventional or adapted land-based construction techniques. This leverages the efficiencies of rolling stock, compared to marine vessels, to move material and equipment. Additional but minimal island construction will take place in the summer months including gravel farming, sheet pile installation, and island armament installation.

Island construction will commence in 1Q Execute Year 2 as soon as the ice road from the mine site to the island site has been completed. Gravel will be hauled from the mine site over the ice road. The gravel haul will continue for about 50 to 70 days, and by mid-April all gravel should be in place. Slope protection installation will follow, beginning before breakup and continuing into 3Q Execute Year 2. The driven sheet pile wall around much of the island perimeter will be installed before the end of 3Q Execute Year 2. Well conductors and some foundation piles will be driven during this same timeframe. A detailed description of the island design and construction techniques is provided in Section 6 of this plan.

3.2.5 Pipeline Installation

Pipeline construction is planned for the winter after the island is constructed. The pipeline will extend from the island to a tie-in with the Badami Pipeline system. The pipeline will be constructed from 1Q Execute Year 3 to 2Q Execute Year 3. The proposed winter Liberty offshore pipeline installation techniques are adaptations of onshore buried pipeline construction and installation technology utilizing conventional land-based construction and pipe laying equipment. These are the same techniques that were used on the North Slope at Northstar, Oooguruk, and Nikaitchuq developments.

The offshore and onshore pipeline segments are planned to be installed within the same time frame with two separate construction spreads of equipment and manpower. The onshore sequence of activities includes the installation of Vertical Support Members (VSMs), placement of the pipeline on the VSMs, and installation of the pigging facilities at the Badami tie-in pad. The onshore section is approximately 1.5 miles long.

For the offshore segment, construction will progress from shallower water to deeper water with multiple construction spreads. The pipeline trench will be excavated, pipeline bundle laid in the trench, and the trench backfilled. Boring studies have indicated that there will not be significant areas of unsuitable materials along the pipeline route, and HAK intends to place all material back in the trench slot. Work will be done from thickened ice using conventional excavation and dirt-moving construction equipment. The offshore pipeline is about 5.6 miles long. Hydrotesting of the entire pipeline will be completed prior to commissioning in 3Q Execute Year 4, during the full facility start-up. A detailed description of the pipeline design and installation techniques is provided in Section 7 of this plan.

3.2.6 Facilities Construction

3.2.6.1 Module Fabrication

Most facilities (process equipment, utilities, pipe racks, shops, living quarters) for LDPI will be modular in design, fabricated in a shop, trucked up the Dalton Highway, and installed with local labor. By limiting vessel and module sizes to the maximum size that can be moved by truck, a number of advantages, including quicker time to engineer and quicker time to fabricate, are realized. In addition, truckable modules are safer and easier to fabricate and operate, there is little risk of design flaws, and they take advantage of the economies of experience in the fabrication shop. The same cannot be said of sealift size modules that can only be delivered in open-water season.

3.2.6.2 Transportation of Modules and Material

All modules, buildings, and material for on-site construction will be trucked to the North Slope via the Dalton highway and staged at West Dock, SDI, or in Deadhorse. Depending on the season, the equipment and material will be transported via coastal barges in open water, or ice roads from SDI in the winter. The first modules will be delivered in 3Q Execute Year 2 to support the installation of living, drilling, and production facilities. Remaining process modules will be delivered to correspond with first oil and the ramp up in drilling capacity.

3.2.6.3 Facilities Installation

Onsite facility installation will commence in Execute Year 2 and be completed by the end of Execute Year 4 to accommodate the overall construction and production ramp-up schedule. Some facilities (including some sections of the temporary living quarters) that are required early will be barged in 3Q Execute Year 2 and will be installed and operational by the end of 4Q Execute Year 2. Other modules will be delivered as soon as the ice road from SDI is in place. The concept of using pre-fabricated modules that mate together will be used wherever it makes sense from a cost and schedule perspective. There will however be some facilities, such as tanks and warehouse-type buildings, that will have to be constructed on-site.

3.2.7 Drilling Operations

The drilling unit and associated equipment will be mobilized to the LDPI by barge in 3Q Execute Year 2. Drilling unit commissioning and start-up is scheduled for 1Q Execute Year 3. Drilling will occur year-round, but drilling into the reservoir will be limited to open-water and frozen ice seasons. All the wells are anticipated to be drilled and completed by the end of 2Q Execute Year 5. Each spring and fall, prior to soft/broken ice seasons, sufficient drilling consumables will be stockpiled on the island to allow drilling through the periods when re-supply is limited to personnel, groceries, and small loads via helicopter or hovercraft.

The first well drilled will be the cuttings re-injection and waste mud disposal well. Rock cuttings and excess drilling mud from this well will be stored on site until the disposal well is plumbed and the grind and inject (G&I) facility is commissioned. Alternatively cuttings and drilling muds may be transported to onshore disposal. The next well drilled will be a gas injector so that produced gas can be re-injected into the reservoir. The third well drilled will be a producer which, once completed and connected to the processing facilities, will allow the plant to start up and begin shipping crude oil to market.

A more detailed discussion of the sequence of drilling activities, including drilling unit mobilization, drilling operations, and seasonal drilling restrictions, as well as the drilling order of all wells, is provided in Section 8 of this plan.

3.2.8 Production Operations

Production operations are scheduled to commence upon completion and commissioning of the initial facilities and the completion of the first three wells, as described above. First oil is expected in 1Q of Year 4. Production, drilling, and facility installation activities will occur simultaneously until all the wells are drilled and in service as either a producer or injector. Detailed construction planning will be conducted to ensure that simultaneous operations including construction activities, drilling operations and production operations can be managed safely within the confines of the island and the constraints associated with logistics and living quarters.

With the first production well online, initial production rate is expected to be in the range of 10,000 to 15,000 BOPD. As additional wells are brought online, the production rate is expected to peak at a rate of between 60,000 and 70,000 BOPD. It will take approximately 2 years after first oil to reach peak flow rate from the reservoir. The economic field life is currently estimated at approximately 15 to 20 years. Accordingly, the facilities and pipeline are designed for an operational life of 25 years, based on design criteria which anticipate extreme environmental events (e.g., wave, ice, storm, seismic conditions, etc.) as detailed in the respective sections of this DPP. The integrity of the on-island facilities will be monitored and maintained throughout the life of the facility. In a situation where the operational life of the Liberty Field exceeds 25 years, facility upgrades such as replacement of equipment and/or piping may be required. Identification of critical repairs and/or upgrades would be determined through an Integrity Management Program. Decommissioning would not occur regardless of the productive capability of the Liberty reservoir or other hydrocarbon pools that may be found.

3.2.9 Decommissioning

End of field life is difficult to estimate, as it depends on a prediction of commodity price and operating costs at a point in time far in the future. Preliminary evaluations indicate that all reserves can be recovered within a span of 15 to 20 years. At that time, decommissioning would begin. Removal of facilities and abandonment of the wells is expected to require two winter seasons over a span of 18 months. A more thorough discussion of decommissioning activities is provided in Section 19 of this plan.

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4 SUBSURFACE: GEOPHYSICS, GEOLOGY, RESERVOIR DEVELOPMENT

The objective of the Liberty project is to maximize recovery from the reservoir while minimizing environmental impacts. The subsurface depletion plan, which determines well count, well placement, and size of the surface facilities, stems from the geology and reservoir description. This section describes the geophysical dataset, geology, reservoir rock and fluid properties, and the subsurface depletion plan that will recover as much oil as is practicable.

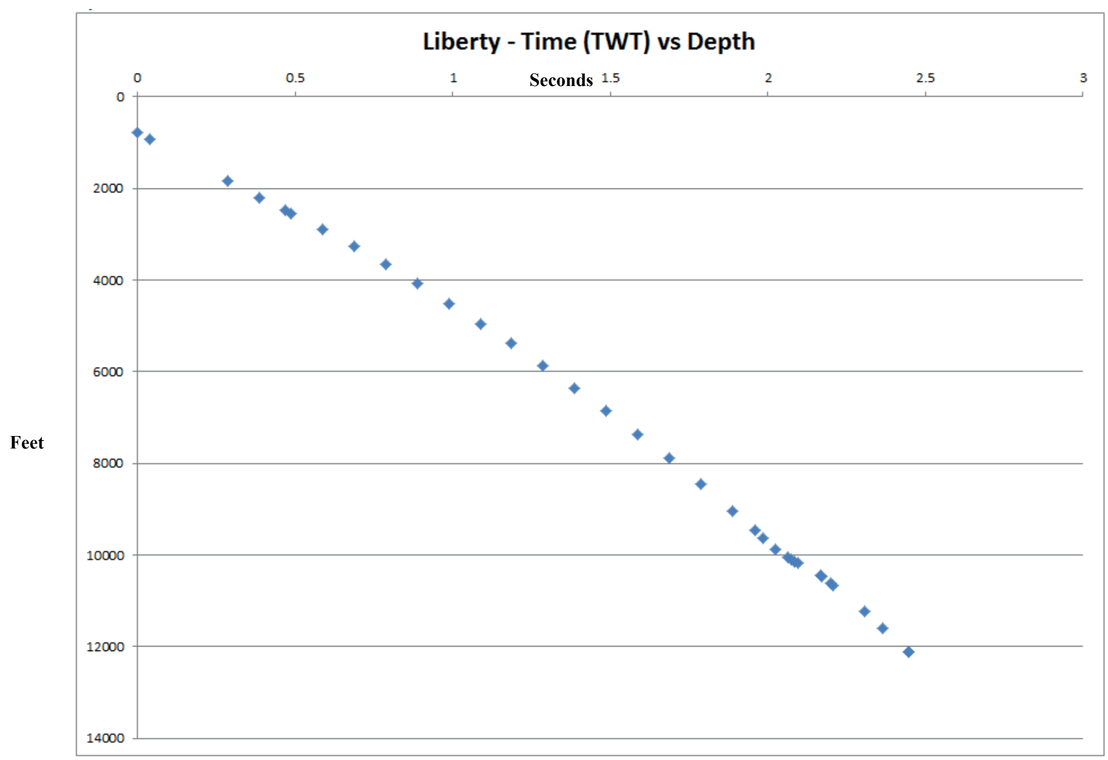
4.1 Seismic Data

There have been two (2) three-dimensional (3-D) seismic surveys shot over the field that have been used to map the structure and define the top of reservoir and the field limits. The initial 3-D survey was acquired in 1995 and covers the field down-dip to West Mikkelsen No. 4 well. This is the survey that is used to image the reservoir section. A more recent 3-D survey was conducted during the open-water season of 2008 and covers the development area, but was specifically designed to investigate and image the shallower horizons in preparation for the drilling of uERD wells. This dataset is not used to image the reservoir section. A high resolution seismic survey was conducted in 2014 for the purposes of evaluating shallow geological and archaeological hazards. The results of the survey and from the 1995 survey have been used to complete additional seismic details shown in Appendix B.

4.1.1 Time Versus Depth Chart

The current structure map is made from Pre-stack Depth Migrated data. This data was transformed from seismic depth straight to well depth. The chart showing the relationship of seismic depth to well depth is shown in Figure 4-1.

Figure 4-1. Time Versus Depth Chart



4.2 Geology and Reservoir Description

Four wells have penetrated the Liberty reservoir, including Tern Island Wells 1A, 2A, and 3 drilled by Shell, and the Liberty No. 1 well drilled by BPXA (Figure 2-2). The Liberty No. 1 well confirmed the presence of hydrocarbons on Federal lease OCS-Y 1650 in March 1997, which initiated development plans. A 3-D seismic survey covers the accumulation and is used to map the top of the reservoir and define the prospect limits.

The Liberty No. 1 well established the presence of producible hydrocarbons within the Kekiktuk Zone 2 reservoir, as shown in the stratigraphic column depicted in Figure 4-2. The Liberty accumulation is similar to the nearby Endicott Field, except that the Liberty reservoir only includes the K2 interval of the Kekiktuk formation. Both fields have structural-stratigraphic traps involving north-west trending faults and reservoir truncation by the Lower Cretaceous Unconformity (LCU). The Liberty Field is bounded to the southwest by Fault "A" (or the "Tigvariak" Fault), and to the northeast by Fault "B."

The Zone 2 reservoir is truncated within the section across the entire Liberty Field and the LCU depth map represents top reservoir structure in the field area (Figure 4-2). The LCU truncates younger strata south of Fault "A" and older strata north of Fault "B." The structure dips regionally to the southeast and the updip trap is formed by reservoir truncation at the LCU (Figure 4-3).

Figure 4-2. Stratigraphic Column of the Kekiktuk Formation

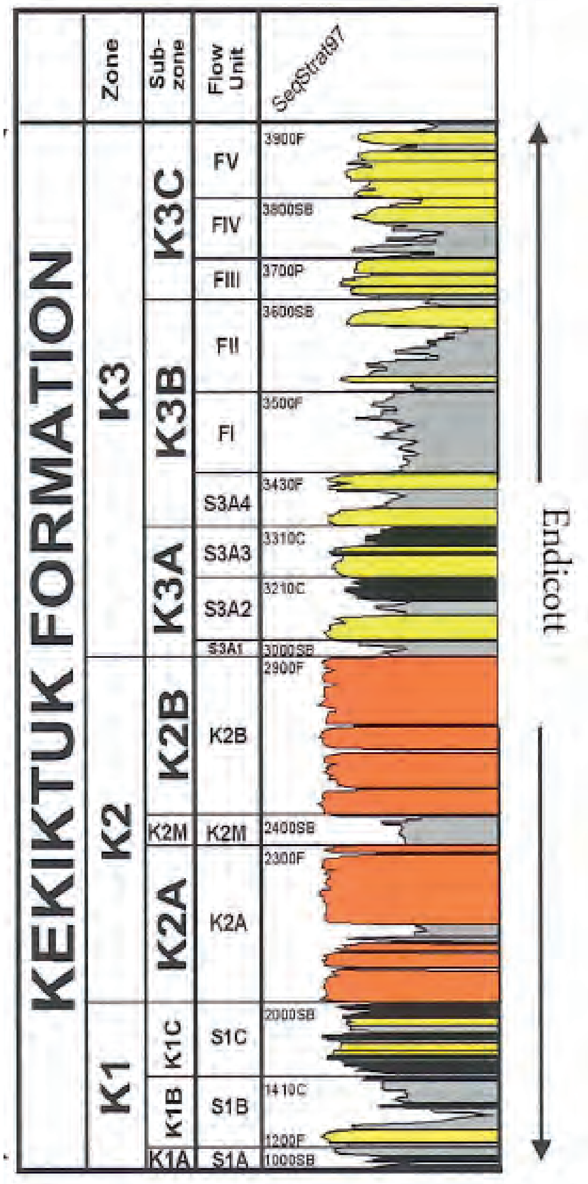
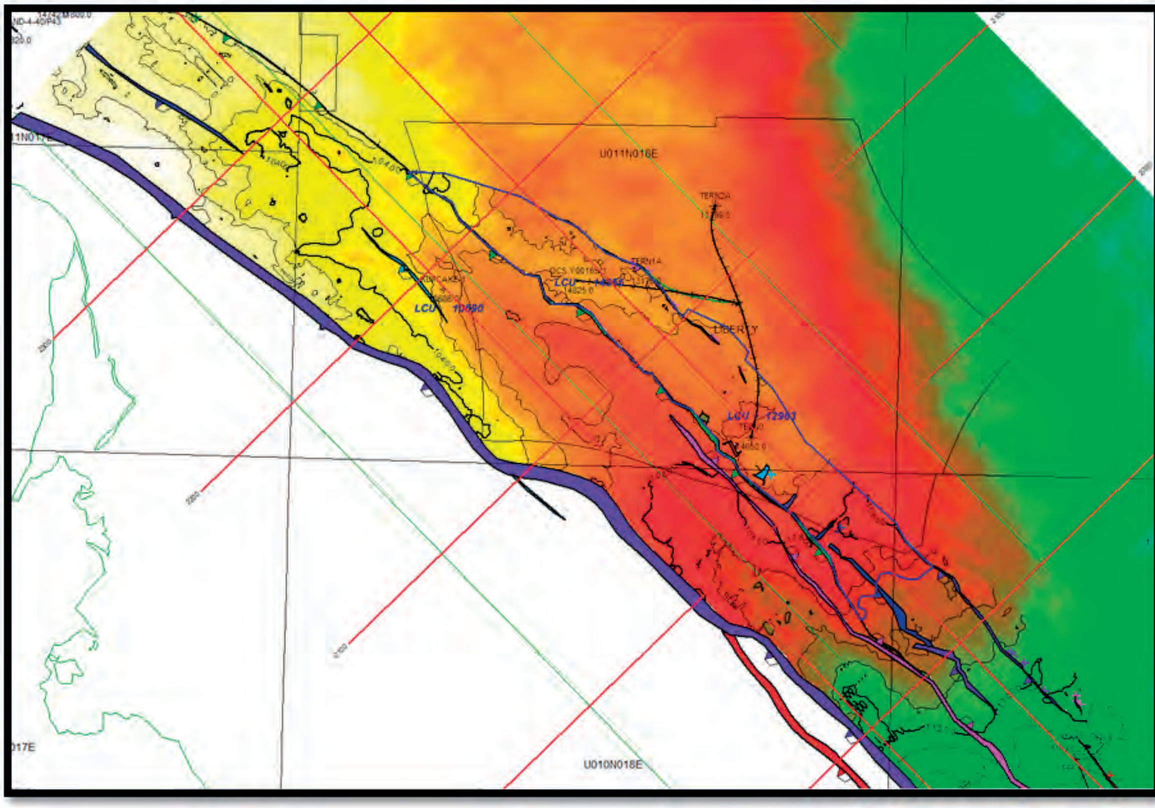


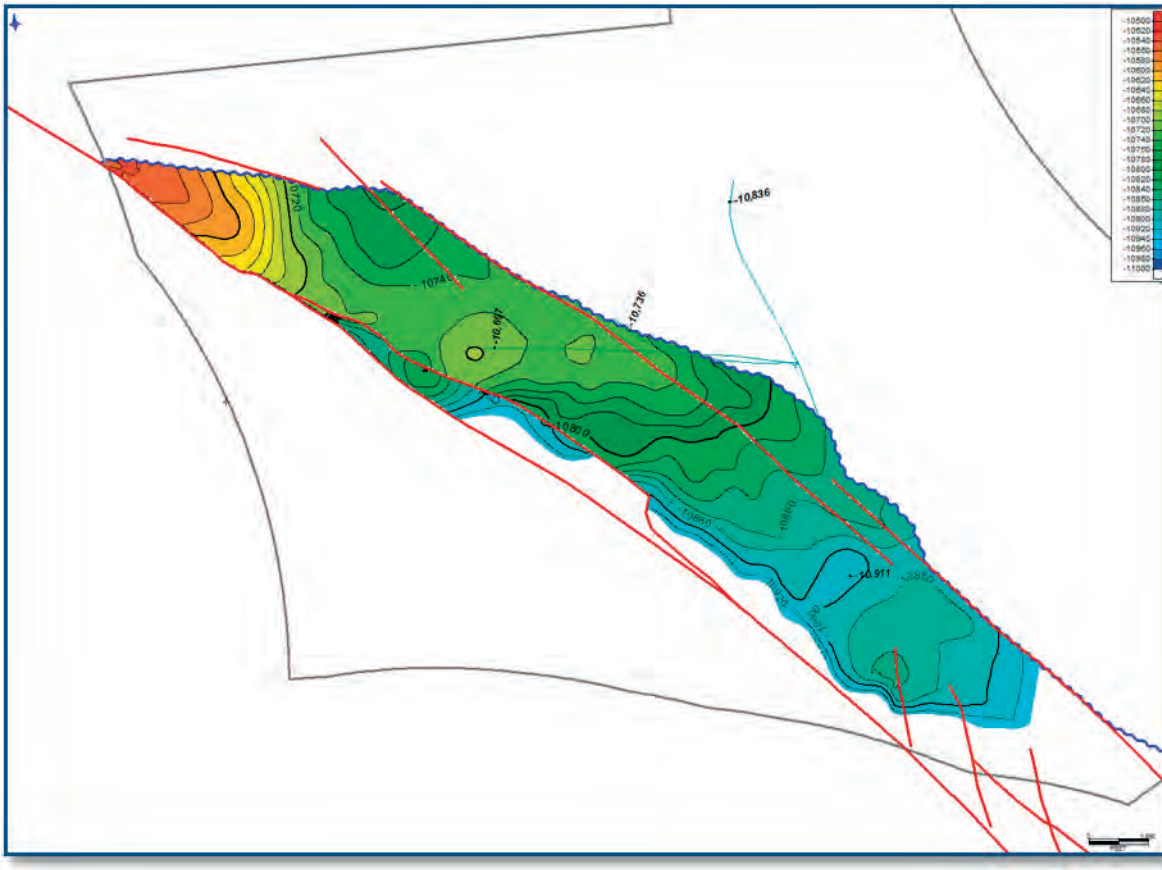
Figure 4-3. LCU Structure Map – Top Reservoir



The Kekiktuk sandstone of the Liberty Reservoir has high-quality rock properties, similar to that of the Endicott Field (Figure 4-4). The Zone 2 interval, with a net to gross ratio of over 90 percent, has the best quality rock. Subzone 2A is 80 to 150 feet thick in the field area and has an average porosity of 18 to 19 percent. Subzone 2B is 80 to 140 feet thick and has an average porosity of 18.5 to 21 percent. The average permeability of Zone 2 is in the range of 400 to 1,600 millidarcy (mD). The drill stem test and pressure buildup from Liberty No. 1 indicated an effective permeability of 640 mD.

The oil column height is approximately 380 feet, as measured from the top of mapped structure to the logged oil-tar contact. The average oil saturation is approximately 95 percent. Gas was not encountered in the Liberty No. 1 well or Tern Island No. 3 well, yet the oil is near bubble point, indicating the potential for a gas cap at the crest of the structure. Fluid studies suggest a range of possible outcomes with the most likely scenario of a very small (less than 1 billion cubic feet) gas cap with a gas-oil contact of 10,565 feet total vertical depth subsea (TVDSS). Top tar represents the base of producible hydrocarbons in the Liberty Reservoir, and its limit is constrained by the Liberty No. 1 and Tern Island No. 3 wells in Zone 2. In the Liberty No. 1 well, the oil-tar contact is near the base of Zone 2 at 10,932 feet TVDSS, with an overlying oil column at the top of the reservoir. In Tern Island No. 3, the oil-tar contact is 10,922 feet TVDSS in the Zone 2 reservoir. This type of basal “tar mat” is common in North Alaska oil fields, including the Endicott Field and Prudhoe Bay Field. The top of the tar mat is relatively flat in these fields, and the same is expected at Liberty. The tar mat is approximately 120 feet thick with a tar-water contact in Tern Island No. 3 at a depth of 11,046 feet TVDSS.

Figure 4-4. K2B Structure Map



The Tern Island lA and 2A wells have proven that there is one or more Zone 1 accumulations north of Fault “B” that are not in fluid communication with the main Liberty reservoir (Figures 4-5, 4-6, 4-7, and 4-8). Tern Island 2A flowed 87 barrels of oil per day from Zone 1 at a depth of about 11,400 feet TVDSS. This is about 350 feet deeper than the base of tar in Tern Island No. 3. Tern Island lA flowed oil from a broad interval that is deeper than known water in the Liberty Field (about 10,750 feet to 11,400 feet TVDSS). It is uncertain if the Zone 1 oil tested in Tern Island lA and Tern Island 2A are part of the same accumulation. It is possible that Fault “B” separates the Tern Island 1A/2A Zone 1 accumulation from Liberty, or it is possible the Zone 1 hydrocarbons are stratigraphically trapped in thin discontinuous sands and the trap is independent of the faulting. Further drilling will be required to understand the nature of the Zone I accumulation(s) and assess the possibility for commercial development. HAK may evaluate the Zone I accumulation(s) from the Liberty Field development island, where it can be appraised at reasonable costs.

Figure 4-5. Location of Cross Section A-A' and B-B'

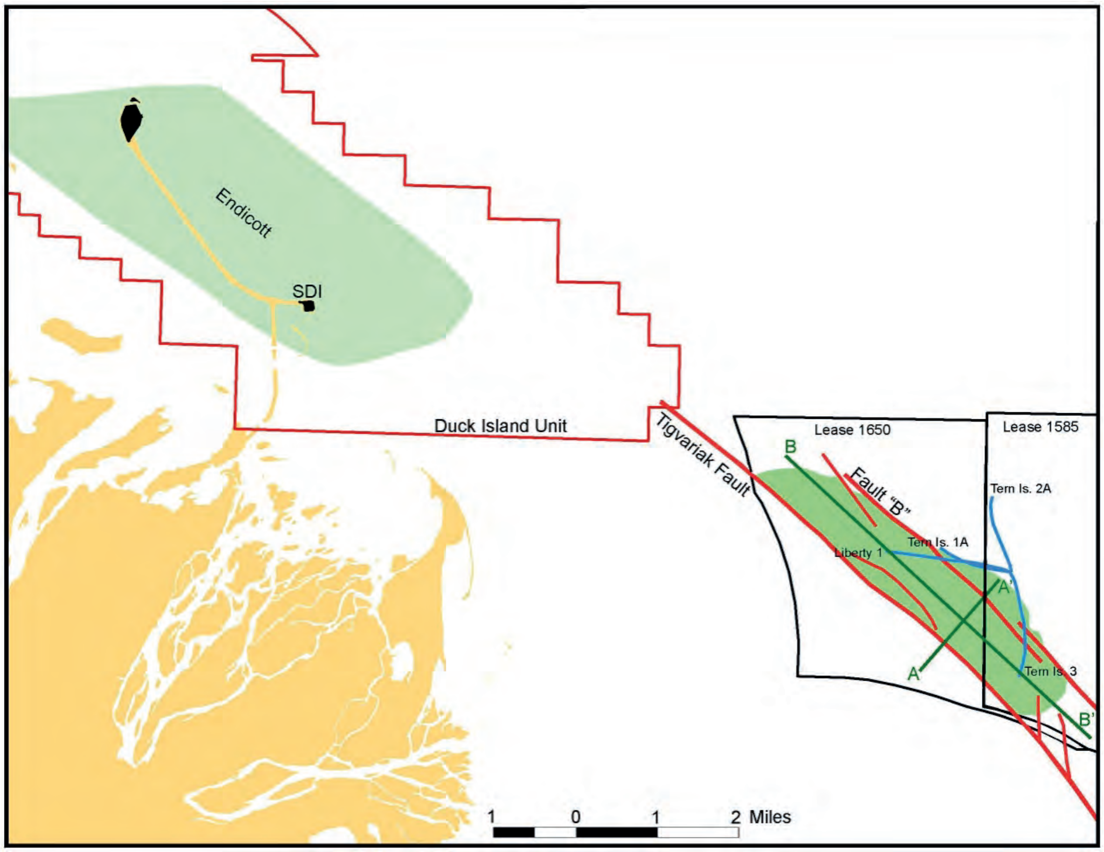


Figure 4-6. Structural Cross Section A-A'

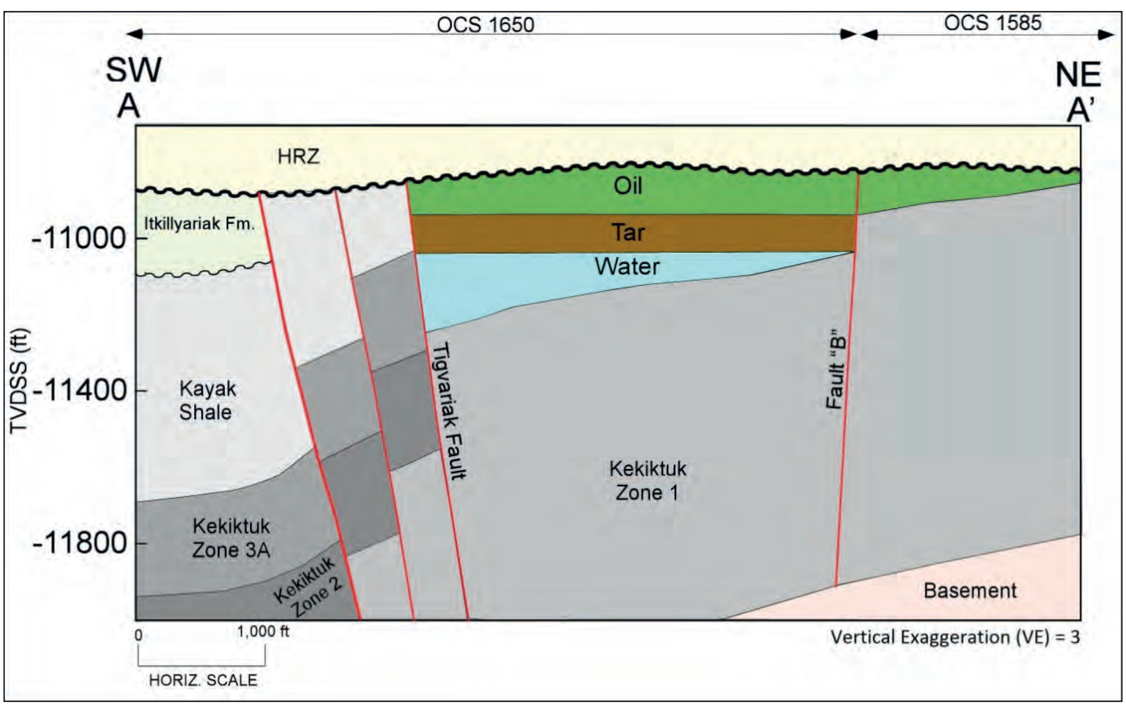


Figure 4-7. Structural Cross Section B-B’

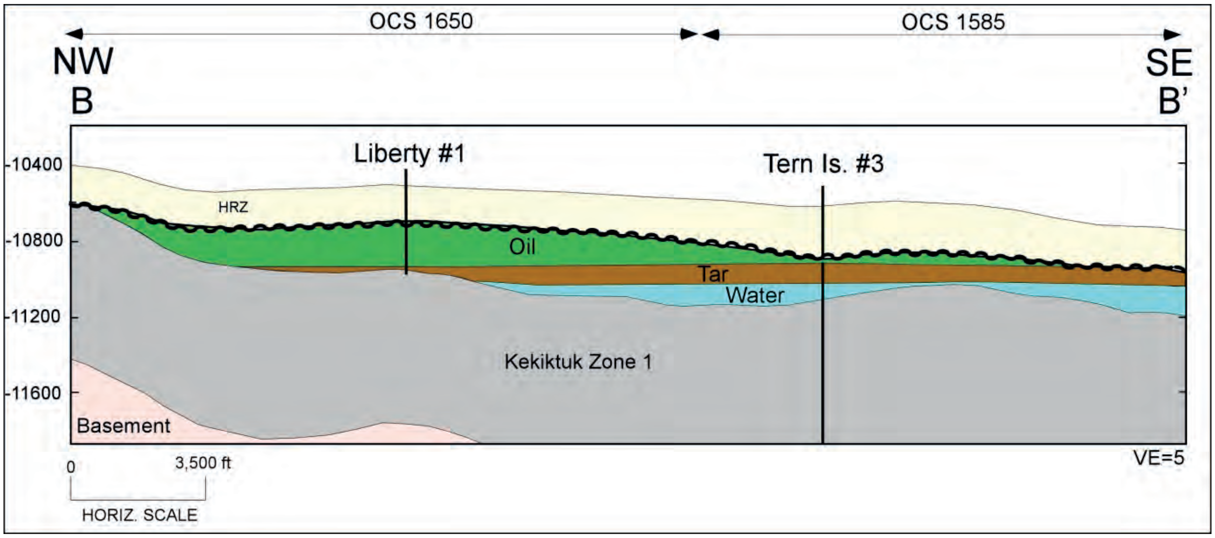
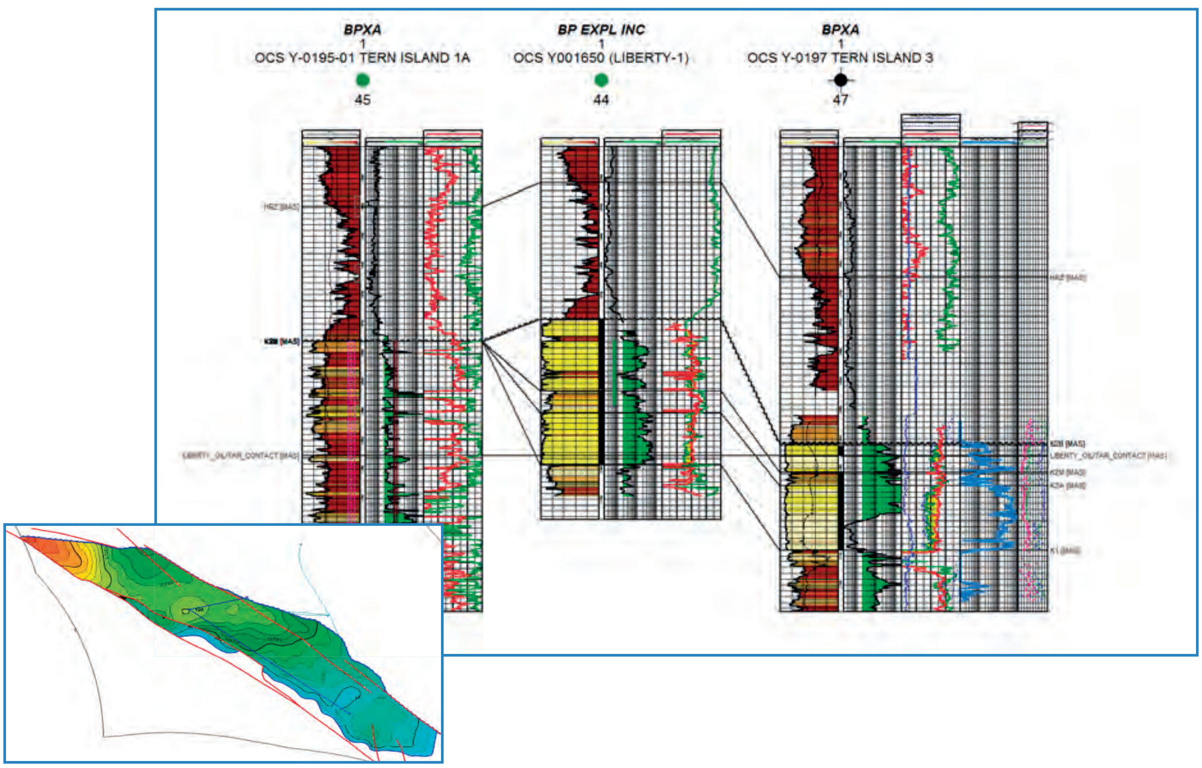


Figure 4-8. Log-Based Structural Cross Section, Liberty Field



4.2.1 Reservoir Rock Properties

Reservoir rock properties have been gathered from whole core data, sidewall core data, and electric line log data. Rock properties are summarized in Table 4-1.

Table 4-1. Liberty Reservoir Rock Properties

PROPERTY	LIBERTY	ENDICOTT (ANALOG FIELD)
Average Gross Pay Thickness	230 ft	800 ft
Average Net Pay Thickness	190 ft	400 ft
Average Porosity, Range	18 – 20%	18 – 20%
Average So, Range	90 – 95%	90 – 95%
Average Permeability, Range	500 – 1,500 mD	400 – 1,600 mD

4.2.2 Reservoir Fluid Properties

Reservoir fluid samples were obtained during the Liberty #1 well flow test. The average reservoir fluid properties are summarized in Table 4-2. Other North Slope fields, including Prudhoe Bay and the analog Endicott Field, have a tar layer as well.

Table 4-2. Liberty Average Reservoir Fluid Properties

PROPERTY	LIBERTY	ENDICOTT (ANALOG FIELD)
API gravity	24° to 27° API	23° to 24 °API
Viscosity	0.68 cP	0.9 cP
Reservoir Temperature	215 °F	218 °F
Solution GOR, Rs	872 SCF/STB	770 SCF/STB
B_o	1.47 RB/STB	1.35 RB/STB
Psat (Bubble Point)	4973 psia	4838 psia

Key: API = American Petroleum Institute; B_o = formation volume factor - oil; cP = CentiPoises; GOR = gas-oil ratio; Psat (Bubble Point) = saturation pressure; psia = pounds per square inch absolute; RB = reservoir volume barrel; Rs = solution gas-oil ratio; SCF = standard cubic feet; STB = stock tank barrel.

4.2.3 Estimate of Recoverable Reserves

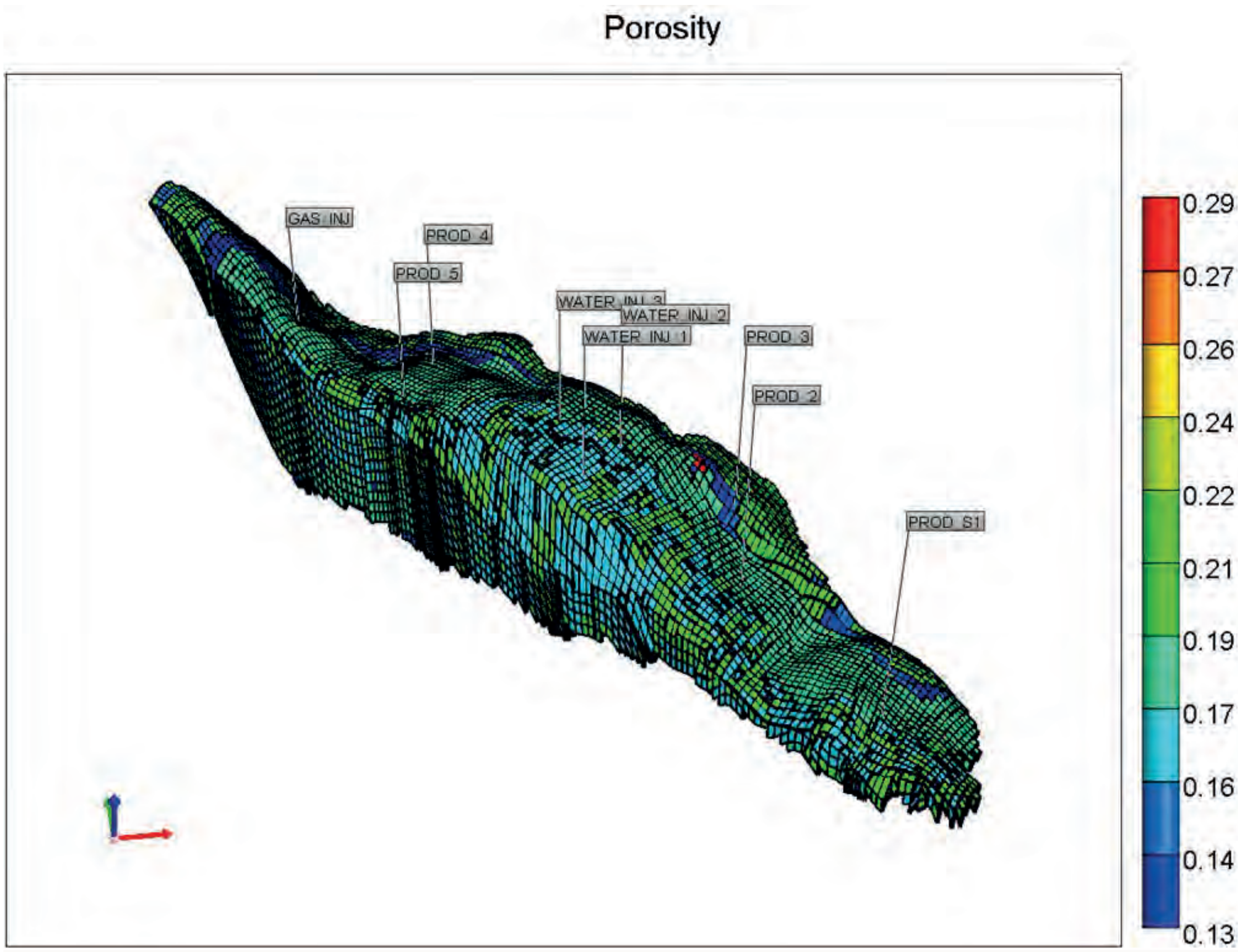
Given the geology, rock, and fluid properties discussed in the previous sections, the original oil in place estimated via a simulation model is approximately 230 million barrels of oil (MMBO). A recovery factor of 55 percent, which is seen currently at Endicott in the K2A sand, yields 167 MMBO recoverable.

4.3 Reservoir Development Plan

Reservoir simulations and experience with the Endicott field allow reservoir planners to propose the most efficient method to maximize oil recovery from the Liberty Field, based on the current dataset of logs and cores. However, as more wells are drilled and more information is gathered, there needs to be flexibility in well placement, well count, and production handling capacity to account for a maturing understanding of the subsurface and to account for actual well performance. The proposed development plan is based on a depletion scheme of five producers and four water and/or gas injectors in the main reservoir, with the flexibility to increase the well count by three producers and two injectors. This development scheme also allows for testing the presence of movable oil in the southern fault block and producing it with up to two wells.

All of the wells will be drilled from one offshore gravel island location. The producer to injector ratio is not the driver in this depletion plan, although initiating injection as soon as possible and maintaining an injection to withdrawal ratio (I:W) of at least 1.0, to maintain reservoir pressure is critical to maximizing recovery. A 3-D rendering of the reservoir model is shown in Figure 4-9. Shown is the placement of the three water injectors near the middle of the field. To the southeast and down dip are three producers. To the northeast and up dip are two producers. Furthest northeast is a gas injector at the crest of the structure.

Figure 4-9. Reservoir Model



This depletion scheme is the result of hundreds of reservoir simulations that investigated the impacts on rate, recovery, drilling costs, and processing costs of several different schemes including:

- A traditional waterflood of downdip water injection and updip gas injection
- More wells: waterflood patterns with tighter well spacing
- Gas injection at various locations to optimize gas placement and minimize gas cycling
- Horizontal wells

Given the quality of the rock, with average permeability in the wells expected to be in the 500 to 1,000 mD range, and the relatively good quality oil with American Petroleum Institute (API) gravities in the 24° to 27° range, the reservoir simulations found that there was little to no recovery benefit to developing the field with more than five producers and a few well-placed injectors to match reservoir voidage with adequate gas and water injection. This conclusion is supported by experiences at Endicott where recoveries of wells with good permeability were very high, and these wells, which are the best analogs to the wells that will be drilled at Liberty, were found to drain a much larger area than the average Endicott pattern size would indicate. The benefits of minimizing the numbers of wells translates into fewer wells, smaller island, less drilling risk, and quicker ramp up to full production.

Injection of gas and then water will begin as soon as practical in the drilling order. The first three wells into the reservoir will include a gas injector, oil producer, and water injector. Subsequent wells will be drilled in the order which will optimize production rate and overall field recovery. Once waterflood breakthrough occurs, all of the produced water will be treated and re-injected with additional volumes of sea water to match injection with withdrawal volumes. At the beginning, approximately 70 percent of the produced gas will be re-injected, with the remainder used as fuel gas to run the drilling unit, power plant, and process facilities. Later in field life, as produced oil and produced gas decline, most of the produced gas will be used to fuel the facilities so water injection will have to increase to match offtake.

The proposed development plan includes provisions for evaluating additional reserves as new well information is obtained. The major design feature to allow for utilization of future subsurface data is the inclusion of more well slots than needed for initial development. Additional slots could be used for future appraisal drilling, or additional development wells. If additional economically recoverable accumulations are found, for example in the K-1 zone, existing island infrastructure would be used to produce these hydrocarbons. In effect, this could extend the life of the project by continuing production over a longer time period than envisioned for the known Liberty accumulation. Future geological and geophysical activities include those as listed in this section and in Section 7.

4.4 Predicted Rate Profile

Based on the depletion strategy described above, the production of oil, water, and gas and the corresponding rates of injection for water and gas are shown in Figure 4-10. This production profile shows average annual production rates of about 60 thousand barrels of oil per day (MBOD), less than the estimated plant capacity of 65 MBOD. This annualized average is slightly lower due to plant and well downtime as a result of maintenance shutdowns, equipment reliability, pipeline slowdowns, and/or well work. It should also be noted that predictions at this stage of the development, before development wells are producing, are often found to be in error. To account for this uncertainty, the drilling plan, number of well slots, and processing capacity must be designed to adjust to actual conditions. The effect of this inherent uncertainty in predicted reservoir performance, and its effects on process sizing and the ability to process high fluid rates, is discussed in Section 9.1 of this plan.

4.5 Shallow Hazards

In summer of 1997, BPXA conducted a shallow hazards survey of the proposed development area (Duane Miller and Associates 1998). The geophysical systems used for the survey included a high resolution seismic profiling system, an intermediate seismic system, a high frequency seismic profiler, digital side-scan sonar, and digital fathometer. No shallow hazards were discovered as a result of that survey. Geophysical data and the interpretive results were submitted to the Minerals Management Service (MMS) under separate cover in February 1998, prepared in accordance with specification NTL 89-2, Section G.

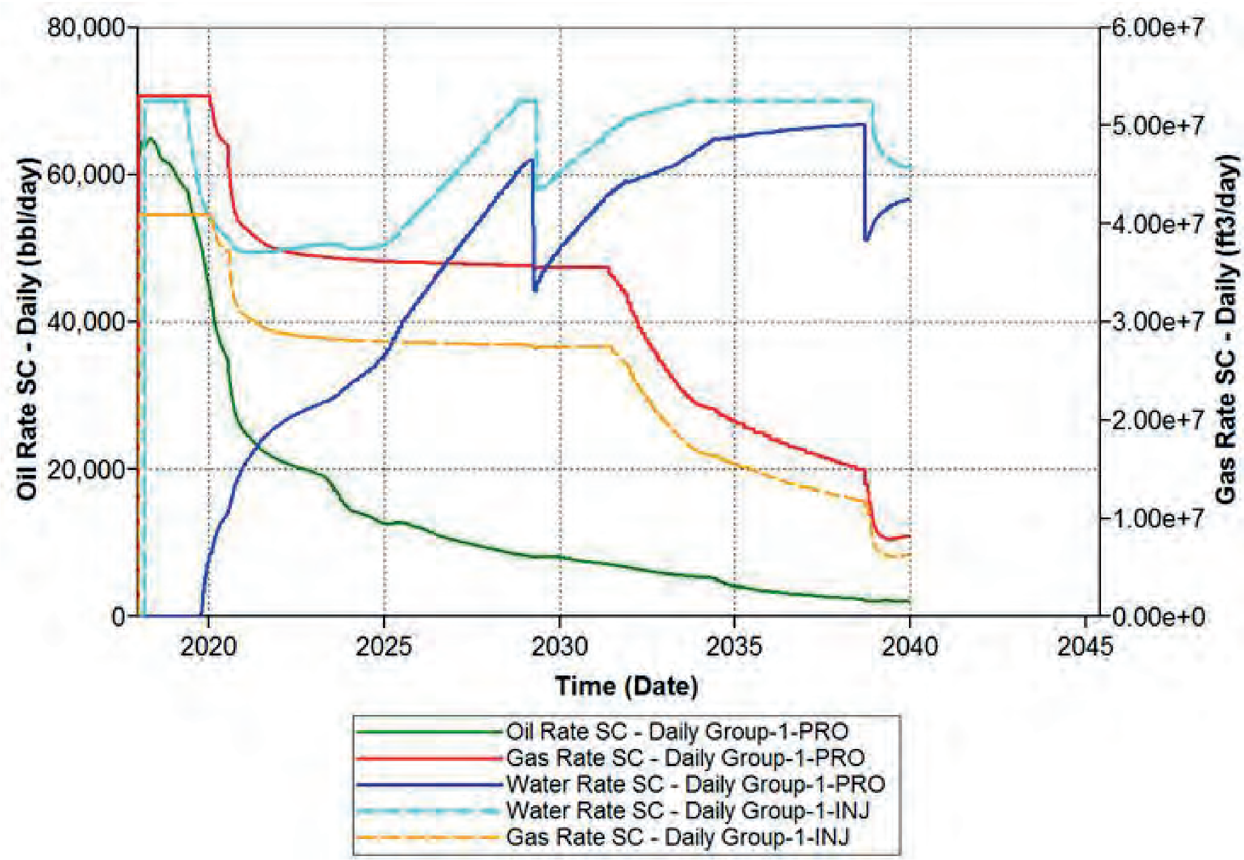
In 1998, Watson Company Inc. completed a high resolution geophysical pre-installation pipeline survey along the western route of the proposed pipeline. The survey included the acquisition of digital side scan sonar, sub-bottom profiler, and bathymetric data. The field effort included a centerline and a 300 meter offset line for the west pipeline route. Two track lines were taken along this route. The MMS study *Evaluation of Sub- Sea Physical Environmental Data for the Beaufort Sea OCS and Incorporation into a Geographic Information System (GIS) Database*, OCS Study MMS 2002-017, contains a comprehensive database that synthesized spatial and attribute information collected during shallow geological and geophysical surveys of the OCS in the Beaufort Sea, including two years of pipeline route surveys for the Liberty Development. This information will be refined with information from additional studies that HAK has conducted in summer 2015 and will be provided when the report from the 2015 surveys is finalized in approximately September 2015.

Extensive work has been done to analyze the overburden and the associated risk. Previous surveys have shown no significant seafloor or manmade feature that would pose a problem for drilling. All five exploration wells drilled in the area were reviewed for risk of gas and hydrates (Liberty #1, Kupcake #1, and Tern Island #1A, #2A, and #3). In general, there is not a significant risk of encountering shallow gas or methane hydrates while drilling the first 5,000 feet TVDSS. Within the intermediate casing string, minor gas shows have been encountered in the sand above the UG4 coals and are believed to be related to the coal. Minor oil shows appear to be related to residual saturation from the migration of hydrocarbons through the Ugnu sands. Since there is monoclonal dip and no structures mapped in this section, no significant gas or oil accumulations in the overburden are expected.

The majority of the overburden section is at or near hydrostatic pressure, except in the highly radioactive zone (HRZ), which is overpressured (1 to 2 pounds per gallon) and remains 2 to 4 pounds per gallon below the fracture gradient. Pore Pressure/Fracture Gradient work has been done in all of the surrounding exploration wells and shows no significant change from well to well. Wells in this study include: Liberty #1; Kupcake #1; Tern Island #1A, #2A, and #3; WMikkel #1, #2, #3, and #4; and SDI #1; and 3-47/Q-35. Minimal faulting is seen in the overburden above the HRZ and should not pose a drilling risk.

An additional shallow hazards survey was completed in 2014, and the preliminary data was submitted to BOEM under separate cover. The data is being analyzed and will be incorporated into HAK's current understanding of hazards.

Figure 4-10. Projected Rate Profile



5 ACCESS TO PROJECT AREA

Logistics is a critical consideration in all aspects and phases of the Liberty Development. The LDPI is separated from existing North Slope infrastructure by water; the nearest gravel pad and road is the Endicott SDI and causeway, about 7.3 miles west-northwest of the site. Transportation and re-supply needs include the ability to safely transport personnel, supplies, and equipment to and from the site at any time of year. During construction, large quantities of gravel, pipe, and heavy modules will be moved to the island. Drilling operations will require re-supply of mud products, cement, casing, tubing, wellheads, and other material to the island. During ongoing field operations, replacement parts and consumables will be needed on a continuing basis. Table 5-1 summarizes basic project transportation needs and identifies the frequency of those needs.

Table 5-1. Estimated Transportation Requirements

PROJECT ACCESS NEEDS	FREQUENCY	
	ONGOING	DISCRETE
Transport gravel from mine site to construction site	--	✓
Transport pipeline construction materials	--	✓
Transport production modules	--	✓
Transport drilling unit	--	✓
Transport personnel	✓	--
Transport supplies and equipment to the site. Waste removal.	✓	--
Mobilize personnel/equipment for oil spill preparedness activities	✓	--
Emergency transport of relief drill rig	--	✓

5.1 Access Needs and Modes

Various options have been evaluated and selected to move personnel and material to and from the site. The following sections describe the basic features and limitations of each mode. Table 5-2 shows seasonal limitations associated with each mode of transportation.

Table 5-2. Seasonal Access Limitations

MODE OF TRANSPORTATION		OPERATIONAL SEASON (TYPICAL)
Ice Road	Over Tundra	January to mid-April
	Over Sea Ice	February to mid-May
Vessels, Barges	Coastal	Early July to Mid-October
	Seagoing	Not required
Helicopter		Year Round, weather limited
Hovercraft		Year Round, limited by wave height and broken ice conditions
Arktos™ All-Terrain Vehicles		Year Round, for emergency evacuation only

5.1.1 Road System

Road vehicle traffic will use the Alaska Highway System to transport material and equipment from supply points in Fairbanks, Anchorage, or outside of Alaska to the supply hub of Deadhorse. North Slope gravel roads will be used for transport from Deadhorse to the SDI. Existing gravel roads within the Endicott field between the Main Production Island (MPI) and the SDI will also be used to support the project. No new gravel roads will be constructed.

5.1.2 Ice roads

During winter, ice roads will be built to support island and pipeline construction activities, and will be used in subsequent years to support drilling activities and production operations. An ice road connecting SDI to LDPI is expected to be constructed annually to resupply the island and transport personnel. Ice roads are commonly used on the North Slope for winter tundra travel typically from January through mid-April, and for offshore access typically from February through mid-May. Roads across the sea ice are constructed by grading the sea ice and thickening with water, as needed, to provide a surface suitable for vehicular traffic. Roads across the tundra are constructed by laying water down to protect the tundra, after the soil is frozen and there is adequate snow cover. Approximate ice road routes during island and pipeline construction are shown in Figure 5-1. The ice road route to support ongoing re-supply and production operations is shown in Figure 5-2.

Figure 5-1. Ice Road Locations for Island and Pipeline Construction

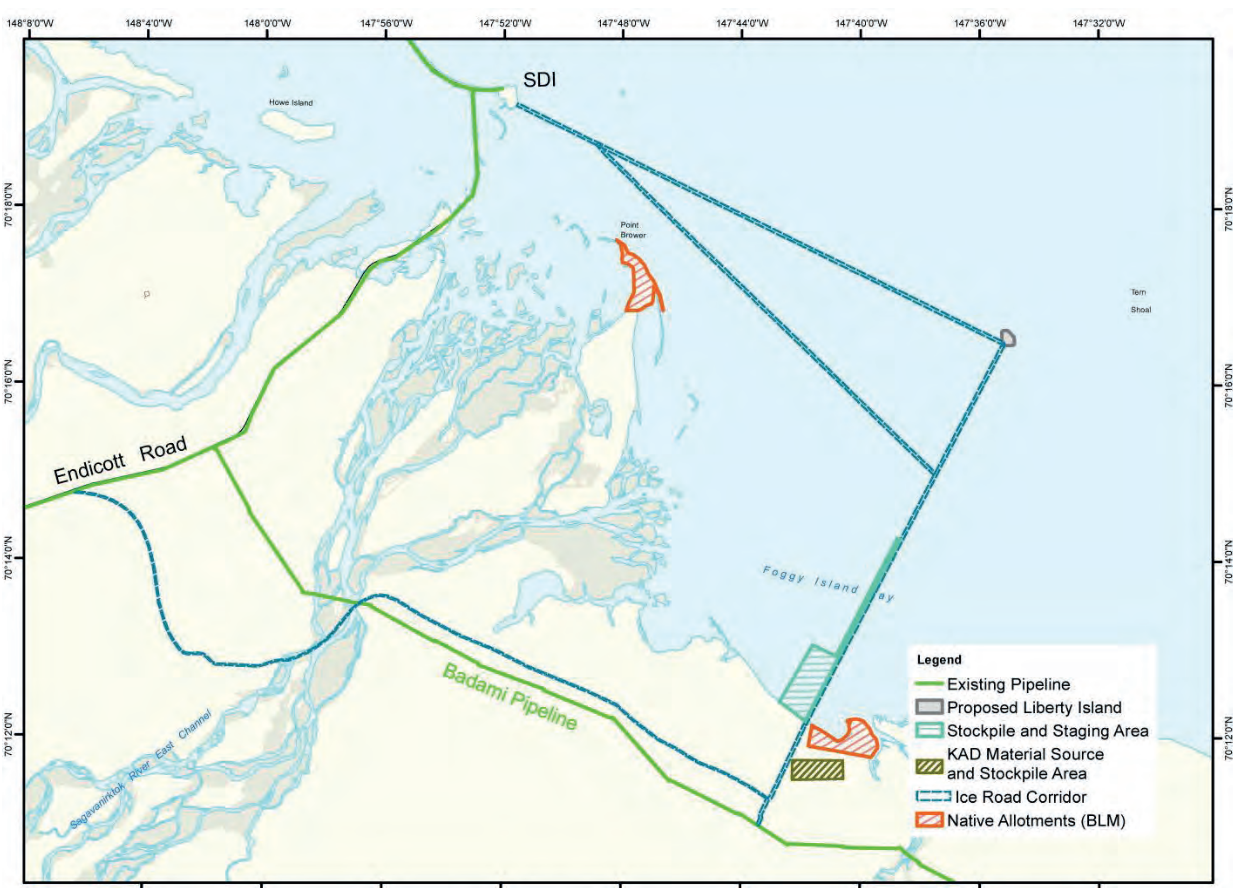
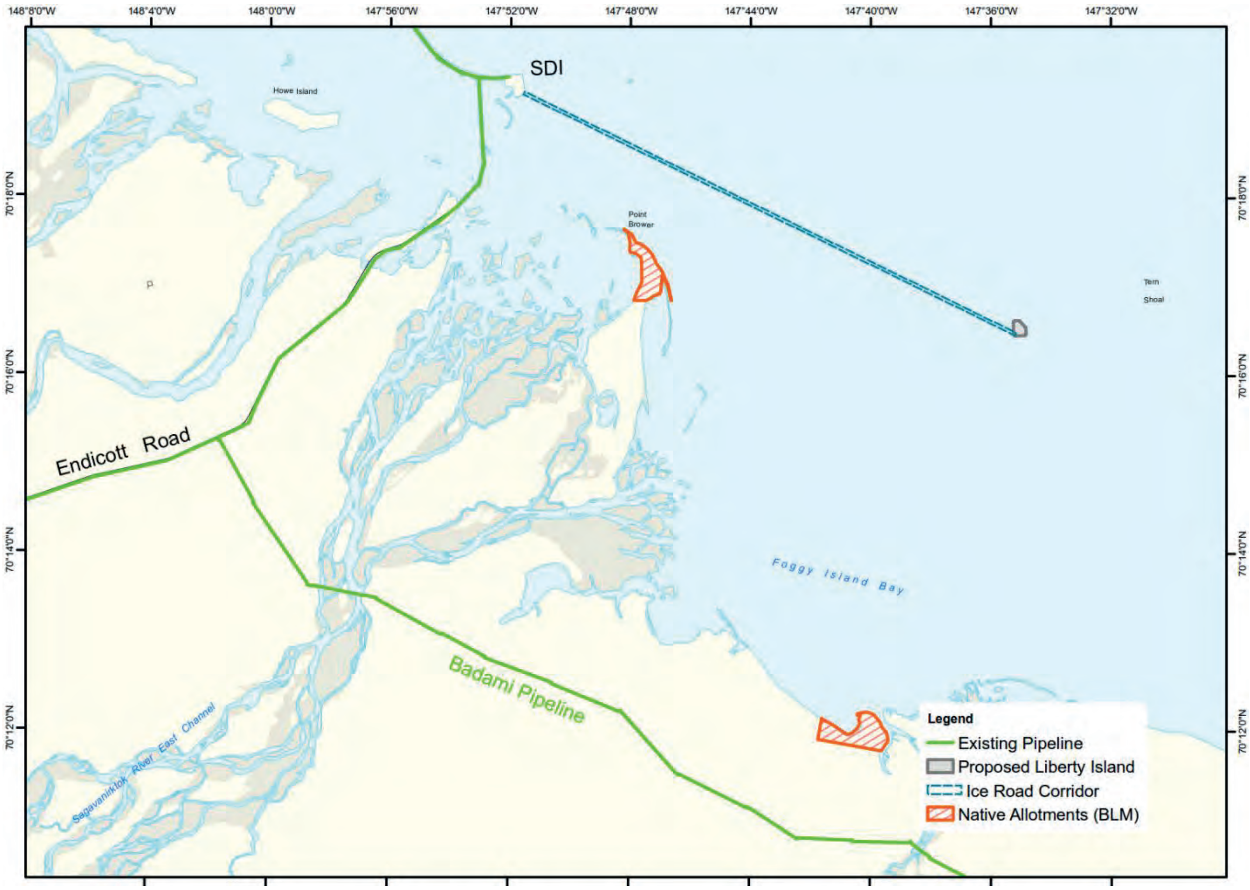


Figure 5-2. Annual Ice Road Corridor for Operations



5.1.3 Marine Access

During the open-water season, barges, hovercraft, and other vessels will be used to transport equipment, personnel, and supplies to LDPI. Large vessels can winter in the Prudhoe Bay area and travel to the LDPI in the open-water season, and will be generally chartered on a seasonal basis or long-term contract. Vessels will include barges and tugs to move large modules and equipment. Smaller vessels will be used to move personnel, supplies, tools, and smaller equipment. Hovercraft will transport personnel and small loads during shoulder seasons when ice roads and open-water vessel support are not available. Arktos™ all-terrain machines will be used for emergency evacuation. The marine routes to move equipment from West Dock (Prudhoe Bay) to LDPI, and to support operations from SDI are shown in Figure 5-3.

Table 5-3 provides descriptions of the types of offshore vessels that are anticipated to be used within 25 miles of the LDPI for construction and oil spill response training activities, drilling support, and routine operations. To date, no specific offshore vehicles have been procured; therefore, the information shown are best-estimates of the types and numbers of offshore vessels that will be used, the time period that each vehicle type will be deployed, the storage capacity of fuel tanks for the specified offshore vessel type, and the frequency of visits to the LDPI.

Figure 5-3. Offshore Marine Transportation Routes

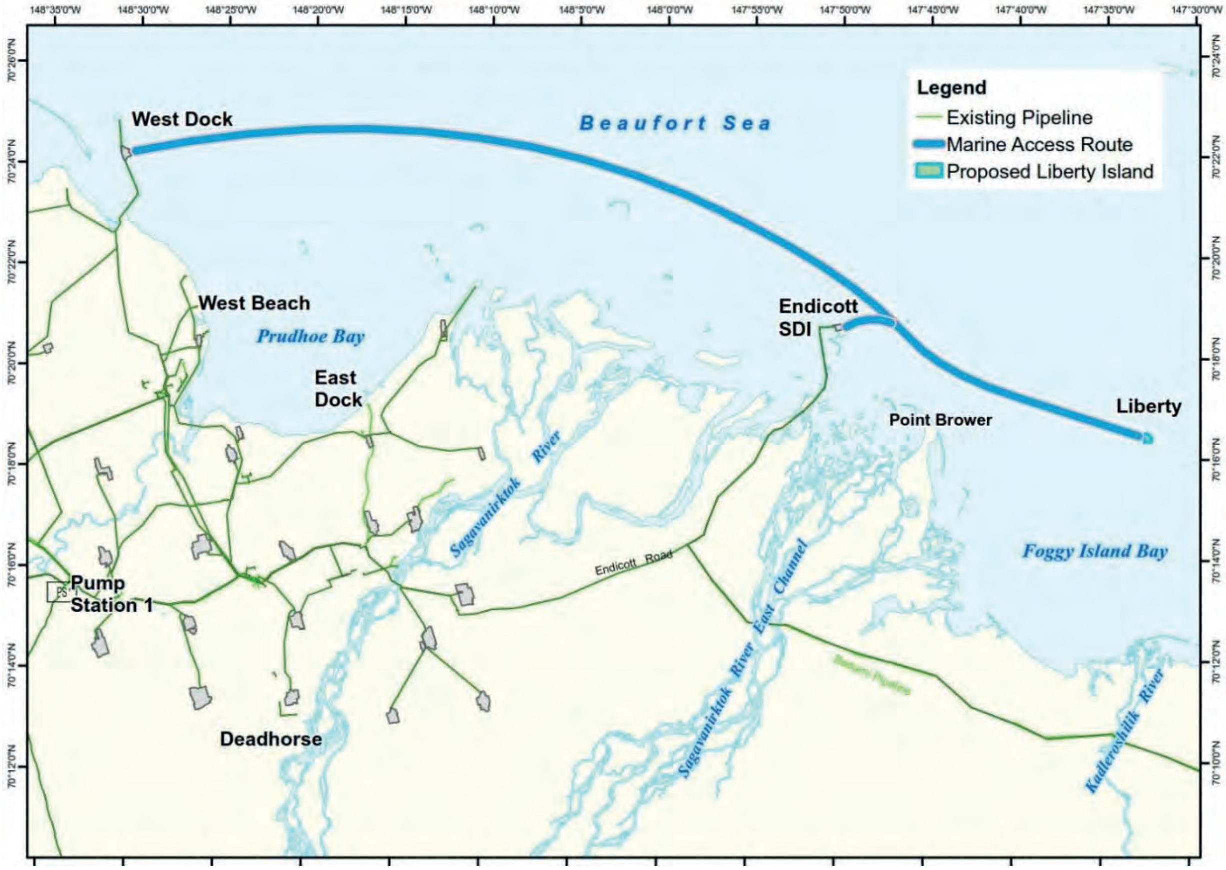


Table 5-3. Estimated Marine Traffic

MODE	Number of vessels	FUEL CAPACITY (ESTIMATED GALLONS)	2015 DATA GATHERING	2016-2019 CONSTRUCTION (TRIPS)	2018 SPILL DRILL (TRIPS)	2016-2020 DRILLING AND OPERATIONS (TRIPS)	BEYOND 2020 OPERATIONS (TRIPS)
OPEN-WATER SEASON FOR VESSELS (Typically July to mid-October)							
Coastal Barge	1 to 2	700		3/day	2/day	20/year	10/year
Assist Tug	1	22,000		3/day	2/day	20/year	10/year
Crew Boat	1 to 2	300		12/day	12/day	2/day	90/year
Bathymetry Vessel	1	300	1 survey	1 survey	1 survey	1/year	1/year
Spill Response Vessels	See marine spread in OSRP	150,000			1 drill per year		

MODE	Number of vessels	FUEL CAPACITY (ESTIMATED GALLONS)	2015 DATA GATHERING	2016-2019 CONSTRUCTION (TRIPS)	2018 SPILL DRILL (TRIPS)	2016-2020 DRILLING AND OPERATIONS (TRIPS)	BEYOND 2020 OPERATIONS (TRIPS)
YEAR-ROUND OPERATIONS							
Hovercraft	1	250		3/day	Up to 6/day	2/day	2/day
Arktos™	2				Demonstration	As needed	As needed

5.1.4 Air Access

Year-round helicopter access to the LDPI is planned, and a helicopter landing site will be constructed on LDPI near the living quarters. Air operations are often limited by weather conditions and visibility. In general, air access will be used for movement of personnel and foodstuffs, and for movement of supplies or equipment when necessary. Helicopter use is also planned for pipeline surveillance, personnel transport, re-supply during the broken ice seasons, and access for maintenance and inspection of the onshore pipeline system. Typically air traffic routing is as direct as possible from departure locations such as the SDI, West Dock or Deadhorse to the LDPI, with routes and altitude adjusted to accommodate weather, other air traffic, and subsistence activities. The aircraft flights will be coordinated between HAK and regulatory agencies to avoid disturbances to biological resources. Table 5-4 shown below describes the type of aircraft and frequency of trips during the construction phase and production operations phase of the project.

No fixed-wing aircraft are planned to support the Liberty Development at this time.

Table 5-4. Estimated Air Traffic

MODE	FUEL CAPACITY (EST. GALLONS)	2015 DATA GATHERING	2016 -2019 CONSTRUCTION (TRIPS)	2018-2021 DRILLING (TRIPS)	BEYOND 2021 OPERATIONS (TRIPS)
Helicopter	400	1/week	1-2/day	2/day	1-2/day

5.1.5 Surface Transportation

Access to the LDPI by surface transportation is limited by periods when ice roads can be constructed and used. Surface transportation to the onshore pipeline can occur in winter on ice roads and can occur in summer by approved tundra travel vehicles. By far, the largest volume of traffic will occur during gravel hauls to create the LDPI.

Table 5-5. Estimated Surface Traffic

MODE	FUEL CAPACITY (EST. GALLONS)	2015 DATA GATHERING	2016 -2019 CONSTRUCTION (TRIPS)	2018-2021 DRILLING (TRIPS)	BEYOND 2021 OPERATIONS (TRIPS)
Surface vehicle[1]	80[2]	--	21,000 per season	400 per season	100 per season

Notes:
1. Surface vehicles: heavy duty diesel trucks, light duty diesel pickup trucks, trimmers, tractors, loaders, and excavators, etc.
2. 80 Gallons is approximate average of the surface vessel described above.

5.2 Access by Project Phase

This section outlines modes of access to the island and along the pipeline corridor during each phase of the project (construction, drilling, and production operations). Air, ice road, and marine access will all be required to support the Liberty project. The Oil Spill Response Plan (OSRP) contains additional detailed information about access logistics and equipment requirements needed to support spill response. Emergency evacuation will be via helicopter, marine vessels, or Arktos™ Vehicles. Prior to starting construction, a detailed evacuation plan will be completed addressing emergency response and evacuation procedures for all phases of the project.

5.2.1 Construction Phase

Construction of the Liberty Development is planned for 40 to 48 months from late in 3Q Execute Year 1 through installation of the last process modules in 2Q Execute Year 5. The project schedule and sequence is seasonal, as it relies on ice roads and the sea ice as a work platform. If certain aspects of the project are delayed by a month, it may mean a year delay in the construction schedule. Project construction is planned in the following sequence once the execution phase begins after approvals and sanction. Note: All years refer to the "Execute Schedule" as described in Section 3 of this DPP.

- Winter of Execute Year 1/2: Build LDPI; haul gravel, install sheet pile wall, and shore protection.
- Winter of Execute Year 2/3: Install subsea pipeline bundle and build LDPI infrastructure.
- Execute Years 3 through 4: Install LDPI process facilities, mobilize drilling unit.
- Late Execute Year 4 or Early Execute Year 5: Commission and start-up process facilities.

The construction work is planned around a number of physical and regulatory constraints, including:

- There is no permanent road access to LDPI or the proposed Liberty gravel mine site west of the Kadleroshilik River.
- Over-the-ocean ice road access to LDPI will be used when ice conditions allow.
- Tundra ice road access to the gravel mine site will be used when tundra travel is allowed. Tundra travel access is granted by the State of Alaska based on the snow and frost depth.
- Barge and boat access to LDPI and SDI will be used when open-water conditions are available.
- Hovercraft access to LDPI is available much of the year.
- Helicopter access to LDPI is available all year, except during high winds or fog. There may be seasonal helicopter restriction due to wildlife or subsistence activity.
- There is year-round gravel road access to SDI and Endicott. Weights and widths along the gravel road are limited by some one-way bridges.
    - o The one-lane Sagavanirktok River Bridge is limited to 115 tons total load/60 tons per axle. Overload permits can be obtained after effects of specific loads are calculated.
    - o The one-lane Endicott Causeway Bridge is limited to 116 tons total load/58 tons per axle. Overload permits can be obtained.
- Truckable modules can be hauled from Fairbanks, Anchorage, other parts of Alaska, and the Lower 48, except during spring road restrictions.
- Operations must avoid risk of impacting bowhead whale migration routes from noise levels in the water above 120 decibels (dB).
- Equipment activity within 1 mile of a known polar bear den is prohibited, without special approval from the U.S. Fish and Wildlife Service (USFWS).
- Operations must mitigate risk of impacts to ice seals.
- Wildlife interaction planning will include specific controls for construction and operations.

Liberty construction will begin in 4Q Execute Year 1 and will continue past start-up and into Execute Year 5. The seasonal nature of access to the offshore LDPI dictates the construction sequence and schedule. In general, ice roads will be used in the winter months, marine vessels will be used in the summer months, helicopters will be used during all seasons, and hovercraft will be used in the shoulder season when ice roads and open water are not available.

During winter construction, workers will access the project area from existing facilities via existing gravel roads and the ice road system. Construction vehicles will be staged at the construction sites, including the gravel mine. Helicopter use during this period may also occur. By spring breakup, all materials needed to support ongoing construction will have been transported to the island over the ice road system. Personnel will access the island during breakup via helicopter or hovercraft. During the open-water season, personnel will continue to access the island via helicopter, hovercraft, or crew boat. Any needed construction materials and supplies will be mobilized to the site by barge from West Dock or Endicott. After start-up in Year 4, the number of helicopter flights needed for personnel transport will decrease.

During breakup and freeze-up, access will be primarily via helicopter and/or hovercraft. In the period between completion of hydro-testing and facilities start-up, an estimated one to two flights per week will be required for access to the pipeline corridor, including personnel and equipment access to the tie-in area. Equipment located at the pipeline tie-in location and the pipeline shore landing will be accessed by helicopter or approved tundra travel vehicles to minimize impacts to the tundra.

5.2.2 Access during the Drilling Phase

After the island is constructed and the drilling area is prepped for drilling operations, a drilling unit will be mobilized to the LDPI. The drilling unit will be mobilized from the gravel road system via barge from West Dock. During the drilling phase of the project, resupply will occur via barge in the summer and via ice road during the winter; this resupply will be integrated with the resupply needed to support construction and production operations. Drilling is anticipated to occur over a span of 2 years.

During the drilling phase, Liberty Development will rely heavily on the ability to store sufficient drilling equipment and consumables at LDPI for the periods of non-supply between the ice road season and the open-water season. It is anticipated that consumables will be resupplied each spring prior to breakup and each fall prior to freeze-up to allow drilling to continue year round. As detailed in Section 8, and in accordance with the OSRP, drilling through the reservoir section will be limited to open-water and frozen ice seasons. However, hole sections above the reservoir section can and will be drilled throughout the year. This will require the supply and staging of drilling consumables during supply seasons, and continuous access by personnel, to support year-round drilling.

5.2.3 Production Operations Access

Once oil production has begun, resupply of personnel and consumables in support of production operations will take on a routine nature of seasonal activities. After project start-up, activities on the island will include routine production operations and equipment maintenance. By 1Q Execute Year 5, drilling is scheduled to be completed, and only production-related activities will occur. In later stages of the project, infill drilling, sidetracks, or rig workovers may occur to increase reserves or repair broken wells. In this case, transportation requirements would be similar to levels experienced during development drilling.

During production operations, aerial helicopter surveillance will be conducted of the offshore and onshore pipeline corridor on a periodic basis. A helicopter landing site will be constructed at the pipeline tie-in pad to allow routine access without the need for gravel road access. During routine production and maintenance operations, visits to the pipeline pads will be based on a maintenance or pigging schedule, or signs of flow upsets.

5.1 Support Vessels and Aircraft

5.1.1 General Information

Table 5-6 and Table 5-7 provide descriptions of the types of offshore vehicles that are anticipated to be used within 25 miles of the LDPI for construction and oil spill response training activities, and drilling support and routine operations, respectively. To date, no specific offshore vehicles have been procured. Therefore, the information in Table 5-6 and Table 5-7 are best-estimates of the quantities of offshore vehicle types that will be used, the time period that each vehicle type will be employed, the storage capacity of fuel tanks for the specified offshore vehicle type, and the frequency of visits to the LDPI.

Table 5-6. Offshore Vehicle Construction and Spill Response Training Activities

DESCRIPTION[1]	QTY[1]	FUEL TANK CAPACITY[2] (GALLONS)	LOCATION	PROJECT YEAR 1		PROJECT YEAR 2		PROJECT YEAR 3		TRIPS TO LDPI[1]
				DURATION (WEEKS)	PERIOD[3]	DURATION (WEEKS)	PERIOD[3]	DURATION (WEEKS)	PERIOD[3]	
Island Construction										
All-Terrain Vehicle	12	10 - 50	Between Gravel Mine and LDPI	17	Q1 - Q2	-[4]	-	-	-	1/year
Bulldozer	3	75 - 125		10	Q1 - Q2	-	-	-	-	1/year
Crane	1	75 - 125		4	Q2	6	Q1 - Q3	-	-	1/year
Excavator	2	300 - 350		10	Q1 - Q2	-	-	-	-	1/year
Grader	4	100 - 150		17	Q1 - Q2	-	-	-	-	1/year
Loader	4	150 - 200		17	Q1 - Q2	6	Q1 - Q2	-	-	1/year
Roller	1	25-75		10	Q1 - Q2	-	-	-	-	1/year
Tractor	24	75 - 125		14	Q1 - Q2	-	-	-	-	2/day
Trimmer	2	50 -100		7	Q1	-	-	-	-	1/year
HDDT[5]	29	50 -100		35	Q1 - Q3	25	Q1 - Q2	-	-	1/year
Pipeline Construction/Installation										
All-Terrain Vehicle	7	10 - 50	Between Badami Pipeline Tie-In and LDPI	1	Q4	20	Q1 - Q2	-	-	1/Year
Bulldozer	3	75 - 125		-	-	19	Q1 - Q2	-	-	1/Year
Crane	31	75 - 125		-	-	15	Q1 - Q2	-	-	1/Year
Excavator	12	300 - 350		-	-	16	Q1 - Q2	-	-	1/Year
Grader	4	100 - 150		1	Q4	20	Q1 - Q2	-	-	1/Year
Loader	11	150 - 200		1	Q4	20	Q1 - Q2	-	-	1/Year
Man Lift	7	10 - 50		-	-	15	Q1 - Q2	-	-	1/Year
Snowblower	3	50 -100		-	-	19	Q1 - Q2	-	-	1/Year
Tractor	4	75 - 125		1	Q4	20	Q1 - Q2	-	-	1/Year
Trencher	4	50 -100		-	-	11	Q1 - Q2	-	-	1/Year
Trimmer	3	50 -100		1	Q4	20	Q1 - Q2	-	-	1/Year
HDDT[5]	79	50-100		1	Q4	26	Q1 - Q2	-	-	1/Year

Table 5-6. Offshore Vehicle Construction and Spill Response Training Activities

DESCRIPTION[1]	QTY[1]	FUEL TANK CAPACITY[2] (GALLONS)	LOCATION	PROJECT YEAR 1		PROJECT YEAR 2		PROJECT YEAR 3		TRIPS TO LDPI[1]
				DURATION (WEEKS)	PERIOD[3]	DURATION (WEEKS)	PERIOD[3]	DURATION (WEEKS)	PERIOD[3]	
Facilities Installation										
HDDT[5]	40	50-100	LDPI	-	-	22	Q2 - Q3	39	Q1 – Q4	1/year
Winter Spill Response Training Exercise										
Rolligon	2	50 -100	Foggy Island Bay	-	-	-	-	1	Q1	-
Snowmobile	12	10 - 50		-	-	-	-	1	Q1	-
Excavator	2	300 - 350		-	-	-	-	1	Q1	-
Loader	2	150 - 200		-	-	-	-	1	Q1	-
Skid Steer	4	10 - 50		-	-	-	-	1	Q1	-
Tractor	2	75 - 125		-	-	-	-	1	Q1	-
Trencher	2	50 -100		-	-	-	-	1	Q1	-
HDDT[5]	11	20 - 250		-	-	-	-	1	Q1	-

Notes:
1. Estimated vehicle type, quantity, and frequency of visits to LDPI. Additional offshore vehicle information is provided in the Air Quality Impact Analysis (EIA, Appendix A).
2. Estimated range of fuel tank capacities for vehicle type.
3. Annual quarter of anticipated offshore vehicle use. Q1= Jan. through Mar., Q2 = Apr. through Jun., Q4 = Oct. through Dec.
4. '-' = Not applicable.
5. HDDT = Heavy-Duty Diesel Truck.

Table 5-7. Offshore Vehicle Drilling Support and Routine Operations

DESCRIPTION[1]	QTY[1]	FUEL TANK CAPACITY[2] (GALLONS)	LOCATION	PROJECT YEAR 3+		TRIPS TO LDPI[1]
				DURATION (WEEKS)	PERIOD[3]	
Drilling Support						
HDDT[4]	4	50 - 100	Between Alaska State Coastline and LDPI	15	Q1 - Q2	1/week
Ice Road Construction / Maintenance						
All-Terrain Vehicle	12	10 - 50	Between Alaska State Coastline and LDPI	22	Q1 - Q2, Q4	1/month
Bulldozer	1	75 - 125		20	Q1 - Q2	1/month
Grader	4	100 - 150		22	Q1 - Q2, Q4	1/month
Loader	3	150 - 200		22	Q1 - Q2, Q4	1/month
Snowblower	1	50 -100		20	Q1 - Q2	1/month
Tractor	6	75 - 125		22	Q1 - Q2, Q4	1/month
Trimmer	3	50 -100		22	Q1 - Q2, Q4	1/month
HDDT[4]	20	50 -100		22	Q1 - Q2, Q4	1/month

Notes:
1. Estimated vehicle type, quantity, and frequency of visits to LDPI. Additional offshore vehicle information is provided in the Air Quality Impact Analysis (EIA, Appendix A).
2. Estimated range of fuel tank capacities for vehicle type.
3. Annual quarter of anticipated offshore vehicle use. Q1= Jan. through Mar., Q2 = Apr. through Jun., Q4 = Oct. through Dec.
4. HDDT = Heavy-Duty Diesel Truck.

5.2 Island Access Air Emissions

This section provides projected emissions of sulfur dioxide (SO_2), particulate matter (PM) in the form of PM_{10} and $PM_{2.5}$, nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) that will be generated by the support vessels, offshore vehicles, and aircraft that will operate within 25 miles from the LDPI. The basis of the emissions calculations is provided in the air quality impact analysis (AQIA) that is being submitted with the EIA in Appendix A of this document. The AQIA contains supporting information including emission unit (EU) ratings, EU manufacturer data, and all proposed emission reduction measures.

Table 5-8 and Table 5-9 provide the projected peak hourly emissions, in pounds per hour (lb/hr), and total annual projected emissions in tons per year (tpy), respectively, from the vessels in the project inventory. The projected peak hourly emissions in Table 5-8 are based on the assumption that each EU operates continuously at maximum capacity for at least 1 hour. The total annual emissions in Table 5-9 are based on the assumption that each EU operates at maximum capacity during each year. Table 5-10 provides the projected emissions over the duration of the proposed project.

Table 5-11 and Table 5-12 provide the projected peak hourly emissions, in lb/hr and total annual emissions in tpy, respectively, for offshore vehicle source groups described in Section 5.1. The peak hourly emissions in Table 5-11 are based on the assumption that each EU operates continuously at maximum capacity for at least 1 hour. The total annual emissions in Table 5-12 are based on the assumption that each EU operates at maximum capacity during each year. Table 5-13 provides the projected emissions from over the duration of the proposed project.

Table 5-14 provides the projected peak annual emissions in tpy and projected emissions over the duration of the proposed project, respectively, for the aircraft described in Section 5.1.

Table 5-8. Support Vessel Projected Peak Hourly Emissions

DESCRIPTION[1]	QUANTITY	MAXIMUM RATING/UNIT[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (lb/hr/unit)				
			SO_2	PM[2]	NO_X	CO	VOC
Routine Vessel Activity							
Hovercraft (Griffon 200TD)	1	355 hp	0.004	0.14	2.33	2.04	0.14
Crew Boat	1	740 hp	0.008	0.28	4.87	4.26	0.29
Tug	1	600 hp	0.006	0.23	3.95	3.45	0.24
Barge	1	1,500 hp	0.015	0.57	9.86	8.63	0.59
Sea Ice Strudel Mitigation							
Tug	1	600 hp	0.006	0.23	3.95	3.45	0.24
Open Water Oil Spill Response Training Exercise							
Response Tug (Response Barge) [3]	1	2,052 hp	0.021	0.79	13.49	11.81	0.81
Response Tug (Storage Barge)	1	1,662 hp	0.017	0.64	10.93	9.56	0.65
Skimming Vessel (42' x 15")	4	990 hp	0.010	0.38	6.51	5.70	0.39
Boom Towing Vessel (34' x 12')	24	700 hp	0.007	0.27	4.60	4.03	0.28
Ignition Vessel (25' x 8')	2	300 hp	0.003	0.11	1.97	1.73	0.12
Residue Collection Vessel (25' x 8')	2	500 hp	0.005	0.19	3.29	2.88	0.20
Large Airboat (30' x 12')	4	700 hp	0.007	0.27	4.60	4.03	0.28
Small Airboat (22' x 7')	4	350 hp	0.004	0.13	2.30	2.01	0.14
Jet Boat with Trailer	2	150 hp	0.002	0.06	0.99	0.86	0.06
Lamor Mini-Max with Power Pack	10	10 hp	0.0001	0.004	0.07	0.06	0.004
Small Airboat (22' x 7')	20	400 hp	0.004	0.15	2.63	2.30	0.16
Large Landing Craft (55' x 18' and 45' x 16')	2	1,000 hp	0.010	0.38	6.58	5.75	0.39
Skimming Vessel (42' x 15")	4	920 hp	0.009	0.35	6.05	5.29	0.36
Boom Towing Vessel (38' x 14')	2	500 hp	0.005	0.19	3.29	2.88	0.20
Boom Towing Vessel (25' x 11')	4	600 hp	0.006	0.23	3.95	3.45	0.24
Support Vessel (32' x 9')	1	500 hp	0.005	0.19	3.29	2.88	0.20
Support Vessel (34' x 11')	1	500 hp	0.005	0.19	3.29	2.88	0.20

Notes:

1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information included in the AQIA provided with the EIA (Appendix A).
2. PM is equal to PM_{10} and $PM^{2.5}$. $PM_{2.5}$ is conservatively estimated to be equal to PM_{10}.
3. Emissions rated were modeled before the OSRP equipment was determined. Four response tugs were modeled. The number of response tugs has been corrected, but the emissions horsepower and emission rates were kept at the four tug emission rates for added conservatism.

Table 5-9. Support Vessel Maximum Projected Annual Emissions

DESCRIPTION[1]	QUANTITY	MAXIMUM RATING/UNIT[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TPY/UNIT)				
			SO_2	PM[2]	NO_X	CO	VOC
Routine Vessel Activity							
Hovercraft (Griffon 200TD)	1	355 hp	0.016	0.55	9.41	8.24	0.56
Crew Boat	1	740 hp	0.012	0.45	7.77	6.80	0.46
Tug	1	600 hp	0.010	0.37	6.30	5.51	0.38
Barge	1	1,500 hp	0.025	0.92	15.74	13.78	0.94
Sea Ice Strudel Mitigation							
Tug	1	600 hp	0.002	0.08	1.33	1.16	0.08
Open Water Oil Spill Response Training Exercise							
Response Tug (Response Barge) [3]	1	2,052 hp	0.002	0.066	1.13	0.99	0.068
Response Tug (Storage Barge)	1	1,662 hp	0.001	0.053	0.92	0.80	0.055
Skimming Vessel (42' x 15")	4	990 hp	0.001	0.032	0.55	0.48	0.033
Boom Towing Vessel (34' x 12')	24	700 hp	0.001	0.023	0.39	0.34	0.023
Ignition Vessel (25' x 8')	2	300 hp	0.0003	0.010	0.17	0.15	0.010
Residue Collection Vessel (25' x 8')	2	500 hp	0.0004	0.016	0.28	0.24	0.017
Large Airboat (30' x 12')	4	700 hp	0.001	0.023	0.39	0.34	0.023
Small Airboat (22' x 7')	4	350 hp	0.0003	0.011	0.19	0.17	0.012
Jet Boat with Trailer	2	150 hp	0.0001	0.005	0.08	0.07	0.005
Lamor Mini-Max with Power Pack	10	10 hp	0.00001	0.0003	0.01	0.005	0.0003
Small Airboat (22' x 7')	20	400 hp	0.0003	0.013	0.22	0.19	0.013
Large Landing Craft (55' x 18' and 45' x 16')	2	1,000 hp	0.001	0.032	0.55	0.48	0.033
Skimming Vessel (42' x 15")	4	920 hp	0.001	0.030	0.51	0.44	0.030
Boom Towing Vessel (38' x 14')	2	500 hp	0.0004	0.016	0.28	0.24	0.017
Boom Towing Vessel (25' x 11')	4	600 hp	0.001	0.019	0.33	0.29	0.020
Support Vessel (32' x 9')	1	500 hp	0.0004	0.016	0.28	0.24	0.017
Support Vessel (34' x 11')	1	500 hp	0.0004	0.016	0.28	0.24	0.017

Notes:

1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information included in the AQIA provided with the EIA (Appendix A).
2. PM is equal to PM_{10} and $PM^{2.5}$. $PM_{2.5}$ is conservatively estimated to be equal to PM_{10}.
3. Emissions rated were modeled before the OSRP equipment was determined. Four response tugs were modeled. The number of response tugs has been corrected, but the emissions horsepower and emission rates were kept at the four tug emission rates for added conservatism.

Table 5-10. Support Vessel Maximum Projected Emissions for Project Duration

DESCRIPTION[1]	QUANTITY	MAXIMUM RATING/UNIT[1]	TOTAL POLLUTANT EMISSIONS (TONS/UNIT)				
			SO_2	PM[2]	NO_X	CO	VOC
Routine Vessel Activity							
Hovercraft (Griffon 200TD)	1	355 hp	0.48	17.80	305.91	267.67	18.31
Crew Boat	1	740 hp	0.36	13.56	232.99	203.87	13.95
Tug	1	600 hp	0.18	6.65	114.34	100.05	6.85
Barge	1	1,500 hp	0.45	16.64	285.86	250.13	17.11
Sea Ice Strudel Mitigation							
Tug	1	600 hp	0.01	0.31	5.30	4.64	0.32
Open Water Oil Spill Response Training Exercise							
Response Tug (Response Barge) [3]	1	2,052 hp	0.002	0.07	1.13	0.99	0.07
Response Tug (Storage Barge)	1	1,662 hp	0.001	0.05	0.92	0.80	0.05
Skimming Vessel (42' x 15")	4	990 hp	0.001	0.03	0.55	0.48	0.03
Boom Towing Vessel (34' x 12')	24	700 hp	0.001	0.02	0.39	0.34	0.02
Ignition Vessel (25' x 8')	2	300 hp	0.0003	0.01	0.17	0.15	0.01
Residue Collection Vessel (25' x 8')	2	500 hp	0.0004	0.02	0.28	0.24	0.02
Large Airboat (30' x 12')	4	700 hp	0.001	0.02	0.39	0.34	0.02
Small Airboat (22' x 7')	4	350 hp	0.0003	0.01	0.19	0.17	0.01
Jet Boat with Trailer	2	150 hp	0.0001	0.005	0.08	0.07	0.005
Lamor Mini-Max with Power Pack	10	10 hp	0.00001	0.0003	0.01	0.005	0.0003
Small Airboat (22' x 7')	20	400 hp	0.0003	0.01	0.22	0.19	0.01
Large Landing Craft (55' x 18' and 45' x 16')	2	1,000 hp	0.001	0.03	0.55	0.48	0.03
Skimming Vessel (42' x 15")	4	920 hp	0.001	0.03	0.51	0.44	0.03
Boom Towing Vessel (38' x 14')	2	500 hp	0.0004	0.02	0.28	0.24	0.02
Boom Towing Vessel (25' x 11')	4	600 hp	0.001	0.02	0.33	0.29	0.02
Support Vessel (32' x 9')	1	500 hp	0.0004	0.02	0.28	0.24	0.02
Support Vessel (34' x 11')	1	500 hp	0.0004	0.02	0.28	0.24	0.02

Notes:

1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information included in the AQIA provided with the EIA (Appendix A).
2. PM is equal to PM_{10} and $PM^{2.5}$. $PM_{2.5}$ is conservatively estimated to be equal to PM_{10}.
3. Emissions rated were modeled before the OSRP equipment was determined. Four response tugs were modeled. The number of response tugs has been corrected, but the emissions horsepower and emission rates were kept at the four tug emission rates for added conservatism.

Table 5-11. Offshore Vehicle Projected Peak Hourly Emissions

OFFSHORE VEHICLE SOURCE GROUP[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (LB/HR/SOURCE GROUP)					
	SO_2	PM_{10}	$PM_{2.5}$	NO_X	CO	VOC
Island Construction	0.16	7.12	6.83	77.47	62.02	5.64
Pipeline Construction / Installation	0.18	5.78	5.31	70.06	36.60	5.08
Facilities Installation	0.03	0.24	0.08	1.70	0.81	0.07
Drilling Support	0.01	0.04	0.01	0.18	0.07	0.01
Winter Spill Response Training Exercise	0.04	1.85	1.73	15.47	10.50	1.37
Ice Road Construction / Maintenance	0.07	2.70	2.52	28.87	20.66	2.22

Note:
1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information included in the AQIA provided with the EIA (Appendix A).

Table 5-12. Offshore Vehicle Maximum Projected Annual Emissions

OFFSHORE VEHICLE SOURCE GROUP[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TPY/SOURCE GROUP)					
	SO_2	PM_{10}	$PM_{2.5}$	NO_X	CO	VOC
Island Construction	0.16	5.95	5.52	63.74	50.28	4.56
Pipeline Construction / Installation	0.19	5.63	5.09	64.07	36.72	4.66
Facilities Installation	0.05	0.42	0.14	3.20	1.58	0.13
Drilling Support	0.01	0.08	0.02	0.40	0.16	0.02
Winter Spill Response Training Exercise	0.003	0.16	0.15	1.30	0.88	0.12
Ice Road Construction / Maintenance	0.09	3.27	3.05	35.21	24.77	2.69

Note:
1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information included in the AQIA provided with the EIA (Appendix A).

Table 5-13. Offshore Vehicle Maximum Projected Emissions for Project Duration

OFFSHORE VEHICLE SOURCE GROUP[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TON/SOURCE GROUP)					
	SO_2	PM_{10}	$PM_{2.5}$	NO_X	CO	VOC
LDPI Construction	0.20	6.37	5.73	67.18	51.87	4.75
Pipeline Installation	0.11	5.06	4.91	60.30	35.51	4.50
Facilities Installation	0.07	0.59	0.19	4.45	2.18	0.18
Drilling Support	0.17	1.21	0.38	6.29	2.50	0.34
Winter Spill Response Training Exercise	0.003	0.16	0.15	1.30	0.88	0.12
Ice Road Construction/Maintenance	2.1	75.9	70.8	816.9	574.6	62.4

Note:
1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information included in the AQIA provided with the EIA (Appendix A).

Table 5-14. Aircraft Projected Emissions Summary

DESCRIPTION[1]	MAKE/MODEL[1]	POLLUTANT EMISSION RATE[1]				
		SO_2	PM[2]	NO_X	CO	VOC
Peak Projected Annual Emissions (TPY)						
Fixed-Wing Aircraft	DHC-6 Twin Otter	< 0.001	0.003	< 0.001	0.015	0.008
Helicopter	AugustaWestland 139	0.07	0.04	0.45	6.98	2.53
Total Projected Emissions for 30-Year Project Duration						
Fixed-Wing Aircraft	DHC-6 Twin Otter	< 0.001	0.003	< 0.001	0.015	0.008
Helicopter	AugustaWestland 139	2.1	1.2	13.4	209.3	75.8

Notes:

1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information included in the AQIA provided with the EIA (Appendix A).
2. PM is equal to PM_{10} and $PM^{2.5}$. $PM_{2.5}$ is conservatively estimated to be equal to PM_{10}.

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6 ARTIFICIAL GRAVEL ISLAND

The Liberty Drilling and Production Island (LDPI) is an artificial island to be constructed in 19 feet of water in Foggy Island Bay in the Beaufort Sea. The artificial island includes strategic placement of approximately 833,000 cubic yards (cy) of gravel, secured with sheet piling, and armored with linked concrete mats. The surface of the island is designed to be 15 feet above sea level with a working surface of approximately 9.3 acres and a design seabed footprint of approximately 24 acres.

A number of structural alternatives to a gravel island were considered for offshore drilling at Liberty, as described in Section 2.2 of the EIA (Appendix A). None were deemed more suitable for the near-shore, relatively shallow water environment of the Liberty Development. As a result, an artificial gravel island was selected as the preferred structure for development of the Liberty reservoir.

Artificial islands in the Alaska Beaufort Sea date back to the mid-1970s. In the last 40 years, eighteen (18) islands have been constructed for exploration and development of oil and gas off the coast of Alaska. The majority of the artificial islands were constructed in shallow water depths less than 20 feet. The two (2) most recent artificial islands constructed in the Beaufort Sea were in approximately 6 feet of water; Oooguruk Island and Nikaitchuq Island. Five (5) artificial islands, including Northstar Island, have been constructed in deeper waters up to 40 feet.

The water depth of the island also contributes to the severity of the environmental factors that affect the island design. The relatively shallow depth of LDPI shelters the island from exposure to severe wave and ice conditions that have been observed at islands in deeper water. Proven armor systems such as sacrificial shores, gravel bags, concrete structures, linked concrete mats, and steel plates were considered for the protection of LDPI. The island will have a sloped armor system that includes linked concrete mats.

A 3-D view of the configuration and conceptual layout of the LDPI is depicted in Figure 1-1. Additional location information is provided in Section 2.3. The island coordinates (AKSP3 NAD83) and design specifications are summarized in Table 6-1 below:

Table 6-1. Design Summary for the Liberty Drilling and Production Island

ITEM	DESCRIPTION
NAD83 Coordinates, Latitude	70° 16' 28.511"N
NAD83 Coordinates, Longitude	147° 35’10.772"W
Surface Dimensions (approximate)	600 by 800 feet
Bottom Dimension (approximate)	892 by 1092 feet
Height (Working Surface)	15 feet above MLLW
Dock Size (included in bottom dimension)	90 by 200 feet
Gravel volume (approximate)	833,000 cubic yards
Concrete Blocks	23,000 blocks

In March 1998, BPXA conducted a geotechnical investigation near the island location (Duane Miller & Associates 1998). Five holes were drilled: one to an approximate 74 foot depth below mudline, and four to about 50 to 58 feet below mudline. Soils types were generally sands and gravels overlain by silts. Additional, partial borings completed in winter of 2014 provided the top 50 foot characteristics of the island location (Golder Associates 2014). Based on this dataset, the island work surface will be overbuilt by a height of 3 feet on the working surface and by 2 feet on the bench surface. This overbuild will compensate for settling and thaw subsidence. In winter 2015, additional borings will be drilled and analyzed to determine soil characteristics. This data will be used to confirm the design basis and finalize construction details affecting the overbuild.

6.1 Island Design Basis

The LDPI design was based on technical and operational issues as well as environmental factors as described in the sections below.

6.1.1 Environmental Factors

The primary forces that will act on the LDPI will be ocean waves and currents, wind, and sea ice. Site-specific studies of ice and oceanographic conditions, including extreme design events, were completed in the preliminary engineering phase. Oceanographic conditions considered include water depth, surge elevations, and tidal oscillation; waves (e.g., heights and periods; maximum significant wave during easterly and westerly storms); and currents (e.g., circulation dynamics, speed beneath ice and in open water). Based on recent oceanographic site-specific mathematical modeling, the storm surge water levels and significant wave heights for return events that span 10 and 200 years were determined. Extreme water levels for the westerly storm events increase from +3.9 feet (MLLW) for the 10-year event to +5.8 feet for the 200-year event. Likewise, the expected 10-year westerly significant wave height of 6.6 feet compares to the 200-year event prediction of 9.1 feet. The mean approach direction of westerly storm waves is 329^{o}T ±30^{o}. Due to limitations on storm-related water level increases, waves arriving from the east are smaller than the north-westerly conditions, with a 200-year easterly event predicted to produce a significant wave height of 6.6 feet. The mean approach direction for easterly storm waves is 082^{o}T ±22^{o}. The 200-year wave and water level is the basis of LDPI design.

The LDPI siting and conceptual design was completed based on the environmental analyses described in the sections below. Site-specific design features are described in Section 6.2, followed by the advantages offered by these features.

6.1.1.1 Ocean Waves and Currents

The wave height predictions for the near shore location of LDPI are substantially less than those expected at other offshore sites, such as Northstar Island. Due to its location beyond the barrier islands and in deeper water, the offshore location of Northstar yields design wave heights that are approximately double those at Liberty. The LDPI site lies shoreward of offshore islands and shoal complexes, including Dinkum Sands, the McClure Islands, and the Stockton Islands. These shoals and islands prevent large waves and deep-keeled ice features from entering Foggy Island Bay and impacting the LDPI.

6.1.1.2 Sea Ice

Sea ice conditions that were factored into the design include ice characteristics, ice thickness, ice movement, and ice pile-up. The Liberty location lies within Steffanson Sound and Foggy Island Bay, protected from large multi-year ice by offshore shoals and barrier islands. For this reason, the ice conditions that will affect the proposed island and subsea pipeline will be limited to first-year ice, rather than the more severe challenges of thick multi-year ice. Ice conditions and design or extreme values considered for Liberty are shown in Table 6-2.

Ice pressures and global ice loads were computed based on the dimensions of the LDPI. The global average ice pressure is determined to be 140 to 160 pounds per square inch (psi). Higher local ice pressures are computed for the sheetpile structures, such as docks and/or barge landings, that could lead to localized sheetpile damage over small surface areas.

Seasonal movement of the sea ice during breakup and freeze-up can cause ice piles to form against the shore and offshore structures. Such events have been experienced in the past within the Liberty Development area. Ten historical ice piling occurrences in the Liberty Development area (Tern Island, Duck Island III, and Jeanette Island) were evaluated. Seven of these events were documented at nearby Tern Island during the 1982 to 1985 period. Most of the pile-up events occurred during freeze-up in October; however, one event occurred during breakup in July. These historical ice pile heights ranged from a low of 3 to 5 feet to a high of 30 to 35 feet above mean sea level, both at Tern Island in 1983 and 1985, respectively.

Table 6-2. Seasonal Ice Characteristics and Design Values for Liberty Development

ICE CONDITION OR PARAMETER	AVERAGE/TYPICAL VALUES	DESIGN OR EXTREME VALUES
Ice type	First Year Ice	Thick first year ice; Consolidated rubble; no multiyear ice
Ice Zone	Landfast ice	Landfast ice
Ice Season:		
Freeze-up	October 21 ±9 days	September 20 to October 25
River Overflood	May 27 ±6 days	June 22 to July 10
Break-up	July 4	
First open water	July 19	
Ice season duration	288 ±10 days	
Open-water season duration	94 ±13 days	
Summer ice invasion	Occur 75% of summers	Two times during early summer
Maximum sheet ice thickness	6 feet	7.5 feet

Site-specific and structure-specific analyses were performed to predict the extent of potential extreme ice encroachments onto the work surfaces of the LDPI. These analyses provide guidance for the establishment of safe buffer zones around the perimeter of the work surfaces where permanent facilities and other critical equipment should not be placed. General guidance suggests a buffer zone width of 40 to 50 feet is appropriate for the LDPI outside of the sheet pile wall. The buffer zone width of 40 to 50 feet, defined as the distance inside the sheetpile wall that should not contain permanent facilities for fear of ice encroachment, was computed based on 10 pile-up events spanning 1981-1985 (Vaudrey 2013). Seven of the ten events were noted at Tern Island, Shell's exploration island that was built in 1982 very near (approximately 1.9 miles from) the site of the proposed Liberty Development and Production Island (LDPI). Given Tern Island's proximity to the proposed LDPI, these events are highly relevant. The buffer zone width was calculated from a precise statistical analysis of surveyed ice features reacting with the designed island cross-section. The buffer zone distance at the island, given the presumed LDPI elevation and cross-section (50-ft bench), was 37 feet for the 100-year ice pile event (Vaudrey 2013). In designing the LDPI, the buffer zone width was increased to 45 feet to be conservative. A similar analysis was performed at the shore crossing, and the buffer zone requirement was determined to be 83 feet; this was increased to 100 feet to be conservative. This buffer zone is useful for accessing and maintaining process equipment, so it serves operational needs as well as minimizes the risk of ice encroachment.

6.1.1.3 Climate Conditions

Climate conditions considered include temperature, precipitation, wind direction, and velocity. According to the American Meteorological Society (AMS), climate change is defined as the systematic change in the long-term statistics of climate elements sustained over several decades or longer (AMS 2000). For Liberty

Development, the environmental features most sensitive to climate change include: sea level rise, air temperature variation, sea ice modification, and permafrost degradation. The expected effects of climate change (e.g., warmer winters, diminished ice cover, thinner ice, extended open-water season, increased storminess) underscore the need for a structural design that can be adapted to projected new conditions, when and where appropriate. Site-specific mathematical modeling techniques (based on historical data) were used to identify trends in: sea level rise, weather and the ice environment, wave conditions during open water, and permafrost degradation. This adaptive design concept was considered in designing the LDPI.

6.1.1.4 Offshore Geology

Offshore geology conditions considered include surficial sediments (type, characteristics), permafrost, and Boulder Patch substrate. The LDPI has been located on bottom substrate of fine sands, soft silts and clay about 6 to 8 feet thick, with a layer of permafrost varying in depth below the seabed. A summer bathymetric and side-scan sonar survey was conducted in summer 2013 and summer 2014, with the objective of characterizing bottom features (e.g., ice gouges) as well as estimating concentration of hard-bottom habitat (Boulder Patch) within the project area. In April 2014, a winter "through ice" seabed reconnaissance was conducted at the island site (Coastal Frontiers 2014). Holes were cut into the ice at 120 locations, and an underwater video camera was lowered to the seafloor and rotated. No Boulder Patch habitat was found at the proposed island site.

6.1.2 Technical Factors

The foundation for new facilities at LDPI will be a combination of pad footings and piles, and will not depend on a permafrost substrate for direct support (as is the case with typical VSMs for onshore pipelines). The data collected from the Northstar facility has provided substantial insight into the effects of thermal settling as well as corrective actions to prevent similar occurrences on LDPI.

The LDPI includes slope armor placed over an above-water bench. At the back of the bench, a vertical steel sheet pile wall approximately 8 feet high will be used. As long-term changes in sea level and wave conditions are evaluated, the island design profile can be modified, if warranted. Island slope profile changes that would be considered to diminish island surface flooding include: raising the above-water bench and/or raising the top elevation of the sheetpile wall. Either or both of these profile changes would reduce wave run-up on the structure and the accompanying wave overtopping, resulting in reduced island flooding potential. To support this future construction, the proposed plan view layout has a large surface area (approximately 9.3 acres) with open space around the work surface perimeter that is capable of supporting future construction efforts to modify the elevation of the bench and sheetpile wall.

6.2 Design Features, Island Structure

The island will be constructed of gravel from the proposed mine site west of the Kadleroshilik River. During the process of construction, sections of sea ice will be cut and removed over the location of the island. Once the ice is removed, gravel will be poured through the water column to the sea floor, building the island structure from the bottom up. A conical pile of gravel will form on the sea floor until it reaches the surface of the ice. The construction will continue with a sequence of removing additional ice and pouring gravel until the surface size is achieved. It is estimated that the footprint of the island at the seafloor will be approximately 24 acres; assuming that the footer of island protrudes 80-100 feet from the above sea level bench. See Figure 6-2 for a profile of the island showing the sea level bench compared to the sea floor surface.

Table 6-3 is a summary of the design dimensions and features of the LDPI.

Island slope protection is required to assure the integrity of the gravel island by protecting it from the erosive forces of waves, ice ride-up, and currents. In addition, by reducing the risk of erosion and associated introduction of sediment into the water column, slope protection offers a means to protect water quality. Linked concrete mat armor has been successfully used at other islands in the Beaufort Sea (see Figure 6-1). As part of preliminary engineering, a large-scale model was created at the O.H. Hinsdale Wave Research Facility at Oregon State University to study various slope armors and profiles. The armor components selected for testing included: linked concrete mat; linked steel mat (below water only); large concrete cubes; AMAX interlocking concrete units; gravel bags (upper slopes); and a steel sheetpile enclosure wall. It was concluded that slope armor types could be combined in hybrid profiles to best utilize their qualities and characteristics, which lead to the design described below.

Table 6-3. Design Summary for LDPI

FEATURE	DESCRIPTION [1]	
Surface Dimensions	Production processing area:	240 ft x 480 ft
	Power generation and control room area:	120 x 180 ft
	Drilling unit, support, and staging area:	240 ft x 360 ft
	Camp and camp utilities area:	120 ft x 300 ft
	Temporary camp and support area:	120 ft x 200 ft
	Relief well drilling area:	120 ft x 240 ft
	Ring Road:	30 ft x 2,560 ft
	Decks and Landing:	100 ft x 200 ft
Height of Working Surface	15 ft above MLLW	
Total Surface Area Total Seafloor Area	9.3 acres 24 acres	
Gravel Volume (approximate)	833,000 cy	
Sheetpile Wall	2,700 LF of Z-Pile Top of sheetpile is +20 ft on east side and +25 ft on west side where storm surge and high waves will be produced by westerly storms.	
Sheetpile around Well Row	1,100 LF of Pipe-Z, top at grade level	
Slope Protection – Concrete Mat	430,000 sq. ft.	

Note:
1. All values (e.g., dimensions, volumes, and areas) are approximate, based on current project design.
Key: cy = cubic yard; ft = feet; LF = linear feet; MLLW = mean lower low water.

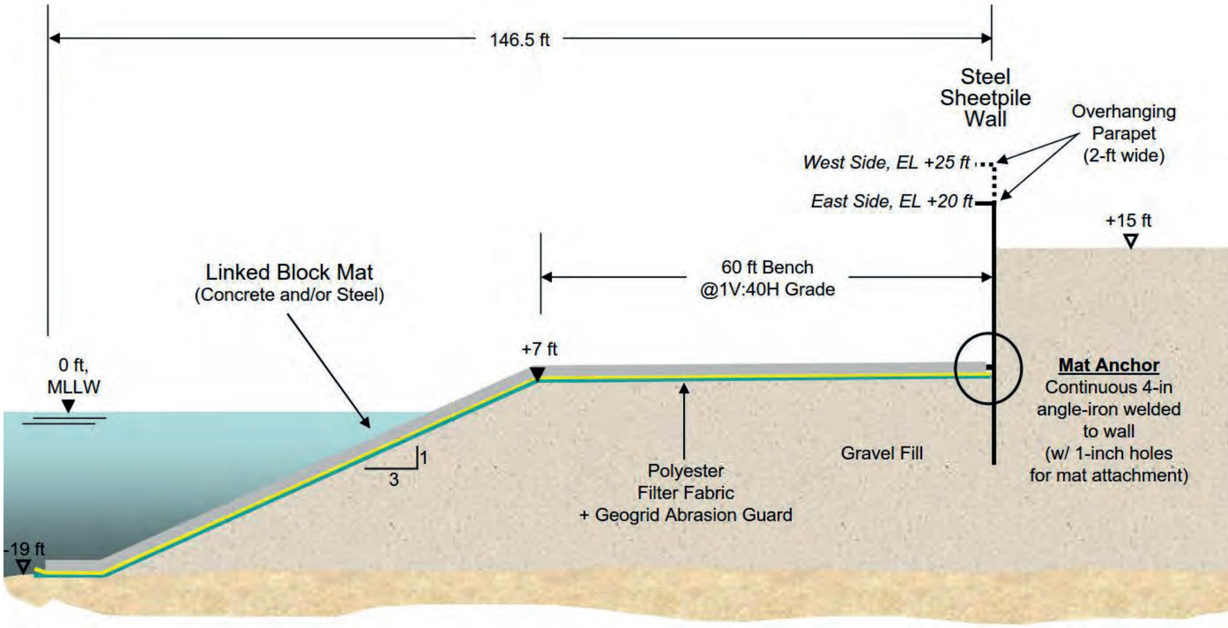
As shown in Figure 6-2, the island will have a working surface elevation of 15 feet above MLLW, with a sheet pile wall rising to 20 to 25 feet above MLLW depending on the side of the island. The slope protection profile includes a 60-ft wide bench covered with linked concrete mat that extends from the sheetpile wall to slightly above MLLW, concrete mat continues to -19 feet, as shown on Figure 6-2. The elevation of the outer edge of the bench subgrade is +7 feet (MLLW). The bench dissipates wave and ice forces and will provide operational support for equipment and personnel around the island for construction, maintenance, spill response, and major incident evacuation. The horizontal distance from the sheetpile wall to the toe of the slope armor measures approximately 150 feet. It is these dimensions that were used to calculate the seabed footprint of the island.

At the back of the 60-foot wide bench, a vertical sheetpile wall is installed. The wall protects the work surface of the island from ice and wave impacts. It also prevents polar bears and other marine mammals from entering the work area. This design is similar to that at Northstar Production Island, constructed by BPXA in 2000. Given the high storm surge and larger waves that are expected to arrive at the Liberty Production Island site from the west and northwest, the wall will be higher on the west side than on the east side. This differing wall height was also implemented at Northstar. Engineering work will be conducted in the Final Engineering phase to confirm the exact height and construction techniques for the sheet pile wall. At this time, the wall elevation on the east side is assumed to be +20 feet (MLLW), and the elevation on the west side is assumed to be +25 feet (MLLW).

The surface of the above-water bench and the submerged slope will be protected by a linked concrete mat system, similar to the armor that protects the slopes at both Endicott and Northstar, as shown in Figure 6-2. Because the island location for LDPI is within the protective shelter provided by offshore barrier islands, the ocean environment will be similar to Endicott, where the linked concrete mat has performed with minimal maintenance since its construction in 1985-86. The Liberty site is not as challenging as the deeper, more exposed Northstar location (39-foot water depth) where concrete mat repair has been required due to damage caused by large waves and thick multi-year ice. The linked concrete mat requires a high strength, yet highly permeable woven polyester fabric under layer to contain the gravel island fill. The filter fabric panels will be overlapped and tied together side-by-side (requiring diving operations) to prevent the panels from separating and exposing the underlying gravel fill. Above the fabric under layer, a robust geo-grid will be placed as an abrasion guard to prevent damage to the fabric by the linked mat armor. At the top of the sheetpile wall, overhanging steel "parapet" will be installed. The parapet is designed to prevent wave passage over the wall in order to reduce wave overtopping rates to acceptable values.

Figure 6-1. Linked Armor on Endicott Island

Figure 6-2. Island Profile



Maintenance procedures designed to inspect for damage and repair such damage will be implemented. An annual inspection will be conducted including a slope protection inspection, a topographic survey, and a bathymetric survey.

1. Slope Protection Annual Inspection: A detailed inspection of the island slope protection system will be conducted during the open-water season to document changes in the condition of the island slope protection system that have occurred since the previous year's inspection. Above-water activities will consist of inspecting the dock and sheetpile enclosure, and documenting the condition of the island bench and Arktos ramps. The below-water slopes will be inspected by divers contracted separately by HAK. The results of the below-water inspection will be recorded and interpreted for repair if needed

2. Topographic Survey: Topographic data on shore-perpendicular profiles on the above-water portion of the island will be obtained using traditional surveying techniques.

3. Bathymetric Survey: Multi-beam bathymetry and side-scan sonar imagery of the below-water slopes and adjacent sea bottom will be acquired. In water too shallow to be accessible by the larger vessel, the condition of the slopes shall be documented by obtaining soundings on a minimum of 28 shore-perpendicular profiles using a single-beam echo sounder operated from a shallow-draft inflatable survey vessel. These transects shall be coincident to those identified in the topographic survey.

Key preliminary findings of the inspection tasks identified above will be developed, particularly those concerning the extent of observed damage and the possible need for maintenance. A report will be prepared that conveys the methods employed and results obtained as part of the inspection. Any damaged mats or sheetpile would be repaired or replaced.

After final engineering is completed and before construction begins, technical review and verification of the island structural design will be completed in accordance with the requirements of 30 CFR 250.909, Platform Verification Program Requirements.

6.3 General Island Shape and Layout

The plan for the LDPI considered a number of factors, including the amount of space required to build facilities, conduct drilling operations, house personnel and equipment, and accommodate a relief well location. Factors that defined the orientation and shape of the LDPI included wave and ice loads, prevailing winds, and access for boats and hovercraft. All of these considerations resulted in a working surface area of 9.3 acres in a basic rectangle shape with a corner removed to minimize the footprint of the island. The island shape is shown in Figure 6-3.

The LDPI will have a helipad for air access. Barges, hovercraft and small boats will land at two (2) designated areas on the island. There will be two docks incorporated into the west and east benches of the island for receiving freight from deep-side shell barges and as well as smaller/shallow draft barges. An access ramp will be provided from one (1) landing area to the island surface for transportation of supplies. Separated from the main landing area, a ramp will be provided for the Arktos™ emergency escape vehicles. Ocean ice roads will transition to the island surface at the landing areas. There is additional space for truck and vehicle access through the center of the island for resupply of drilling and production consumables.

The relief well area is reserved for a second drilling rig and support accessories, and is sized to accommodate expected requirements for responding to a well blowout scenario with a relief well. Accessories include well capping equipment (e.g., front-end loader, large crane, and vacuum truck) and well control contingency equipment (e.g., connex containers, pump units; fire water monitor skids) and required warm storage.

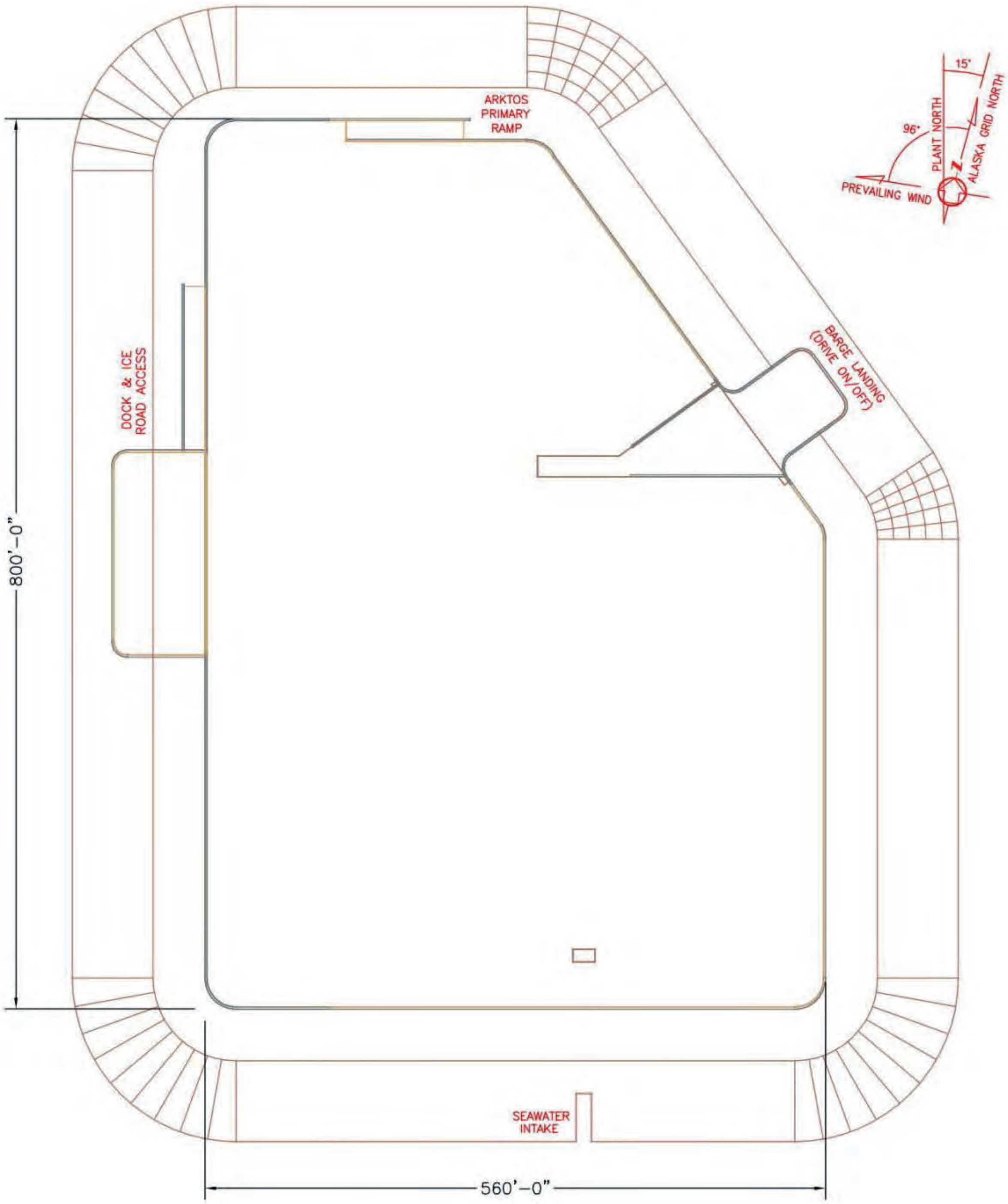
6.4 Design Advantages, Impact Mitigation

The LDPI design presented above has a number of advantages over other design options, as described below.

- Separation of drilling and production facilities from the camp addresses health and safety considerations. The camp area is separated from the production facilities, drilling area and tank farm, and adjacent to the emergency evacuation areas. This location is also crosswind of the Process Area (based on the prevailing wind direction). The accommodations area has been sited perpendicular to the prevalent wind direction and therefore crosswind of oil or gas released from a major upset event or a loss of well control.
- The LDPI work area provides space for storage of well capping response equipment, area for debris removal and storage, camp and utilities infrastructure, spill response staging area, relief drilling rig, and drilling facilities. The dock is available for barge access.
- The helipad is sited on the far north end of the island for air support.
- The well row is aligned parallel to the prevailing wind to allow access to a blowout well from the least-affected side.
- The 15-foot well spacing will help facilitate well capping and allows heavy equipment to access and excavate around wells, as needed, while minimizing effect on neighboring wells.
- Sheetpile wall surrounding the LDPI is intended to deter polar bears from accessing the work surface as well as to prevent equipment and facility damage by encroaching ice sheets.
- The 60-foot wide bench provides an operational work space around the entire island to land small vessels or hovercraft, perform oil spill response activity, and serves as an evacuation route for personnel.
- Bench and sheetpile wall can be modified to respond to climate change induced sea level rise, if required.

- Concrete mat at the base of the island will provide several acres of new hard-bottom habitat that could potentially support colonization of Boulder Patch organisms.

Figure 6-3. Artificial Island Shape



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7 PIPELINE SYSTEM

This section provides a summary of the proposed Liberty pipeline system, based on preliminary engineering to date. Engineering studies of the proposed route and design, and studies of alternative approaches, has confirmed that the proposed system is the best and least impactful way to deliver sales oil crude from LDPI to the market. However, final engineering is ongoing, so some of the details and features described below may be altered prior to submittal of final drawings. Following reviews with the Alaska State Pipeline Coordinator's Office (SPCO) and Bureau of Safety and Environmental Enforcement (BSEE), and completion of final engineering, a detailed design package will be provided in the Application for Pipeline Right-of-Way submitted to the SPCO, and in the Pipeline Right-of-Way application submitted to BSEE.

Sales oil will be exported from the island through a subsea 12-inch x 16-inch pipe-in-pipe (PIP) system that is bundled to a nominal 4-inch coiled utility line, along with an armored fiber optic cable. The utility line will be installed as a contingency for possible future use as a fuel gas delivery line or to allow for a circulation loop with the 12-inch export line for upset conditions. The export line will be a DOT pipeline and the utility line is assumed to be a USDOI flowline.

The offshore pipeline bundle system will extend approximately 5.6 miles from the island to a shore crossing located west of the Kadleroshilik River Delta. The overland segment extends 1.5 miles from the shore crossing to the existing Badami pipeline. The Liberty pipeline will tie into the existing Badami 12-inch oil pipeline, and Liberty oil will be transported to TAPS Pump Station 1 via the Badami to Endicott pipeline network.

7.1 Pipeline Corridor

The proposed pipeline route is shown in Figure 7-1. The route is divided into two segments: offshore and onshore.

The offshore route segment is a nearly straight route from the LDPI to a landfall located about 5.6 miles to the south-southwest of the island. As part of the work conducted to prepare the original DPP in 2000, the offshore route was selected based on bathymetric data, minimizing the route traversing strudel scour zones, avoidance of the Boulder Patch, and on landfall siting criteria. The point of landfall was chosen based on relatively lower coastal erosion rates (long-term rate of 2 feet per year), the need for a high bank, avoidance of archaeological and cultural sites, avoidance of private property, and avoidance of salt marsh. Additional borings in winter and bathymetric and shallow seismic surveys will be conducted as part of final engineering to finalize the exact route and trenching specifications.

The overland route is approximately 1.5 miles long. It extends south to a tie-in with the Badami sales oil pipeline approximately 1.5 miles west of the Kadleroshilik River. The overland route avoids major lakes and intersects the Badami pipeline at a proposed, new gravel pad.

The offshore buried pipeline will approach the island in a trench. A sheet pile corridor will be used to transition the pipeline from the buried offshore mode to the working surface of the LDPI. After construction, the permanent operational right-of-way will include about 37 acres of the OCS, and about 130 acres of State of Alaska lands and waters.

Figure 7-1. Liberty Project Pipeline System, Offshore and Onshore Sections

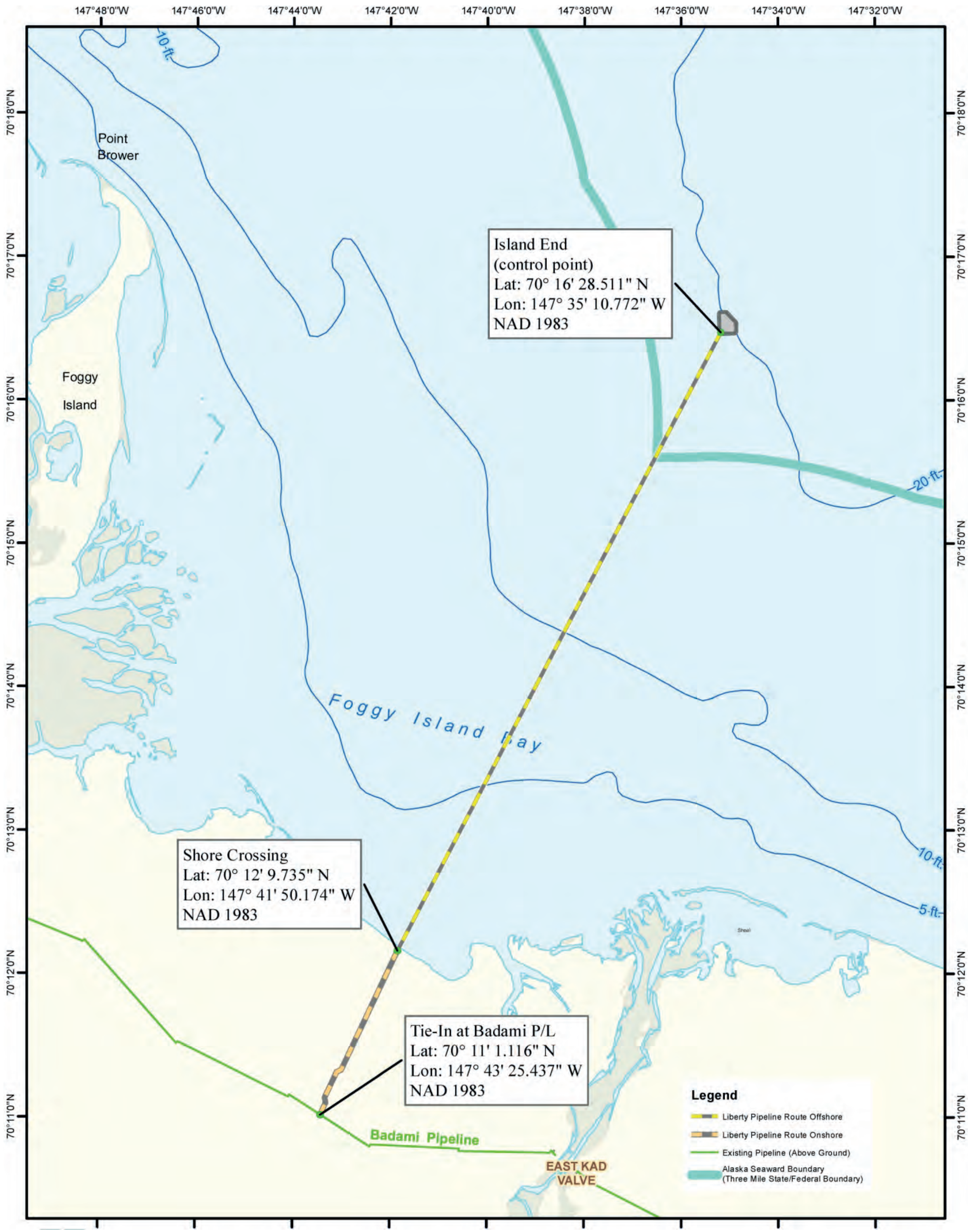
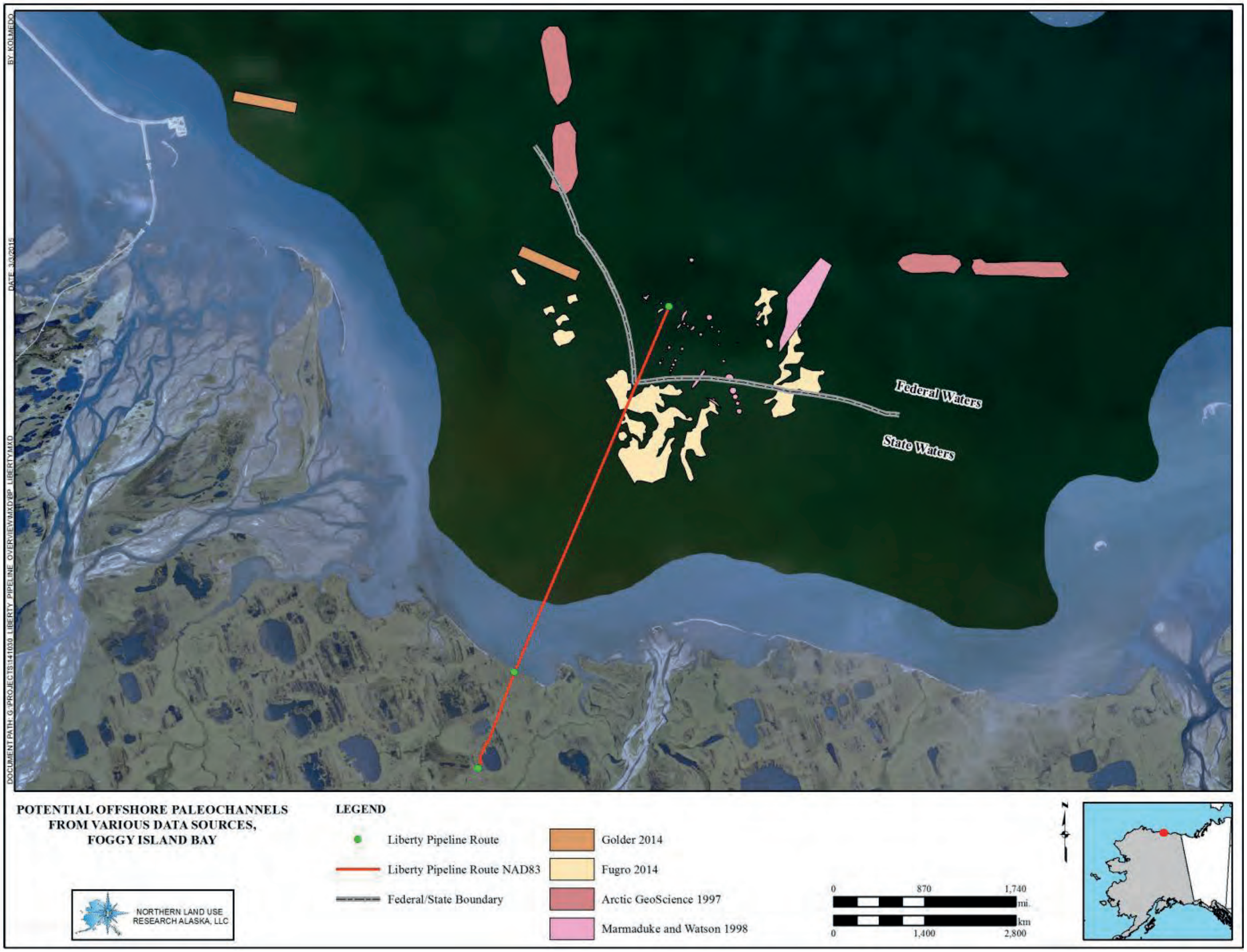


Figure 7-2. Potential Offshore Paleochannels



7.2 Offshore Pipeline Design

7.2.1 Design Basis

Based upon the soil characteristics and the predicted environmental loading conditions along the pipeline route, such as permafrost thaw settlement, seabed ice gouging, strudel scour, and upheaval buckling, the mechanical design of the pipelines will be based on a limit-state design approach. The primary design considerations for limit-state design include critical strains in bending and the burst pressure for individual lines. For example, the compressive and tensile strain limits (engineering critical analysis [ECA] weld flaw sizes) for the pipelines will be evaluated in detail.

The HAK Liberty offshore pipeline limit-state design approach is effectively the same as the previous three offshore limit-state pipeline designs currently in operation in the Alaskan Beaufort Sea. However, these prior projects were either installed before the latest DOT requirements were drafted (Northstar) or are classified as a flowline (Oooguruk, Nikaitchuq) and not subject to DOT regulation. The Liberty pipeline will be a DOT pipeline, and as such there may be special federal permit requirements for limit state or strain-based design of the offshore pipelines. The Pipeline and Hazardous Material Safety Administration (PHMSA) currently has no published requirements for using strain-based design for offshore pipelines. However, the HAK Liberty project will provide PHMSA with a strain-based design plan for review.

Historical local and regional data are being used for the purpose of ice gouge and strudel scour design for 100-year exceedance probability events. The preliminary target trench depth range is 11 feet to 13 feet with a minimum 7.5 feet of depth of cover to the top of the pipe. Analyses will be performed for ice gouge, strudel scour, and permafrost to evaluate the maximum strain in the pipelines over this trench depth range. Approximately 7 feet is the estimated maximum trench bottom width. The physical parameters of pipeline design are further described below.

The offshore mechanical design for the bundle is required to be in accordance with the codes identified in Table 7-1.

Table 7-1. Pipeline Tasks and Governing Codes

TASK	GOVERNING CODE
Pipeline Design and Operation	ASME B31.4, ASME B31.8, 49 CFR Parts 192 and 195 and API RP 1111
Pipeline Manufacturing	API 5L, API 5LCP, and NACE MR-0175
Cathodic Protection Design	DNV-RP-F103 and ISO 15589-2
Pipeline Installation	ASME B31.4, ASME B31.8 and API RP 1111

Key: API = American Petroleum Institute; ASME = American Society of Mechanical Engineers; CFR = Code of Federal Regulations; ISO = International Standards Organization; NACE = National Association of Corrosion Engineers.

7.2.2 Upheaval Buckling

Trenched pipelines operated at elevated temperatures and pressures are potentially subject to vertical instability resulting in the pipe lifting above the trench bottom. The action of strudel scour or ice gouging can expose pipelines in extreme cases and has been taken into consideration for the depth of cover for the pipeline bundle, material selection, and bundle configuration. If such upheaval buckling occurs, the pipelines could experience bending strains that exceed their critical design strain limits for local pipe body buckling and weld fracture. If significant uplift occurs and the pipelines rise out of the trench, they may be exposed to other environmental loads such as moving sea ice. Potential upheaval buckling forms the basis for much of the operational monitoring requirements. HAK believes that the likelihood of upheaval buckling is low based upon the implementation of temperature monitoring and leak detection programs.

The existence of subsea pipelines in the Arctic operating with no occurrence of upheaval buckling to date is due to similar design and monitoring programs. Nevertheless, a potential event will be incorporated into the design basis. Monitoring of the pipeline through a proactive pigging program, a fiber optic distributed temperature sensing system, and leak detection systems will help minimize this risk.

There are currently three subsea pipeline systems installed and operating in the Beaufort Sea: Northstar, Oooguruk, and Nikaitchuq. Each has been operated successfully without occurrences of upheaval buckling. These pipeline systems are similar to the proposed Liberty pipeline in that they are in relatively shallow depths and are close to shore. Because they are similar to Liberty they provide a significant experience base for the design, installation, and operation of the Liberty pipeline (Lanan 2011).

Upheaval buckling is a design issue that is not unique to the Arctic, although the lower temperatures of the Arctic create a higher differential temperature and differential pressure between installation and operating conditions that may increase the risk of upheaval buckling (Paulin 2014). Upheaval buckling occurs because of the introduction of axial compressive forces caused by the constrained expansion set up by thermal and internal pressure actions, and has been frequently documented for offshore pipelines. Generally, the Alaskan Beaufort seabed conditions include ice-rich permafrost found nearshore to water depths of approximately 5 feet (Lanan 2011). Remnant subsea permafrost may be found at varying depths below the mudline beyond the 5-foot isobath. Increased risk of thaw settlement and/or frost heaving may be caused by underlying permafrost conditions, resulting in an increase in the risk of upheaval buckling (Paulin 2014). Combined with other factors related to pipeline profile during construction, there could be an increase in the risk of upheaval buckling for Arctic pipeline systems. Problems associated with upheaval buckling may include high bending stresses and loss of protective solid cover, but may not directly cause a leak or exceed other limit states. Installation procedures are a primary consideration to minimize the risk of upheaval buckling.

The Northstar pipeline design and trenching requirements were primarily controlled by seabed ice gouging for deeper waters outside of the Beaufort Sea barrier island and permafrost thaw subsidence for shallower areas (Lanan 2011). The minimum depth of cover was 6 to 9 feet, and the maximum water depth was 37 feet. Upheaval buckling and strudel scour load conditions were generally not found to control the trench depth requirements. Pipeline surveillance and monitoring programs for the Northstar system include annual seabed bathymetry surveys to measure seabed depression over the pipeline trench, strudel scour, etc. and periodic 3-D inertial geometry pig inspections, which measure the pipeline geometry profile as it passes through the line and may detect potential pipeline stresses. Over the life of the project, observed seabed depression was a maximum of 1.46 meters relative to the surrounding seabed (Paulin 2014). However, up to 0.61 meters of seabed permafrost thaw subsidence was anticipated in the design. Increased subsidence in the deeper water areas can be attributed to both thaw settlement as well as the thaw bulb expanding deeper than predicted. Northstar also has a LEOS leak detection system included in the pipeline bundle which contains a semi-permeable tube capable of detecting very small hydrocarbon leaks.

The Oooguruk flowline system was installed in a single bundle (pipe-in-pipe design) in a maximum water depth of 7 feet, and with a minimum depth of cover of 6 feet (Lanan 2011). Controlling design criteria for this flowline system was minimizing the thermal effects on winter sea ice and the prevention of upheaval buckling through minimum trench backfill thickness and greater trench bottom prop heights. A fiber optic cable distributed temperature sensing system was installed for real-time monitoring of potential flowline bundle exposure. Leak detection in the Oooguruk flowline bundle is provided with multiple flow monitoring and supplemental hardware based systems on each line. The annulus vacuum pressure is monitored, and the fiber optic cable distributed temperature sensing system is used for additional monitoring. These monitoring systems allow the definition of alarm thresholds that can indicate leaks and potential changes of the burial condition. Monitoring also includes summer seabed surveys and periodic 3-D inertial geometry pig inspections.

The Nikaitchuq flowlines were also installed in single bundle (pipe-in-pipe design) and the overall system is similar to that of Oooguruk. The maximum water depth of the Nikaitchuq flowline system is 10 feet, with a minimum depth of cover of 8 feet. The Nikaitchuq flowline route passes through a subsea shoal area with frozen soil extending approximately 20 feet below the mudline, and subsea permafrost is located along the route and at the shore crossing location. Avoiding upheaval buckling was a controlling criterion for defining the depth of cover and required trench backfill thickness. Similar to the proposed Liberty pipeline, the Nikaitchuq flowline system was based on a limit-state design approach, with the primary design considerations including critical strains in bending and the burst pressure for individual lines. Leak detection in the Nikaitchuq flowline system is the same as used by the Oooguruk system.

The proposed Liberty pipeline is similar to that of the three existing Beaufort Sea subsea pipelines. Minimum backfill thickness is planned at approximately 7.5 feet, and the maximum water depth is approximately 19 feet. The proposed Liberty pipeline employs a pipe-in-pipe design and a fiber optic cable distributed temperature system to provide monitoring. The annulus pressure will be continually monitored to provide secondary leak detection. Monitoring will also include annual surveys and three types of intelligent inspection pigging (See Sections 7.6.2 and 7.9). Pipeline thaw settlement is estimated at approximately 0.6 feet based on a predicted thaw bulb growth of approximately 64 feet after 30 years of operation. The final pipeline and construction design will be based upon final geotechnical reports and final modeling results.

7.2.3 Ice Gouging

Ice gouges are caused by irregular ice keels beneath the floating pressure-ridge sea ice and other isolated ice features that contact the seabed. Using methods similar to those used on previous projects, including Northstar, an ice gouge depth based on the 100-year event will be calculated. The pipeline bundle depth of cover will be sufficient to limit the resulting pipeline strains due to a 100-year ice gouge depth within allowable limits. Graphical and analytical probabilistic analyses as well as a non-linear finite element analyses will be performed to evaluate pipeline integrity in the event of a maximum 100-year return gouge depth.

The 100-year event will be calculated using existing and future data sets. Vaudrey (2013) used historical data dating back to 1972 to perform a statistical analysis on extreme values of ice gouges. Calculations for the Liberty area suggest a 100-year gouge depth of 3.5 feet and a 1000-year gouge depth of 4.5 feet. Figure 7-3 shows historic ice gouge locations in proximity to the proposed pipeline.

7.2.4 Strudel Scour

Strudel scour is caused by springtime river floodwater draining through holes or discontinuities in the landfast sea ice. Powerful strudel jets can develop at the drain sites and create scour depressions in the sea floor that could affect the buried pipeline bundle. Strudel scours are identified to be a risk in the Liberty Development project area, and are a significant design consideration for upheaval buckling and pipeline spanning. The 100-year event can be calculated using existing and future data sets. Vaudrey (2013) considered strudel scour and ice gouge data, dating back to the early 1980s. His data was not site-specific but encompassed data from the present Liberty area, the mouth of the Sagavanirktok Delta, and the Northstar (Kuparuk River) area. By including the Sagavanirktok River data, deeper strudel scours were considered in the analysis than would be encountered along the proposed Liberty pipeline route. The only site-specific data collected to date along the proposed Liberty pipeline route was collected by Coastal Frontiers in 1997 (41 strudels, max depth = 7.8 feet) and 1998 (17 strudels, max depth = 3.5 feet). However, when Vaudrey broadened his database to include offsite data (e.g., Sagavanirktok River mouth), the 100-year scour depth was 32 feet and the maximum horizontal dimension (the breadth of the scour on the seabed) was estimated to be 850 feet for the 100-year event. This was based on the statistical analysis of actual strudel scour measurements, including data that was distant from the present Liberty pipeline route.

The site-specific database will be broadened in the future with annual surveys conducted during the summers of 2015, 2016, and 2017, which will then total 5 years of data (when combined with the 1997 and 1998 data).

Although strudel scour depths in excess of 20 feet have been documented in Foggy Island Bay, the maximum scour depth among the 16 features measured within one nautical mile of the proposed pipeline route during the late-1990s was 3.5 feet. While a strudel of this depth would not expose the pipeline bundle, it could remove backfill over a pipeline prop (grade inconsistency) that could cause the pipeline bundle to uplift (see Upheaval Buckling). Figure 7-4 shows the locations of strudel drainage features and strudel scours mapped in the project vicinity. Additional site-specific surveys will be carried out annually to further evaluate site-specific strudel scour risk, and appropriate mitigation efforts will be implemented as warranted.

Recent observations suggest that strudel scours can infill naturally after one or more open-water seasons. The average infill rate among 39 relict scours investigated nearby off of the Sagavanirktok River Delta in 2014 was 5.0 ft/yr. Infilling varied from negligible to nearly 13.0 ft/yr, and was loosely correlated with water depth (with higher infilling rates typically occurring in shallower water).

Because river overflood onto the sea ice is a necessary condition for strudel scouring, an assessment of past overflood events can be used to evaluate the risk of strudel scour potential along the proposed pipeline route. Although the extent of river overflood varies significantly each year, sufficient information exists to statistically characterize the annual magnitude of overflooding in the project area. Figure 7-4 illustrates the probability of river overflood occurrence in the Liberty project area. The isolines of annual occurrence are based on an analysis of 21 years of mapped river overflood limits spanning the period from 1973 to 2014. The results indicate that overflood water may not reach the pipeline in some years, but could impact as much as 3.6 nautical miles of the alignment during extreme events.

Water depth also plays a key role in strudel scour formation, with the highest frequency and severity of scour formation occurring in water depths ranging from about 5 to 10 feet. In water depths less than about 5 feet, the presence of bottomfast ice typically prevents the occurrence of strudel drainage until late in the overflood period, and any resultant scouring tends to be milder. Based on the NOAA contours and the results of the 1998 Liberty Pipeline Route Survey Program, about 2 nautical miles (~40% of the entire proposed pipeline length) lies within the boundary of the maximum overflood limit and the 5-foot contour. The proposed route was selected in part to minimize the exposure to the primary strudel zone.

Site-specific overflood exceedances, based upon 21 years (1973, 1981, 1983, 1986, 1997-2013) of data, as well as strudel locations can be seen in Figure 7-4.

Figure 7-3. Ice Gouge Locations in Proximity to Proposed Pipeline

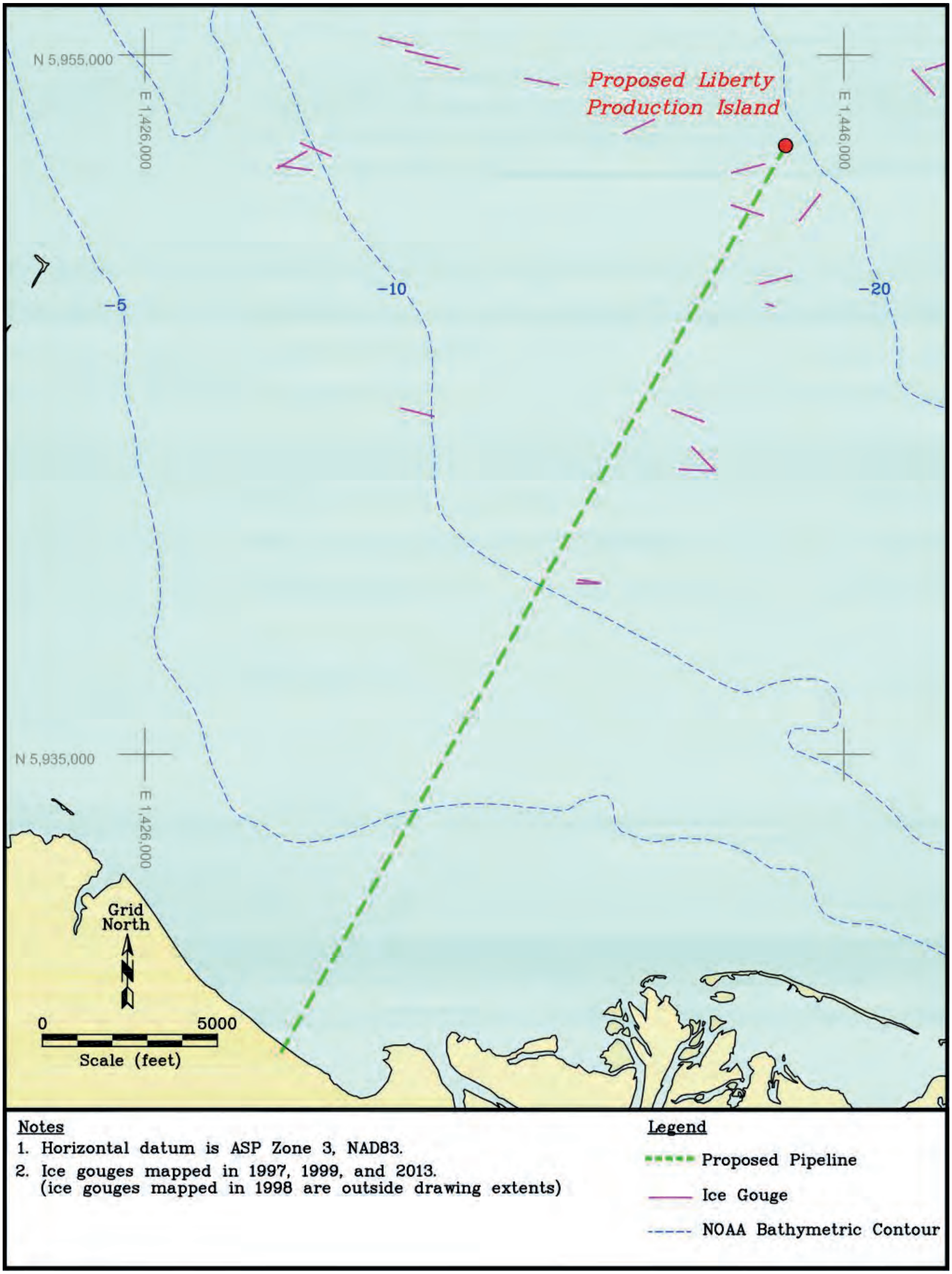
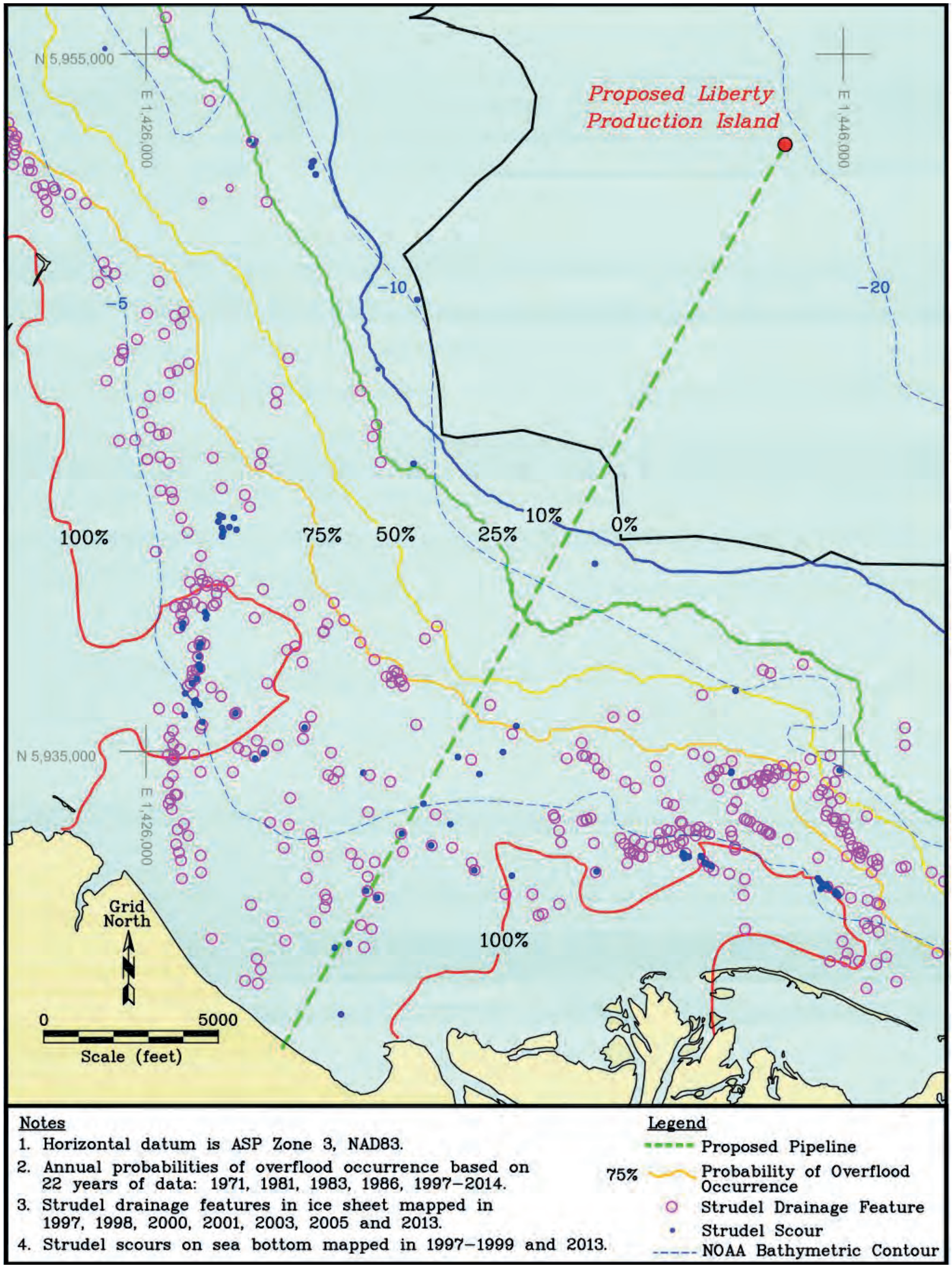


Figure 7-4. Surveyed Strudel Scour Locations with Overlay of Pipeline Route

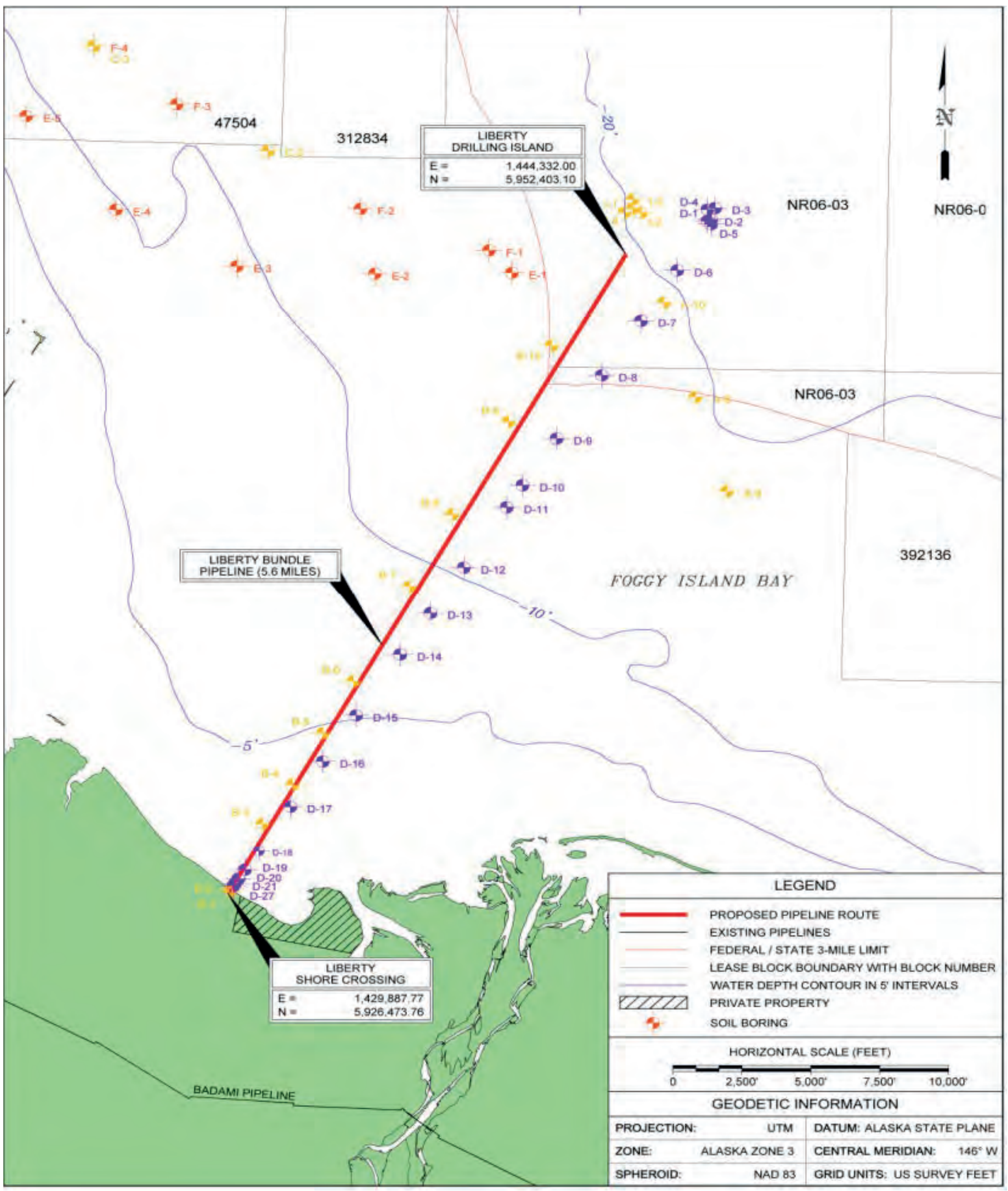


7.2.5 Geotechnical Data

Liberty Field geotechnical and geophysical programs have been conducted in the past to assess the soil conditions at previously proposed island sites and along potential routes. The existing relevant boulder and kelp patch habitat and boring data sets for the Liberty project are listed and briefly described below.

Boulder and cobble concentrations are found in the area of Liberty project site in Foggy Island Bay. This area is referred to as the Boulder Patch. The HAK proposed Liberty pipeline route will avoid the Boulder Patches as much as practicable. In the past, geotechnical data has been collected in and around the proposed pipeline route corridor. Two of the datasets (B and D) were collected along previous marine pipeline alignments that were very similar in geometry and location to the proposed pipeline corridor, and boring locations for both data sets can be seen in Figure 7-5.

Figure 7-5. Boring Locations



The first boring dataset consists of the 'B' borings, collected in 1997. There are 12 B borings collected in close proximity from shoreline to approximately 4.76 miles along the route towards the island. The second boring dataset consists of the 'D' borings, collected in 1998 There are 14 D borings collected in close proximity of the proposed alignment spanning the entire length of the route. The B borings were drilled to depths ranging from 10-ft to 50-ft below seafloor, and the D borings were drilled to depths ranging from 15-ft to 75-ft below seafloor. The deeper borings were drilled at the Island location. The borings along the route generally were drilled to a 30-ft depth. Additional borings will be collected in 2015 and will go to a deeper depth (~75 feet) below mudline.

7.2.5.1 Soil Boring Set B

- (B-1, B-1A, B-2) – These onshore/nearshore borings contain bonded permafrost throughout the entire depth of the bore.
- General: The boring set B hole locations can be seen in Figure 7-5.

7.2.5.2 Soil Boring Set D

- (D-1 through D-6) – These borings are generally to the east of the proposed alignment. The seafloor is relatively flat and divided into three layers: the upper silt layer, intermediate clay/silt, and underlying granular sand/gravels. Geophysical records indicate a soft layer may extend out to the south. At the D-6 boring location, a 6-ft thick layer of soft silt was found.
- (D-6 through D-11) – The seafloor gently rises from -22 feet to -15 feet. Soils consist of sand, silty sand, some soft silt, and pockets/layers of peaty soil. A shoal is located just south of D-8 and consists of a uniform fine-grained, clean sand. The shoal is 4.5 feet thick and appears to extend along the alignment for about 1,400 feet.
- (D-11 through D-13) – The seafloor rises from -15 feet to -7 feet at a gradient of 0.3%. This increase in slope may represent an intermediate coastline or small drop-off. Boring D-12 on the slope shows silty sand interbedded with a medium stiff silt to a depth of 10 feet. Stiff silt is found below that depth with sandy gravel appearing at a depth of 16 feet.
- (D-13 through D-20) – The seafloor rises only 3 feet between these boring locations. Throughout this section, the dominant material is silty sand with thin interbeds of silt and thin organic rich layers. At borings D-16 and D-17, the underlying gravelly sand is shallower than 10 feet.
- (D-21 through D-27) – Soil at the shoreline transition consists of a thin surface layer of sand and soft silt with the underlying sand and gravel at shallow depths of 5 to 6 feet. Boring D-21, drilled only 230 feet from shore, contained marginally frozen soils. Boring D-27 contained 2.7 feet of bottom-fast sea-ice and the soil was well frozen but with little thaw strain potential.
- General: With exception to the near shore borings, no frozen soils were encountered at any location along the D soil boring offshore pipeline route. However, the deeper borings drilled in 1997 and 1998 showed conditions that would suggest that the material beneath the alignment could be ice bonded. The D boring hole locations can be seen in Figure 7-5.

7.2.6 Permafrost Thaw Settlement

Permafrost is defined as soils (onshore or offshore) that remain below 32°F for at least 2 years. Because the freeze point of the pore water in marine sediments is less than 32°F due to its salinity, "permafrost" may not necessarily contain frozen ice. The following discussion therefore relates to thaw-sensitive ice-bonded subsea permafrost. Permafrost can range in thickness from less than a few feet to greater than 3,000 feet. Thaw-stable permafrost contains little or no ice and is typically found in bedrock, or in well-drained, coarse-grained sediments such as sand and gravel. Thaw settlement associated with thaw-stable permafrost is minor. Thaw unstable permafrost is found in poorly drained, fine-grained soils such as silts and clays, and can contain large amounts of ice. Thawing of ice-rich permafrost can result in loss of soil strength, excessive settlement, free-standing water, and accelerated surface erosion onshore or at shore crossings. Irregular, discontinuous ice-bonded permafrost soil conditions might be present within the pipeline depth of thermal influence. When the pipeline bundle becomes operational and the temperature of the pipelines increase, warming of the surrounding soil will create a thaw bulb. The extent of the thaw bulb, the soil type, moisture content, and the stratigraphic profile are the primary factors that determine the potential for differential thaw settlement along the pipeline alignment.

Permafrost was observed in the onshore soil borings and the borings in the nearshore area. Bonded ice was observed 45 feet below the seafloor at a previous 1990s drillsite island location. The borings at a previous island location are in approximately 18- to 20-ft water depth. Further geotechnical investigation will be conducted in the 2014-15 winter work season to increase the accuracy of the geothermal modeling.

Geothermal modeling was used to predict the growth of the thaw bulb around the buried offshore pipeline bundle over the design life of the project. Input data for the geothermal model prediction included pipeline configuration, pipeline burial depth, pipeline operating temperature, climate (ambient temperatures and snow depths), sea depth, and soils data from previous boreholes. Soils data included stratigraphy, soil texture (USCS), soil moisture content, density, salinity, and whether the soil is ice-bonded. Ambient temperatures were assumed to continue to warm at approximately 12 °F per century over a 30-year pipeline design life. The modeling predicted that the thaw bulb is likely to extend approximately 64 feet below seabed after 30 years using assumed soils data. Boreholes to be drilled during March/April 2015 are planned to be drilled to 75 feet below seabed. When data from the March/April 2015 boreholes and laboratory test data are available, the thaw-bulb growth and thaw settlement prediction will be updated. Finite element analyses will be performed to estimate the maximum strain in the pipelines in the event that the bundle is exposed to loading from the design permafrost thaw settlement.

7.2.7 Trench Volume and Stability

The volume of material that can be excavated from a trench with unrestrained stable side slopes depends on soil type. The borings and geotechnical data used in this analysis comprise a collection of historical and more recent data being collected during the winter of 2014-15 in proximity to the proposed route. The estimated excavated trench volume for the entire route length based on the estimated slopes is approximately 480,000 cubic yards (cy). These preliminary findings will be re-evaluated when the 2015 geotechnical survey data are available.

In order to determine if an unrestrained slope is stable, it is necessary to compare the shear stress developed along the critical failure surface to the shear strength of the soil. This process is called slope stability analysis, as shown in Figure 7-6.

The predominant soil profile within the excavated trench profile (0 - 13 feet) can be generalized as sands and silts with varying degrees of intermixing (sandy silts and silty sands). For the purpose of this slope stability and excavated trench volume analyses, the stratigraphy and geotechnical soil behavior is considered similar and continuous for the entire length of the pipeline route.

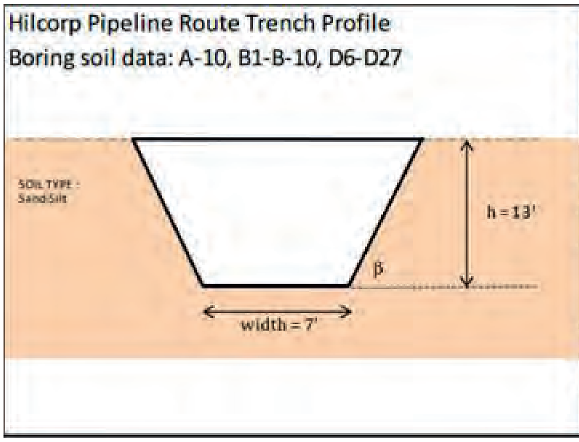
Although minor variations of the general soil profile are observed at isolated locations along the route within the historical boring dataset, the influence of these variations is considered negligible and the profile used for the slope stability analyses is considered conservative. Conservative means the estimated excavation volumes should be greater than expected. For further soil parameter definition and confirmation, future boring data collection along the route alignment will further enhance the assessment of geotechnical parameters and, thus, refine the slope stability assessment. Refer to Table 7-2 for the summary of the trench volume and trench dimensions

Table 7-2. Preliminary Trench Wall Slope and Volume Calculation Results

BORING SOIL DATA	SOIL TYPE	TRENCH HEIGHT (ft)	TRENCH BOTTOM WIDTH (ft)	TRENCH LENGTH (ft)	WALL SLOPE (degree)	TRENCH VOLUME (ft^3)	TRENCH VOLUME (cy)
A-10, B1-B-10, D6-D27	SP-SM	13	7	29,674	26	12,982,240	480,824

Key: cy = cubic yard; ft = feet; ft^3 = cubic feet.

Figure 7-6. Slope Stability Analyses



Input - Soil Type (SP-SM)			
cohesion	c'	psf	0
soil friction	ϕ'	degrees	30
unit weight	γ	pcf	124
salt water UW	γ_w	pcf	64
submerged unit weight	γ'	pcf	60
Factor of Safety	FS		1.24
Trench depth	h	ft	13
Tan ϕ'/FS			0.47
Output	β	degrees	**26**

7.2.8 Climate Change Considerations for Design

Climate change has been defined as systematic change in the long-term statistics of climate elements (e.g., temperature, precipitation, wind) sustained over several decades or longer (AMS 2000).The expected effects of climate change will be considered (i.e., warmer winters, diminished ice cover, thinner ice, extended open-water season, increased storminess, etc.), and designs will be compatible with possible future modifications to adapt to these conditions, where and when appropriate. Based on available information, permafrost degradation due to climate change is not considered a threat to new infrastructure proposed for Liberty development. New data from ongoing studies monitoring soil temperature trends in Prudhoe Bay will be reviewed in future design phases to validate that there have been no changes to assumptions made.

Long-term changes in sea level from the effects of climate change are expected to have minimal impact to the offshore pipeline bundle, except possibly to strudel scour location, frequency, and intensity. The impact of strudel scour on the pipeline bundle is addressed in both routing and design. In addition, annual surveys will be completed to assess trends associated with strudel scour and ice gouge impacts, and mitigation measures would be implemented if warranted. For example, mitigation could include yearly monitoring and control of strudel occurrence, operational procedure changes, as well as protective measures installed on the seabed.

While it is difficult to predict what effects climate change could have on the environment around the subsea trenched pipeline bundle, changes will be monitored through periodic surveys. Should new trends arise, they will be analyzed against the design and operational conditions to ensure that integrity is maintained.

7.3 Offshore Pipeline Design Parameters

The proposed pipeline design employs a PIP design to allow for thermal insulation to reduce heat transfer to surrounding soils, and for continuous monitoring of the annulus for supplementary leak detection and to reduce the risk of a pipeline spill under certain potential failure conditions. Included in the pipeline bundle is a fiber optic cable for communications/control and distributed temperature monitoring, as well as a coiled line pipe utility line that can serve multiple uses in the future, such as a fuel gas line and/or as a circulation loop.

7.3.1 Notable Design Features

A number of issues are addressed in routing, design, and monitoring to mitigate potential risk to pipeline integrity, such as thaw settlement. Key design advantages include:

- Limit-state design, including finite element analysis of the pipeline bundle, to determine the maximum longitudinal strains (axial and bending) in the pipelines, based on predicted permafrost thaw settlement and the expected environmental and operational loadings.
- The use of a vacuum insulated PIP configuration for the single-phase production pipeline to reduce heat transfer into the surrounding soils and to provide a secondary leak detection system by annulus pressure monitoring.
- Fiber optic cable distributed temperature sensing system.
- Straight line route to minimize route length.
- The use of thaw stable gravel bedding beneath the pipeline at the shore and LDPI approach transitions.

7.3.2 Pipeline Material Specifications

The PIP will move sales quality crude from LDPI to the Badami common carrier line. The specifications for the pipeline design are listed in Table 7-3.

Table 7-3. Liberty Offshore Pipeline Design Properties

DESIGN PROPERTY	SPECIFICATION
Design flowrate	65,000 BOPD
Maximum operating pressure	1415 psig
OD of inner export pipe	12.75” (12” nominal)
Nominal wall thickness, inner PIP	0.500”
Grade of inner PIP	API-5L X52
OD of outer PIP	16.00”
Nominal wall thickness, outer PIP	0.625”
Grade of outer PIP	API-5L X52
Nominal diameter of coiled tubing spare	4.0”
Nominal wall thickness	0.300”
Grade of coiled tubing	API-5LCP X65

7.3.3 Trenching and Burial Depth

Upheaval buckling has been identified as the driver for the required trenching and burial depth of the pipeline bundle. When a bundle is installed in an excavated trench and fully backfilled, the bundle will be axially restrained along its length, away from its surfacing points at the ends due to the frictional restraining forces of the surrounding soil. Once the axially restrained bundle is put into operation, significant compressive force due to pipeline differential temperatures and pressures will develop.

At local trench bottom imperfections (also known as props), an effective vertical (upheaval) component of the bundle compressive force can result, with sufficient upward force to exceed the normal restraint provided by the bundle's submerged weight, bending stiffness, and backfill soil overburden. The trenched bundle experiencing this force may displace vertically toward the path of least resistance. This potential vertical instability and displacement is termed upheaval buckling. If this displacement is significant, it could potentially risk the integrity of the bundle or leave it exposed to other environmental loading conditions above the seabed.

As described above, ice gouge, strudel scour, and permafrost thaw settlement analyses will be performed to calculate the maximum strain in the pipelines at the expected Depth of Cover (DOC) range. DOC is defined as the distance from the original seabed elevation to the top of pipe, while "backfill thickness" is the thickness of the soil directly over the top of pipe. The "target trench depth" is greater than the DOC and must allow for the pipeline bundle diameter, over-excavation, survey errors, and seabed smoothing. A conceptual pipeline bundle trench is shown in Figure 7-7. It was concluded from preliminary offshore pipeline protection assessments that the minimum backfill thickness required to avoid upheaval buckling of the pipeline bundle is approximately 7.5 feet. This value will be reviewed and, if required, updated during the final engineering phase of the project. In addition, an Archaeological Discovery Plan will be drafted prior to construction that will provide the management guidelines for archaeological discoveries during trenching excavation.

7.4 Shore Crossing Location

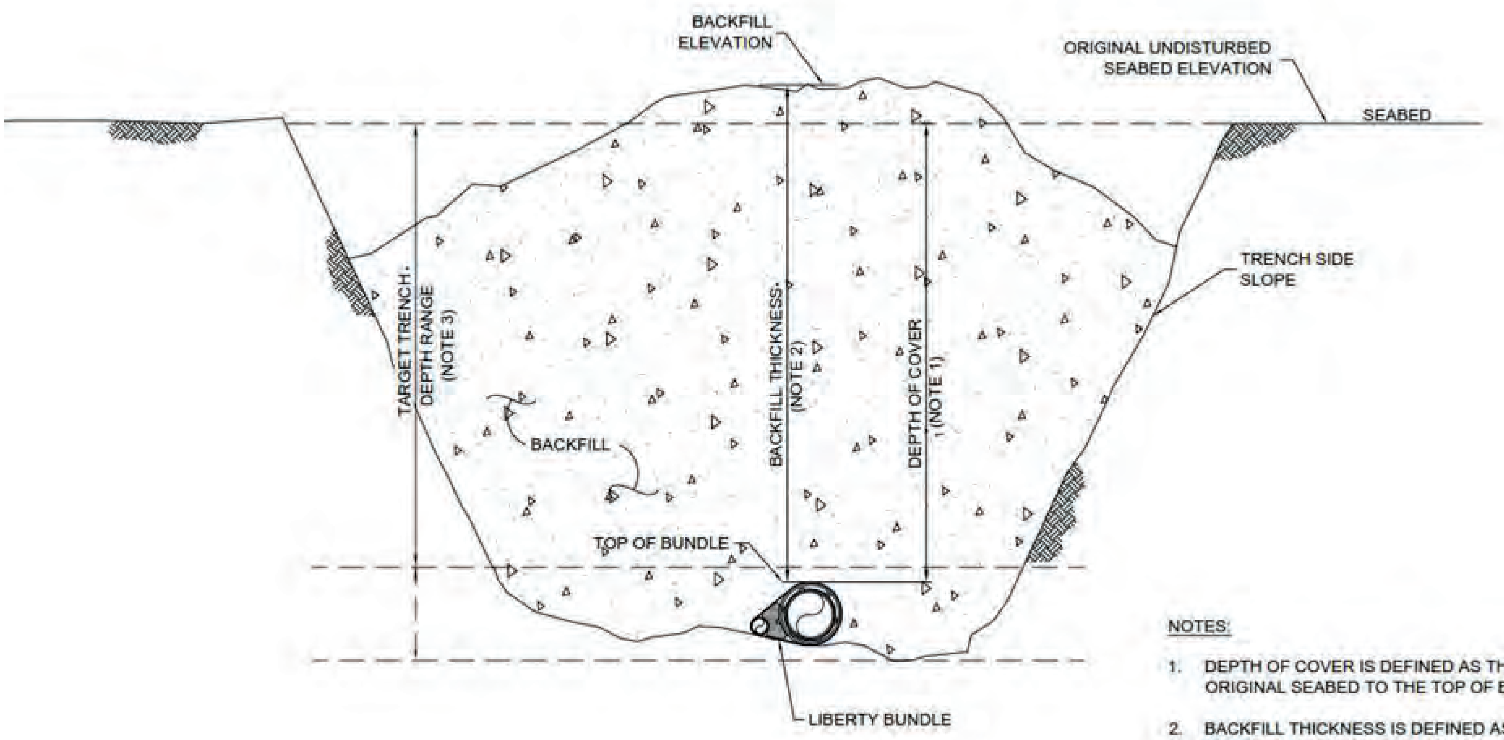
The proposed location for the pipeline shore crossing is approximately 450 feet to the west of the native allotment (NA) FF-12053 (USS-8120) that is on the west side of the Kadleroshilik River Delta. This is the same shore crossing location that was the basis for the "West Route" option that was evaluated and described in the 2002 FEIS (MMS 2002a). The preliminary surfacing location will be determined based on the expected 2 ft/yr shoreline erosion rate. See Figure 7-8 for the proposed shore crossing concept.

7.5 Onshore Pipeline Design

Considerations for the overland pipeline route include avoidance of private property and archeological sites, avoidance of deep lakes, streams, salt marsh topography, and acceptable Badami pipeline tie-in location. The proposed shore-crossing site avoids NA FF-12053 to the east and archaeological sites to the west.

The onshore portion of the sales oil line will be elevated on vertical support members (VSMs) similar to typical onshore pipelines on the North Slope. "L" or "Z" style expansion loops, typically consisting of 90-degree bends, will be used for the onshore pipeline to account for the effects of thermal expansion and will be spaced approximately 3,300 feet apart. A typical "L" or "Z" style loop is shown in Figure 7-9. The pipeline will have a minimum elevation of 7 feet above the tundra surface to not hinder wildlife passage. The design parameters for the onshore pipeline are shown in Table 7-4 below, but may be optimized in the next phase of engineering.

Figure 7-7. Offshore Pipeline Trench (Typical)



NOTES:

1. DEPTH OF COVER IS DEFINED AS THE DISTANCE FROM THE ORIGINAL SEABED TO THE TOP OF BUNDLE.
2. BACKFILL THICKNESS IS DEFINED AS THE DISTANCE BETWEEN THE TOP OF BUNDLE AND THE BACKFILL ELEVATION ABOVE THE BUNDLE.
3. TARGET TRENCH DEPTH IS GREATER THAN THE MINIMUM DEPTH OF COVER AND MUST ALLOW FOR THE PIPE BUNDLE DIAMETER, SURVEY TOLERANCES, AND SEABED SMOOTHING.

TYPICAL OFFSHORE TRENCH CROSS-SECTION

N.T.S.

Figure 7-8. Liberty Shore Crossing Diagram

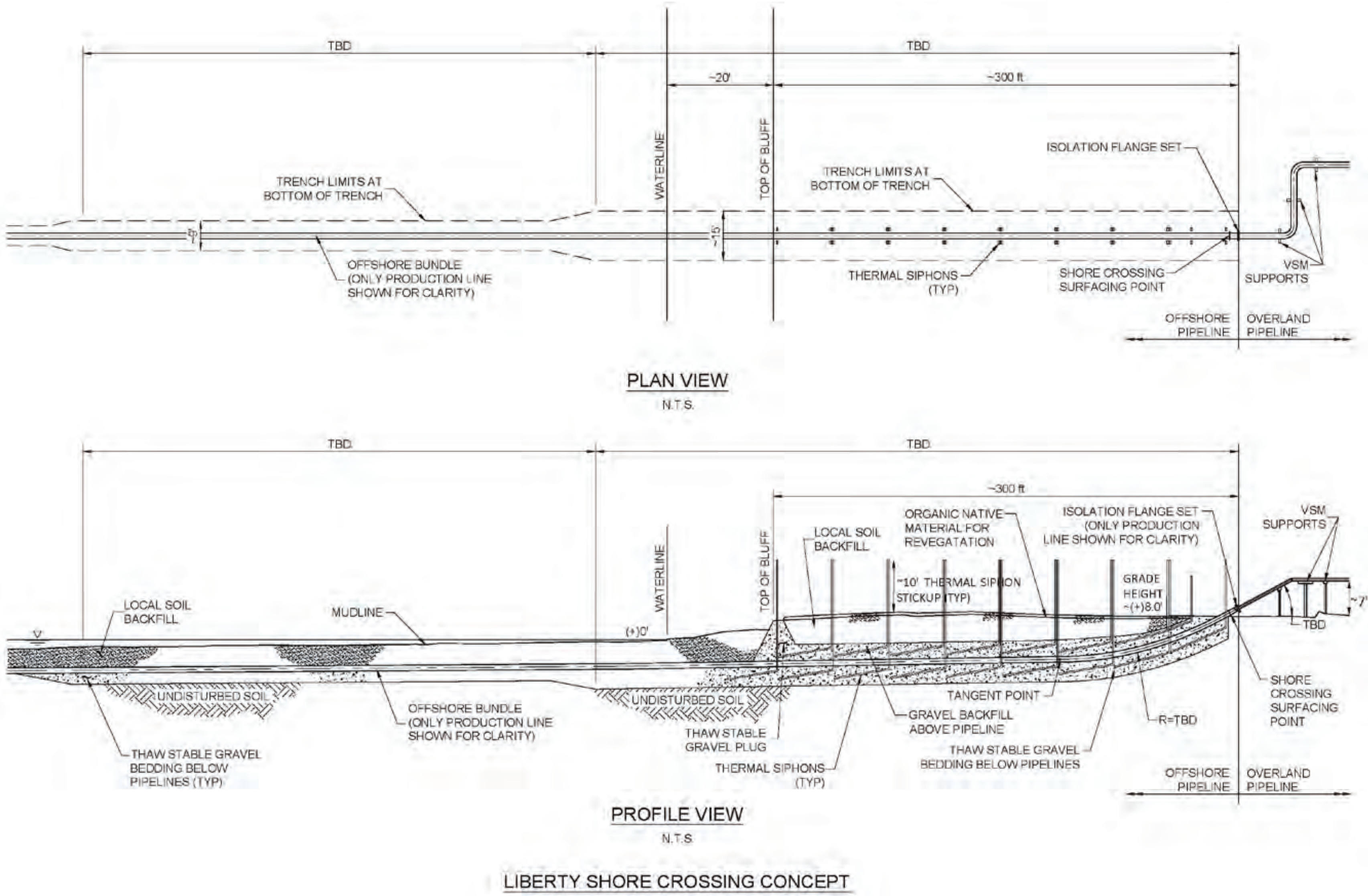
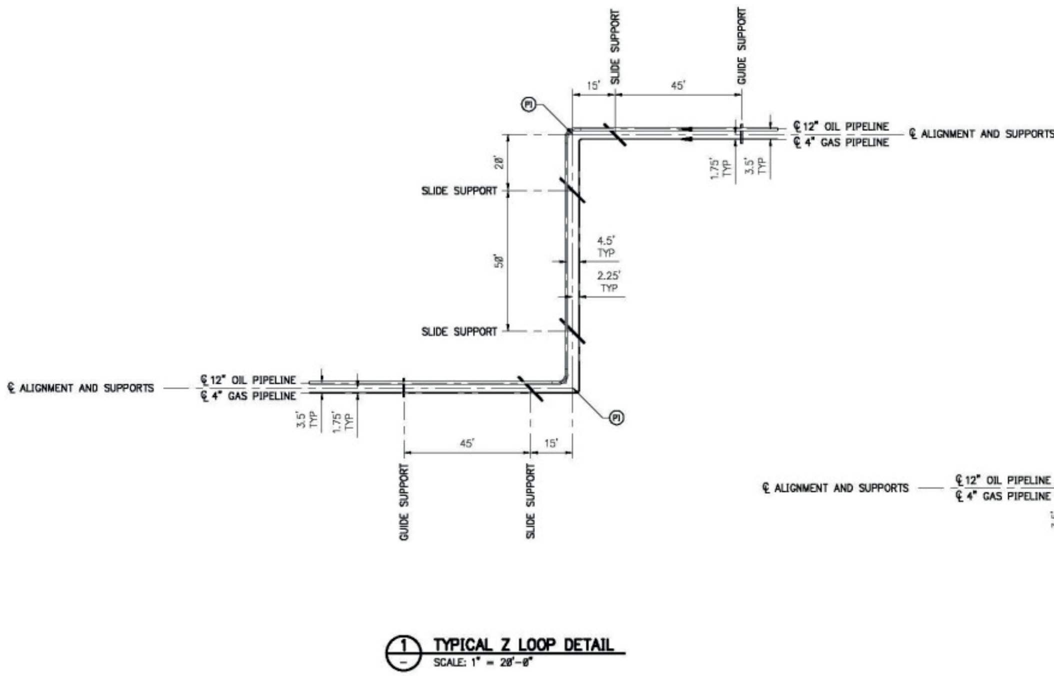


Figure 7-9. Typical Z Loop Detail



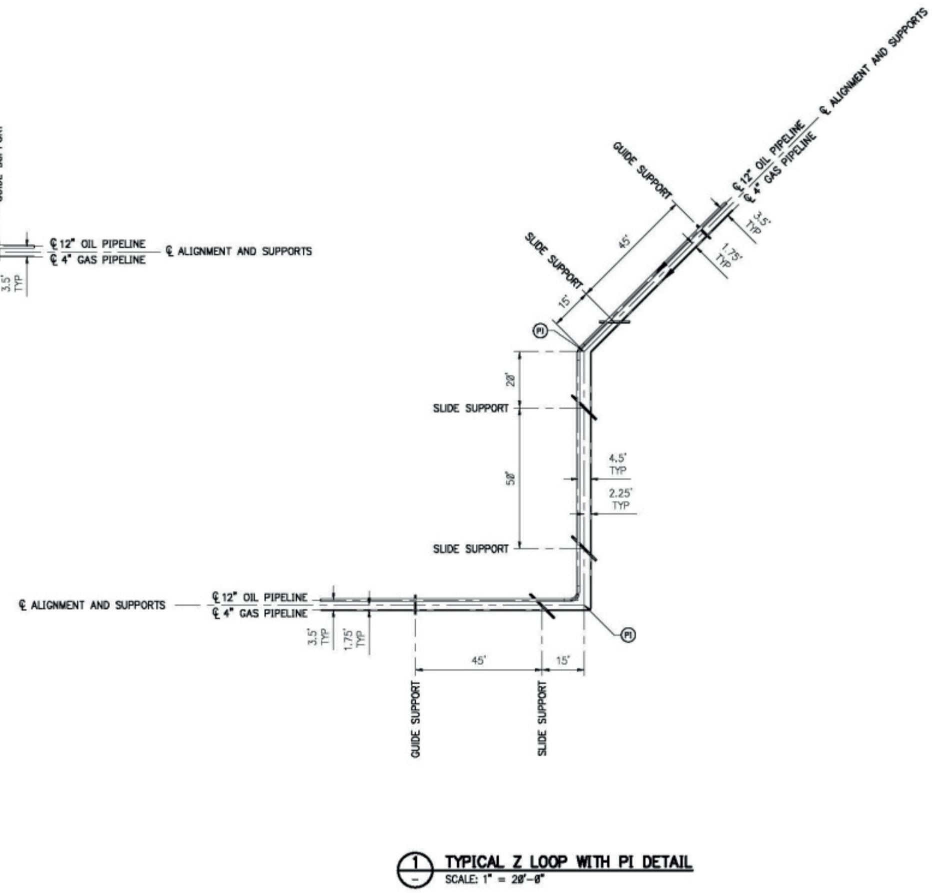


Table 7-4. Liberty Onshore Pipeline Design Parameters

	12" OIL PIPELINE	4" FUEL GAS/UTILITY PIPELINE
Outside Diameter (OD)	12.75"	Nominal 4.000"
Wall Thickness	0.281"	0.300"
Line Class	ANSI #600 Class	ANSI #1500 Class
Line Pipe	API 5L X65	API 5L X65
Coating	12-mils fusion bonded epoxy (FBE)	20-mils FBE
Insulation	2" Polyurethane Foam Insulation w/ Galvanized Steel Jacketing	None
Bends	5D Radius Induction Bends	5D Radius Induction Bends
Vibration Dampeners	Top mounted "Tuned Vibration Absorbers" (TVAs)	Top mounted TVAs
VSMs	Main Type: 8.625" OD x 0.375" WT Loops and Anchors: 12.75" OD x 0.500" WT	Main Type: 8.625" OD x 0.375" WT Loops and Anchors: 12.75" OD x 0.500" WT
Valves	1-each Actuated ANSI #600 SDV (Ball Valve) and 1-each Manual ANSI #600 Ball Valve at the Badami Tie-In	1-each Actuated ANSI #1500 SDV (Ball Valve) and 1-each Manual ANSI #1500 Ball Valve at the Badami Tie-In

7.6 Pipeline Features

7.6.1 Tie-in Facilities, Valves and Pigging

Automated pipeline isolation valves will be located on the LDPI and at the proposed gravel pad at the Badami tie-in point. The conceptual pad design is illustrated in Figure 7-10 and Figure 7-11. The final facilities and pad design at the Badami tie-in will be determined during the final design phase of the project. The tie-in pad will be approximately 170 feet by 155 feet, requiring approximately 3,500 cy of gravel. Gravel for the pad will be obtained from the proposed mine site (see Section 10.3). Given the exposed nature of the Badami pipeline tie-in pad, Remote Terminal Unit (RTU) facilities that measure flowrate and house sensors and communications will need to be contained in an enclosure. The RTU will require heaters; propane tanks will be buried on the pad to supply a fuel source for the Thermo-electric generators/heaters and ensure a continual heat source for the RTU. Any lighting at structures associated with the pipeline, including at the tie-in pad, will be minimal and consist of manually activated lighting predominantly used in winter on an as-needed basis.

Pigging facilities will include a pig launcher on the LDPI, and a pig receiver at the tie-in to the Badami pipeline. It is proposed that the oil pipeline will use the following pig types during their design life:

- Wall thickness measurement pigs capable of measuring metal loss on the ID and OD of the pipeline
- Geometry measurement pigs (3D axial, vertical, and lateral) capable of measuring pipe physical positions for comparison to previous surveys
- Caliper pigs capable of measuring pipe ID for identifying denting, buckling, or other potential blockages
- Cleaning pigs to remove any paraffin, scale, sediment, or water in the pipeline
- Inhibitor distribution pigs if corrosion inhibition is required

Figure 7-10. Badami Tie-In Pad, Plan View

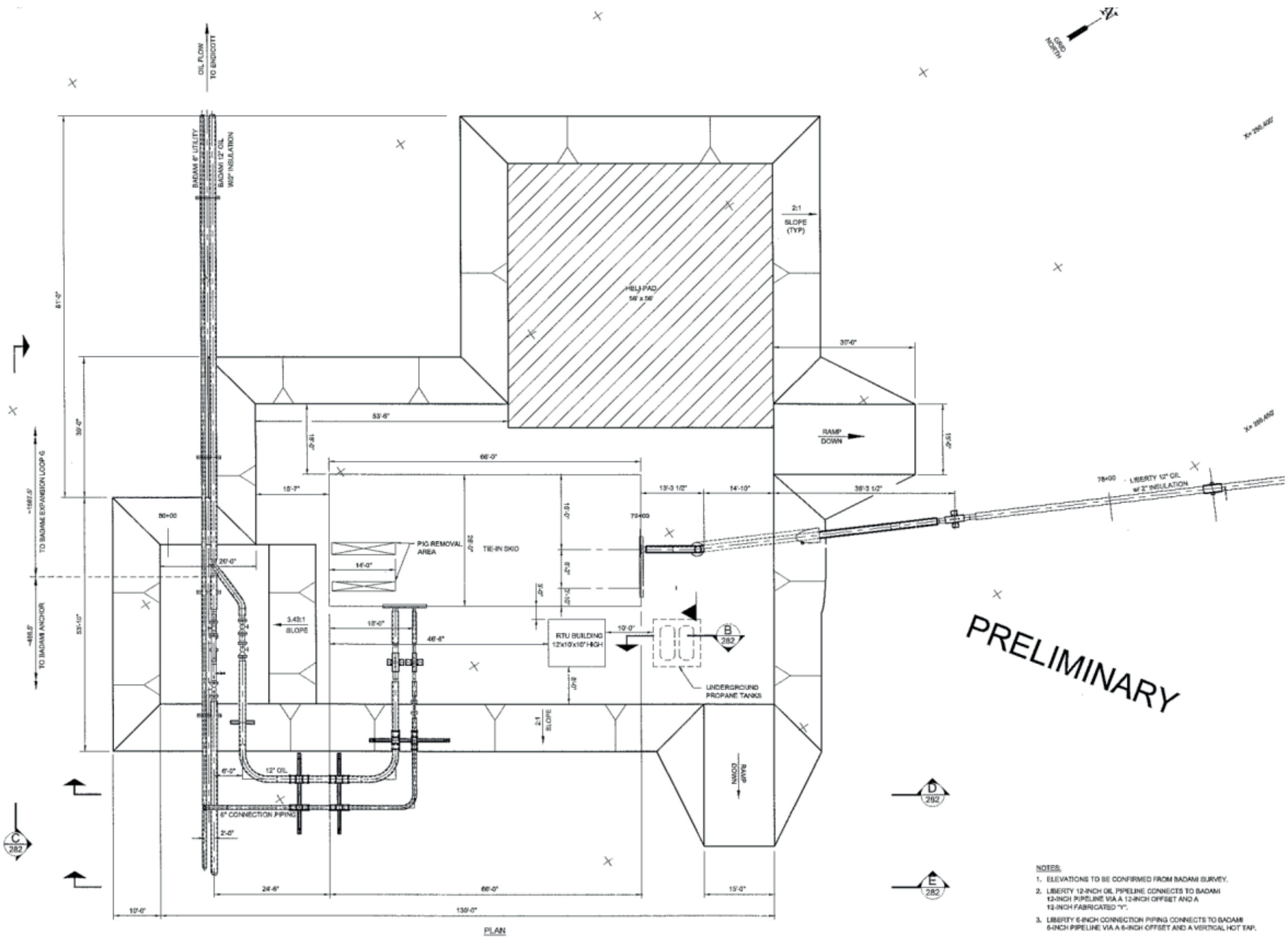
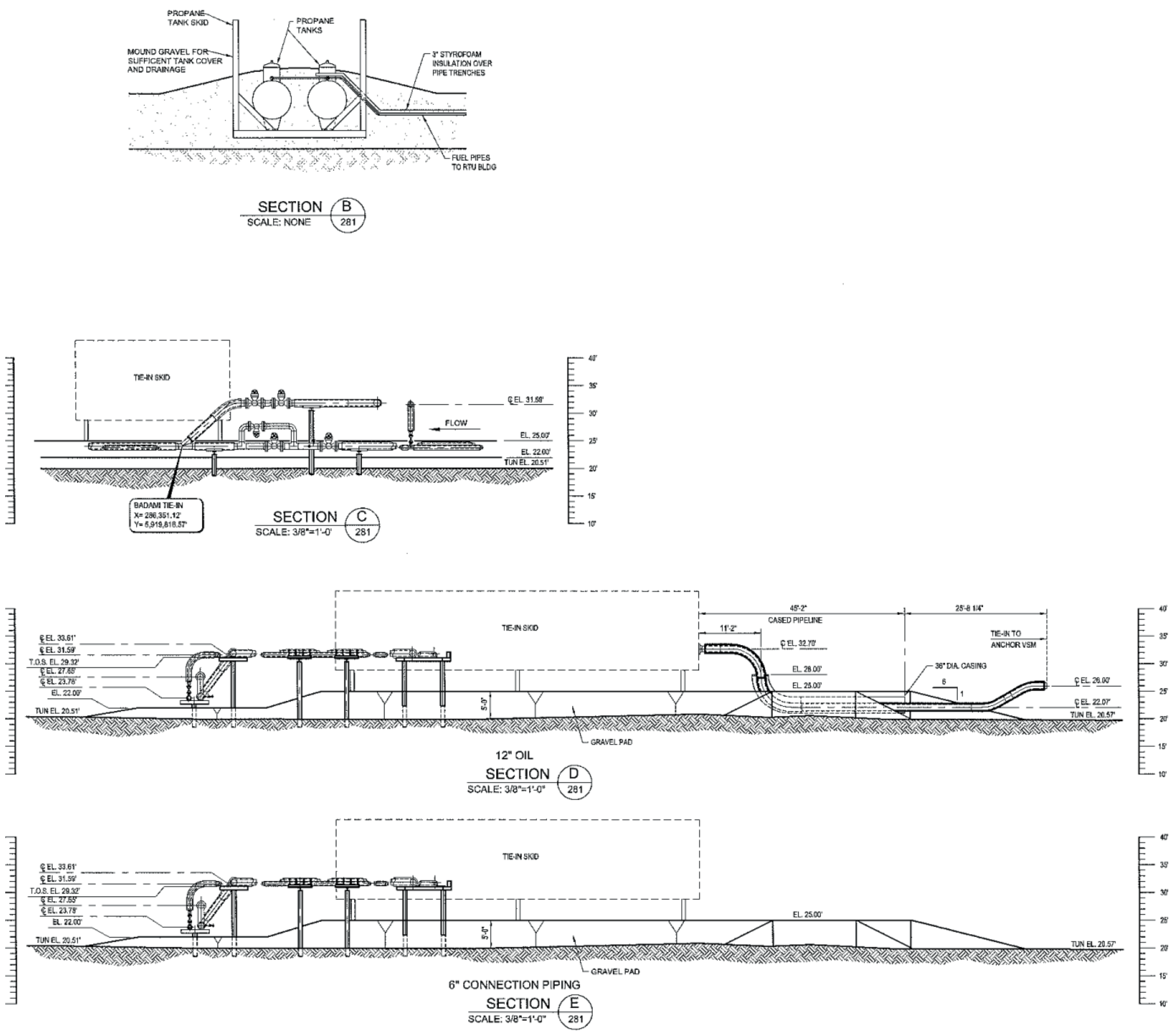


Figure 7-11. Badami Tie-In Pad, Elevation View



7.6.2 Leak Detection

Mass balance and pressure monitoring leak detection systems will be incorporated into the export pipeline design. These systems work in parallel and provide redundant measurements to ensure accuracy. It is expected that under optimal conditions, these systems would be capable of detecting a leak of 1 percent of volumetric flow in the pipeline over a 24-hour period. Custody transfer metering will be located on the LDPI and a flow meter will be located at the tie-in with the Badami Pipeline to enhance the performance of the leak detection system. Communication links to interface with the Badami and Endicott pipeline leak detection systems and controls will also be provided.

In addition to leak detection systems that are typically installed on single pipe systems, the Liberty offshore pipeline segment will use a PIP design that allows for real-time monitoring of the annulus between the two pipes. By evacuating air from the annulus and creating a vacuum, a leak can be detected by an increase in pressure. There will be natural fluctuations of pressure as a result of temperature changes that will be factored into the warning system, but the monitoring of the annulus is considered as best available technology as a method of monitoring for a leak.

The maximum worst-case spill volume for the offshore pipeline is estimated to be limited to 3,979 barrels, based on the volume inside the 12-inch pipeline over a distance of 7.1 miles, the total length of the offshore portion and onshore portion of the pipeline. This estimate is based on the worst-case assumption of a guillotine break in both the inner pipe and outer pipe, which has an extremely low chance of possibility.

The subsea pipeline leak detection systems (mass balance, pressure, and PIP annulus monitoring) would detect leaks far smaller than a maximum worst case discharge volume. Abnormal changes in the annulus temperature can also be used as a leak indicator. Details on the installation of these redundant leak detection systems will be provided in the supporting documentation for the application for pipeline right-of-way.

The fiber optic distributed temperature monitoring system will be able to identify slight changes in the temperature of the backfill, and therefore will provide early detection for any changes in environmental conditions (e.g., erosional events). HAK is committed to measures that can be implemented to further reduce the chance and volume of a worst-case pipeline leak. Such measures include surveillance of the pipeline route, investigation of suspected imbalances, frequent meter proving, and implementing operational procedures for pipeline shut-downs in the event a leak below the detection limits is suspected but not indicated by the leak detection systems.

7.7 Onshore Pipeline Installation

The overland portion of the pipeline will be supported on VSMs from the transition point between buried and elevated mode to the tie-in with the Badami Sales Oil Pipeline. The aboveground pipeline will include expansion loops or offsets to account for thermal expansion or contraction of the pipeline. The bottom of the pipeline will be elevated to a minimum of 7 feet above the tundra surface, per Figure 7-12. Design and installation of the VSMs will be completed following typical procedures used for other elevated pipelines on the North Slope. The VSM piles will be set using a sand slurry. The overland pipeline site plan is shown in Figure 7-13.

Figure 7-12. Above-Ground Pipe on VSM (Typical)

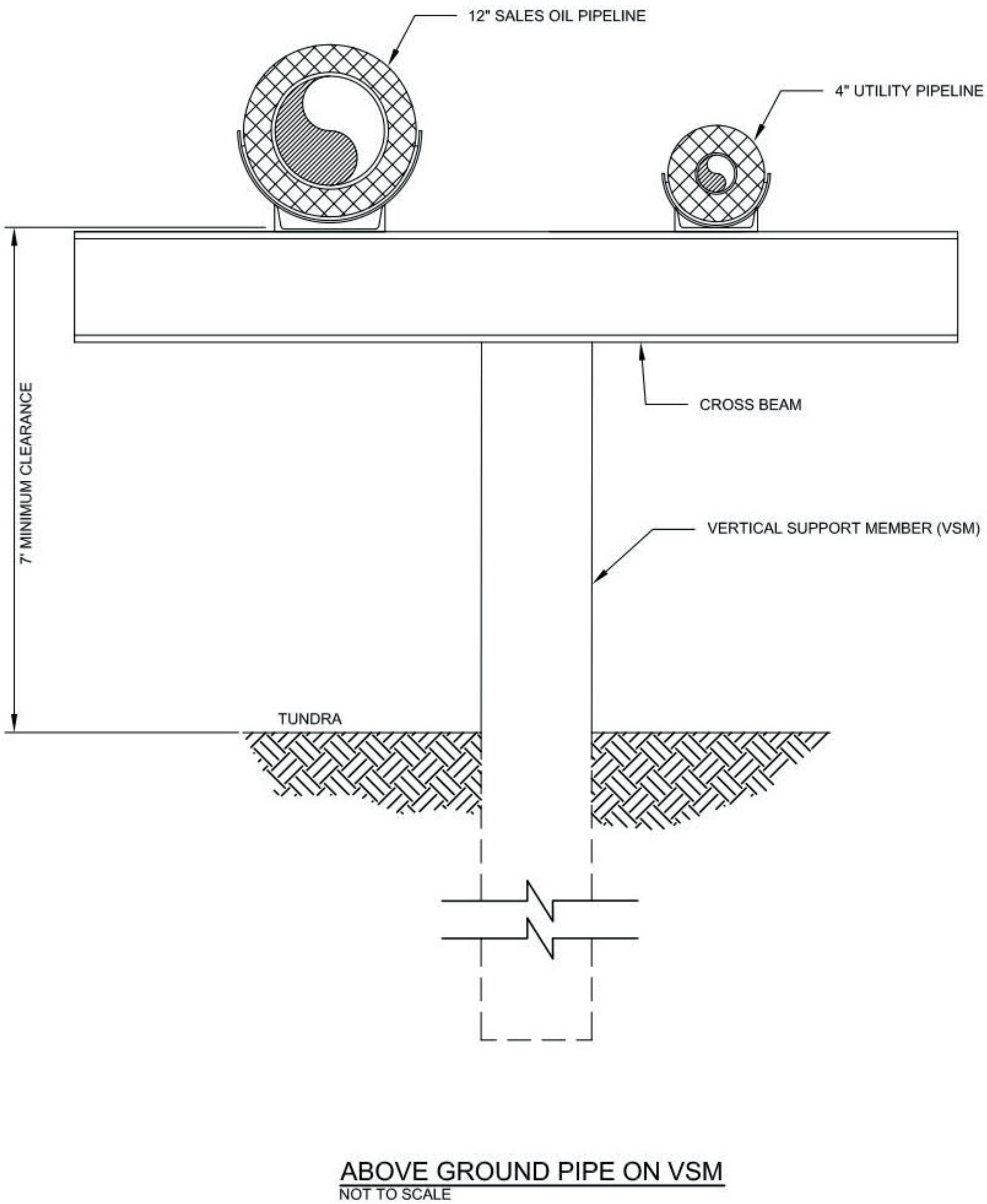
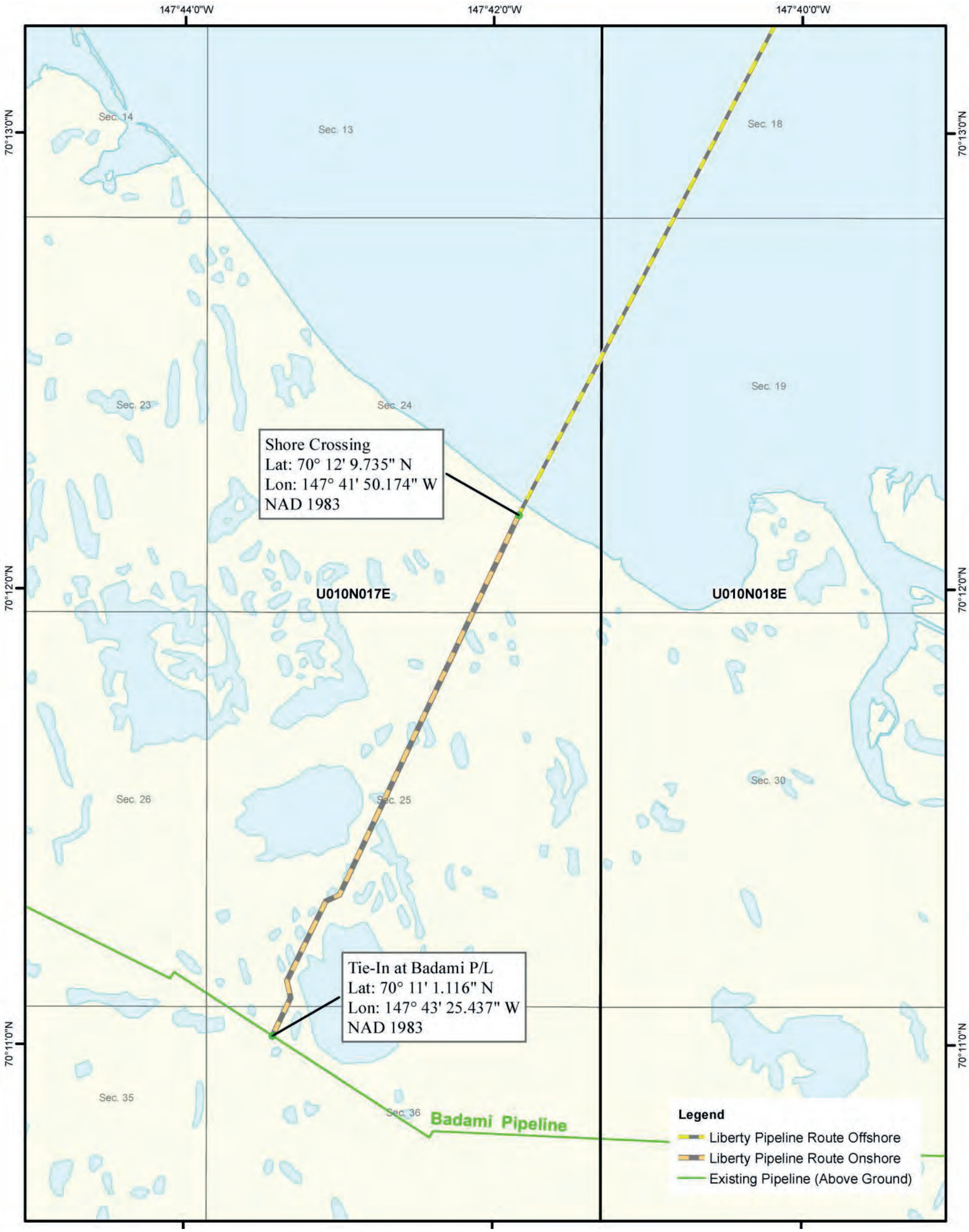


Figure 7-13. Overland Pipeline Site Plan



At the pipeline intersection with the Badami ice road corridor, a road crossing will be installed to facilitate uninhibited access over the pipeline. The pipeline will continue on VSMs to the Badami tie in pad. A typical road crossing detail is shown in Figure 7-14 and Figure 7-15.

Figure 7-14. Typical Road Crossing Elevation

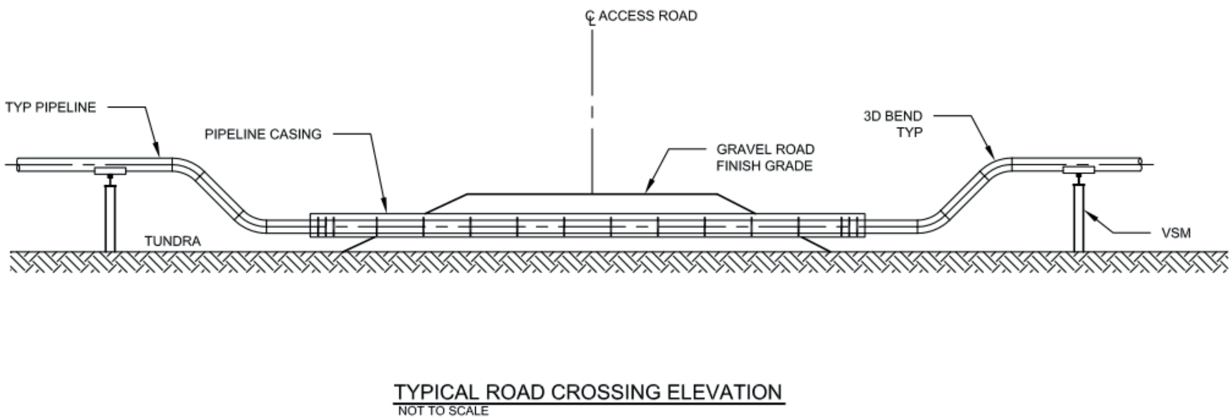
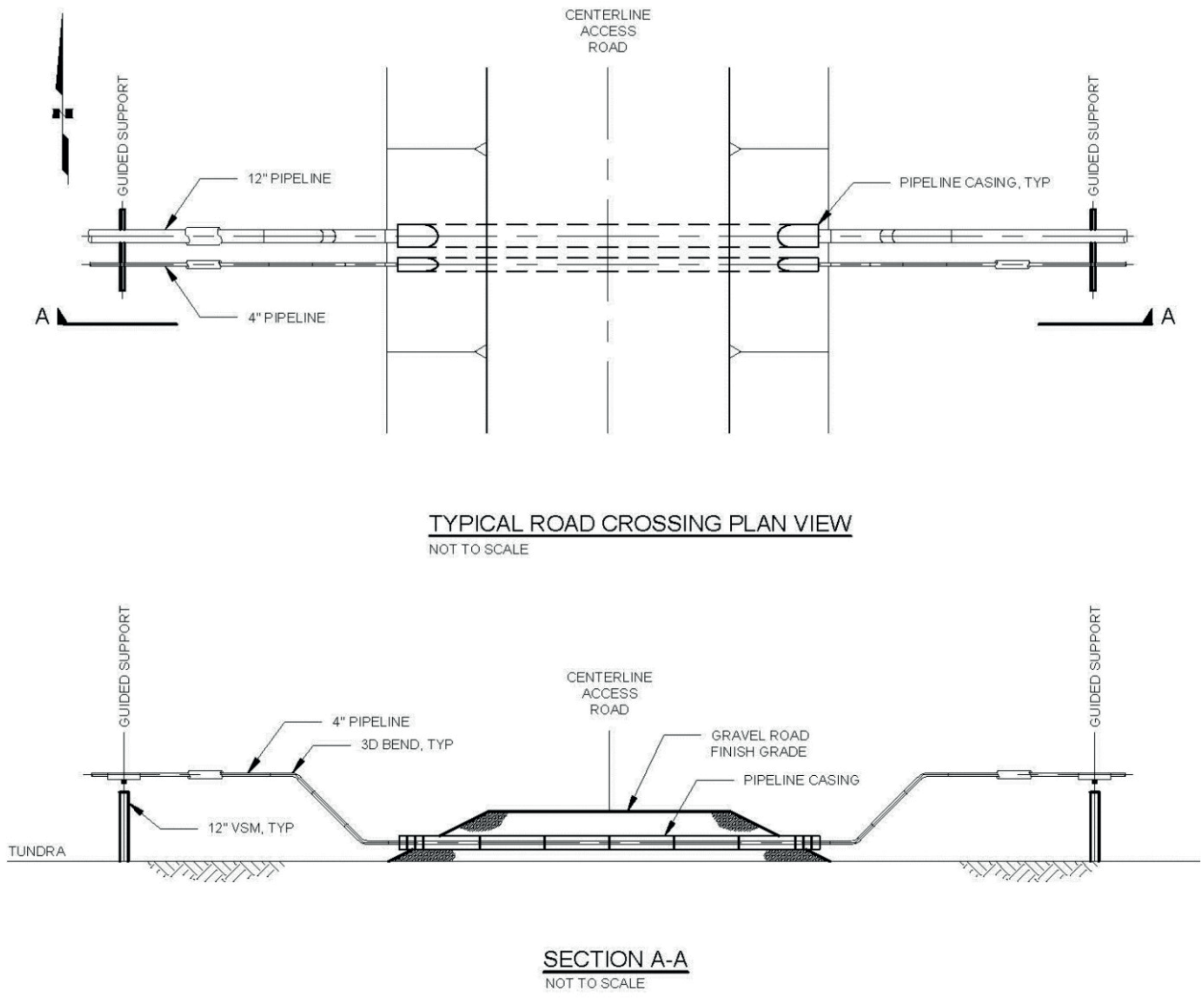


Figure 7-15. Typical Road Crossing Plan View



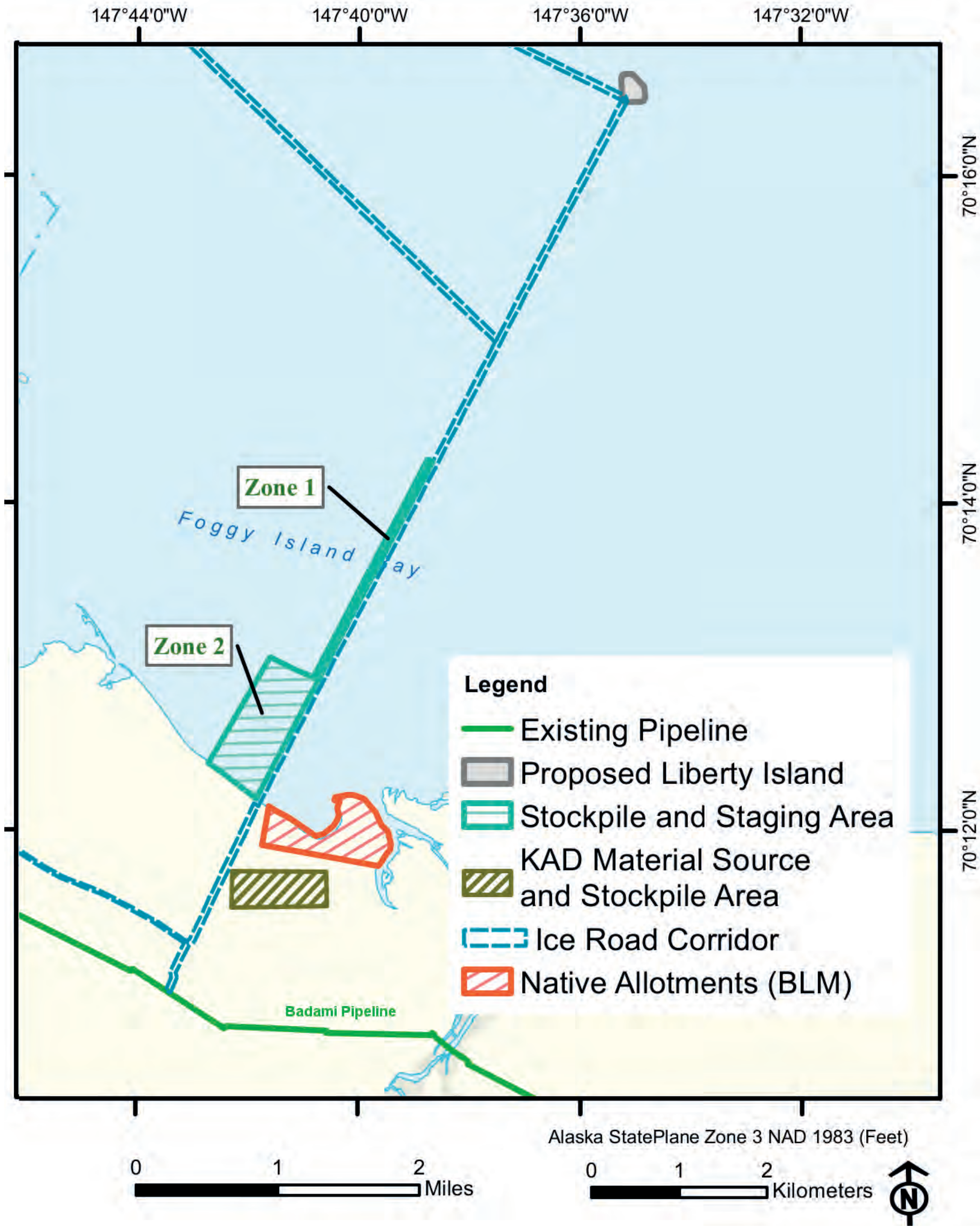
The tie-in to the Badami pipeline will include a gravel pad with a working surface area of approximately 170 feet by 155 feet, including a helipad on one side. The working surface will be approximately 5 feet above ground level, with a slope of 3:1. The footprint to toe of slope of the pad is determined to be 0.75 acres. A site plan of the Badami tie-in pad and facilities is shown in Figure 7-10.

The facilities on the pad include a pig receiver module and may include an RTU. Included in the tie-in is the connection from the Liberty 12-inch oil line to the Badami oil line. The nominal 4-inch fuel gas line will be blind flanged at either the shore crossing or at the Badami tie-in to allow flexibility for future use. A crossover line will be required for thawing the backfill offshore portion prior to start-up and may be required for upset conditions (e.g., Badami Line shutdown).

7.8 Offshore Pipeline Installation

The offshore section of the pipeline will be constructed during the winter within a proposed temporary construction right-of-way (250 feet wide onshore, 1,500 feet wide offshore). An ice road and/or thickened sea ice will be built within the construction right-of-way to support pipeline construction. Figure 7-16 shows the proposed pipeline route and ice road corridor. An additional temporary site for staging of construction materials and construction support will be required. This site will be located close to shore on grounded sea ice (generally less than 5.5 feet water depth), artificially thickened as required to support construction equipment. The offshore ice road and the temporary site will serve as temporary storage areas for trench spoils.

Figure 7-16. Excavated Material Storage



Offshore, the pipeline will be buried in a subsea trench. The proposed minimum depth of cover over the pipeline bundle is approximately 7.5 feet below mudline; target trench depth is 11 to 13 feet. The proposed target trench depth will be reviewed during the design phases of the project and updated if required. Depth of cover is defined as the distance from the original seabed to the top of pipe. In addition, the pipeline will be buried from the shoreline to an inland point where the pipeline transitions from buried to elevated.

7.8.1 Transition Area Offshore to Onshore

The transition point will be located to provide protection from coastal erosion expected during the pipeline design life, plus a safety factor. A photo of the transition point is shown in Figure 7-17. This set back distance accounts for the average long-term erosion rate and the maximum expected short-term erosion rate. HAK estimates long-term (period from 1949 to 1995) erosion rates of about 2 feet per year at the shore crossing location (Coastal Frontiers 1996). The proposed length of the onshore setback is approximately 350 feet, starting from the 4 foot elevation to the daylight of the pipeline. This set back distance also accounts for any potential ice ride-up associated with onshore sea ice movement.

Figure 7-17. Pipeline Subsea to Onshore Transition

The transition trench may extend up to 350 feet long and 150 feet wide at the top. Select, thaw-stable backfill will be used as necessary to minimize thaw settlement in the transition zone between the offshore segment and the onshore segment. This thaw stable material, which is composed of larger sand particles, will be sampled to ensure low fines to inhibit moisture and ice accumulation in the soil. The soil will be placed in lifts and compacted. The quantity of select backfill expected to be required, based on trench geometry, is approximately 3,000 cy. The actual quantity of thaw-stable bedding will be based on the thaw settlement analyses to be completed during the design phases.

Preliminary design does not have a shore crossing valve but does have an isolation valve at the Badami tie in location. Valve pads will be located at the landfall transition point if a valve is included in the design at this location.

After laying the pipeline, the trench will be backfilled. Cuttings from VSM installation may also be placed in the onshore portion of the trench. In the onshore portion of the trench, the backfill will be topped with a thin layer of fine-grained soils and organics, and seeded as needed to promote re-vegetation. Coarser granular material from the gravel mine or the excavation will be used at the shore crossing as needed to achieve erosion resistance similar to the adjacent, undisturbed material. This plan minimizes any increase in erosion due to construction through coastal bluffs.

7.8.2 Offshore Trenching

The trench in which the offshore pipeline bundle will be laid will be excavated through the sea ice in the winter. The execution sequence of the trenching operations is as follows:

- Thicken sea ice along route. For the floating ice section in particular, this is required to support the excavation weight temporarily, as well as the required construction equipment, and support the loads associated with pipeline installation. Where bottomfast ice is present, thickening of the sea ice will also be required.
- Cut a slot in the ice. The slot will be approximately 5 to 7 feet wide. The ice will be cut into blocks using an ice trencher and removed by conventional excavation equipment. The ice will be transported to a location away from the work site to a storage area on grounded sea ice to prevent excessive deflection of the ice in the work area.
- Excavate the trench using long-reach excavators with pontoon tracks. Excavated material will be backfilled over the pipeline in another area of the trench or stockpiled in a designated area.

7.8.3 Pipeline Bundle Makeup and Installation

One or both of the following techniques will be used to assemble the pipelines prior to pipe laying: (1) string and weld, or (2) prefabricate and transport pipeline strings. For the string and weld method, a side boom or crane will unload pipe joints from transport vehicles and string the pipe joints end to end along the right-of-way. Each pipe joint is then welded together near its final as-laid position. Alternatively, the pipe joints will be welded into strings up to 1 mile in length at the make-up site, and these strings would be pulled into place and welded onto the end of the pipeline. In both cases, testing of the completed welds would be performed using non-destructive techniques. Field joints will be coated with a corrosion protection coating, and cathodic protection anodes will be installed at the designated spacing. Pipe-in-pipe fabrication will include installing radiation barrier and spacers on the outside of the 12-inch pipe prior to pulling it into sections of the 16-inch outer pipe. The 12x16-inch PIP will be bundled with the 4-inch pipe and fiber optic cable on the ice surface near the trench. Pipeline installation will follow immediately behind the trenching spread. Side booms will be used to control the vertical and horizontal position of the pipeline as it is lowered down through the water column to the trench bottom. It is possible that weather or ice conditions could dictate a temporary or seasonal abandonment of the pipeline before construction is completed. Therefore, there will be an abandonment and recovery plan in place for the Liberty offshore pipeline.

7.8.4 Offshore Trench Backfill

If practical, once construction is underway, excavated trench spoils will be transported and placed as backfill over recently laid pipeline segments in a continuous process. During the initial stage of construction however, the spoils excavated from the trench will be temporarily stockpiled on grounded ice along the route on the west side of the trench out to approximately the 8- to 9-foot water depth. Spoils will later be removed from the stockpile and transported and placed in the trench as backfill after the pipe is placed in the trench. As needed, frozen spoils will be trimmed to aggregate size to facilitate even backfilling.

The trench will be backfilled with both native spoils and select backfill when the observed trench parameters (e.g., depth, properties) do not meet the design requirements. Loose gravel will be used as trench fill material where needed based on the surveyed as-laid configuration of the pipeline bundle in the trench. If required, gravel-filled geotextile bags will be placed axially across the pipeline in the trench, providing uplift resistance during pipeline operation. The bags would then be buried within the remaining native backfill material. Using this method, bags would be buried well below the seafloor and would not be exposed to ice or erosion forces. Bags would be placed as required during construction, depending on the pipeline bundle, as-laid vertical profile. The bags would be installed using tongs, following the same general method used to install bags used for island slope protection at other North Slope locations. These tongs are specially designed to avoid damaging or breaking the bags.

The estimated excavation for the offshore trench is approximately 490,000 cy. These quantities will be refined after the 2014-15 geotechnical investigation and after detailed engineering is complete. The design trench reflects expected construction conditions and the trench excavation limits. This estimate takes into account the potential for the trench walls to form at shallower angles than cut.

7.8.5 Excess Backfill

In the process of trench excavation, HAK intends to minimize the amount of construction spoil requiring disposal by re-using this material as trench backfill to the maximum extent possible. It is also possible that portions of the ice slot could be reopened and excess spoils placed over the previously backfilled trench to eliminate or further reduce the disposal volume. There are conditions, though, under which some excavated material cannot be placed back into the trench and will require disposal.

It is HAK's intent that all material will be placed back in the trench slot above the pipeline. The borings do not conclude that there will be significant areas of unsuitable materials. The soil reports conducted previously in vicinity to the proposed pipeline illustrate the following strata of materials:

i. (0-11.7 feet) – Soft to very stiff, moist, dark grey to black silt; trace to few fine sand, low to medium plasticity, stratified layers up to ¼-inch thick, micaceous, few shell, unfrozen.

ii. (11.7-15 feet) – Very stiff, moist, dark grey to black, lean clay; medium to high plasticity, stratified layers of silt/clay up to ¼-inch thick distributed evenly, unfrozen.

The disposal of excess spoils away from the trench is only for contingency purposes. Situations requiring disposal of excess backfill may be due to several factors, including displacement by the pipeline, the use of select backfill (e.g., gravel) when required, and bulking due to the natural swell of excavated materials placed back into the trench. Another case may result from uncontrolled circumstances (e.g., bad weather) that may force construction crews to abandon the site before all operations have been completed, leaving some excavated material on the ice surface.

7.8.6 Temporary Storage of Backfill

The 200-foot-wide section along the west side of the pipeline trench from the 8-foot isobath to shore will be the primary storage area for trench spoils (Zone 1). See Figure 7-16.

The second storage site will be located on the west side of the pipeline right-of-way on grounded sea ice inside the 5-foot isobath (Zone 2). Approximate maximum dimensions of the site will be 5,000 feet by 2,000 feet (230 acres). This area will serve as the temporary storage location for materials excavated during trenching operations that cannot be immediately transported for backfill along the pipeline. HAK intends to reuse excavated material as pipeline trench backfill to the maximum extent practicable. It will also be the location of materials temporarily stored there if the weather or ice conditions dictate the abandonment of operations prior to completion. Other important criteria include maintaining a safe distance from active pipe laying operations, reasonable hauling distance, storage only on grounded sea ice, and local transport mechanisms.

The additional stockpile location would be used as a disposal location for stockpiled excavated materials in the event weather or ice conditions dictate the abandonment of operations prior to completion. The maximum quantity of spoils stockpiled or left for disposal on this site at any one time is estimated at 10,000 cy. Spoils will normally be stacked or groomed to maintain an approximate depth of 1 to 2 feet. It is HAK's intent to clear Zone 2 of all construction spoils at the end of construction. This will be accomplished by scraping the ice with heavy equipment, leaving at most, a very small amount of sediment remaining in the frozen matrix.

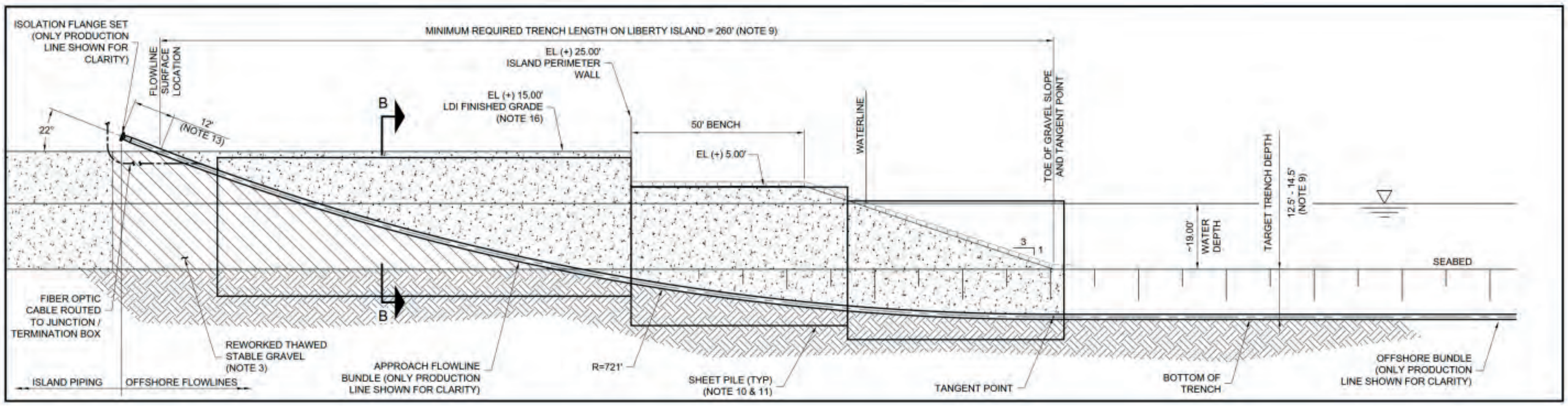
Unfavorable weather may prevent the transportation of all the temporarily stored spoils back to the open trench section, resulting in sections of the trench not being fully backfilled. Trench conditions would be evaluated the following summer (and annually). As the backfill thaws, additional backfill will more than likely need to be placed.

7.8.7 Pipeline/Island Transition

Liberty Island will be a gravel island located in a water depth of approximately 19 feet. The Liberty pipelines must transition from an offshore trench to a tie-in location above ground on the gravel island. Based on previous projects, it is assumed that the pipeline bundle will approach the island in a vertical sweep lay configuration, inside a sheet piled trench with a minimum radius of curvature for the sweep of approximately 640 feet. A sheetpile corridor will be used to transition the pipeline from the buried subsea mode onto the island surface, see Figure 7-18. The pipeline string will be lowered to the bottom of the pre-excavated trench. Fill will then be placed over the pipeline bundle to complete the island.

The offshore pipelines, following the sweep lay approach, will surface on the gravel island, and the offshore/on-island pipeline specification break will be defined by an isolation flange set. Just before the isolation flange, the export oil PIP system will require a steel bulkhead to control differential expansions between the inner and outer pipes and provide a rigid pressure-tight connection between the inner and outer pipes. The final tie-in welds will be made on the ice sheet after which the pipeline is installed.

Figure 7-18. Transition from Buried Subsea to Island



7.8.8 Hydrotesting

After installation, the pipelines will be pressure tested to satisfy applicable regulations and codes. To reduce the volume of fluid required, the offshore and overland 12-inch and 4-inch pipeline segments will be tested one after the other by transferring the testing fluid from one to the other. Hydrostatic test fluids may be stored for future work, injected into an approved disposal well, or sent back to the supplier for recycling. Hydrotest fluids will be transported to the job site by tank trucks and transferred through hoses via a fill pump into the pipeline segment to be tested. Portable containment (drip pans with absorbent liners) will be placed under each fitting and connection. Continuous monitoring will be effected whenever transfers are in progress. Upon completion of testing, the fluids may be temporarily left in the pipeline or stored at the Liberty facility for future use (e.g., backfill thawing, pipeline warm-up), transported to the contractor's permanent tanks for storage and reuse, or injected into approved wells.

Several options for test fluids are being considered, including glycol, or a water/glycol mixture. If any glycol is used, the test fluids would be recovered and returned to the vendor for future use, recycling, or approved disposal. If seawater is used it will be discharged in accordance with the terms of the LDPI National Pollutant Discharge Elimination System (NPDES) permit.

7.9 Safety and Leak Prevention Measures

The proposed Liberty pipeline includes the following measures to assure safety and leak prevention:

- The pipeline route in Foggy Island Bay is shoreward of the barrier islands and shoals, thus affording protection from large ice keels that could gouge the seabed.
- The present design calls for trenching the pipeline in the seabed so that the top of the pipe is at least 7.5 feet below the original seabed (this is more than 4 times the deepest measured ice gouge in the vicinity of the pipeline route). The trench will then be backfilled over the top of the pipes.
- The pipeline will be designed to accommodate bending without leaking in the event of an ice keel, spanning due to a strudel scour, and predicted maximum permafrost thaw subsidence.
- The pipelines will be coated on the outside and protected with anodes to prevent external corrosion.
- The shore transition is buried to protect against storms, ice pile-up, and coastal erosion. The shore transition site will be set back from the shoreline.
- A best available technology leak detection system will be used during operations to monitor for any potential leaks (see OSRP for more detail).
- The PIP design will provide additional leak detection capability through annulus monitoring.
- Intelligent inspection pigs will be run during operations to monitor pipe conditions, measure any changes, and evaluate upheaval buckling and/or thaw settlement risk.
- The elevated overland pipeline section will be of conventional, proven North Slope design.
- The pipeline is designed with no flanges, valves, or fittings in the subsea section to eliminate the possibility of leaks from such components.
- A fiber optic distributed temperature sensing system will be employed along the buried subsea pipeline. This system will be able to detect soil temperature variations along the pipeline route, indicating erosional or similar environmental changes.

7.10 Monitoring and Surveillance

HAK will conduct long-term monitoring and surveillance of the pipeline system to assure mechanical and operational integrity and as required by SPCO and BSEE. The purpose of this monitoring and surveillance program will be to assure design integrity and to detect potential problems. The program will generally include visual inspections/aerial surveillance and pig inspections.

Visual inspections of the pipeline system will be conducted by aerial surveillance as required. The goal of these surveys will be to supplement pipeline monitoring systems through visual observation. Pipeline isolation valves will be inspected on a regular basis.

In addition to visual observations/inspections, HAK will conduct a regular oil pipeline pig inspection program to assess continuing pipeline integrity. Three types of data collection pigs will be used:

- Wall thickness measurement pigs
- 3D geometry pigs (axial, vertical, and lateral)
- Mechanical damage pigs

In addition to routine meter, pump, and valve operations, the main focus of the operating procedures for the subsea pipeline bundle will be to monitor integrity of the components. Monitoring the subsea pipeline will involve a continual review of flow properties, pressure-based monitoring, fiber optic cable temperature sensing monitoring, and various inspections. A pipeline bundle monitoring plan will be developed, similar to the general monitoring plan shown in Table 7-5.

After the backfill has thawed and settled, locations where the backfill thickness does not meet the design requirements will be backfilled with gravel. The pipeline bundle alignment will be surveyed each year over the design life for strudel scour and other potential impacts to the bundle.

If mitigation for strudel induced upheaval buckling is deemed necessary, mitigation would likely include placement of additional gravel, cobbles, and/or concrete blocks over the affected section of the trench. Based on potential scour size, the width and depth of the protection material would be determined; as currently envisioned, this protective material coverage might extend approximately 30 feet along both sides of the center line of the pipeline route.

Table 7-5. Pipeline Monitoring Plan

OPERATIONS AND MAINTENANCE PARAMETER			PRODUCTION PIPELINE[1]	FUEL GAS/ UTILITY PIPELINE
Leak Detection	Continuous Monitoring	Pressure Monitoring/Pressure Safety Low (PSL) Monitoring	✓	✓
		Annulus Pressure Monitoring	✓	
		Mass balance	✓	✓
Operational Pigging		Mechanical damage caliper pigs for pipe ovality	✓	
		Wall thickness measurement pigs for internal and external corrosion inspections	✓	
		Geometry (mapping) measurement pigs (3-dimensional x, y, and z coordinates)	✓	✓[2]
		Cleaning pigs	✓	✓
Operational Monitoring		Temperature	✓[3]	✓
		Cathodic protection reference cell potential, anode potential for flowlines, and potential across isolation flanges	Outer casing pipe	✓
		Continuous fiber optic cable (FOC) temperature integrity and seabed erosion monitoring (offshore)	✓	
		Biocide dosing for microbiological influenced corrosion (MIC) (if required)	✓	✓
Monitoring Surveys		River flood gauge monitoring for determining timing of river overflood in spring of each year, including annual overflights	✓	
		Monitoring shore crossing gravel transition points, piping supports, flanges, settlement and expansion displacements	✓	
		Annual bathymetry, strudel scour, and ice gouge surveys (offshore survey vessel)	✓	
		Annual strudel protection surveys (offshore survey vessel)	✓	

Notes:

1. The subsea production pipeline is a pipe-in-pipe (PIP) system with a 12-inch outer diameter (OD) inner pipe and an 16-inch OD outer pipe.
2. Inferred from production line.
3. The fiber optic distributed temperature sensing system also monitors the temperature of the 16-inch OD pipe of the PIP pipeline.

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8 DRILLING

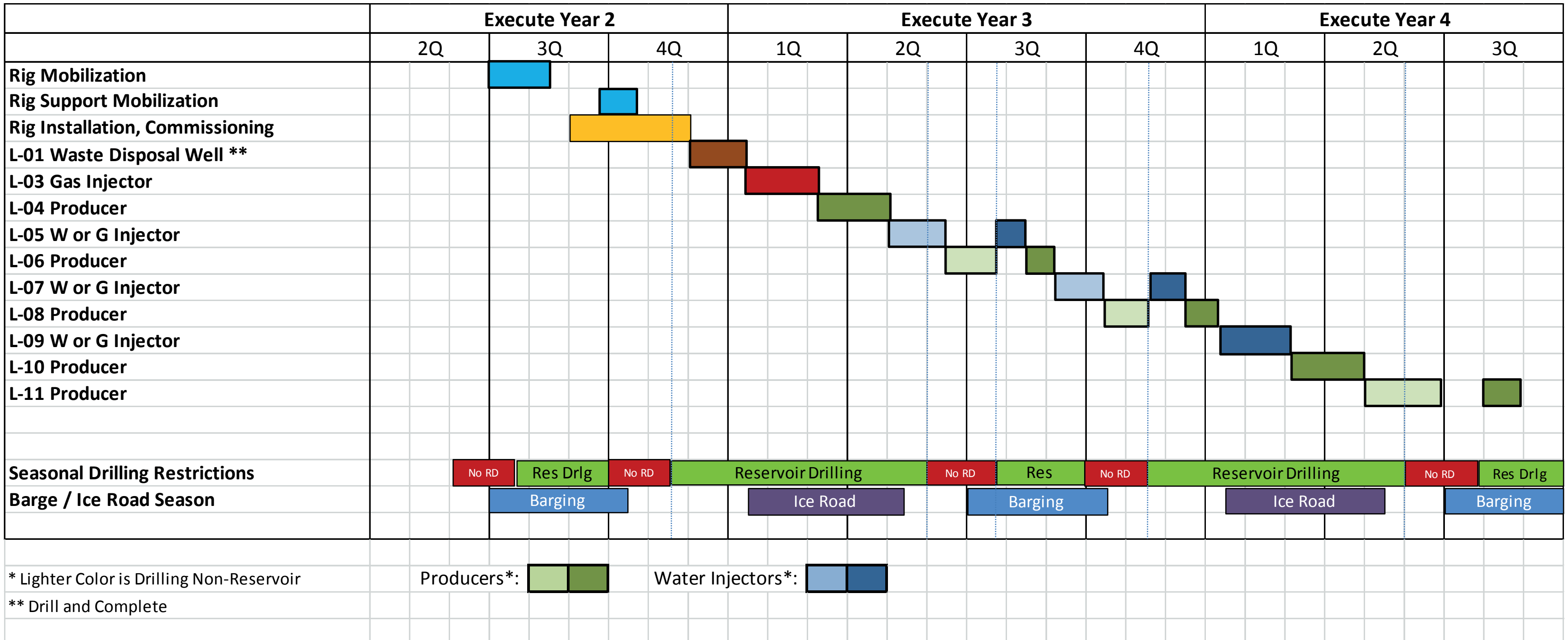
This section of the DPP describes all aspects of the drilling element of the project including the drilling unit mobilization and drilling schedule, drilling unit (drilling rig), well designs, completion designs, and well control procedures. Note: All references to timing and year of activities are the year of the Execute Schedule that has been de-coupled from the Review Schedule, as described in Section 3 of this DPP.

8.1 Drilling Unit Mobilization and Drilling Schedule

The detailed drilling schedule shown in Figure 8-1 shows that the drilling unit will be mobilized during open-water barge season of Year 2, after the island is constructed and the well row is prepped for installation of the drilling unit. Re-assembly of the drilling unit with moving system and functional testing will continue through year end of Year 2. Much of the drilling support equipment including the mud mixing facilities, the bulk mud and cement silos, and the G&I unit will be delivered during open-water season of Year 2. Remaining equipment to commission the drilling facilities will be delivered as soon as the ice road is operational in 1Q of Year 3. As the drilling unit and drilling support equipment is nearing the commissioning phase, downhole drilling equipment and consumables will be delivered to the site. Subsurface drilling operations are scheduled to begin in 1Q Year 3 using diesel engine powered generators (gen-sets) to power the drilling unit, and standalone diesel powered gen-sets for the drilling support equipment. The waste mud and cuttings well will be drilled first, so that cuttings from subsequent wells can be disposed of as they are created. The first development well into the reservoir will be a gas injector so that produced gas from all subsequent producers can be re-injected into the reservoir. The second development well will be a producer. Once the first producer is flowing and excess gas can be re-injected, the drilling unit will be converted to run on natural gas fired gen-sets for the remainder of the drilling operations.

Drilling will continue as either year-round batch drilling down to and including the intermediate casing above the reservoir, or with reservoir drilling during the open-water and frozen ice seasons. Drilling through the reservoir section will be limited to the open-water season (~July 15 through ~October 1) or during frozen ice season, which begins with 18 inches of ice (~November 15) and ends June 1 as prescribed in the OSRP.

Figure 8-1. Drilling Schedule



8.2 Drilling Unit Layout

8.2.1 Island Layout, with Drilling Unit and Support Modules

The island layout as shown in Figure 6-3, allows both drilling operations and facilities installation and operations to operate effectively and safely with simultaneous operations. The drilling footprint, including the drilling unit, utility module, G&I plant, and mud/cement support facilities, occupies much of the area in the center of the island on both sides of the well row. A single row of wells offers the optimal use of a set of “skid beams” or “walking beams” to move from one well to another along a rail system. In addition to the drilling unit and support modules, the total drilling footprint includes:

- Clearance on both sides of the drilling unit to move from one end of the well row to the other.
- Pipe loading and access to the pipe shed and laydown areas in front of the drilling unit.
- Area for storage of well consumables including casing, tubing, sack material, wellheads, and downhole drilling equipment.

8.2.2 Well Spacing

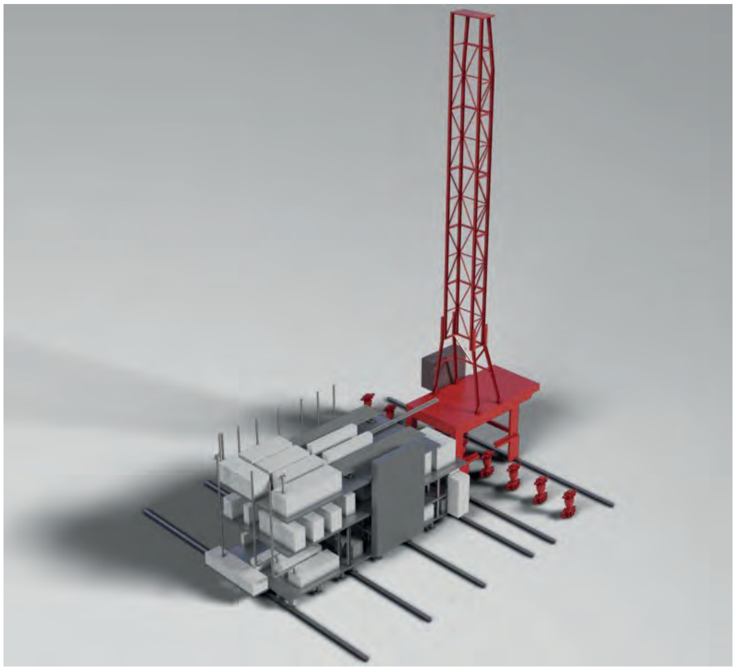
The well spacing evaluation included all factors around drilling unit design, thaw subsidence, access for well control, and overall island geometry. Accounting for these factors, it was determined that the wells would be drilled on 15 foot surface wellhead spacing. Once the wells are drilled and the drilling unit is out of the way, each well would have its own individual wellhouse, similar to the design used at Endicott and Northstar.

8.2.3 Drilling Unit Design

Several drilling unit designs and actual drilling units were considered for use on the LDPI, including existing North Slope style wheeled and skid-able rigs, a new build drilling unit based on traditional North Slope designs offered by a drilling contractor, and a drilling unit design that is optimized around mobility and functionality. The other type of drilling unit that was evaluated is a traditional offshore platform drilling unit, which allows for the drilling unit to skid from well to well within well bay (multiple rows) arrangement, or along a single well row using a skid beam or rail arrangement.

Of all the options that have been evaluated, the choice of drilling unit has been narrowed to two options. The first option is the use of an existing platform-style drilling unit that HAK owns and operates in the Cook Inlet. Designated as Rig 428, the rig has been used recently and is well suited in terms of depth and horsepower rating to drill the wells at Liberty. It consists of a drilling module and a utility module. In one proposed configuration, the drilling module would skid along the well row, and the utility module would skid along a second set of mat-supported skid beams. In this arrangement, both modules would move together from well to well, while minimizing access limitations to the neighboring wells. A 3-D rendering of Rig 428 in a land-based configuration is shown in Figure 8-2.

Figure 8-2. Drilling Unit – Modified Rig 428



A second option that is being investigated is a new build drilling unit that would be built to not only drill Liberty development wells, but would be more portable and more adaptable to other applications on the North Slope. Although Rig 428 could certainly drill the Liberty wells safely and efficiently, it may be found that financial funds to repower the rig and funds to modify a platform drilling unit for application at Liberty are better applied toward a new build drilling unit that can drill at other North Slope pads once drilling is complete at Liberty. A possible drilling unit layout of this type of unit is shown in Figure 8-3.

Figure 8-3. Drilling Unit - Option #2

Regardless of the drilling unit that will be chosen or built for the Liberty project, the drilling unit will include low emissions engines and will meet all the requirements as described in Section 8.3.1 below.

8.2.4 Drilling Support Modules

The space around the well row has been optimized by deploying a below-grade flowline arrangement, which allows for the pad space on both sides of the well row to accommodate all drilling functions. The south side of the well row (toward the facilities) is designed to accommodate the G&I plant, heated liquid mud mixing area, the bulk silos and dry bulk vacuum system for storing, moving, and mixing dry bulk mud products such as barite and bentonite, as well as dry bulk cement products. The G&I plant will be located close to the waste mud disposal well on the east end of the well row, with access areas reserved to move drill cuttings and waste mud from the drilling unit to the G&I facility for re-injection down the disposal well. The cement bulk plant is likely to be located on the far west end of the well row, and the bulk mud silos and liquid mud mixing equipment will be located toward the center of the well row. The other service units are mobile and will be located near the function they support.

8.3 Description of Drilling Rig (Drilling Unit)

Whether Rig 428 is upgraded, or a new drilling unit is built, the drilling unit will be powered with a new, low emission engines and new or re-conditioned drilling equipment. Safety features will include a surface hole diverter system; a main blowout preventer (BOP) stack consisting of 5,000 pounds per square inch (psi) annular preventer and 5,000 psi ram preventers (x3), adaptor spool, choke and kill lines, choke manifold, BOP control system, and remote panels; degasser; and drill string BOP devices. Fire/first aid items will include fire extinguishers, fire hoses, first aid kits, stretchers, breathing packs etc. The drilling unit will be designed and built in accordance with 30 CFR 250.459. A more detailed description of the well control and BOP system is described in Section 8.7 of this DPP.

8.3.1 Drilling Unit Power

The drilling unit will be powered with a set of diesel-driven internal combustion engines, and then once wells are flowing and fuel gas available, the drilling unit will be powered with a set of natural gas-fired internal combustion engines.

8.3.2 Drilling Unit Specification and Capabilities

Drilling unit construction or unit upgrades (if Rig 428) will begin as soon as all permits have been secured and the project is financially sanctioned. The drilling unit will include, at a minimum, the set of equipment shown in Table 8-1.

Table 8-1. Rig 428 Equipment Specifications

EQUIPMENT	RATING	NOTES
Draw Works	2100 HP rating	Modern, AC driven draw works.
Mast	1,000 kip rating	Compatible with top drive, casing running tool. Capable of standing back 20,000 feet of 5" drill string.
Crown Block	500 ton rating	
Traveling Block	500 ton rating	
Rotary	37.5 inch	For drill string make-up only.
Top Drive	40,000 to 60,000 ft-lbs torque	
Mud Pumps	2 x 1,700 HP triplex	5,000 psi fluid end.

Table 8-1. Rig 428 Equipment Specifications

EQUIPMENT	RATING	NOTES
Pit System	800 to 1,200 bbl	
BOP System	13-5/8", 5,000 psi	Standard surface BOP stack.
Power/Fuel	Diesel or Gas, capable of operating on electric	Rig will run off of diesel power for first three wells and if plant is down. Will run on natural gas when wells are flowing.
Drill Pipe	5, 4, 3.5 inch	Standard size, weight, and grade drill pipe.
HVAC	Boilers and Air Heaters	As required to operate in Arctic winter conditions.
Winterization System		Enclosed, insulated, and heated to allow continuous operation in Arctic winter conditions or fabricated using materials suitable for operation in low temperatures.
Move System		Skid beam (rail) arrangement on a set of parallel skid beams, either pile or mat supported
Workshop		As required to perform routine rig repairs and maintenance.
Warehouse		As required to manage critical rig spares inventory.
Camp	80 to 120 man	Camp to house drilling and facility construction personnel

8.3.3 Drilling Unit Mud Circulating and Pit System

The pit system will be designed to include up to 1,200 barrels (bbls) in the active system, with at least five compartments to manage the flow of drilling fluid from the return line to the suction tanks that supply the high pressure mud pumps. The solids control system will include multiple state-of-the-art shale shakers, a mud degasser, hydro-cyclones, and centrifuge to remove drill solids and maintain good fluid properties. The circulating system will include two or three high pressure triplex mud pumps capable of circulating up to 800 gallons per minute or circulating pressures up to 5,000 psi. The system will be designed and constructed in accordance with 30 CFR 250.458-459.

8.3.4 Drilling Unit Safety Equipment

The LDPI drilling unit will be designed with the following safety equipment.

- Well control equipment, including surface hole diverter system, main BOP stack, choke manifold, accumulator closing system, and control panels. The BOP stack will include shear rams. All blowout preventer equipment (BOPE) will meet regulatory standards.
- Flow monitoring system to detect downhole flow.
- Pit volume totalizer system to monitor drilling mud volumes in the drilling unit pits to allow detection of possible influx volume from downhole formations.
- Trip tank to monitor for proper hole fill when running drill pipe into and out of the well. Trip tank can help detect potential influxes from swab pressures and potential mud losses from surge pressures.
- Mud gas separator and vacuum degasser.
- Drill string and tubular BOP devices including inside blowout preventer (IBOP), full opening safety valve, upper and lower Kelley valves.
- Hydrogen sulfide (H_2S) and combustible gas detector and alarm systems.
- Fire detection and suppression system.
- Crown savers, mud pump pressure relief valves, and torque limiters.
- First aid equipment and supplies.

Note: A detailed description of the kick detection and BOPE is given in Section 8.7 of this plan.

8.3.5 Drilling Unit Fuel and Lubricants

Diesel fuel will be used to power the drilling unit until production is established and until fuel gas can be taken from the produced gas stream. Diesel will also be used to freeze-protect wellbores and pipelines when and where required to prevent fluid in the pipe from freezing.

Motor oil will be used in all internal combustion engines and most rotating equipment to minimize wear on bearing surfaces. Other type of lubricants such as grease, lube oil, and hydraulic oil will be required to run the drilling equipment. These chemicals will be regularly consumed as a dirty batch is replaced by clean, new lubricant. The expected usage of diesel fuel, freeze protection fluid, and lubricants is shown in Table 8-2.

Table 8-2. Drilling Unit Fuel and Lubricants

PRODUCT	TYPICAL USE	VOLUME USED (ESTIMATE)	STORAGE VOLUME
Arctic Grade Ultra Low Sulfur Diesel	Fuel for backup power generation, drilling operations, mobile equipment	7,500 gpd	500,000 gallons (storage in two double-walled above-ground storage tanks)
Arctic Grade Ultra Low Sulfur Diesel	Freeze Protection	4,200 gal/well	25,000 gal
Motor Oil		2,000 gal/well	4,000 gal/well
Other Lubricants		10 cases/well	20 cases
Hydraulic Fluid		200 gal/well	1,000 gal

8.3.6 Drilling Unit Pollution Prevention Equipment

The LDPI drilling unit will include the following pollution prevention equipment:

- A well cellar that has been approved as secondary containment.
- Secondary containment required to meet regulatory requirements.
- Fluid transfer procedures for fluid transfers to and from the drilling unit.
- A structure and drain system that also offers containment.

8.4 Well Design

8.4.1 Casing Design and Cementing Program

The casing design is similar for the producers and the injectors. Each will have the same casing size, and the casing shoes will be set at the same stratigraphic interval. The base design is as follows:

- **Conductor:** all wells will have 20” conductor driven to 160 feet total vertical depth subsea (TVDSS), which is about 140 feet below the mudline. The conductors will likely be driven with impact hammers at a time of year that whales are not present in the area.
- **Surface Casing:** 13-3/8” casing will be set in the SV5 shale at approximately 4,700 feet TVDSS, which gives adequate fracture gradient strength to drill the intermediate hole.

- **Intermediate Casing:** 9-5/8" casing will be set just above the top reservoir to case off the highly radioactive zone (HRZ) shale and provide for a good test of the casing shoe and casing integrity prior to drilling into the reservoir interval.
- **Production liner:** A 7" liner will be set through the entire reservoir section. Some wells may drill and expose the Kekiktuk Zone 1 interval. Adequate rathole or sump will be drilled along the zones of interest.

The surface casing will be cemented to surface with a cementing program that ensures adequate coverage without exceeding the fracture gradient at the casing shoe. During the final engineering phase, the drilling engineers will determine the slurry weight of the cement, as well as the use and location of cementing tools, including float equipment, stab-in devices, and stage tools if necessary. The intermediate casing will have adequate cement coverage to ensure pressure integrity at the shoe, and cement coverage in the annulus to ensure casing integrity and prevent external corrosion. The liner cementing program will be designed to allow for perforations in zones of production or injection, and ensure adequate wellbore integrity for the life of the well. All casing designs and cementing programs will be designed and executed in accordance with 30 CFR 250.420 – 428.

The cementing program will be based on current North Slope practices. It is anticipated that the surface casing job will utilize excess slurry along with two-stage cementing equipment in order to ensure cement slurry back to island surface. The intermediate casing cement will be displaced 1,500 feet above the shoe to ensure adequate protection across the lower zones. Liners will be completely cemented. The product, description, and expected usage of cementing chemicals is shown in Table 8-3.

Table 8-3. Summary of Chemicals Used in the Cementing Programs

CHEMICAL CONSTITUENTS (MAJOR COMPONENTS)	DESCRIPTION	PROJECTED AMOUNT[1, 2] (BBL/WELL)
17-1/2" Hole Surface Casing Cement, Tail Slurry, 1st Stage		450 bbl
Neat Cement	Class G	194,472 lb
Antifoam Agent, all purpose	D-046	400 lb
Dispersant	D-065	600 lb
Fluid Loss	D-167	700 lb
Fresh Water Spacer (D-182 & D-031)	Mud Push II	35 bbl
17-1/2" Hole Surface Casing Cement, Lead Slurry, 2nd Stage		1000 bbl
Cement	Arctic Lite CRETE	290,000 lbs
Fresh Water Spacer (D-182 & D-031)	Mud Push II	35 bbls
17-1/2" Hole Surface Casing Cement, Tail Slurry, 2nd Stage		90 bbl
Neat Cement	Class G	40,000 lb
Antifoam Agent, all purpose	D-046	80 lb
Dispersant	D-065	120 lb
Fluid Loss	D-167	150 lb
12-1/4" Hole Intermediate Casing Cement, Tail Slurry		130 bbl
Neat Cement	Class G	56,000 lb
Antifoam Agent, all purpose	D-046	111 lb
Dispersant	D-065	170 lb
Fluid Loss	D-167	200 lb
Antisettling	D-153	111 lb

Table 8-3. Summary of Chemicals Used in the Cementing Programs

CHEMICAL CONSTITUENTS (MAJOR COMPONENTS)	DESCRIPTION	PROJECTED AMOUNT[1, 2] (BBL/WELL)
Retarder	D-177	12 gal
Fresh Water Spacer (D-182 & D-031)	Mud Push II	35 bbls
8-1/2 Hole Production Casing Cement, Tail Slurry		80 bbl
Neat Cement	Class G	33,000 lb
Antifoam Agent, all purpose	D-047	70 gal
Dispersant	D-065	163 lb
Gasblock	D600G	695 gal
Fluid Loss	D167	65 lb
Retarder	D177	21 gal
Fresh Water Spacer (D-182 & D-031)	Mud Push II	35 bbls

Notes:
1. Amounts for the drilling and completion fluid are estimated and are calculated from hole volume including washouts.
2. No drilling fluids are planned for surface discharge to the marine environment. Waste drilling and completion fluids will be disposed of through a permitted disposal well or backhauled to a permitted waste management facility.

8.4.2 Completion Design, Tubing Size

The completions will be optimized in terms of perforated interval, packer setting depth, and in some cases, the tubing size. The base plan is to drill an 8-1/2” hole through the reservoir section and set a 7” liner. This allows for a packer to be set up in the intermediate casing, with tubing tail into the liner. The proposed tubing size and completion design for the three types of wells is described below:

- **Oil producers** - predominantly 5-1/2” tubing, which allows for higher flow rates per well than smaller tubing. Gas lift mandrels will be spaced to kick-off the well and lift the well from just above the packer.
- **Water injectors** - 5-1/2” tubing required for maximum injection rate with minimal pressure loss. Packer will be set at bottom of the intermediate casing or near the top of the production liner. The injectors may require future intervention for profile modification, so monobore completions with 5-1/2” liner and 5-1/2” tubing are being considered as a way to allow for thru-tubing changes in the injection profile.
- **Gas injectors** - 5-1/2” tubing is required for maximum injection rate and minimum compression horsepower. Monobore completions may be used on some of these wells.

The injectors, both gas and water, will have plastic-lined L80 carbon steel tubing installed to minimize the effects of corrosion caused by oxygen entrainment in the water. Special metallurgy is not required for injectors. Oil producers will have 13 percent chromium tubing installed. The metallurgy for the liner and the wellhead/Xmas of producers will be designed to minimize the corrosion effects of high concentrations of carbon dioxide.

The producers and injectors will have surface controlled subsurface safety valves (SSSV). The dedicated water injectors will have injection valves installed. All SSSVs and check valves will be wireline retrievable. All completion and wellhead/Xmas tree equipment will be rated to 5,000 psi. Completions will be designed and implemented in accordance with 30 CFR 250.500-531 of Subpart E – Oil and Gas Well Completion Operations. Diagrams of the proposed completion designs are shown in Figure 8-4 and Figure 8-5.

Figure 8-4. Typical Oil Well Completion

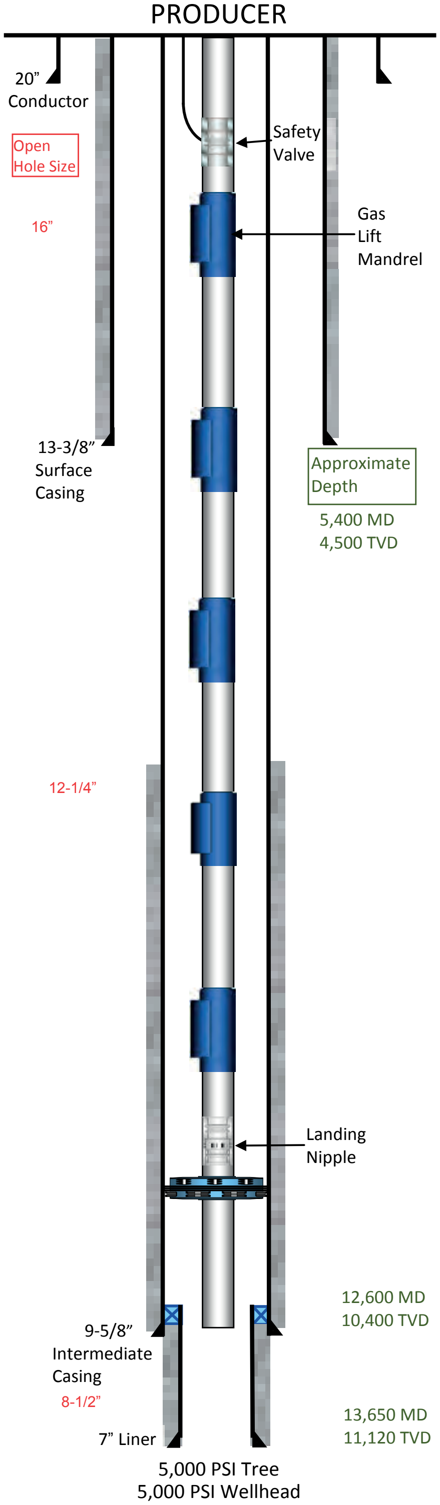
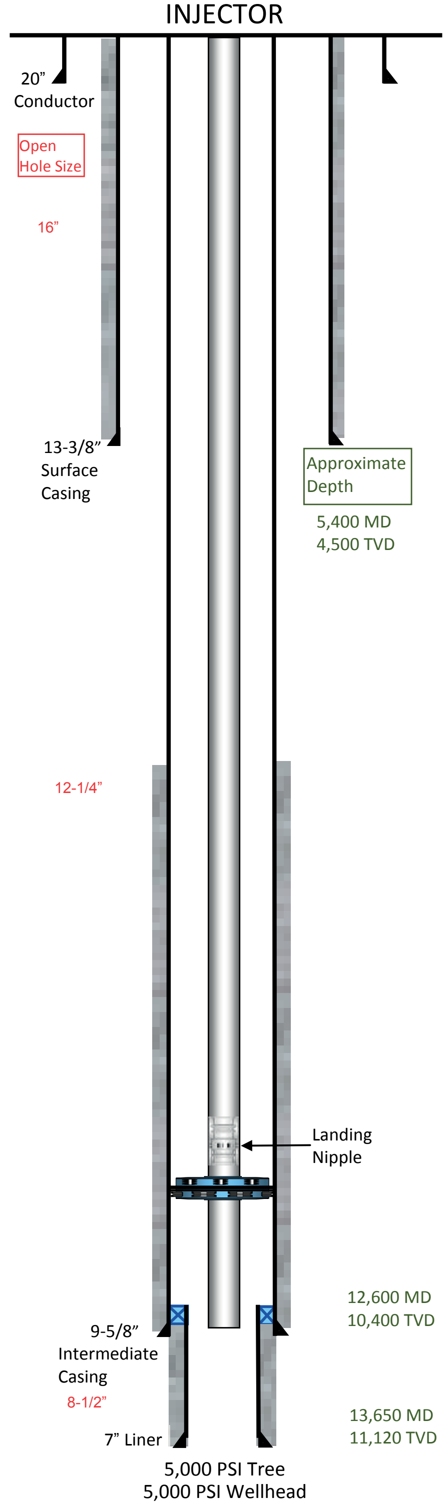


Figure 8-5. Typical Injection Well Completion



8.4.3 Drilling Fluid Program

The drilling fluid program will be designed to meet all the objectives of proper mud weight, rheological properties, lubrication, and cuttings removal. The drilling fluids will be tailored for each hole section, based on the specifics around hole size, circulating rates, and the type of formation that will be drilled. The drilling program will be designed and maintained in accordance with 30 CFR 250.455-459.

Drilling fluids for Liberty will be seawater based, which differs from the normal North Slope drilling fluids which are freshwater based. Given the location of LDPI with no year-round supply of fresh water available and limited storage capacity on the island, freshwater mud systems are not considered a viable option. The surface hole will be drilled with a seawater spud mud with the required viscosity for effective hole cleaning. Lost circulation materials may be required. The intermediate hole will be drilled with a non-dispersed low solids seawater/polymer mud with the mud weight necessary to control pore pressure and maintain hole stability while drilling the HRZ shale. The actual mud weight will be determined based on hole conditions and instrument readings, but it is likely to be in the range of 9.5 pounds per gallon (ppg) to 11.0 ppg. The Kekiktuk reservoir interval will be drilled with the same drilling fluid system as the intermediate hole, but with a density that is suited to the production interval, which may be less than what was required to maintain hole stability in the intermediate section. No drilling fluids are planned for surface discharge to the marine environment. Waste drilling and completion fluids will be disposed of through a permitted disposal well or backhauled to a permitted waste management facility. The product, description, and expected usage of mud chemicals is shown in Table 8-4.

Table 8-4. Summary of Drilling Fluids and Drilling Fluid Chemicals

CHEMICAL CONSTITUENTS (MAJOR COMPONENTS)	DESCRIPTION	USAGE RATE[1] (BBL/DAY)	PROJECTED AMOUNT (BBL/WELL)
Sea Water Based Spud Mud (17.5 inch Hole)		1,500	6,000
Aquagel	Bentonite Clay		100,000 lbs
Barite	Barium Sulfate		200,000 lbs
Barazan D	Viscosifier		8,000 lbs
Soda Ash	Alkalinity Agent		8,000 lbs
PacL	Cellulose Polymer		20,000 lbs
Con Det	Wetting agent		50,000 lbs
Drill N Slide	Lubricant		25,000 lbs
Caustic	NaOH/KOH		4,000 lbs
Low Solids, Non- Dispersed SW based Drilling Fluid (12-1/4" & 8-1/2" Hole Sections)		700	10,000 bbl
KCL	Salt/Shale stabilizer		250,000 lb
Barazan D	Viscosifier		25,000 lbs
PacL	Cellulose Polymer		32,000 lbs
Dextrid	Starch/Filtration Control		32,000 lbs
Barotrol	Shale stabilizer		60,000 lbs
BDF-515	Filtration Control		60,000 lbs
Aldacide	Biocide		20,000 lbs
Baracor 700	Corrosion Inhibitor		16,000 lbs

Table 8-4. Summary of Drilling Fluids and Drilling Fluid Chemicals

CHEMICAL CONSTITUENTS (MAJOR COMPONENTS)	DESCRIPTION	USAGE RATE[1] (BBL/DAY)	PROJECTED AMOUNT (BBL/WELL)
Barascav D	Oxygen Scavenger		8,000 lbs
Baroid 41	Barium Sulfate		500,000 lbs
Contingency Chemicals			
Baracarb 5	Lost circulation Material, calc carb		50,000 lbs
Baracarb 25	Lost circulation Material, calc carb		50,000 lbs
Baracarb 50	Lost circulation Material, calc carb		50,000 lbs
Baracarb 150	Lost circulation Material, calc carb		10,000 lbs
Steelseal 50	Graphite based LCM		25,000 lbs
Steelseal 100	Graphite based LCM		25,000 lbs
Steelseal 400	Graphite based LCM		25,000 lbs
Baroseal F	Fibrous LCM		15,000 lbs
Baroseal M	Fibrous LCM		15,000 lbs
Barofibre	Fibrous LCM		15,000 lbs
Black Magic	Lubricant		5,000 lbs
NXS Lube	Lubricant		50,000 lbs
Baroid 41	Barium Sulfate		500,000 lbs
Completion Fluid		500	2,500
Sodium Chloride	NaCl		50,000 lbs
Potassium Chloride	KCl		20,000 lbs
Corrosion Inhibitor	Amine Based		10,000 lbs

Note:
1. Usage rates for the drilling and completion fluid are estimated.

8.4.4 Directional Drilling and Surveying

The well profiles that have been designed for all wells are based on a simple "build and hold" slant well, with tangent angles below 65 degrees that will allow for wireline and/or coiled tubing intervention on all wells. Kick-off depths will be staggered at approximately 1500 feet true vertical depth (TVD), and the build rates will be provisionally planned at 3 to 4 degrees/100 feet maximum for surface and intermediate hole sections. The spider plot of Liberty locations and well trajectories is shown in Figure 8-6 and Figure 8-7. The wells are within a 2-mile radius of the island.

Table 8-5 lists the measured depth, TVD, departure, and the surface and bottom hole total depth coordinates for all the wells.

Directional surveys will be gathered on a real-time basis with measurement while drilling (MWD) tools or with wireline devices as necessary to monitor the location of the wellbore at all times. Directional surveying will be conducted in accordance with 30 CFR 250.461.

Figure 8-6. 2D Spider Plot of Liberty Wells

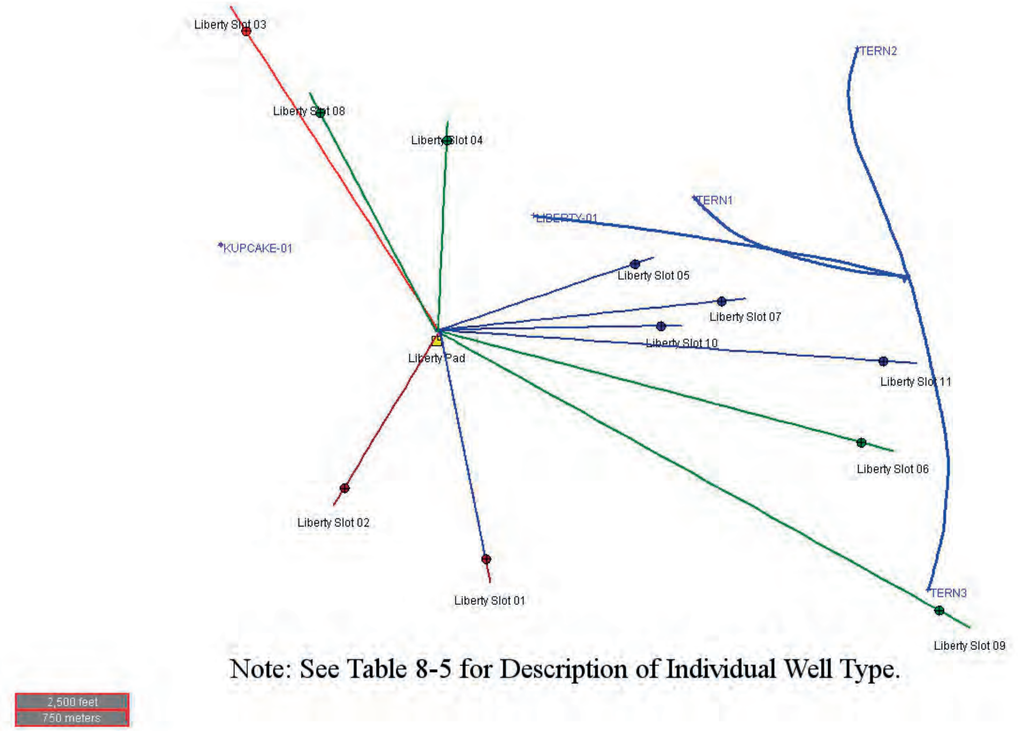


Figure 8-7. 3D Spider Plot of Liberty Wells

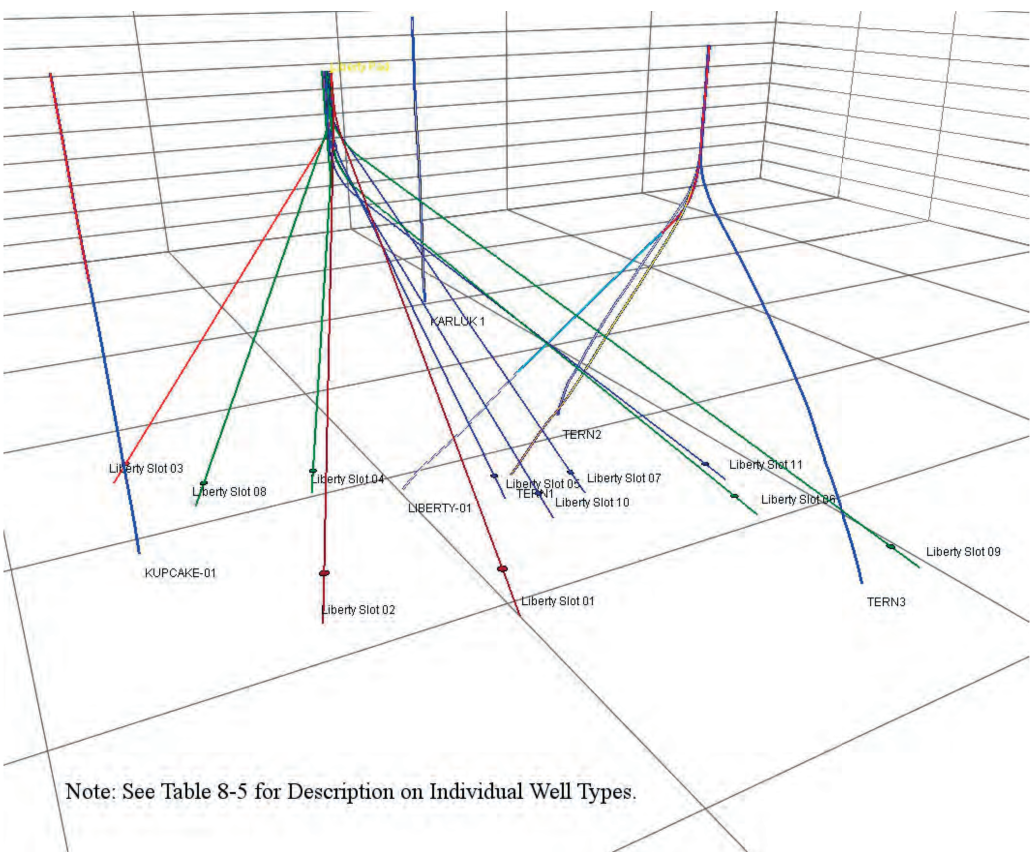


Table 8-5. Well Depth and Bottom Hole Locations

Well Name	Reservoir	Type	Order	Surface Location		Top Reservoir		Top of Reservoir Location		Total Depth		Bottom Hole Location		Inc	Azimuth	Logging Method	Well Stepout	Casing Design
(Slot No.)				Easting (ASP3 ft US-NAD 83)	Northing (ASP3 ft US-NAD 83)	TVD (ft SS)	MD (ft RKB)	Easting (ASP3 ft US-NAD 83)	Northing (ASP3 ft US-NAD 83)	TVD (ft SS)	MD (ft RKB)	Easting (ASP3 ft US-NAD 83)	Northing (ASP3 ft US-NAD 83)	(Degrees)	(degrees)		(ft)	
Slot 1		Back up Disposal Well		1,444,783.75	5952626.52	-9000.00	10491.00	1445802.219	5947570.947	9843.00	11491.00	1445908.22	5,947,043.94	32.50	167.00	LWD/WL	5695.00	2 strings
Slot 2	Ugnu/SV	Disposal	1	1,444,769.25	5952630.43	-9000.00	9957.00	1442652.247	5949150.896	9895.00	10957.00	1442420.25	5,948,769.89	26.50	210.00	LWD/WL	4519.00	2 strings
Slot 3	K1	Far North Gas Injector	2	1,444,754.75	5952634.35	-10500.00	13350.00	1440462.192	5959310.978	11267.00	14350.00	1440115.32	5,959,850.98	39.90	325.70	LWD/WL	8579.50	3 strings
Slot 4	K1	Central Producer	3	1,444,740.25	5952638.27	-10745.00	11643.00	1444932.157	5956881.016	11659.00	12644.00	1444950.15	5,957,285.02	23.80	1.10	LWD/WL	4652.00	3 strings
Slot 5	K1	Northern Water Injector	4	1,444,725.75	5952642.18	-10720.00	11809.00	1449112.126	5954131.061	11615.00	12809.00	1449534.12	5,954,274.07	26.50	69.75	LWD/WL	5079.00	3 strings
Slot 6	K1	South Central Producer	5	1,444,711.25	5952646.10	-10800.00	15057.00	1454152.091	5950161.132	11472.00	16057.00	1454868.09	5,949,972.15	47.75	103.26	LWD/WL	10503.00	3 strings
Slot 7	K1	Central Water Injector	6	1,444,696.75	5952650.02	-10720.00	12600.00	1451042.108	5953301.089	11558.00	13600.00	1451585.10	5,953,357.10	33.00	82.70	LWD/WL	6925.00	3 strings
Slot 8	K1	Northern Producer	7	1,444,682.25	5952653.93	-10680.00	12111.00	1442112.187	5957490.979	11551.00	13111.00	1441882.19	5,957,924.98	29.40	330.50	LWD/WL	5969.00	3 strings
Slot 9	K1	Far South Producer	8	1,444,667.75	5952657.85	-10880.00	17179.00	1455882.134	5946431.174	11482.00	18179.00	1456580.15	5,946,043.20	53.00	117.50	LWD/WL	13626.00	3 strings
Slot 10	K1	Southern Water Injector	9	1,444,653.25	5952661.77	-10760.00	12050.00	1449692.129	5952751.062	11636.00	13050.00	1450174.12	5,952,760.07	28.80	87.50	LWD/WL	5522.00	3 strings
Slot 11	K1	South Central Producer	10	1,444,638.75	5952665.68	-10770.00	15264.00	1454639.072	5951971.148	11427.00	16264.00	1455391.09	5,951,919.17	49.00	92.50	LWD/WL	10779.00	3 strings
Slot 12		Open		1,444,624.25	5952669.60	Future Development well to be drilled as required												
Slot 13		Open		1,444,609.75	5952673.52	Future Development well to be drilled as required												
Slot 14		Open		1,444,595.25	5952677.43	Future Development well to be drilled as required												
Slot 15		Open		1,444,580.75	5952681.35	Future Development well to be drilled as required												
Slot 16		Open		1,444,566.25	5952685.27	Future Development well to be drilled as required												

Well Name	Reservoir	Type	Order	Surface Location				Top of Reservoir Location				Bottom Hole Location			
(Slot No.)				Lat_DD NAD83	Lon_DD NAD83	Lat_DMS NAD83	Lon_DMS NAD83	Lat_DD NAD83	Lon_DD NAD83	Lat_DMS NAD83	Lon_DMS NAD83	Lat_DD NAD83	Lon_DD NAD83	Lat_DMS NAD83	Lon_DMS NAD83
Slot 1		Back up Disposal Well		70.27522868	-147.5827198	70° 16' 30.823" N	147° 34' 57.791" W	70.261493	-147.573427	70° 15' 41.374" N	147° 34' 24.337" W	70.26006077	-147.5724603	70° 15' 36.219" N	147° 34' 20.857" W
Slot 2	Ugnu/SV	Disposal	1	70.27523835	-147.5828378	70° 16' 30.858" N	147° 34' 58.216" W	70.265584	-147.599217	70° 15' 56.101" N	147° 35' 57.182" W	70.26452638	-147.6010112	70° 15' 52.295" N	147° 36' 3.640" W
Slot 3	K1	Far North Gas Injector	2	70.27524801	-147.5829559	70° 16' 30.893" N	147° 34' 58.641" W	70.293175	-147.619103	70° 17' 35.430" N	147° 37' 8.771" W	70.29462461	-147.622027	70° 17' 40.649" N	147° 37' 19.297" W
Slot 4	K1	Central Producer	3	70.27525768	-147.583074	70° 16' 30.928" N	147° 34' 59.066" W	70.286859	-147.582414	70° 17' 12.694" N	147° 34' 56.692" W	70.28796409	-147.5823538	70° 17' 16.671" N	147° 34' 56.474" W
Slot 5	K1	Northern Water Injector	4	70.27526735	-147.5831921	70° 16' 30.962" N	147° 34' 59.491" W	70.279642	-147.548028	70° 16' 46.712" N	147° 32' 52.900" W	70.28006202	-147.544644	70° 16' 48.223" N	147° 32' 40.719" W
Slot 6	K1	South Central Producer	5	70.27527702	-147.5833101	70° 16' 30.997" N	147° 34' 59.917" W	70.269144	-147.506468	70° 16' 8.920" N	147° 30' 23.284" W	70.26867655	-147.5006417	70° 16' 7.236" N	147° 30' 2.310" W
Slot 7	K1	Central Water Injector	6	70.27528668	-147.5834282	70° 16' 31.032" N	147° 35' 0.342" W	70.277509	-147.532249	70° 16' 39.031" N	147° 31' 56.095" W	70.27769891	-147.5278685	70° 16' 39.716" N	147° 31' 40.327" W
Slot 8	K1	Northern Producer	7	70.27529635	-147.5835463	70° 16' 31.067" N	147° 35' 0.767" W	70.288324	-147.605361	70° 17' 17.965" N	147° 36' 19.298" W	70.28949235	-147.6073144	70° 17' 22.172" N	147° 36' 26.332" W
Slot 9	K1	Far South Producer	8	70.27530602	-147.5836644	70° 16' 31.102" N	147° 35' 1.192" W	70.259073	-147.491742	70° 15' 32.662" N	147° 29' 30.273" W	70.25805982	-147.4860256	70° 15' 29.015" N	147° 29' 9.692" W
Slot 10	K1	Southern Water Injector	9	70.27531568	-147.5837824	70° 16' 31.136" N	147° 35' 1.617" W	70.275913	-147.543054	70° 16' 33.287" N	147° 32' 34.993" W	70.27597111	-147.5391577	70° 16' 33.496" N	147° 32' 20.968" W
Slot 11	K1	South Central Producer	10	70.27532535	-147.5839005	70° 16' 31.171" N	147° 35' 2.042" W	70.274121	-147.502892	70° 16' 26.836" N	147° 30' 10.412" W	70.27402977	-147.4968009	70° 16' 26.507" N	147° 29' 48.483" W
Slot 12		Open		70.27533502	-147.5840186	70° 16' 31.206" N	147° 35' 2.467" W	Future Development well to be drilled as required							
Slot 13		Open		70.27534468	-147.5841367	70° 16' 31.241" N	147° 35' 2.892" W	Future Development well to be drilled as required							
Slot 14		Open		70.27535435	-147.5842548	70° 16' 31.276" N	147° 35' 3.317" W	Future Development well to be drilled as required							
Slot 15		Open		70.27536402	-147.5843728	70° 16' 31.310" N	147° 35' 3.742" W	Future Development well to be drilled as required							
Slot 16		Open		70.27537368	-147.5844909	70° 16' 31.345" N	147° 35' 4.167" W	Future Development well to be drilled as required							

8.4.5 Data Acquisition

LWD (logging while drilling) tools in the drill string will be utilized to capture formation data as it is being drilled. There will also be an electric wireline logging unit on the island to support drilling and completion operations. Open hole logging is anticipated in some upper hole sections and all production hole sections. Some cased hole logging operations will also be carried out.

8.5 Drilling Waste Management

Given the remoteness of Liberty to the existing North Slope infrastructure, the processing and disposal of drilling, camp, and production waste must be carried out at the island. Minimizing all waste volumes generated will be a priority. Drilling waste management for the Liberty development is a critical process in the drilling operation. Waste disposal must take place concurrently with waste generation, as limited cuttings or fluids storage areas exist on the island to accommodate a backlog waiting processing. Section 11.12 discusses Liberty waste management in more detail.

8.5.1 Disposal Well

The largest waste stream generated during drilling operations is drilling fluid and drilled cuttings. A waste disposal well will be the first well to be drilled at Liberty so that cuttings and fluids from subsequent wells can be processed through the G&I facility and disposed down the well. The waste disposal well will be completed in the West Sak/Ugnu Formation between 6,600 and 7,900 feet TVDSS or the Lower Sagavanirktok Formation between 5,350 and 6,600 feet TVDSS, depending upon the permeability of the zones. The 2000 Liberty DPP, Appendix A, describes the general geology of the Liberty area and contains a detailed description of the geology of the proposed injection and confining zones. A second disposal well is planned as a contingency well should problems arise with the first well or a second waste disposal well is needed.

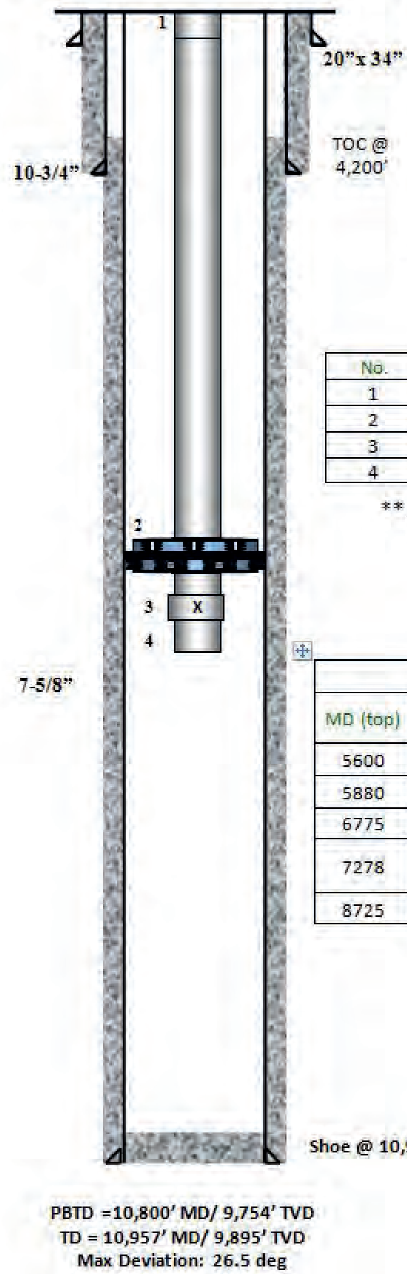
The cuttings and fluids from the disposal well may be temporarily stored on the Liberty pad or at an onshore facility pending disposal. Temporary storage on the LDPI would be in a bermed, lined area. Once the disposal well and injection facilities are commissioned, drilling wastes will be disposed of downhole in the disposal well on the LDPI or at another approved disposal well.

Two disposal wells will be permitted, but only one will be drilled initially. The second well will only be drilled if the original well becomes damaged or unusable beyond repair. As a contingency, disposal permits for annular injection will be obtained with each permit to drill application. If the disposal well experiences downtime, drill fluids and cuttings can be processed and disposed of via annular injection.

Injection wells have been in use on the North Slope of Alaska for more than 30 years without serious mishap. Injection wells are required to be sited and designed to protect any underground potential source of drinking water. They must be constructed to contain the injected material in a specific geological zone, adequately isolated to protect potential drinking water. Wells are tested during the construction process to assure casing is tightly set in targeted formations, and wells are monitored throughout operations to assure they have maintained their mechanical integrity and continue to protect potential drinking water and contain the waste in the designated waste injection zone.

Figure 8-8 provides a schematic of the planned LDPI Disposal Well. Each casing is cemented into its position, and cement tested for soundness before drilling the hole for the next casing. The tubing, which carries the injected waste, is set in place with a packer. The annulus between the tubing and casing is monitored to confirm the packing is tight, and all injection is taking place below the tubing and into perforations designed to convey the water to the receiving formation. The tubing and packer can be removed for maintenance, should the monitoring indicate that maintenance is required. Mechanical integrity of the disposal well will be determined following commonly accepted standards and codes including pressure testing of the annular space. All casing designs, cementing programs, and testing will meet the requirements of 30 CFR 250.420-428.

Figure 8-8. Injection Well Schematic



CASING DETAIL							
Size	Type	Wt	Grade	Conn.	ID	Top	Btm
20" x 34"	Conductor	78.6# 123.65#	A-53	Weld	19.25"	Surf	80'
10-3/4"	Surf. Csg	45.5	L-80	BTC	9.950"	Surf	5,200'
7-5/8"	Prod. Csg	29.7	L-80	BTC	6.875"	Surf	10,957'
TUBING DETAIL							
4-1/2"	Tubing	12.6	L-80	BTC-mod	3.958"	Surf	5,700'

JEWELRY DETAIL

No.	Depth	ID	OD	Item
1	18'	4.00"	-	Tubing Hanger, 4-1/2"
2	~5,600'			7-5/8" x 4-1/2" Retrievable Production Packer
3	~5,650'			4-1/2" X-Nipple
4	~5,700'			4-1/2" Tailpipe

** Jewelry set depths will be finalized after reviewing the open hole logs **

Formation Tops				
MD (top)	TVDss (top)	MD (btm)	TVDss (btm)	Item
5600	5100	5880	5350'	Sagavanirktok Formation (Upper Confining Zone)
5880	5350	6775	6150	Sagavanirktok Formation (Upper Injection Zone)
6775	6150	7278	6600	Sagavanirktok Formation (Upper Injection Zone)
7278	6600	8725	7900	West Sak / Ugnu Formations (Lower Injection Zone)
8725	7900	9070	8200	Canning Fmr (Lower Confining Zone)

8.5.2 Cuttings Processing and Injection Equipment

Cuttings will be processed by a ball mill or similar grinding equipment to a size capable of injecting down the disposal well. A size classification system using screens and/or hydro-cyclones will allow the finely ground cuttings to be blended into a slurry while routing the larger cuttings particles to the grinding equipment for size reduction and then blended into the slurry. Cuttings and mud will be mixed in a slurry and injected by pumping down the disposal well. The mud and cuttings drilling wastes will be processed real-time with the drilling operation (no long-term on-site storage available). The mud and cuttings processing equipment may either be part of the drilling unit equipment or a separate stand-alone facility, depending on the final drilling unit configuration.

8.6 Drilling Supply Chain and Logistics

8.6.1 General

As described in Section 5 of this DPP, because LDPI is not connected by road to the existing North Slope infrastructure, the drilling operation will rely heavily on the ability of storing sufficient drilling equipment and consumables on site for the periods of non-supply between ice roads (January to April-May) and open-water season (July to September).

The drilling unit and ancillary equipment will be mobilized via barge to the LDPI during open-water season Year 2. Drilling consumables (casing, tubing, mud, cement) will initially be transported to the LDPI to allow drilling to commence in 3Q Year 2. Drilling cement will be transported in bulk sacks and transferred to silos for storage on the island. Liquid drilling fluid products will be shipped in 55-gallon drums or 15- or 30-barrel totes as needed, and dry mud product will be shipped in bulks sacks. Initial transportation of drilling fluids and chemicals will be by barge during the open-water mobilization of the drilling rig, support infrastructure, and drilling materials. Drilling fluids and chemicals will be resupplied as required by winter ice road and summer barge support. It is anticipated that adequate drilling materials will be stored on LDPI to allow continuous drilling operations during the shoulder season when there is no barge or ice road support. It is therefore anticipated that transport will occur every 3 months, and the maximum volume of transported fluids and chemicals at any one time will be approximately 2 wells worth. The usage rates of drilling fluids and chemicals per well are shown in DPP Tables 8-3 and 8-4. Re-supply as needed outside of the shoulder seasons will occur via barge in the summer and by ice road in the winter. Personnel, lighter-weight equipment and freight (including groceries) may be transported by helicopter or hovercraft during shoulder seasons. It is intended that the helicopter selected will be capable of carrying sling loads such that small equipment used to support the drilling, facilities, and production operations can be moved from and to LDPI any time of year.

8.6.2 Island Storage Requirements

The drilling footprint on the island will be used for storage of the following items in addition to the drilling unit and its movements:

- **Bulk Plant:** the plant will include an enclosed cutting station, compressor, and small electrical generator to supply power for lights and heat. It is intended that bulk materials will be blown from the storage silos to the cement pumping unit or mud mixing tanks.
- **Mud Materials:** storage silos will be dedicated for barite as well as 1-ton bags. Included in the volume of barite to be stored will be an amount sufficient to increase mud density to handle a well control situation on the longest well drilled immediately prior to a re-supply period. Other dry mud materials will be stored in mud boxes to keep them out of the weather and minimize loss to damaged bags.
- **Cement Materials:** Storage silos will be dedicated for cement storage as well as 1-ton bags. Also included will be a blend tank, vacuum or blow facilities, and cement blending facilities.
- **Tubulars:** will be stored on pipe racks on the island.
- **Completion Equipment and Wellheads/Xmas Trees:** an area will be required for trees and wellheads, packer, safety valves, gas lift mandrels, and other completion equipment.
- **Diesel Storage:** diesel will be provided to drilling from the facilities diesel storage tank.

- **Cement Unit:** an electric cement unit will be located on the island to support drilling and completion operations.
- **Logging Unit and Service Building:** an electric logging unit will be located on the island to support drilling and completion operations.

In addition, during the winters when production well drilling is occurring, an additional storage area of approximately 350 by 700 feet may be built on the sea ice on the east side of the island. This site would be used to store tubulars and other clean materials.

8.7 Liberty Well Control and Emergency Response

The primary well control mechanism for the Liberty development drilling program will be the hydrostatic pressure exerted by the drilling fluid. The optimal mud weight used will be based on information gathered on offset wells including Liberty No. 1, the Tern Island wells, and wells drilled at the Endicott field. Other engineering decisions that factor into the primary well control plan include casing setting depths, casing burst ratings, fracture gradient of the exposed shoe, and pressure losses while circulating. All data of a geologic and engineering essence have been included in the drilling design basis, which defines the proposed mud weights, casing design, and proposed circulating system practices. Note: The drilling fluid program will be designed and implemented in accordance with 30 CFR 250.455-459.

The secondary well control mechanism for the Liberty development drilling program equipment is a BOP system, which includes the equipment, personnel, and procedures used to detect a kick and control a well that has been exposed to an underbalance condition. A description of the three components of this system is given below:

8.7.1 Equipment

Equipment is composed of kick detection equipment and well shut-in or BOPE, as described below:

8.7.1.1 Kick Detection, Kick Prevention Equipment

As described above, the primary well control mechanism is mud weight. Equipment that is used to determine the pore pressure of the formation that is being drilled, and the necessary mud weight to control said pressure includes equipment operated by the Mud Logger, and equipment that is part of the drilling unit, as listed below:

- **Gas detection, gas measurement** – Used to detect and measure gas that is circulated to the surface with the drilling mud that was in the pore space of the drilled formation, or has flowed into the wellbore. Measurements and changes in "background gas," "connection gas," and "trip gas" provide indications of the presence of gas and whether the hydrostatic pressure of the mud column is above or below the pore pressure of the formation.
- **Presence of shows** – Equipment used to measure and analyze the presence of oil or gas in the cuttings or in the mud. Used to estimate the location of hydrocarbons in the formation.
- **LWD tools –** These are downhole tools that measure properties of the drilled formation including resistivity, porosity, and density. These data are used to estimate the presence of hydrocarbons and its flow potential, and indicates whether pore pressure is increasing in depth.
- **Mud flow sensors, mud pit volume totalizers** – This equipment is used to measure the flow of mud coming out of the well and compared to flow rate in to determine if there is influx into the wellbore from the formation.
- **Trip tank –** This is a dedicated tank that is used to measure the volume of mud required to replace the volume of the drill string that is being removed from the hole during the trip. If the

hole is not taking as much fluid as the volume of steel being removed, it is an indicator that there is an influx into the well from the formation.

- **Mud gas separator and vacuum degasser** – This equipment is that part of the mud circulating system that separates gas from mud. It allows for delivery of gas entrained in the drilling fluids, or gas from a kick, away from the drilling unit.

Note: The equipment used to monitor the drilling fluids will be designed and implemented in accordance with 30 CFR 250.457.

8.7.1.2 Blow Out Preventer Equipment

Rig 428 is outfitted with a standard surface BOP stack, which will include shear rams and the other equipment that is required to shut-in a well that has been exposed to an underbalance condition and has "taken a kick." A short description of this equipment is given below. Note: All BOPE including the surface stack, choke manifold, accumulator unit, Kelley valves, stab in floor valve, and IBOPs are designed, installed, maintained, tested, and inspected in accordance with 30 CFR 250.440-441 and CFR 250.443-451.

- **Surface hole diverter system** – Includes an annular type preventer, knife gate valve, a diverter spool, and diverter line (flowline) to allow for diversion of produced fluid away from the drilling unit area if a kick is taken while drilling the surface hole section. This is replaced with the full annular with 3 ram BOP stack after surface casing is set and cemented. The diverter is designed, installed, and maintained in accordance with 30 CFR 250.430-434.
- **BOP stack, accumulator system, and choke manifold** – Includes from bottom to top: wellhead or mud cross, three sets of ram type preventers, an annular type preventer. One of the ram type BOPs includes blind-shear rams that can cut drill pipe in the hole.
- **Accumulator system** – This is also referred to as a closing unit. It is the self-contained hydraulic system with redundant power sources used to actuate the ram preventers, annular BOP unit, and hydraulically operated valves associated with the BOPE.
- **Choke manifold** – Used to circulate and control the flow of fluids into or out of the well. The choke manifold is designed and installed in accordance with 30 CFR 250.444.
- **Drill string and inside tubular BOP devices** – These are machined subs with integrated valves that are screwed into drill pipe connections on the drill string to prevent flow from coming up the inside of drill pipe. This equipment is designed and installed in accordance with 30 CFR 250.445.

8.7.2 Personnel – Training, Certifications, and BOP Drills

The HAK operated drilling unit on the Liberty project will be continuously supervised by a Drilling Supervisor, who will be an experienced drilling professional versed in all issues related to primary and secondary well control. At any given time, there is one individual in charge of all decisions related to well control. Due to the remote nature of this work, the "Drilling Supervisor" position is staffed with two individuals on-site at all times who each work a daily schedule of 12 hours on, 12 hours off. With a work schedule of 2 weeks on, 2 weeks off, there will be a total of four Drilling Supervisors assigned to this project. All Drilling Supervisors will be trained and certified in well control topics in accordance with CFR 250.1500-1510 according to Subpart O – Well Control and Production Safety Training.

In addition to the Drilling Supervisors, all supervisory and senior members of the drilling contractor crew including the Toolpusher, Driller, Assistant Driller (if required), and Derrickmen will be "BOP certified" in accordance with 30 CFR 250 Subpart O and the training program will be periodically assessed by the Bureau of Safety and Environmental Enforcement (BSEE). Crews will be trained to identify warning signs of hazards and to avoid escalation. The curriculum consists of training in blowout prevention technology and well control. Certified training of personnel will include hands-on simulator practice for recognizing an influx, well shut-in, and circulating the influx out of the wellbore. Well-specific shut in procedures will be posted on the drilling unit. All of these individuals will know how to operate the BOPE, and all will know what signs to look for as indicators of underbalance drilling conditions.

Personnel will be trained and drilled on how to quickly recognize, communicate, and react to abnormalities. Kick detection and well control drills will be routinely conducted and documented. The drills cover the basic drilling unit operations where well control issues could happen, such as on bottom drilling, tripping pipe, running casing, and drill pipe out of the hole. The purpose of these drills is to reduce time for Driller, drill crew, and mud loggers to detect and react to early well control indicators.

All drilling supervisory staff and all members of the drilling crew will participate in well control drills on a periodic basis to ensure everyone knows their responsibilities and how to carry them out. Well Control drills will be conducted in accordance with 30 CFR 250.462.

8.7.3 Procedures and Guidelines

Maintaining well control is the top priority of any drilling program. To prevent loss of well control, HAK Drilling Engineers design the well casing, cement system, and drilling mud program to maintain well control and mechanical integrity of the well at all times. During drilling operations, monitoring and measurements systems are used by trained professionals to assess current drilling conditions and ensure well control. Drilling parameters are adjusted as required to maintain well control. The practices and equipment that HAK will deploy have been tested and proven elsewhere. Described below is how HAK combines proper equipment with properly trained personnel to design a system that will prevent loss of well control at the Liberty project.

8.7.3.1 Well Planning and Well Design

Each well will be drilled according to a location-specific, detailed well plan after BSEE approves the Application for Permit to Drill (APD). The process to prevent a loss of well controls starts with well planning and well design. Well control is integral to the well planning phase. This drilling team analyzes all data including: seismic data, well data from analogous wells, and regional models to predict pore pressure and fracture gradients, formation depths, and to develop a detailed understanding of the reservoir. Drilling engineers use pressure predictions from this process to design drilling mud programs with sufficient hydrostatic head to overbalance the formation pressures from surface to total well depth. In addition to reservoir pressures, other factors influencing the mud weight program include shale conditions, fractures, lost circulation zones, and stuck-pipe prevention. The well casing program is designed to allow for containment and circulation of a formation fluid influx out of the wellbore. Casing is designed to contain the maximum anticipated pressures during a well control event. Cements are designed to meet well-specific zonal isolation requirements and are based on the well temperatures, pressures formations, and reservoir fluids. Well planning and designs conform to or exceed 30 CFR 250 requirements.

8.7.3.2 Drilling Operations

Once the drilling unit has been fully commissioned and the BOPE has been tested, drilling will commence using an overbalanced mud weight to control the well. The pressure exerted by the mud column will exceed formation pressure at any point in the well. Mud properties will be monitored and maintained to ensure uniformity. Insufficient mud weight could lead to an underbalanced condition, and may, in turn, result in an influx of formation fluids. Excessive mud weight may result in lost circulation to a weak formation, which could in turn lead to a drop in fluid level and an underbalanced condition. A range of mud weights will be used as the well is drilled to provide the proper well control for the formation and hole conditions encountered. The weight of mud being pumped into the hole and weight of mud in the returns are monitored to ensure a homogeneous weight of the entire mud system. A difference in mud weight of the returns could signal an influx of formation fluid into the wellbore. Quick checks of oil staining of cuttings, elevated chloride content, and change in background gas concentration would confirm an influx. If an influx of formation fluid into the wellbore occurs, the BOP will be used to immediately shut in the well.

While drilling, the well will constantly be monitored for pressure control. The mud weight (the primary well control mechanism) will be monitored and adjusted to meet actual wellbore requirements. Drilling unit and mud logger pressure volume temperature (PVT) and Flo-Show alarms will be set to the lowest practical limits. Standpipe pressure and downhole pressure while drilling (PWD) tools will be closely monitored for pressure reduction below the mud weight hydrostatic. Gas monitoring systems will be fully functional and operating. Automatic and manual monitoring equipment will be installed to detect abnormal variation in mud system volumes and drilling parameters.

8.7.3.2.1 Well Control During Surface Hole Drilling on Diverter

The Liberty wells surface hole will be drilled with a well flow diverter system installed on the well conductor. The diverter does not provide a well shut-in capability but does divert any well flow away from the drilling unit and is a safety device to protect the drilling unit personnel. The diverter line is preliminarily planned to be a 16-inch nominal ID equipped with flanges and with dual diverter lines that will be rigged up to allow for downwind capability at all times. The first diverter line will be routed from the drilling floor to the eastern edge of the LDPI. A second diverter line will then be routed south along the bench area to discharge on the southeast corner of LDPI. Winds are predominantly from an easterly direction. The living quarters, heliport, emergency generators, and warehouse are located on the northwest section of the LDPI away from the diverter system and out of the predominant wind direction. See DPP Figure 9-5 for a conceptual rendering of the proposed LDPI. Two control stations will be in operation; one on the drilling floor, and the other being a remote station away from the drilling floor. All valves will be remote-operated and full opening. Turns in the diverter lines will be minimized and radius of curvature of turns will be maximized. The diverter lines will be securely anchored to prevent whipping and vibration. HAK will conduct a shallow drilling hazards evaluation to identify and characterize shallow drilling hazards for the proposed Liberty wells from the surface down to the surface casing setting depth. Surface locations are chosen to avoid potential seafloor and subsurface drilling hazards, including shallow hydrocarbon-bearing intervals and shallow water flow zones. Shallow hazard assessments include thorough analysis of seismic data (seismic facies determination, amplitude analysis, and geological structure mapping) and the integration of relevant offset well information. The surface hole interval for the Liberty wells is characterized as being normal pressure and no presence of hydrocarbon bearing intervals or gas hydrates.

8.7.3.2.2 Well Control While Drilling Below the Surface Hole

During drilling operations below the surface casing, the full 5,000 psi rated BOP stack will be installed and will be capable of shutting in the well to contain any unplanned flow from the well. The primary well control barrier will be the hydrostatic pressure of the drilling or completion fluid. Should an influx occur, the BOP will be used to close in the well and provide a barrier against release of formation fluids. The surface stack BOP to be used by HAK meets or exceeds the standards as defined in regulation 30 CFR 250 Part D. Once installed, the BOP is tested according to BSEE requirements.

8.7.4 Well Control Emergency Response

8.7.4.1 Contingency Planning

HAK maintains a Well Control Contingency Plan (WCCP) (see Appendix H, Well Control Contingency Plan Outline) that defines the responses to various well control incidents, and emergency procedures that establish the management system that is formed to respond to an incident. HAK contracts with well control specialists to provide support in response to well control incidents. Well control services include, but are not limited to, firefighting equipment and services, specialty blowout control equipment and services, directional drilling services, and high pressure pumping services. HAK categorizes well control incidents as Level 0 and Level 1 incidents, as described below.

8.7.4.2 Level 0 Incident

The Level 0 incidents are basic well control incidents that can be handled with on-site resources. These incidents include well kick, total loss of return flow, small surface leaks, stripping pipe, and shearing pipe. If a kick or influx of formation fluid occurs, secondary well control methods will be applied. The well annulus will be shut in and isolated with the BOP. The drill string will be isolated with one or more inside BOP devices. Surface pressures will be allowed to stabilize and will then be measured. The pressure readings will enable the calculation of the new kill-weight mud density needed to regain primary well control. A standard well kill procedure will be implemented to circulate the kill-weight mud and safely remove formation fluids from the hole. Mud-gas separators and degassers will be used to remove gas from the mud as it is circulated out of the hole. After this procedure is completed, the kill effectiveness will be confirmed and the well will be opened while monitoring for flow. Drilling operations will resume when the well is no longer flowing and conditions are stable.

8.7.4.3 Level 1 Incident

A Level 1 incident is a loss of well control where there is an uncontrolled release of well fluids from the well as in a surface blowout. The response to a surface blowout at Liberty will have the three major components as discussed below. The Liberty Development has a single island that will support both the well capping and relief well response operations. The surface intervention well capping and relief well operations will begin immediately and operate simultaneously.

Well Ignition

Well ignition of the blowout well as soon as practical is one of the key components of the Liberty OSRP that includes well capping as the first line of defense, concurrent with drilling a relief well. Due to the relatively high gas-oil-ratio (GOR) of the Liberty reservoir fluid, a blowout well would have a very large methane vapor cloud around the well that could accidentally ignite at any time, resulting in a large explosion. Well capping professionals will not approach the well until it has been ignited. Wellhead burning of the oil and gas fluids is also an effective means to greatly reduce the volume of oil that contacts the island and surrounding water. Wellhead burning also reduces the safety risks associated with pooling of flammable oil and accumulation of explosive gas that would add risk to the source control activities.

Based on the research to date and a simulation of contingency options, an uncontrolled blowout will be ignited as soon as it is safe to do so. The optimal point in time to ignite a blowout will be made after assessing the safety concerns to personnel and the facility, and the disposition of the drilling unit and the drilling unit move system, while addressing pertinent environmental considerations and notifying the agencies. Personnel safety has the highest priority. Ignition and sustained combustion of the oil and gas plume results in a safer working environment for the well capping and relief well operations, and for responders attempting to contain and/or recover oil downstream of the blowout.

To summarize the operation, if the well experiences a failure of the BOP system that results in an uncontrolled blowout, the first step will be to remove personnel from harm’s way in case the well ignites on its own. The drilling unit would be skidded or dragged off of the well that is flowing uncontrollably, and the plume of oil and gas would then be ignited with the use of a pedestal-mounted flare launcher. Once the well is on fire, then well capping experts can assess the situation and begin well capping operations to bring the well under control.

Surface Intervention – Well Capping

It is highly likely that a surface intervention in the form of well capping would be the mechanism to successfully stop a blowout well at Liberty. Well capping is the primary mechanism that has successfully controlled most land well blowouts, as Liberty would be classified with a surface BOP stack on the island. HAK has consulted with one of the industry leaders in well control to incorporate design features into the island to facilitate well capping operations. Incorporating well capping considerations into the island design criteria will minimize the well capping response time to regain control of a blowout well.

Surface intervention involves work done on the wellhead to maintain or regain control of the well. During drilling, the BOP is attached to the well head and can be used to stop or divert flow to the surface. Should the BOP be damaged or unable to control flow to the surface, it may be removed and replaced with a "capping stack." Both the drilling BOP and capping stack provide direct surface intervention capabilities.

The capping stack may include ram-type BOP units equipped with blind and/or pipe rams, spacer spools, and flow crosses (or mud crosses) for pumping kill weight fluid into the well or for flowing the well in a controlled manner. Uncontrolled fluids may be diverted for collection and handling. The drilling BOP would be removed from the well if necessary and a capping stack would be installed. The Liberty-specific capping stack equipment options will be identified and sourcing plans determined prior to drilling.

Well capping support equipment that would be needed immediately will be staged on the LDPI prior to drilling. Specialized equipment not located in Alaska will be mobilized as needed from identified lower 48 locations. It is anticipated that surface intervention efforts will successfully stop the flow from a blowout in less time than is required to drill a relief well. Various crossovers and spools, ram sets, and other equipment (including demolition tools for clearing debris away from the well) are typically included in the capping stack response package. All of the equipment will be designed for conditions found in the Arctic, including ice and cold temperatures. This equipment will also be designed for maximum reliability, ease of operation, flexibility, and robustness so it could be used for a variety of blowout situations.

Efforts to contain the blowout will begin immediately after the well control is lost. The island design, well spacing, and skid beam arrangement has been designed to facilitate capping efforts. The North Slope spill response system built around ACS would be mobilized immediately after well control is lost. Sensitive site protection and oil containment and recovery tactics would be implemented. The positioning of oil response containment and recovery equipment will be coordinated with well capping operations to avoid interfering with capping source efforts. Containment efforts will continue during relief well drilling operations unless it is unsafe to do so. The surface oil spill response fleet would remain and oil spill cleanup would continue, as necessary, until the blowout is under control. The step by step procedure to cap well is given below:

1. Secure the site – Shut in and secure the existing wells. Depressurize flow lines.
2. Clear the site – Remove equipment, materials, and debris as necessary to create sufficient working room.
3. Move the drilling unit, drilling unit modules, and debris to create access to the wellhead.
4. Evaluate well head condition and create a forward plan.
5. Remove damaged BOP or wellhead to allow capping or well killing.
6. Cap well and shut in, or kill well and cap.

Subsurface Intervention - Relief Well and Dynamic Kill

The general strategy for killing a blowout using a relief well is to drill a specially designed well to intersect the blowout well at some point along its path, usually near the top of the source reservoir. Then, kill weight fluid is pumped from the relief well into the original wellbore at sufficient pump rates to stop formation fluids from flowing, thus bringing the blowout well under control. Finally, both wells are properly plugged and abandoned using procedures approved by the BSEE.

A relief well plan will be developed for each Liberty Development well. This plan would include the exact plans and source of equipment to begin drilling the relief well as soon as possible. Also included in the relief plan are the directional calculations to intersect the subject well at the proper depth. The north end of LDPI design provides the surface location for a Liberty relief well. Some materials for the relief well will be staged on the island to minimize the time to rig start-up. The relief well rig mechanical requirements will be determined in the planning process and relief rig options developed. The relief well rig may be mobilized on demand or may be staged on the island prior to development drilling.

9 PROCESS FACILITIES, ON-ISLAND SUPPORT FACILITIES

This section describes the process facilities that will be located on LDPI in order to deliver sales quality crude to the Badami pipeline, process water for waterflood injection, and compress gas for fuel use and injection. It includes the design basis used for sizing equipment, as well as the key principles that drive the design and operating philosophies.

9.1 Design Basis

The proposed LDPI facilities are designed to process a total combined produced fluids rate of 70,000 barrels of fluid per day, providing sales quality crude oil to the Badami Pipeline.

Truckable, pre-fabricated modules will be used for the process facilities. Therefore, the majority of the process facilities are designed to have multiple trains, also known as identical groups of equipment that work in parallel to each other. The initial processing concept is that at peak production, up to seven (7) production trains will be installed, one for each of the producing wells. Each producing well is aligned with a production train and individually metered. Each production train includes produced fluid separation equipment and produced water treatment. Additional operational flexibility will be designed into the piping system to allow wells to be diverted and/or commingled to an alternate production train. Each train is designed to process up to 15,000 barrels of fluid per day, see Section 4.2.2 for Reservoir Fluid Properties. Also, see Figure 9 1, Simplified Block Diagram.

Waterflood and produced gas injection will begin just after start-up to maintain reservoir pressure and maximize oil recovery. Produced water and treated sea water will be commingled for waterflood injection. Treated sea water will also be used to create potable water and utility water used at LDPI. Process facilities include water injection pumps sized for a total flow of 80,000 barrels of water per day (BWPD) at 4,000 psi for waterflood injection.

Produced gas separated in the production modules will be compressed in the gas compression system for three main services: fuel gas, lift gas, and injection gas. Lift gas will be supplied to each producing well. Early in field life, approximately 3 million standard cubic feet per day (MMscf/day) at 2,400 psi, for a total demand of 21 MMscf/day will be used. Late in field life, the lift gas requirements will be approximately 6 MMscf/day. Any remaining produced gas, less fuel gas burned, will be injected at 4,800 psi for enhanced oil recovery.

The field life is estimated to be approximately 15 to 20 years. The facilities and pipeline are designed to have a minimum operational life of 25 years.

The design basis for additional process facilities and utilities—such as chemical injection, heating mediums, instrument air, power generation, potable water, waste treatment, control systems, and metering—are described in the sections below.

9.1.1 Guiding Principles

The process facilities for LDPI have been developed with the following guiding principles:

- Operational safety is the first priority. Equipment will be designed, tested, and operated such that personnel safety is never compromised.
- Environmental impacts are minimized and the risks of spills to the environment are mitigated. Environmental footprints, air emissions, and waste are considered throughout the design process.
- Conventional and proven technology is incorporated to the maximum extent possible, to include previous North Slope offshore developments and other cold climate installations.

- Capital and operating costs are minimized to reduce life cycle costs and extend field life.
- Alternatives are evaluated and robust design calculations are applied to ensure project success
- Applicable building codes and regulatory requirements are adhered to throughout the design process

9.1.2 Use of Truckable Modules

The LDPI facility design represents a departure from the traditional approach of utilizing huge sealift modules by limiting the size of all modules and vessels to fit within the envelope of a road-truckable module. Hilcorp (HAK) has found that when single-train vessels become so large that they exceed the size of a typical installation found in Canada or the Lower 48, the theory of economies of scale no longer applies. An analysis of the two approaches, confirmed with experience, has demonstrated that sealift modules are not the optimal approach in this application for three major reasons:

1. Excess structural steel is required to withstand ocean wave-induced acceleration loads, which are much higher than service loads. This leads to higher costs.
2. Sealift modules are one-of-a-kind assemblies, so they require considerable more time to engineer and build than off-the-shelf designs.
3. Huge vessels and piping systems do not leverage the fabrication shop learnings and efficiencies that are associated with traditional size modules.

By limiting the size of the vessels to conventional sizes, the installation of process facilities will benefit from proven and reliable designs, shorter engineering times, and much quicker fabrication schedules. However, the treatment process will require multiple vessels, or production trains, in order to meet the required capacities necessary to adequately develop the Liberty reservoir. The consequence of this approach is that additional piping, pipe manifolds, automated valves, and control logic is required to commingle a fluid stream (oil, water, gas) amongst several vessels or equipment trains.

Another advantage of the multiple train approach is the ability to add additional vessels and/or equipment in the event that actual producing rates or emulsion tendencies are different than predicted. By using smaller modules that can be combined with existing modules, the ability to upsize plant capacity is relatively straightforward, as long as a footprint was set aside to accommodate eventual conditions.

A third major advantage of utilizing multiple trains is the ability to respond to major upsets or equipment downtime without the need to shut down the entire system. If a single piece of equipment or vessel goes down, that train can be isolated from the rest of the system while it is being repaired. This allows for continued (but curtailed) production, which eliminates the complications of plant and well shutdowns during extreme cold temperature conditions.

9.1.3 Control Philosophy

The LDPI facility automation systems will support safety, environmental, and production needs. Engineering controls are designed around results of hazards reviews, environmental concerns, and Federal regulations, as well as reliability and operational requirements.

The types of DCS/PLC (Distributed Control System/Programmable Logic Controllers) and/or SIS (Safety Instrumented Systems) will be defined by Safety and Environmental Management Systems (SEMS) requirements, technical familiarity, and available support. Fire and Gas safety systems will meet applicable codes. Approved systems are pre-engineered and constructed by companies whose core business is the design and installation of these systems.

The automation and control equipment will be selected to follow industry standards at a minimum, but also to take advantage of current technical improvements. In addition to this, the selected automation system shall be based on what best interfaces with and communicates with existing infrastructure. The complete control system will utilize industry standard valves, switches, transmitters, solenoids, etc., as well as control room monitoring that would follow API and industry standards for functionality and alarming.

See Section 11.6 for additional information about Operational Process Safety Systems and the Plant Shutdown Philosophy.

9.1.4 Sparing Philosophy

The sparing philosophy has been established by the necessity to maintain continuous operation during normal conditions, upset or unstable conditions, and while some equipment is down for routine maintenance. With the multiple train philosophy, it will be acceptable for some parts of the system to be down for equipment repair or maintenance. Nevertheless, there will be spare capacity for critical equipment, as described below:

As a minimum, the design will include the following spare components:

1) Power Generation
   a) Primary Power Generation – 5 generators, each designed for 25% of the required peak load.
   b) Stand-by Power Generation – 3 generators, each designed for 50% of the life support load (life support load includes the living quarters, communication equipment, and critical freeze protection)
2) Gas Compression
   a) Fuel Gas Compressors – 3 compressor packages, each designed for 50% of the design load
   b) Lift Gas Compressors – 3 compressors packages, each designed for 50% of the design load
   c) Injection Gas Compressors – 5 compressors packages, each designed for 25% of the design load
3) Utility packages
   a) Instrument Air – 100% spare
   b) Nitrogen Generation – 0% spare
   c) Process Heaters – 50% spare
   d) Process Pumps – 100% spare, as deemed critical

In general, all pumps identified as critical (i.e., those pumps deemed necessary for continued uninterruptible operation) will have a 100% spare. Other pumps in non-critical service will not have a backup. In these cases a shelf spare will be purchased and warehoused, allowing operations personnel to change out the pump in a reasonable amount of time without production shutdown. Chemical pumps will have several shelf spares as they are essential to the successful processing of the oil and are the most likely to have regular maintenance issues. As a general rule, given that multiple trains allow some production to continue, this project will have more tolerance for downtime compared to single train modules.

9.1.5 Environmental Design Criteria

Environmental design criteria specific to the island for use in design of the structural and mechanical design of the facilities will be developed. Table 9-1 describes the key design criteria used for equipment and material selections.

Table 9-1. Environmental Design Criteria for Surface Facilities

Normal Summer Temperature Range	20°F to 65°F
Normal Winter Temperature Range	-45°F to 25°F
Summer Design Temperature	60°F (55°F wet bulb)
Winter Design Temperature	-50°F
Summer Relative Humidity	50%
Winter Relative Humidity	0% to 5%
Design Wind Velocity (3 second gust)	130 mph
Design Ground Snow Load	50 psf
Seismic Acceleration	Ss = 0.25, S1 = 0.07, Site Class D
Allowable Soil Bearing	4,000 psf

9.1.6 Foundation Design

The island will be constructed of gravel fill placed on the sea floor. A geotechnical report with design parameters for foundations has not yet been completed. Preliminary engineering work and evaluations have resulted in design assumptions as described below.

Consideration has been given to two (2) approaches for supporting equipment: (1) pile foundations that extend through the island fill into the sea floor, and (2) surface foundations that bear on the island fill. Preliminary evaluations point toward surface founded facilities.

Most of the facilities (process modules, pipe racks, shops, power plant, permanent living quarters) will be supported on foundations that elevate the bottom of structure about 3 feet above the island surface. The gap between bottom of structure will provide a thermal break to reduce heat input into the island, allow for access to re-level facilities as foundations creep, and reduce snow drifting potential.

The elevated facilities will be founded on post and pad type foundations, using precast concrete pads and steel column posts. The posts will support a subframe consisting of steel beams bearing on the post caps with diagonal bracing from subframe to pads to resist lateral loads. The modular skids will bear on the subframe and be connected to them by bolting or welding. Future re-levelling will be accomplished using shims between the module skids and subframe.

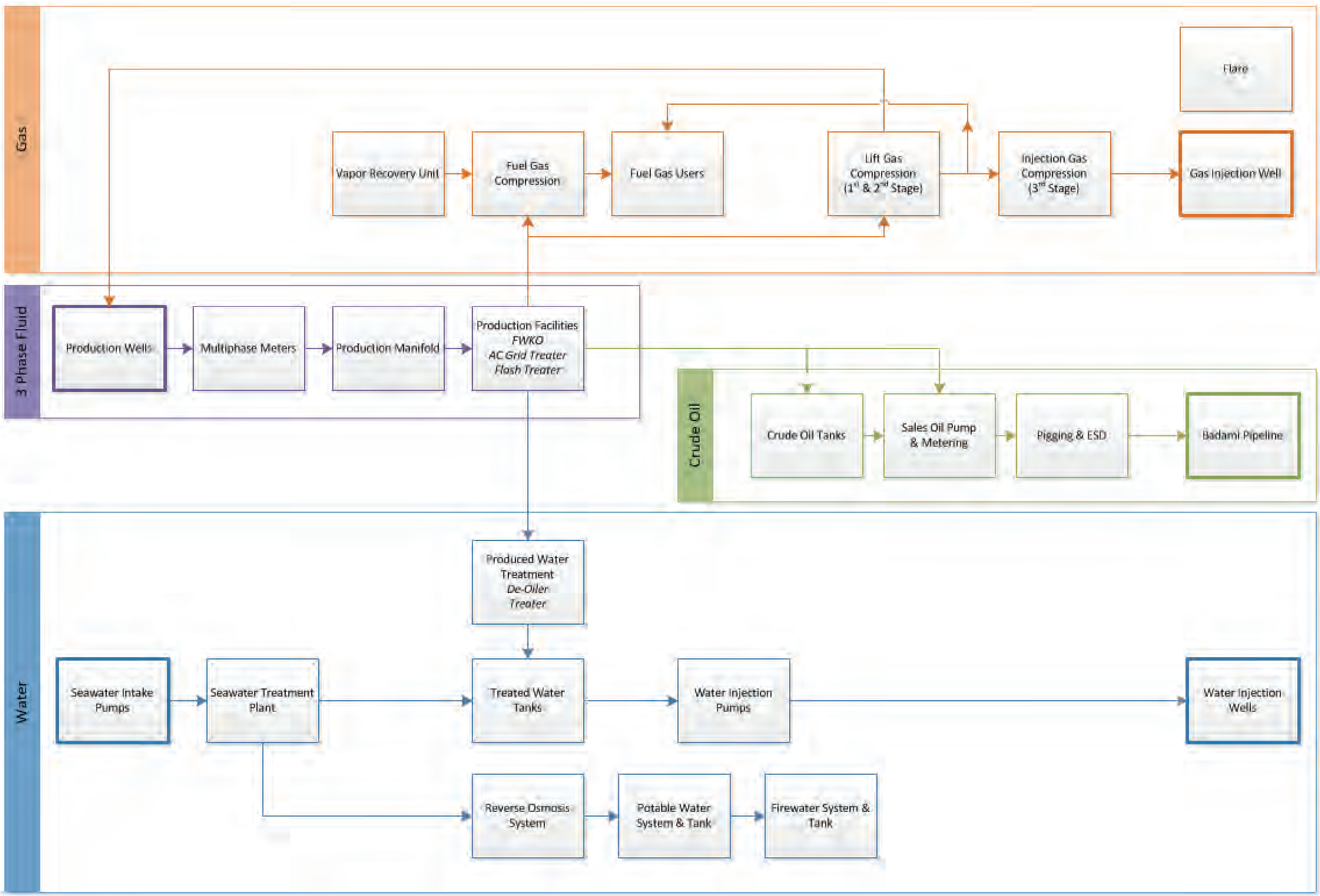
Not all of the facilities lend themselves to elevated support. The tank farm will be founded on large mats bearing on the island surface. The mats will be underlain with insulation to reduce heat input into the island. The gravel under the tank farm will be processed after initial placement to provide a uniform compacted subgrade and to reduce settlement potential. Thermo-siphons may be utilized for additional subgrade stabilization.

Mat foundations bearing on processed and compacted gravel will also be used for the temporary living quarters and the drilling unit, drilling utility module, and grind and inject facility.

9.2 Process Facilities

A simplified process flow diagram is shown in Figure 9-1.

Figure 9-1. Simplified Block Diagram



9.2.1 Oil Separation

Three-phase produced fluid from the wellhead (oil, water, and gas) will flow from the producing wells, through a production manifold, to the production modules. Each production train includes a group of equipment to separate the crude oil from water, gas, and other impurities. The production trains are designed with a distinct series of separator vessels and heat exchangers to manipulate the fluid to specific operating pressures and temperatures. The produced water is collected from each separator and sent to the produced water treatment modules. A simplified process flow diagram of the production module is shown in Figure 9-2. See Section 1.1.1 for details on the produced water treatment. Gas from each separator vessel is collected and sent to the gas compression modules. See Section 1.1.1 for additional information on gas handling.

9.2.2 Sales Oil Conditioning

Crude oil from the production modules is brought together, metered and shipped via sales oil pumps to the subsea pipeline. The crude oil will be actively monitored with an in-line basic sediment and water (BS&W) meter to ensure that the crude oil has been treated sufficiently to meet the sales specification. The conditioned crude will be routed to the sales oil pipeline for shipment to TAPS via the Badami and Endicott Pipeline, see Table 9-2.

Table 9-2. TAPS Sales Oil Specification

PROPERTY	UNIT
BS&W	0.35% @ 120 °F (Max)
True Vapor Pressure @ [Delivery Temperature]	14.2 psia @ 100 °F (Max)
Temperature	105 °F - 142 °F

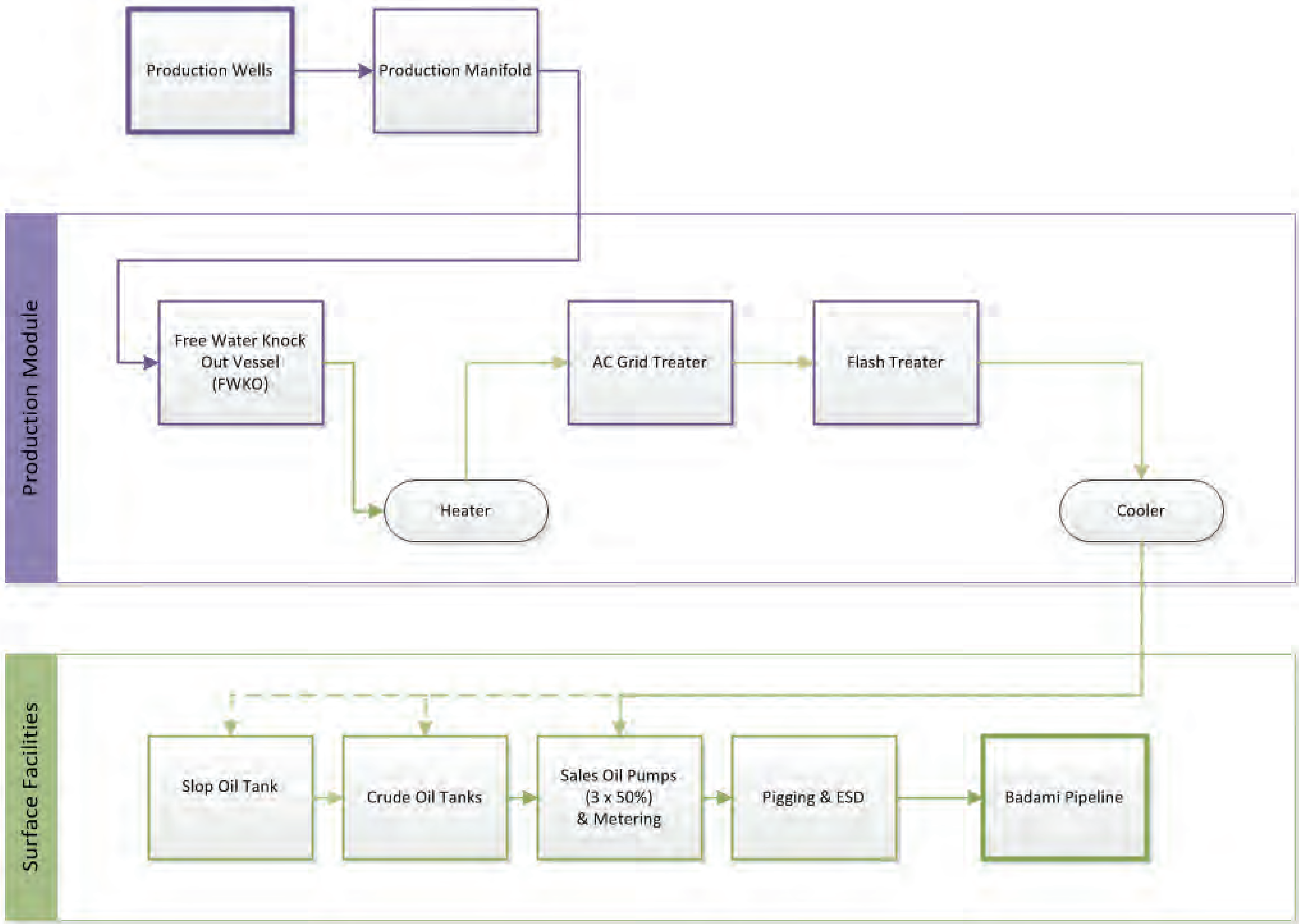
Two (2) crude oil storage tanks will be available for oil storage in upset conditions. The storage tanks will be equipped with a gas vapor recovery system that will collect vapors and return them to the gas compression system. Any fluid that does not meet the specification will be diverted to the slop-oil tank. Fluids in the slop-oil tank will be returned for additional treatment in the production modules.

9.2.3 Production Metering

Process design calculations have determined that based on the rate and fluid properties that are expected from each well, the capacity of a single oil processing train is close to the predicted maximum rate for a producer. The design therefore results in a one-to-one relationship of producer well to oil processing train. Given this relationship, the water, gas, and oil rate from each well can be metered as single phases as part of the processing, which negates the need for a dedicated test separator.

Alternatively or as a backup to this method of measuring production from each well through its process train, a manifold and three-phase meter, or a three-phase meter for every producer, will be installed in the event that more than one well is commingled through a process train. This allows for measuring of flow from individual wells when a train is down, or when multiple trains are required to process the fluid from a single well.

Figure 9-2. Simplified Block Diagram – Production Module



9.2.4 Gas Compression and Treating

The proposed gas compressor facilities will have three (3) primary gas compression trains. Produced gas from each stage of separation within the production modules is combined in gas manifolds and routed to the gas compression modules. Gas compression can be summarized by three categories; fuel gas compression, first and second stage lift gas compression, and third stage injection gas compression. A simplified block diagram of a compressor train is shown in Figure 9-3.

9.2.4.1 Fuel Gas Compression

Low pressure gas from the crude oil separation process will be collected in a common header and routed to the fuel gas compressors. Each of the fuel gas compressors will have multiple stages to allow fuel gas to be supplied at the required pressure to the on-island fired equipment. See Table 9-6, Major Fuel Gas Burning Equipment, for projected fuel gas usage at LDPI. The surplus fuel gas from the fuel gas compressors will be combined with the remaining gas from in the crude oil separation process to the inlet of the first stage of the Gas Lift Compressors.

9.2.4.2 Gas Dehydration

Fuel gas and separated gas collected from the oil separation process will be routed to the first stage of the compression train system. Following the initial stage of compression, all of the gas will be dried in a dehydration system before being routed to the second stage gas lift compressors.

9.2.4.3 Gas Lift Compression

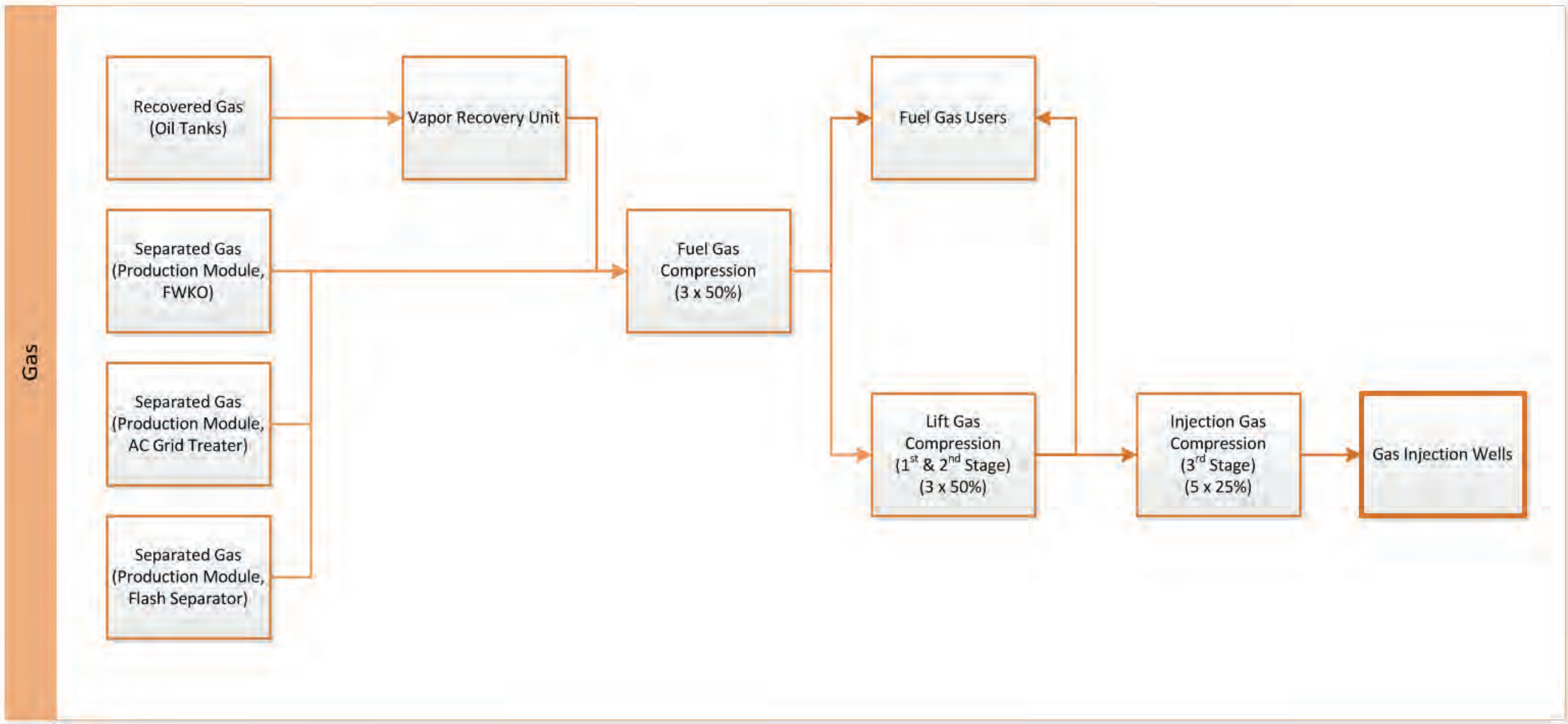
The majority of the produced gas from the crude oil separation process in the production modules will originate from the inlet separator vessel. Surplus fuel gas and separated gas collected from the oil separation process will be combined. This higher pressure gas, approximately 180 pounds per square inch gauge (psig), will feed the first and second stage lift gas compressor.

The lift gas compressors are two (2) centrifugal compressors driven by one (1) natural gas turbine, per gas compressor train. There will be three (3) gas lift compressor trains to accommodate the peak gas rates, projected at 125 MMscf/day and the sparing philosophy (see Section 9.1.4). The majority of the gas compressed in the first and second stage compressors will be forwarded to the third stage compressors for injection gas. A smaller portion of the compressed gas in the lift gas compressors will actually be used for lift gas, approximately 21 MMscf/day for seven (7) production wells. The gas provided for gas lift will be supplied at approximately 2,400 psig.

9.2.4.4 Gas Injection Compression

The injection gas compressors are reciprocating compressors, sized to compress 90 MMscf/day from 2,400 psig to 4,600 psig. Each gas injection compressor train will include one (1) reciprocating compressor driven by one (1) electric motor. To accommodate the sparing philosophy, design rate, and module size requirements, there will be five (5) gas injection trains.

Figure 9-3. Simplified Block Diagram – Compression



9.2.5 Produced Water Treatment

Produced water separated from the crude oil production modules will be treated and re-used in the waterflood program to maintain reservoir pressure. The treatment system will include a produced water surge/skim tank that will de-gas and remove any remaining free oil from the produced water prior to injection. Produced water and treated seawater will be commingled and pumped to a pressure of 2,700 psig for re-injection into the formation for pressure maintenance. Hydrocarbon gases released from the produced water in the produced water tank will be recovered by the first stage compressor. Water quality of injected water is: Oil in Water quality = < 250 ppm.

9.2.6 Seawater Treatment

The Liberty depletion plan is to maintain reservoir pressure and enhance reservoir recovery with a combination of waterflood and produced gas re-injection. In addition to produced water, approximately 80,000 barrels of water per day of treated seawater will be needed for the Liberty waterflood to maintain reservoir pressure during early production. The Liberty seawater treatment plant (STP) will supply treated water for this use. The following description is preliminary and is subject to optimization. No cooling water intakes are planned for this project.

Table 9-3 and the following bullet points summarize the process design basis for the water injection facilities:

- Reservoir pressure will be maintained using a high pressure water injection system.
- The water injection manifold will be configured to allow for water injection down any injector.

Table 9-3. Water Injection Parameters

INJECTION PARAMETER	SPECIFICATION
Water Injection Rate, Maximum Peak	80,000 BWPD
Initial Water Injection	~ 1500 BWPD
Normal Waterflood Flowing Injection Pressure	4,000 psig
Sea Water Injection Temperature	35-100°F

9.2.6.1 Seawater Intake

The seawater intake system design includes measures to minimize the potential for entraining fish in the intake stream. The intake structure consists of an 8’ diameter pipe installed vertically at the Southern end of LDPI, perpendicular to the seafloor, with an internal concrete plug at the base. Approximately 19’ down from the intake, approximately 7’-6” down from the mean low water level), an 8’ x 5’-8”rectangular opening in the side of the pipe allows the inflow of seawater. Inside the opening is a series of vertical pipes that continuously recycle warm seawater from the STP to prevent the intake from freezing. The recirculation system is designed to raise temperature in the intake 0.5 °F over ambient to keep frazil ice from forming on the screens. The system is designed for all recirculating seawater to be drawn back into the seawater sump. The re-circulation pipes will also act as barriers to keep out large fish, animals, and debris.

Downstream of the pipes are two parallel screens located in a vertical position. The dual screen system allows for one screen to be in place when the other is removed for cleaning or repair. For cleaning, the screen closest to the intake pipe will be removed, cleaned, and replaced then the outer screen will be cleaned in a similar manner. The facility operator will be able to remove the screens from the island surface. The intake screen slot size is 0.25 in x 1.0 in (similar to the Endicott STP intake). Downstream of the screens is a 36-inch high-density polyethylene (HDPE) pipe, installed horizontally to intersect the intake and carry seawater, via gravity flow, into a sump, from which seawater is drawn when needed for waterflood operations.

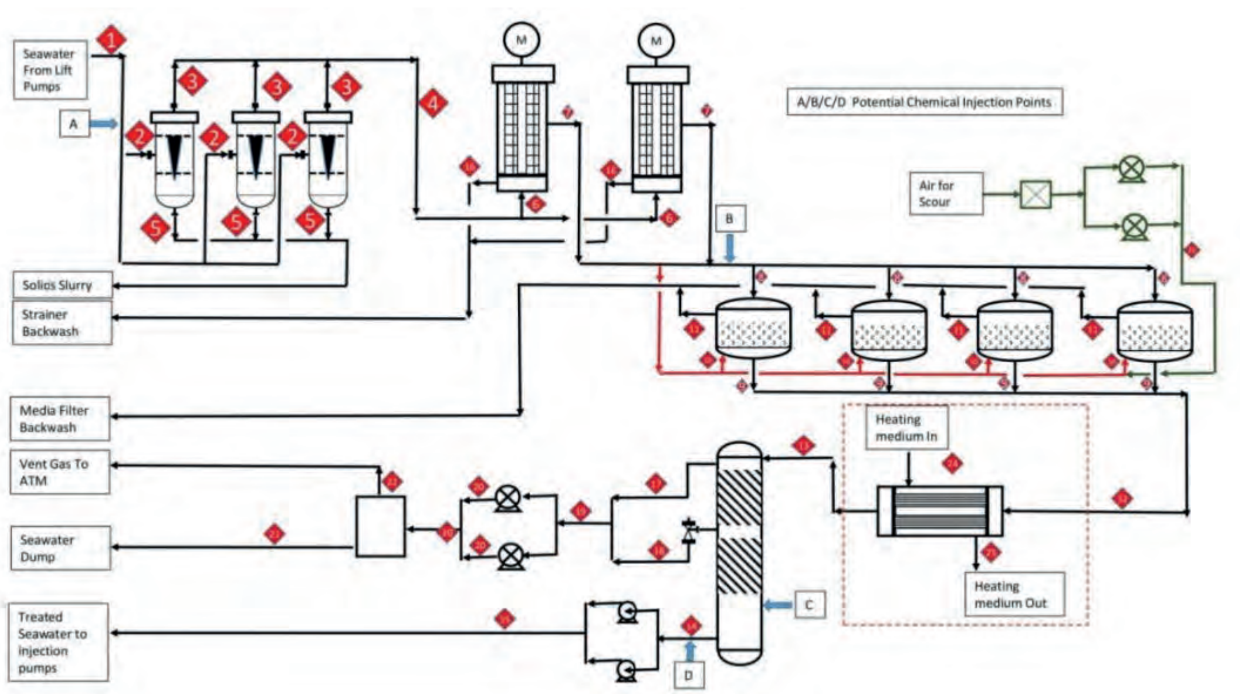
There is a range of operating velocities for the seawater intake. At maximum, the velocity at the bars is 0.46 feet per second (fps), at the first screen it is 0.29 fps, and at the second screen it is 0.33 fps, all below the design criterion maximum of 0.5 fps. This is based on all three pumps in the seawater sump (firewater pump, seawater pump, and utility water pump) operating at the same time, with maximum flow on the intake. Normal operation would consist of the seawater pump and the utility water pump. Typically, only once a week for a few hours, the firewater pump would be activated to test the firewater system, creating maximum flow on the system, resulting in the maximum velocities noted above. The seawater pump in the seawater inlet facility feeds the STP.

As the final design proceeds for the Liberty Project, the STP design will be optimized to consider seasonal limitations, required water quality for injection, environmental impacts, and power needs. In addition, the intake will be equipped to auto flush to rid the system of silt and debris. The auto flush system will minimize the need for personnel to manually clean the intake, thus increasing the safety of the system through design. This design optimization process will address overall intake configuration, including mesh screen sizes, bar placement, and intake velocities.

9.2.6.2 Seawater Treatment Facilities

As shown in Figure 9-4, the first stage of equipment for the STP feed (raw seawater) will be for total suspended solids (TSS) removal. Three solid-liquid hydrocyclones are proposed to remove finer solids down to approximately 30 microns prior to de-aeration. The concentrated TSS from the hydrocyclones will be routed to the seawater outfall for discharge under a National Pollutant Discharge Elimination System (NPDES) permit.

Figure 9-4. Simplified Block Diagram – Seawater Treatment



Second stage solids removal design includes the use of two high performance wedge-wire automatic backwashing strainers designed to remove organic and other neutrally buoyant matter down to 40 microns. The strainers backwash online, and the system can operate with one unit on line and one unit offline for maintenance for extended periods. Third stage solids removal will use four (4) high performance multi-media filters designed to remove 98% of solids down to 5 microns. The four (4) filters will be sized for 50% of the flow rate, which would back wash approximately six (6) times per day per unit, two (2) for continuous operation, one (1) for backwash cycles, and one (1) for maintenance and backup. The unit operations have been designed to minimize the frequency of backwashing; however, the ultimate frequency for back wash is a function of the solids loading in the feed to the system.

Downstream of the hydrocyclones, the seawater will be routed to a heat exchanger (if determined necessary) and then to the de-aerator column where oxygen will be removed by vacuum de-aeration. Oxygen scavenger will be injected in the column sump to remove trace amounts of remaining oxygen to approximately 20 parts per billion (ppb). Corrosion inhibitor and scale inhibitor may be added to the treated water stream before it is injected downhole. Treated seawater and produced water will be combined downstream of their respective booster pumps. Injection pumps will be used to raise the treated water pressure to 2,500 psig for injection into the reservoir.

Chlorine, biocide, antifoam, oxygen scavenger, corrosion inhibitor, and scale inhibitor may be used in the seawater treatment system. All chemicals will be injected downstream of the hydrocyclones, minimizing the possibility of these chemicals being in the discharge streams from the strainers or the hydrocyclones.

The wastewater effluent stream from the STP will carry primarily concentrated TSS that have been removed from the raw seawater, a small temperature increase, and low concentrations of total chlorine residual, similar to STP discharges at other North Slope operating areas. The desander, coarse strainer, and fine filters will produce liquid effluent streams that contain the solids removed from the sea water and a small volume of sea water to transport the solids to the disposal point. The unit operations have been designed to minimize the frequency of backwashing and flushing; however, the ultimate frequency for backwash is a function of the solids loading in the feedwater to the system. If there is a high solids loading due to buoyant sediment being sucked into the pump pit (high tides, storm conditions) or there is a high concentration of organic material (e.g., algal bloom), the backwash frequency may increase and the discharge concentration of TSS will also increase. Assuming all of the incoming seawater solids (30 mg/L) are removed, the daily average discharge rate is expected to be < 1.0 million gallons per day, and the average effluent TSS concentration is expected to be approximately 15,000 mg/L. Additional characteristics of the expected effluent are provided in Appendix E.

The design of the system is such that disposal of residual chemicals is minimized. There will be an amount (yet to be determined) of sodium hypochlorite discharged directly to sea during backwash of the coarse and fine filters, and possibly some biocide and scale inhibitor depending on final selection of dosing points. Chemical dosing will be considered in detail during detailed design since it typically has the largest direct environmental impact on waterflood system design.

9.3 On-Island Support Facilities and Infrastructure

9.3.1 Power Generation

Power generation requirements for the Liberty project is based on the project criteria of a fit-for-purpose design, matched to the peak power load and the changing power load through construction and production phases of field life. The current electrical load requirements show a requirement of 17 megawatt (MW) peak load. This peak assumes gas, oil, and water are all at peak design conditions when electrical loads are at their maximum.

9.3.1.1 Power Loads

All major power loads are listed in Table 9-4 and Table 9-5, ranked according to electrical power requirements. It should be noted that the largest horsepower loads on the island are the centrifugal gas lift compressors, which each will be driven by its own gas-fired turbine, so they are not loads on the electrical power system. All other rotating equipment will be electric drive. The Main Camp (20 persons) load is significantly higher than that for the drillers camp (100 persons), because it includes the ancillary buildings such as hangar, shops, warehouse, tank heating, and etc.

Table 9-4. Facility Power Loads

PROJECT COMPONENT	HEATING LOAD (KW)	LTG LOAD (KW)	PWR LOAD (KW)	PROCESS LOAD (KW)	OTHER LOADS (KW)	TOTAL LOAD (KW)
Transportation	147	13	13	0	250	423
Warehouse/Maintenance Building	212	18	21	1	438	690
Main Camp	350	65	74	0	50	539
Temporary Drillers Camp	89	15	16	0	0	120
Power Generation	226	31	49	0	150	456
Sea Water Treatment and Injection	301	28	0	4,275	2,875	7479
Control Room	112	13	16	0	170	311
Gas Compression and Dehydration	104	11	13	450	400	978
Production Trains	251	24	30	5100	200	5605
Miscellaneous	0	0	0	0	50	50
Totals	1,792	218	232	9,826	4,583	16,651

Table 9-5. Emergency Power Loads

DESCRIPTION	REQUIRED LOAD (KW)
Main Camp Load	488.5
Drillers Camp Load	118
Control Room Load	310
Transportation Load	172
Power and Generation Load	454
Potable Water	75
Total Facility Load	1,617.5

9.3.1.2 Turbine Drive Options

Several options for generating power have been evaluated. At this time, the turbines that have been identified are based on the need for five (5) gas fired turbines; the combined capacity includes spare capacity of 50%. This option is aligned with the LDPI sparing philosophy, see Section 9.1.4. The chosen configuration allows for one turbine to be idle at any time, which allows for redundancy as well as the advantage of overhauling a turbine without curtailing production. It should be noted that the preferred equipment has been selected to define the emission sources and stack heights, as detailed in the Air Emissions section of the EIA.

9.3.2 Communications

The primary communication system between LDPI and shore will be high bandwidth microwave communications to/from a tower on the island to/from a tower at either SDI or MPI at Endicott. An armored fiber optic cable (FOC) will be installed along with the subsea pipeline and will be used for control and communication with the Liberty pipeline facilities on shore. However, at this time, there is no fiber optic trunk running along the Badami pipeline to connect to the node at Prudhoe Bay.

9.3.3 Living Quarters

9.3.3.1 Permanent Living Quarters and Utility Module

The permanent living quarters (PLQ) will provide housing for the permanent operations staff and visitors. The living quarters are designed to house 20 to 30 persons in single rooms with shared bathrooms. The modular facility will also include kitchen, dining, storage, medic station, recreation, office, and assembly areas. The living quarters will be comfortable and durable in order to provide for worker comfort and safety.

The living quarters will be two stories tall, consisting of two layers of six modules, about 10,000 square feet (sf). The modules will be steel framed with exterior steel siding and flat roof. The living quarters will be protected by a fire suppression system.

9.3.3.2 Drilling and Construction Living Quarters

Additional living quarters will be provided to support the construction and drilling activities at LDPI. The drilling and construction quarters will be temporary structures, intended to be removed after the drilling and construction phases are complete. The additional quarters will be sized for a combined construction and drilling crew of 100 people. The modular facility will also include kitchen, dining, storage, medic station, recreation, office, and assembly areas. The construction and drilling quarters will be fit for purpose and durable in order to provide for worker comfort and safety.

The construction and drilling living quarters will be two stories tall, consisting of two layers of 12 modules, about 16,800 sf. The modules will be steel framed with exterior steel siding and flat roof.

The construction and drilling living quarters will be protected by a fire suppression system. Refer to Section 9.5.3 for additional details on the Fire & Gas System for on-island occupied buildings.

9.3.3.3 Living Quarters Utilities

Utilities supporting the living quarters will include domestic water, sewage treatment, solid waste handling, fuel gas distribution, power, and communications.

Domestic water will include a treatment module for the conversion of sea water to potable water and a potable water storage tank. The treatment module and storage tank will serve both the permanent and temporary living quarter facilities.

Sewage treatment will include a module for the treatment of discharge from both of the living quarters facilities. After treatment the fluid will be injected in the disposal well. Solids will be incinerated.

An incinerator skid will be provided for disposal of solid waste generated by the facility. The incinerator will use fuel gas.

A trash compactor and storage skid will be provided for reduction of solid waste. Non-combustible waste will be compacted and stored, and will be transported off island for disposal.

Fuel gas will be extended to the facilities from the natural gas processing equipment.

Power will initially be provided by three diesel-fired generator packages. These packages will initially serve the construction and drilling camp, and then become backup for the main living quarters once the natural gas-driven generators are on-line. The generators will be housed in modules and have local diesel storage, separate from the primary island diesel storage.

A communications center will be located in both of the living quarters facilities. A microwave tower will be installed near the main living quarters.

9.3.3.4 Blast Resistant Design Criteria

Maximizing physical separation between the process areas and living quarters and safety equipment has been provided in the site layout to minimize the consequences of a possible fire or explosion in the process area. The regulated codes and standards required by BSEE do not include requirements for blast resistance or hardening of any of the island facilities. Therefore HAK has not proposed including any criteria for blast resistance in the design of the facilities and/or the living quarters.

9.3.4 Warehouse/Shop Space

A warehouse, mechanic shop, electricians shop, and welders shop will be provided for support of operations. These facilities will be located between the living quarters and the process areas, and will be adjacent to an island access road.

The warehouse will be a tent structure with mat floor system. It will be used to house material and equipment needed for operation and maintenance of the island facilities. The warehouse will be about 1,600 sf and may have a partial mezzanine for storage.

Each shop will consist of two (2) modules stitched together to form one building, about 1,000 sf each.

The warehouse and shops will have heat, lights, and communication, and fire suppression/detection systems.

9.3.5 Vehicle Storage, Arktos Storage

The vehicle storage will be a tent structure with mat floor system. It will be used to house and maintain the vehicles and heavy equipment needed for operation and maintenance of the island facilities. The storage facility will be about 4,800 sf. The facility will have heat, lights, and communication.

A helicopter hangar/Arktos™ storage facility will be provided directly adjacent to the helicopter pad. This tent structure will normally house the Arktos™ vehicles. If the helicopter requires repair while on the island, it can be wheeled into the vehicle storage tent as needed. The facility can also be used as the passenger waiting area. The hangar will be about 4,800 sf. A lighted windsock will be located on the hangar. The facility will have heat, lights, fire suppression, and communication.

9.3.6 General Storage Space

Space near the trade shops has been allocated for locating containers (connex type) for use as unheated storage. The containers would be set on rig mats if intended for long-term storage or directly on the gravel if short term. They would not be connected to utilities.

Open storage areas are provided around the perimeter of the island inside the sheet pile wall for gravel storage area for island surface maintenance, rig mats, pipe, mud products, etc.

9.3.7 Heavy Equipment

Heavy equipment will be permanently located on the island for operation and maintenance. The equipment includes:

- Arktos™ – for emergency escape from the island, stored in hangar adjacent to the living quarters
- Front-end Loader with bucket and forks – for moving materials, snow removal, grading

- Mechanical Truck Crane – for lifting operations, small to medium lifts (<100 ton)
- Crawler Crane – for lifting operations, heavy lifts (>100 ton)
- Portable welding machine and generator
- Vacuum truck
- Portable light plants

9.3.8 Helipad

The helicopter pad will be located on the island perimeter, adjacent to the living quarters and separated from the process areas. The pad will meet appropriate codes and guidelines. Exterior floodlights will be provided for passenger off-loading with flush-mounted lighting around the perimeter of the helipad. The pad will be about 60' x 60'.

9.3.9 Process Control Room

The process control room will be located in the control module with remote connections to the process area. Operating consoles located in the control room will display process conditions and equipment status, including alarms, trip conditions, and fire/gas detection. Alarms will be relayed to the operator in the control room on a real-time basis, allowing the operator to have surveillance capability throughout the processing facilities on LDPI.

The process control system will enable the operator technicians to monitor and control the entire operation. The operator and maintenance technicians will be able to check or configure a device from any control terminal location. The system provides the following capabilities:

- Surveillance and control of all process modules and trains simultaneously.
- Monitor equipment performance.
- Optimization of maintenance activities.
- Early detection of failures of key pieces of equipment.
- Automated process shutdown capability.

9.3.10 Bulk Fluid Storage

9.3.10.1 Crude Oil

On island oil storage will be two (2) 15,000-bbl and one (1) 5,000-bbl oil storage tanks. The two (2) 15,000-bbl tanks will be dedicated to sales quality crude oil ready for shipment to the Badami pipeline. The smaller, 5,000-bbl tank will be committed for off-specification oil. However, in abnormal operating conditions, all tanks can be used to store sales quality crude oil. The total potential on-site oil storage is 35,000 barrels of sales quality crude oil, which represents approximately 12 hours of storage at peak production rates and/or potential storage for the contents of the pipeline in an upset condition. It is anticipated that the wells would be turned down to minimum production rates if an incident occurred that inhibited the movement of oil into the Badami pipeline. It is estimated that the facility will have up to three (3) days of storage at minimum rates.

9.3.10.2 Produced Water and Seawater

A total of two (2) 15,000-bbl water storage tanks will be installed at LDPI for produced water and treated sea water. The water injection system contains two 100% injection pumps that will accommodate continuous peak production requirements.

9.3.10.3 Diesel Storage

A total of two (2) 5,000-bbl diesel storage tanks will be installed at LDPI for fuel, pipeline displacement, and well displacement.

9.3.10.4 Process Area Fire Water

A 5,000-bbl water storage tank will be installed at LDPI for fire water storage.

9.3.10.5 Potable Water

A 1,000-bbl water storage tank will be installed at LDPI for potable and fire water storage for the camp facilities.

9.3.11 Fuel Gas

The fuel gas system is required to provide natural gas for gas turbine-driven power generators, gas turbine-driven gas compressors, process heat, and various process equipment. See Section 1.1.1 for additional information on the fuel gas compressors. Table 9-6 lists the fuel gas burning equipment to be hosted on LDPI.

9.3.12 Instrument and Utility Air

The instrument air will consist of compressors, dryers, and vessels to provide one operational unit and a 100% standby. The instrument air compressors will be driven with electric motors to provide the utility and instrument air to LDPI. The system will dry the air to a dew point of -60°F.

9.3.13 Chemical Injection Facilities and Storage Tanks

The project scope will incorporate facilities to inject chemicals into the process stream at various locations and the required tankage to store chemicals between supply periods. Chemicals that are used to treat the produced fluids include scale inhibitor, corrosion inhibitor, emulsion breaker, and anti-foam. Scale inhibitor primarily impacts downhole tubing and can be most efficiently carried out via periodic downhole squeezes or capillary injection strings. Corrosion inhibitor is often injected at the wellhead, particularly when stainless steel tubing is installed in the well. Chemicals that are injected to improve the separation process, such as emulsion breaker and de-foaming agents, are injected upstream of the first separation vessel and can be injected into subsequent vessels. The type of chemical, its description, and estimated usage and storage volumes on the island are shown in Table 9-7.

Table 9-6. Major Fuel Gas Burning Equipment

DESCRIPTION	QTY	FUEL TYPE	NATURAL GAS		DIESEL FUEL		
			GAS MMSCF/HR PER UNIT	MMSCF/DAY TOTAL	GPH PER UNIT	GPD TOTAL	GPY TOTAL
Power Generation Turbines	5	Fuel Gas	67	8,000			
Drilling Unit Diesel Engine	4	ULSD			15	1,400	511,000
Drilling Unit Gas Engine	3	Fuel Gas	18	1,300			
Drilling Unit Boiler	2	ULSD/Fuel Gas	6	300	55	2,600	949,000
Drilling Unit Tioga Heater	2	ULSD/Fuel Gas	5	200	44	2,100	767,000
G&I Diesel Power Unit	1	ULSD			15	400	146,000
G&I Gas Fired Unit	1	Fuel Gas	18	400			
Gas Compressor	3	Fuel Gas	90	6,500			
Standby/Emergency Generator	3	ULSD			63	4,500	1,643,000
Incinerator	1	Fuel Gas/Diesel	4	100			
Facility HP and LP Flare	1	Fuel Gas/Diesel	4	100			
Drilling Support Equipment	1	ULSD			35	800	292,000
				16,900		**11,800**	

Table 9-7. Chemical Storage and Usage for Liberty Production Operations on LDPI

PRODUCT, DESCRIPTION	TYPICAL USE AND CONCENTRATION	VOLUME USED (ESTIMATE)	STORAGE VOLUME	STORAGE METHOD
LDPI				
EC6085A- Surface Scale Inhibitor	Injection downstream of the wellhead and upstream of the well choke.	3.0 to 3.8 gph	660 gallons	Chemical tote
Diesel fuel – Arctic grade ultra-low sulfur diesel fuel[1]	Fuel for backup power generation, drilling operations, mobile equipment, and well freeze protection.	Backup power and fuel: 183 gph Well freeze protection: 1,834 gph	Backup power and fuel: 117,600 gallons Well freeze protection: 25,000 gallons	Two double-walled above-ground storage tanks at two separate locations
Diesel	Pipeline displacement.	As required for pipeline protection	220,000 gal	Double-walled above-ground storage tank
Methanol - Methyl alcohol stored as a 60/40 mixture of methanol and water	Injection into surface piping for freeze protection and hydrate suppression in the pipeline.	Mean injection rate for: ice mitigation for surface facility= 544 gph; hydrate mitigation for wells = 142 gph	7,200 gallons	Double-walled above-ground storage tank
Sodium Hypochlorite – oxidizing biocide	Disinfection for potable water and MBR CIP.	Mean injection rate for: Potable water = 0.02 gph MBR CIP = 4.3 gph	55 gallons	DOT drum
Citric Acid	For MBR Package Plant.	Mean injection rate: 4.3 gph	To be defined by vendor (Detailed Engineering)	To be defined by vendor (Detailed Engineering)
Anti-scalant (MECO M-237) - Scaling mitigation for desalination equipment	For Evaporator/Vapor Compression System.	Mean Injection Rate: 0.41 gpd	To be defined by vendor (Detailed Engineering)	To be defined by vendor (Detailed Engineering)
Anti-foam agent - Foaming mitigation for desalination equipment	For Evaporator/Vapor Compression System.	Mean Injection Rate: 1.125 gph	To be defined by vendor (Detailed Engineering)	To be defined by vendor (Detailed Engineering)
Corrosion Inhibitor	Production system corrosion control.	To be defined (Detailed Engineering)	To be defined (Detailed Engineering)	To be defined by vendor (Detailed Engineering)
Gluteraldehyde	Biocide for waterflood system.	To be defined (Detailed Engineering)	To be defined (Detailed Engineering)	To be defined by vendor (Detailed Engineering)
Crude oil	Storage for shipment and storage of off spec oil.	To be defined (Detailed Engineering)	30,000 bbl	Two 15,000-bbl API 650 tanks
Injection water	Storage of produced water and treated seawater.	To be defined (Detailed Engineering)	30,000 bbl	Two 15,000-bbl API 650 tanks

Note:
1. An estimated 21,000 bbl of temporary diesel storage will also be required.

9.3.14 Pollution Prevention Equipment

All tanks on the LDPI and the SDI containing hydrocarbon liquids will include secondary containment. The secondary containment may be in the form of a diked area with an impervious liner adequate to hold 110% of the tank or of the largest tank if there are multiple tanks. Alternatively, double-walled tanks may be used where the annulus space serves as secondary containment in case of inner tank failure/leakage.

All process modules will be equipped with welded floors and welded internal sill plates around the interior perimeter of the module, which will allow small spills inside the modules to be confined inside of the module. Production modules will include a collection sump and pump that will allow spills inside the module to be collected and returned to the process.

Permanently placed diesel tanks that will be used to fill mobile equipment will have a secondary containment to include the mobile equipment being filled.

9.3.15 Process Heat Recovery

Process heat for crude heating and fuel gas heating will be provided by a closed loop re-circulating heat medium (water/glycol) system. The normal heat source for the heat medium will be process heat recovery from multiple stage (gas) discharge exchangers. An environmental loop heater, fired by fuel gas, will be used to provide heat to plenums and enclosures as well as standby heat for start-up.

9.4 On-Island Air Emissions

9.4.1 Projected Emissions

This section provides projected emissions of sulfur dioxide (SO_2), particulate matter (PM) in the form of PM_{10} and $PM_{2.5}$, nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) that will be generated by the proposed development and production activities. The basis of the emissions calculations is provided in the modeling report that is being submitted to meet the requirements of 30 CFR 550.249(f) and described in Section 9.4.6. The modeling report contains supporting information including EU ratings, EU manufacturer data, and emission reduction measures.

Table 9-8 lists the EUs planned for operation at the LDPI and includes gas-fired turbines, ultra-low sulfur diesel (ULSD)-fired reciprocating internal combustion engines (RICE), gas-fired RICE, incinerator, flare, and ULSD-fired drilling support equipment.

Table 9-9 and Table 9-10 provide the projected peak hourly emissions, in pounds per hour (lb/hr), and total annual emissions in tpy, respectively, for the LDPI EU inventory. The peak hourly emissions in Table 9-9 are based on the assumption that each EU operates continuously at maximum capacity for at least 1 hour. The total annual emissions in Table 9-10 are based on the conservative assumption that each EU operates at maximum capacity during the entire year. Table 9-11 provides the projected emissions over the duration of the proposed project. The design life of the LDPI and any associated infrastructures is a minimum of 30 years.

Table 9-8. Liberty Drilling and Production Island Emission Unit Inventory

DESCRIPTION[1]	MAKE/MODEL[1]	RATING[1]	FUEL TYPE[1]	MAXIMUM FUEL CONSUMPTION[1]
Power Generation Turbine 1	Siemens SGT-300	7.9 MW	Fuel Gas	88.1 MMBtu/hr
Power Generation Turbine 2	Siemens SGT-300	7.9 MW	Fuel Gas	88.1 MMBtu/hr
Power Generation Turbine 3	Siemens SGT-300	7.9 MW	Fuel Gas	88.1 MMBtu/hr
Power Generation Turbine 4	Siemens SGT-300	7.9 MW	Fuel Gas	88.1 MMBtu/hr
Power Generation Turbine 5	Siemens SGT-300	7.9 MW	Fuel Gas	88.1 MMBtu/hr
Drilling Unit Diesel Engine 1	MTU 16V2000	1,085 bhp[2]	ULSD[3]	53 gal/hr

Table 9-8. Liberty Drilling and Production Island Emission Unit Inventory

DESCRIPTION[1]	MAKE/MODEL[1]	RATING[1]	FUEL TYPE[1]	MAXIMUM FUEL CONSUMPTION[1]
Drilling Unit Diesel Engine 2	MTU 16V2000	1,085 bhp	ULSD	53 gal/hr
Drilling Unit Diesel Engine 3	MTU 16V2000	1,085 bhp	ULSD	53 gal/hr
Drilling Unit Diesel Engine 4	MTU 16V2000	1,085 bhp	ULSD	53 gal/hr
Drilling Unit Gas Engine 1	Caterpillar G3516H	2,762 bhp	Fuel Gas	16.7 MMBtu/hr
Drilling Unit Gas Engine 2	Caterpillar G3516H	2,762 bhp	Fuel Gas	16.7 MMBtu/hr
Drilling Unit Gas Engine 3	Caterpillar G3516H	2,762 bhp	Fuel Gas	16.7 MMBtu/hr
Drilling Unit Cold Start Engine	Caterpillar 3304	150 bhp	ULSD	8 gal/hr
Drilling Unit Boiler 1	NA[4]	6.3 MMBtu/hr	Fuel Gas	0.013 MMscf/hr
			ULSD	46 gal/hr
Drilling Unit Boiler 2	NA	6.3 MMBtu/hr	Fuel Gas	0.013 MMscf/hr
			ULSD[2]	46 gal/hr
Drilling Unit Heater 1	NA	5.0 MMBtu/hr	Fuel Gas	0.010 MMscf/hr
			ULSD	37 gal/hr
Drilling Unit Heater 2	NA	5.0 MMBtu/hr	Fuel Gas	0.010 MMscf/hr
			ULSD	37 gal/hr
G&I Diesel Engine 1	Caterpillar 3512	1,650 bhp	ULSD	85 gal/hr
G&I Diesel Engine 2	Caterpillar 3512	1,650 bhp	ULSD	85 gal/hr
G&I Diesel Engine 3	Caterpillar 3512	1,650 bhp	ULSD	85 gal/hr
Compressor Turbine 1	Siemens SGT-300	11,000 bhp[2]	Fuel Gas	80.9 MMBtu/hr
Compressor Turbine 2	Siemens SGT-300	11,000 bhp	Fuel Gas	80.9 MMBtu/hr
Compressor Turbine 3	Siemens SGT-300	11,000 bhp	Fuel Gas	80.9 MMBtu/hr
Standby/Emergency Generator Engine 1	Caterpillar 3512	1,650 bhp	ULSD3	85 gal/hr
Standby/Emergency Generator Engine 2	Caterpillar 3512	1,650 bhp	ULSD	85 gal/hr
Standby/Emergency Generator Engine 3	Caterpillar 3512	1,650 bhp	ULSD	85 gal/hr
Incinerator	NA[4]	220 lb/hr	Waste	1.1 MMBtu/hr
Flare	NA	40 MMscf/day	Fuel Gas	140 MMscf/yr
Drilling Support Equipment				
Portable Heater	Tioga IDF 3 SCOK	1.0 MMBtu/hr	ULSD	7 gal/hr
Portable Heater	Tioga IDF 3 SCOK	1.0 MMBtu/hr	ULSD	7 gal/hr
Portable Heater	Tioga IDF 3 SCOK	1.0 MMBtu/hr	ULSD	7 gal/hr
Portable Heater	Tioga IDF 3 SCOK	1.0 MMBtu/hr	ULSD	7 gal/hr
Portable Heater	Tioga IDF 3 SCOK	1.0 MMBtu/hr	ULSD	7 gal/hr
Cement Pump	NA	300 hp	ULSD	15 gal/hr
Cement Pump	NA	300 hp	ULSD	15 gal/hr
Light Plant	Ingersol Rand L6-4MH	7 hp	ULSD	0.4 gal/hr
Light Plant	Ingersol Rand L6-4MH	7 hp	ULSD	0.4 gal/hr
Light Plant	Ingersol Rand L6-4MH	7 hp	ULSD	0.4 gal/hr
Large Crane	Manitowoc 999	400 hp	ULSD	21 gal/hr

Table 9-8. Liberty Drilling and Production Island Emission Unit Inventory

DESCRIPTION[1]	MAKE/MODEL[1]	RATING[1]	FUEL TYPE[1]	MAXIMUM FUEL CONSUMPTION[1]
Small Crane	Grove 80 Ton	275 hp	ULSD	14 gal/hr
Loader	Caterpillar 966	286 hp	ULSD	15 gal/hr
Loader	Caterpillar 966	286 hp	ULSD	15 gal/hr
Zoom Boom	Carelift ZB-10044	110 hp	ULSD	6 gal/hr
Hot Oil Unit	NA	485 hp	ULSD	25 gal/hr
Super Sucker Truck	NA	485 hp	ULSD	25 gal/hr
Super Sucker Truck	NA	485 hp	ULSD	25 gal/hr
Mobile Cement Van	NA	485 hp	ULSD	25 gal/hr
Mobile E-Line Unit	NA	485 hp	ULSD	25 gal/hr
Crew Van	NA	485 hp	ULSD	25 gal/hr

Notes:
1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information is included in the modeling report provided with this document.
2. Brake-horsepower.
3. Ultra-low sulfur diesel.
4. Not Available.

Table 9-9. Projected Peak Hourly Emissions

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (lb/hr)				
		SO_2	PM[2]	NO_X	CO	VOC
Power Generation Turbine 1	Siemens SGT-300	4.80	0.58	6.07	2.47	0.19
Power Generation Turbine 2	Siemens SGT-300	4.80	0.58	6.07	2.47	0.19
Power Generation Turbine 3	Siemens SGT-300	4.80	0.58	6.07	2.47	0.19
Power Generation Turbine 4	Siemens SGT-300	4.80	0.58	6.07	2.47	0.19
Power Generation Turbine 5	Siemens SGT-300	4.80	0.58	6.07	2.47	0.19
Drilling Unit Diesel Engine 1	MTU 16V2000	0.01	0.06	1.20	6.25	0.34
Drilling Unit Diesel Engine 2	MTU 16V2000	0.01	0.06	1.20	6.25	0.34
Drilling Unit Diesel Engine 3	MTU 16V2000	0.01	0.06	1.20	6.25	0.34
Drilling Unit Diesel Engine 4	MTU 16V2000	0.01	0.06	1.20	6.25	0.34
Drilling Unit Gas Engine 1	Caterpillar G3516H	0.91	0.17	3.05	15.52	4.45
Drilling Unit Gas Engine 2	Caterpillar G3516H	0.91	0.17	3.05	15.52	4.45
Drilling Unit Gas Engine 3	Caterpillar G3516H	0.91	0.17	3.05	15.52	4.45
Drilling Unit Cold Start Engine	Caterpillar 3304	0.00	0.01	0.10	1.23	0.05
Drilling Unit Boiler 1[3]	NA[4]	0.34	0.05	0.92	0.53	0.04
Drilling Unit Boiler 2[3]	NA	0.34	0.05	0.92	0.53	0.04
Drilling Unit Heater 1[3]	NA	0.27	0.04	0.73	0.42	0.03
Drilling Unit Heater 2[3]	NA	0.27	0.04	0.73	0.42	0.03
G&I Diesel Engine 1	Caterpillar 3512	0.02	0.27	1.82	9.49	0.52
G&I Diesel Engine 2	Caterpillar 3512	0.02	0.27	1.82	9.49	0.52

Table 9-9. Projected Peak Hourly Emissions

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (lb/hr)				
		SO_2	PM[2]	NO_X	CO	VOC
G&I Diesel Engine 3	Caterpillar 3512	0.02	0.27	1.82	9.49	0.52
Compressor Turbine 1	Siemens SGT-300	4.40	0.53	5.91	2.40	0.17
Compressor Turbine 2	Siemens SGT-300	4.40	0.53	5.91	2.40	0.17
Compressor Turbine 3	Siemens SGT-300	4.40	0.53	5.91	2.40	0.17
Standby/Emergency Generator Engine 1	Caterpillar 3512	0.02	0.27	1.82	9.49	0.52
Standby/Emergency Generator Engine 2	Caterpillar 3512	0.02	0.27	1.82	9.49	0.52
Standby/Emergency Generator Engine 3	Caterpillar 3512	0.02	0.27	1.82	9.49	0.52
Incinerator	NA[3]	0.003	0.17	0.32	0.02	0.33
Flare	NA	8.99	4.49	1.12	62.95	0.23
Drilling Support Equipment						
Portable Heater	Tioga IDF 3 SCOK	0.002	0.007	0.15	0.04	0.002
Portable Heater	Tioga IDF 3 SCOK	0.002	0.007	0.15	0.04	0.002
Portable Heater	Tioga IDF 3 SCOK	0.002	0.007	0.15	0.04	0.002
Portable Heater	Tioga IDF 3 SCOK	0.002	0.007	0.15	0.04	0.002
Portable Heater	Tioga IDF 3 SCOK	0.002	0.007	0.15	0.04	0.002
Cement Pump	NA	0.003	0.12	1.97	1.73	0.12
Cement Pump	NA	0.003	0.12	1.97	1.73	0.12
Light Plant	Ingersol Rand L6-4MH	0.0001	0.004	0.03	0.03	0.004
Light Plant	Ingersol Rand L6-4MH	0.0001	0.004	0.03	0.03	0.004
Light Plant	Ingersol Rand L6-4MH	0.0001	0.004	0.03	0.03	0.004
Large Crane	Manitowoc 999	0.004	0.05	0.96	0.37	0.07
Small Crane	Grove 80 Ton	0.003	0.04	0.66	0.23	0.05
Loader	Caterpillar 966	0.003	0.09	0.98	0.49	0.08
Loader	Caterpillar 966	0.003	0.09	0.98	0.49	0.08
Zoom Boom	Carelift ZB-10044	0.001	0.03	0.26	0.11	0.02
Hot Oil Unit	NA	0.005	0.009	0.05	0.02	0.003
Super Sucker Truck	NA	0.005	0.009	0.05	0.02	0.003
Super Sucker Truck	NA	0.005	0.009	0.05	0.02	0.003
Mobile Cement Van	NA	0.005	0.009	0.05	0.02	0.003

Table 9-9. Projected Peak Hourly Emissions

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (lb/hr)				
		SO_2	PM[2]	NO_X	CO	VOC
Mobile E-Line Unit	NA	0.005	0.009	0.05	0.02	0.003
Crew Van	NA	0.005	0.003	0.11	0.01	0.001

Notes:
1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information is included in the modeling report provided with this document.
2. PM_{10} or $PM_{2.5}$. PM_{10} emission rates are used to conservatively estimate $PM_{2.5}$ emissions.
3. Emissions for dual-fuel units are represented by the greater of the emissions during ULSD-fired or gas-fired mode.
4. Not Available.

Table 9-10. Maximum Annual Projected Emissions

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TONS PER YEAR)				
		SO_2	PM[2]	NO_X	CO	VOC
Power Generation Turbine 1	Siemens SGT-300	21.02	2.55	26.60	10.80	0.81
Power Generation Turbine 2	Siemens SGT-300	21.02	2.55	26.60	10.80	0.81
Power Generation Turbine 3	Siemens SGT-300	21.02	2.55	26.60	10.80	0.81
Power Generation Turbine 4	Siemens SGT-300	21.02	2.55	26.60	10.80	0.81
Power Generation Turbine 5	Siemens SGT-300	21.02	2.55	26.60	10.80	0.81
Drilling Unit Diesel Engine 1	MTU 16V2000	0.05	0.23	5.23	27.34	1.48
Drilling Unit Diesel Engine 2	MTU 16V2000	0.05	0.23	5.23	27.34	1.48
Drilling Unit Diesel Engine 3	MTU 16V2000	0.05	0.23	5.23	27.34	1.48
Drilling Unit Diesel Engine 4	MTU 16V2000	0.05	0.23	5.23	27.34	1.48
Drilling Unit Gas Engine 1	Caterpillar G3516H	3.99	0.73	13.34	68.01	19.47
Drilling Unit Gas Engine 2	Caterpillar G3516H	3.99	0.73	13.34	68.01	19.47
Drilling Unit Gas Engine 3	Caterpillar G3516H	3.99	0.73	13.34	68.01	19.47
Drilling Unit Cold Start Engine	Caterpillar 3304	0.01	0.02	0.43	5.40	0.21
Drilling Unit Boiler 1[3]	NA[4]	1.50	0.21	4.03	2.34	0.15
Drilling Unit Boiler 2[3]	NA	1.50	0.21	4.03	2.34	0.15
Drilling Unit Heater 1[3]	NA	1.19	0.17	3.20	1.86	0.12
Drilling Unit Heater 2[3]	NA	1.19	0.17	3.20	1.86	0.12
G&I Diesel Engine 1	Caterpillar 3512	0.08	1.19	7.96	41.58	2.26
G&I Diesel Engine 2	Caterpillar 3512	0.08	1.19	7.96	41.58	2.26
G&I Diesel Engine 3	Caterpillar 3512	0.08	1.19	7.96	41.58	2.26
Compressor Turbine 1	Siemens SGT-300	19.28	2.34	25.88	10.51	0.74

Table 9-10. Maximum Annual Projected Emissions

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TONS PER YEAR)				
		SO_2	PM[2]	NO_X	CO	VOC
Compressor Turbine 2	Siemens SGT-300	19.28	2.34	25.88	10.51	0.74
Compressor Turbine 3	Siemens SGT-300	19.28	2.34	25.88	10.51	0.74
Standby/Emergency Generator Engine 2	Caterpillar 3512	0.08	1.19	7.96	41.58	2.26
Standby/Emergency Generator Engine 3	Caterpillar 3512	0.08	1.19	7.96	41.58	2.26
Incinerator	NA[4]	0.01	0.77	1.39	0.06	1.45
Flare	NA	3.80	1.90	4.89	26.60	0.01
Drilling Support Equipment						
Portable Heater	Tioga IDF 3 SCOK	0.007	0.032	0.644	0.161	0.011
Portable Heater	Tioga IDF 3 SCOK	0.007	0.032	0.644	0.161	0.011
Portable Heater	Tioga IDF 3 SCOK	0.007	0.032	0.644	0.161	0.011
Portable Heater	Tioga IDF 3 SCOK	0.007	0.032	0.644	0.161	0.011
Portable Heater	Tioga IDF 3 SCOK	0.007	0.032	0.644	0.161	0.011
Cement Pump	NA	0.014	0.503	8.646	7.556	0.517
Cement Pump	NA	0.014	0.503	8.646	7.556	0.517
Light Plant	Ingersol Rand L6-4MH	0.0003	0.019	0.126	0.137	0.017
Light Plant	Ingersol Rand L6-4MH	0.0003	0.019	0.126	0.137	0.017
Light Plant	Ingersol Rand L6-4MH	0.0003	0.019	0.126	0.137	0.017
Large Crane	Manitowoc 999	0.019	0.224	4.187	1.607	0.305
Small Crane	Grove 80 Ton	0.013	0.154	2.879	0.985	0.222
Loader	Caterpillar 966	0.014	0.386	4.286	2.138	0.335
Loader	Caterpillar 966	0.014	0.386	4.286	2.138	0.335
Zoom Boom	Carelift ZB-10044	0.005	0.109	1.151	0.458	0.089
Hot Oil Unit	NA	0.023	0.039	0.202	0.080	0.011
Super Sucker Truck	NA	0.023	0.039	0.202	0.080	0.011
Super Sucker Truck	NA	0.023	0.039	0.202	0.080	0.011
Mobile Cement Van	NA	0.023	0.039	0.202	0.080	0.011
Mobile E-Line Unit	NA	0.023	0.039	0.202	0.080	0.011

Table 9-10. Maximum Annual Projected Emissions

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TONS PER YEAR)				
		SO_2	PM[2]	NO_X	CO	VOC
Crew Van	NA	0.023	0.013	0.460	0.062	0.005
	TOTAL	**185**	**36**	**380**	**713**	**89**

Notes:
1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information is included in the modeling report provided with this document.
2. PM_{10} or $PM_{2.5}$. PM_{10} emission rates are used to conservatively estimate $PM_{2.5}$ emissions.
3. Emissions for dual-fuel units are represented by the greater of the emissions during ULSD-fired or gas-fired mode.
4. Not Available.

Table 9-11. Maximum Projected Emissions for Project Duration

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TONS)				
		SO_2	PM[2]	NO_X	CO	VOC
Power Generation Turbine 1	Siemens SGT-300	631	76	798	324	24
Power Generation Turbine 2	Siemens SGT-300	631	76	798	324	24
Power Generation Turbine 3	Siemens SGT-300	631	76	798	324	24
Power Generation Turbine 4	Siemens SGT-300	631	76	798	324	24
Power Generation Turbine 5	Siemens SGT-300	631	76	798	324	24
Drilling Unit Diesel Engine 1	MTU 16V2000	1	7	157	820	45
Drilling Unit Diesel Engine 2	MTU 16V2000	1	7	157	820	45
Drilling Unit Diesel Engine 3	MTU 16V2000	1	7	157	820	45
Drilling Unit Diesel Engine 4	MTU 16V2000	1	7	157	820	45
Drilling Unit Gas Engine 1	Caterpillar G3516H	120	22	400	2,040	584
Drilling Unit Gas Engine 2	Caterpillar G3516H	120	22	400	2,040	584
Drilling Unit Gas Engine 3	Caterpillar G3516H	120	22	400	2,040	584
Drilling Unit Cold Start Engine	Caterpillar 3304	0.2	1	13	162	6
Drilling Unit Boiler 1[3]	NA[4]	45	6	121	70	5
Drilling Unit Boiler 2[3]	NA	45	6	121	70	5
Drilling Unit Heater 1[3]	NA	36	5	96	56	4
Drilling Unit Heater 2[3]	NA	36	5	96	56	4
G&I Diesel Engine 1	Caterpillar 3512	2	36	239	1,248	68
G&I Diesel Engine 2	Caterpillar 3512	2	36	239	1,248	68
G&I Diesel Engine 3	Caterpillar 3512	2	36	239	1,248	68
Compressor Turbine 1	Siemens SGT-300	578	70	776	315	22

Table 9-11. Maximum Projected Emissions for Project Duration

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TONS)				
		SO_2	PM[2]	NO_X	CO	VOC
Compressor Turbine 2	Siemens SGT-300	578	70	776	315	22
Compressor Turbine 3	Siemens SGT-300	578	70	776	315	22
Standby/Emergency Generator Engine 1	Caterpillar 3512	2	36	239	1248	68
Standby/Emergency Generator Engine 2	Caterpillar 3512	2	36	239	1248	68
Standby/Emergency Generator Engine 3	Caterpillar 3512	2	36	239	1248	68
Incinerator	NA[4]	0.4	23	42	2	43
Flare	NA	114	57	147	798	0.3
Drilling Support Equipment						
Portable Heater	Tioga IDF 3 SCOK	0.2	1	19	5	0.3
Portable Heater	Tioga IDF 3 SCOK	0.2	1	19	5	0.3
Portable Heater	Tioga IDF 3 SCOK	0.2	1	19	5	0.3
Portable Heater	Tioga IDF 3 SCOK	0.2	1	19	5	0.3
Portable Heater	Tioga IDF 3 SCOK	0.2	1	19	5	0.3
Cement Pump	NA	0.4	15	259	227	16
Cement Pump	NA	0.4	15	259	227	16
Light Plant	Ingersol Rand L6-4MH	0.01	1	4	4	1
Light Plant	Ingersol Rand L6-4MH	0.01	1	4	4	1
Light Plant	Ingersol Rand L6-4MH	0.01	1	4	4	1
Large Crane	Manitowoc 999	1	7	126	48	9
Small Crane	Grove 80 Ton	0.4	5	86	30	7
Loader	Caterpillar 966	0.4	12	129	64	10
Loader	Caterpillar 966	0.4	12	129	64	10
Zoom Boom	Carelift ZB-10044	0.2	3	35	14	3
Hot Oil Unit	NA	1	1	6	2	0.3
Super Sucker Truck	NA	1	1	6	2	0.3
Super Sucker Truck	NA	1	1	6	2	0.3
Mobile Cement Van	NA	1	1	6	2	0.3

Table 9-11. Maximum Projected Emissions for Project Duration

DESCRIPTION[1]	MAKE/MODEL[1]	MAXIMUM POLLUTANT EMISSION RATE[1] (TONS)				
		SO_2	PM[2]	NO_X	CO	VOC
Mobile E-Line Unit	NA	1	1	6	2	0.3
Crew Van	NA	1	0.4	14	2	0.1
	TOTAL	**5,553**	**1,084**	**11,390**	**21,390**	**2,666**

Notes:
1. Emission unit descriptions, make/model, rating, fuel type, and maximum fuel consumption information is included in the modeling report provided with this document.
2. PM_{10} or $PM_{2.5}$. PM_{10} emission rates are used to conservatively estimate $PM_{2.5}$ emissions.
3. Emissions for dual-fuel units are represented by the greater of the emissions during ULSD-fired or gas-fired mode.
4. Not Available.

9.4.2 Emission Reduction Measures

A description of emission reduction measures that will be implemented at the LDPI are provided in the modeling report described in Section 9.4.6.

9.4.3 Processes, Equipment, Fuels, and Combustibles

Table 9-12 provides a summary of the fuels, combustibles, and storage units that will be located on the LDPI. As shown in Table 9-8, a flare will be used on the LDPI when waste gases cannot be prevented or recovered during development and production activities. The flare will meet the federal requirements in 40 CFR 60.18 and in 40 CFR 63.11. The flare will be rated for a maximum daily rate equal to 40 MMscf/day, but the actual daily flaring rate is anticipated not to exceed 4.0 MMscf/day, and the annual flaring rate is anticipated not to exceed 140 million standard cubic feet per year (MMscf/yr). The pilot flare is anticipated to burn 0.003 MMscf/day and will operate continuously at all times during LDPI operations.

Table 9-12. Fuels, Combustibles, Processes, and Storage Units[1]

DESCRIPTION	FUEL TYPE	MAXIMUM RATING	MAXIMUM CAPACITY
Sales Oil Tank 1[1]	Crude Oil	NA[2]	15,000 barrels
Sales Oil Tank 2[1]	Crude Oil	NA	15,000 barrels
Off-Spec Oil Tank[1]	Crude Oil	NA	5,000 barrels
Pipeline Diesel Tank[3]	Diesel	NA	96,722 gallons
Backup Generator Diesel Tank 1[3]	ULSD[4]	NA	26,000 gallons
Backup Generator Diesel Tank 2[3]	ULSD	NA	26,000 gallons

Notes:
1. Based on information provided after air emissions modeling was conducted; modeling results are not affected.
2. Not applicable.
3. Based on information available at the time air emissions modeling was conducted.
4. Ultra-low sulfur diesel.

9.4.4 Distance to Shore

The distance from the closest onshore area to the LDPI is 4.1 statute miles.

9.4.5 Non-Exempt Facilities

To determine if the LDPI is exempt from any further air quality review, the total annual projected emissions provided in Table 9-10 were compared to the emission thresholds that are based on the formulas provided in 30 CFR 550.303(d). Table 9-13 provides comparisons of the BOEM exemption thresholds with the total annual projected emissions. As shown, the total annual projected emissions exceed the BOEM exemption amounts for SO_2 and NO_X.

Table 9-13. BOEM Exemption Amounts Compared to the LDPI Potential to Emit

POLLUTANT	BOEM EXEMPTION FORMULA	EXEMPTION AMOUNT, E (TPY)	MAX. ANNUAL PROJECTED EMISSIONS (TPY)	EXEMPT?
SO_2	E = 33.3 x D[1]	133.2	185	**NO**
PM	E = 33.3 x D	133.2	36	Yes
NO_X	E = 33.3 x D	133.2	380	**NO**
VOC	E = 33.3 x D	133.2	89	Yes
CO	$E = 3{,}400 \times D^{2/3}$	8,567.5	713	Yes

Note:
1. D is equal to 4.1 statute miles, which is the distance from the LDPI to the nearest onshore location.

Per 30 CFR 550.303(e) through (f), an approved air quality model has been used to demonstrate whether the projected emission impacts exceed the Significance Levels provided in 30 CFR 550.303(e). Table 9-14 provides a summary of the maximum modeled onshore impacts due to the projected emissions from the OCS facility. As shown, none of the maximum modeled impacts exceed the applicable Significance Levels.

Table 9-14. LDPI Maximum Modeled Onshore Impacts

POLLUTANT	AVERAGING PERIOD	SIGNIFICANCE LEVEL[1]	MAXIMUM MODELED ONSHORE IMPACT	SIGNIFICANCE LEVEL EXCEEDED?
NO_2	Annual	1 $\mu g/m^3$	0.52 $\mu g/m^3$	No
CO	8-Hour	500 $\mu g/m^3$	65.1 $\mu g/m^3$	No
	1-Hour	2,000 $\mu g/m^3$	191.3 $\mu g/m^3$	No
PM[2]	Annual	1 $\mu g/m^3$	0.1 $\mu g/m^3$	No
	24-Hour	5 $\mu g/m^3$	0.9 $\mu g/m^3$	No
SO_2	Annual	1 $\mu g/m^3$	0.2 $\mu g/m^3$	No
	24-Hour	5 $\mu g/m^3$	3.5 $\mu g/m^3$	No
	3-Hour	25 $\mu g/m^3$	13.6 $\mu g/m^3$	No

Notes:
1. Source: 30 CFR 550.303(e).
2. PM10 or PM2.5. PM2.5 is conservatively estimated to be equal to PM10.

9.4.6 Modeling Report

A dispersion modeling demonstration has been prepared to evaluate potential air quality impacts against established BOEM Significance Levels. The modeling procedures are consistent with 30 CFR 550.249(e), 40 CFR 51, Appendix W, and BOEM guidance for evaluating offshore drilling and production operations and their impact on coastal air quality.

The modeling report, which contains the details of the modeling approach and results, is provided in Appendix F.

Electronic files have been compiled to consolidate the information listed below and is included with the attached air dispersion modeling report.

1. An electronic copy of the modeling report,
2. Emission calculations,
3. Supporting information used for emission calculations, and
4. Dispersion modeling files.

9.5 Safety Equipment

9.5.1 Safety Systems

The fundamental tenet of the safety system is the segregation of Basic Process Control Systems (BPCS) from the Instrumented Protective Systems (IPS), which performs a safety function. This segregation includes the field devices, data highway, and redundant programmable logic controller(s) (PLC) on LDPI.

All production safety systems will comply with 30 CFR 250 Subpart H and API RP 14C, *Design, Installation and Testing of Surface Safety Systems for Offshore Production Platforms* requirements. To help assure safe operation of the facilities, complete Piping and Instrument Diagrams (P&IDs) and Safety Analysis and Function Evaluation “Safe Charts” will be developed during the detailed engineering phase and maintained throughout the life of the Liberty field.

Each Liberty production well will be equipped with two actuated shut-down valves (SDVs) within the flow path of the producing wells; the Surface Safety Valve (SSV) and a Sub-Surface Safety Valve (SSSV). The SSV is an actuated valve on the wing valve of the tree and is the primary means of isolation from subsurface pressure sources during an upset condition. The SSSV is installed below surface in the tubing string to prevent uncontrolled flow in the event that a wellhead system fails. Both the SSV(s) and the SSSV(s) will be remotely actuated by automated control devices, and will stop the flow from a Liberty production well if the operating parameters are exceeded. These valves can also be closed locally or remotely if needed.

The Liberty production pipeline will be equipped with SDV(s) located on the LDPI prior to the pipeline leaving the island and at the shore crossing where the pipeline daylights, and at the tie-in point to the Badami pipeline. These valves are remotely and automatically closed by the real-time leak detection system in case of a leak or other pipeline upset. These valves can also be remotely closed by a control room operator if needed.

All process modules on the LDPI onshore pipeline facilities will be built to the appropriate hazardous area classification, and will be equipped with fire and gas detection and normal and emergency ventilation systems. These systems will be designed to detect the presence of a combustible gas or fire in the module. If combustible gas or fire is detected, this Emergency Support System (ESS) will isolate the affected area and initiate increased ventilation or system isolation and shutdown of the process.

9.5.2 Firefighting Philosophy and Equipment

The basic philosophy for Liberty is to attempt a response to a fire in the incipient stage. Upon detection of a fire or high gas levels (40% lower explosive limit [LEL]) in the production modules, the ventilation system will shut down, the well or wells will be isolated, and the process modules de-pressured. All personnel will evacuate the production area and return to the muster location. The fire protection system will be either fine water mist, clean agent, or a combination of these systems. The system will be designed in accordance with applicable International Fire Code, International Building Code, and National Fire

Protection Act standards. The electrical equipment in the control module will be protected with portable carbon dioxide extinguishers. Portable firefighting facilities in the form of dry powder and foam will be provided as necessary. Manual actuation of any fire protection systems will be possible either through the central control system or at strategic locations in the plant and camp. Full time fire/gas and process alarm monitoring will be performed from a monitoring station located in the PLQ.

9.5.3 Fire and Gas Detection, Alarm Action and Ventilation Philosophy

A Fire and Gas (F&G) Alarm Control system will be provided, which monitors the plant and provides status information to the main Fire and Gas Alarm Control Panel. Supplemental circuits will provide alarms and status to the central computer system. The system will provide for automatic or manual operation of fire alarms and protection systems. Optical combustible gas detectors for monitoring for the presence of flammable gas and fire will be installed throughout the LDPI process facility modules. Smoke or flame detection will be installed within buildings as necessary. Detection systems will provide both visual and audible alarms throughout the facilities.

Manual fire alarm pull stations will be located at strategic points throughout the facility, and a fire protection panel will be provided with zone indication of detector points. The F&G system will be provided with a dedicated electrical power supply and battery back-up, as required.

When activated, the fire alarm detection system will signal both audible and visual alarms, shutdown process equipment, and purge the facility of process gas. The fire suppression system will be manually activated after visual verification of a fire because there are instances, such as a gas jet fire, where extinguishing should only be done after the fuel supply has been cut off. The normal ventilation system will circulate the air at six (6) air changes per hour (ACPH). During normal operating conditions, up to three (3) ACPH can be recirculated while accompanied with combustible gas detectors at the air intakes. At 20% LEL gas detection, the emergency ventilation fans will increase air changes from six (6) ACPH to twelve (12) ACPH. If the gas concentration continues to rise to 40% Lower Flammable Limit, an Emergency Shutdown (ESD) will be activated, causing the facility to shut down and isolate any sources of produced gas. If the module internal air temperature should drop below 40 ºF, the emergency ventilation system will be shutdown.

The living quarters will have a fire detection and alarm system as well as water suppression system throughout the living quarters. Since the Liberty fuel gas is not likely to be odorized, the living quarters will include combustible gas detection devices installed in the areas where gas is utilized, such as rooms that house gas boilers rooms, hot air gas furnace rooms, and hot water heaters.

The combustible gas detectors shall be connected into the fire and gas alarm control panel that will be specifically listed to accept input from the combustible gas detectors. If low levels of combustible gas (20% Lower Flammable Limit) are detected, the fire/life safety alarms will sound. If higher levels of combustible gas are detected (40% Lower Flammable Limit), a remote gas supply valve will operate, automatically isolating gas supply to the area in the event of a potential release.

9.6 Facility Expansion Options

HAK has evaluated methods by which the planned nominal plant capacity of 65,000 barrels of oil per day (BOPD) could be safely increased with equipment modifications to allow peak production of 75,000 BOPD. A facility expansion or “debottlenecking” effort is often implemented later in field life, after the reservoir deliverability is known with certainty and the emulsion tendencies of the crude and producer water is better understood. While not part of the initial installation, if this option were implemented, it would require reserved space to add an additional oil processing train and manifolding to deliver produced fluid to the train. It may also require pre-dedicated pad space to accommodate a larger produced water treatment train to reduce oil in water that is being re-injected back into the reservoir. If this option were implemented, it would result in increases in peak production rates over current proposed rates, as shown below, but will not require a larger island footprint than what has been described in this plan:

- Sales Oil – 75,000 barrels of oil per day
- Produced Gas – 140 MMscf/day maximum future
- Seawater Treatment – 84,000 barrels of water per day
- Produced Water Handling – 115,000 barrels of water per day
- Water Injection – 161,000 barrels of water per day

9.7 New or Unusual Technology

The Liberty Development will only use equipment regarded as proven technology in the Arctic region. Therefore, all components and processes selected to be used for the Project will have a proven track record. No new or unusual technology will be used by or developed specifically for the Liberty Development. Some of the equipment used will be specific and unique to the project, but the components (e.g., valves, sensors, materials, connection systems, etc.) will be standard.

This is a sound, conservative approach, based on substantial North Slope project experience: 15 exploration and 4 standalone developments in the Beaufort Sea, 3 subsea flowlines/pipelines in the Beaufort Sea, 4 wells drilled in/near the Liberty Reservoir (Liberty No. 1; Tern No. 1, No. 2 and No. 3), and approximately 85 wells drilled in the analogous Endicott Reservoir.

9.8 Overall Facility Layout, Plot Plan Discussion

The LDPI surface layout plan shows the location of all fixed structures and the proposed wells. The LDPI surface layout is shown in Figure 9-5 and Figure 9-6. The process facilities, living quarters, drilling equipment, warehousing and other support buildings pivot around the central location of the well row. The wells will be sited on a single axis, oriented to accommodate the predominant easterly winds in this location of the Beaufort Sea.

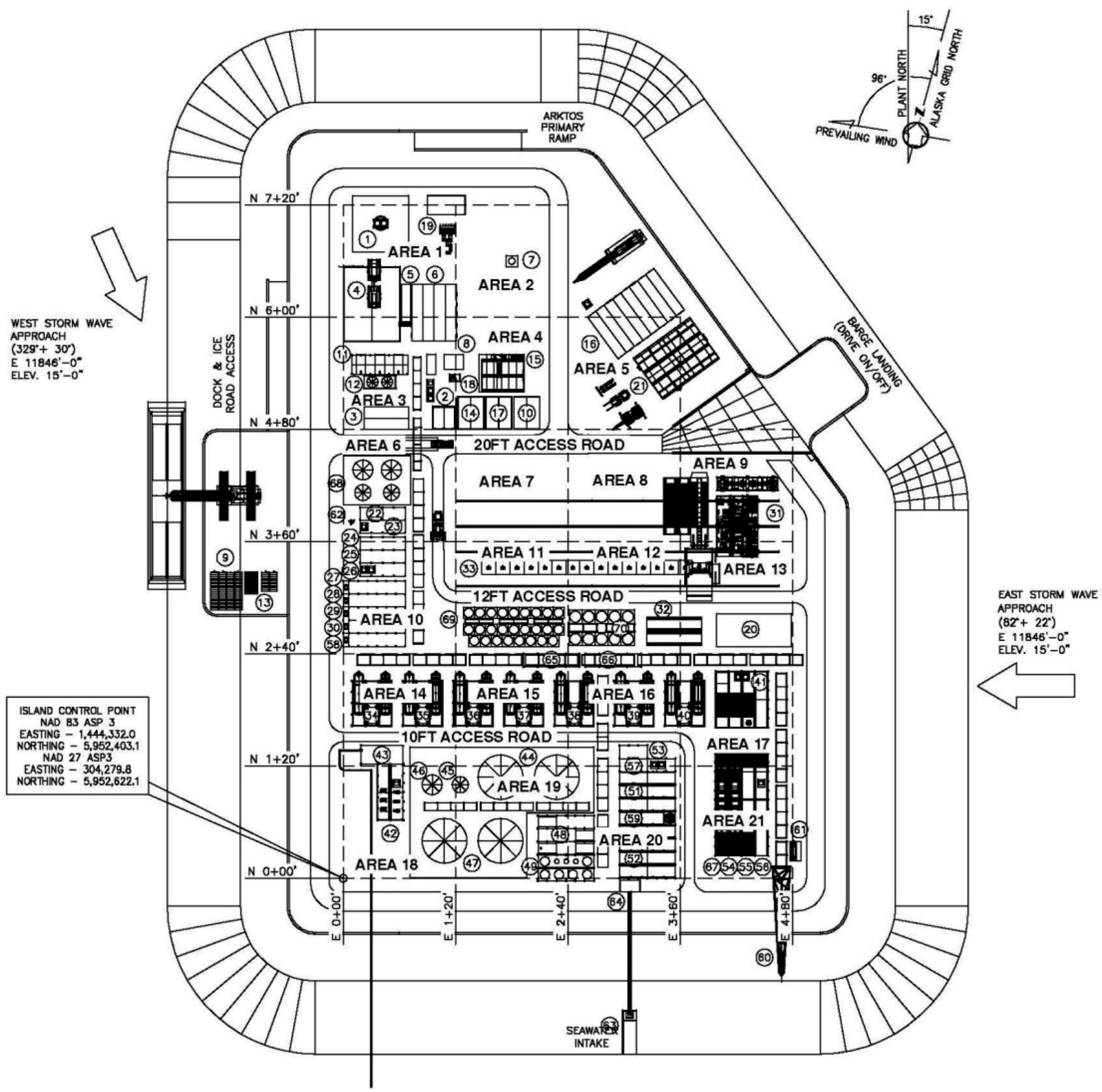
The center of LDPI is dedicated to power generation and drilling. The grind and inject facility will be located near the disposal well on the east end of the well row. The producing wells are notionally aligned with the produced fluid separation modules. The injection wells will be equally spaced between the producers. The central and northeast sections of LDPI are available for storage of drilling consumables. This should be sufficient to safely drill and complete five wells before a re-supply is required.

The process facilities, including produced fluid separation modules, seawater treatment modules, gas compression modules, flare booms, and bulk fluid storage tanks, will all be located to the south of the well row. The high pressure and low pressure flares are located near the gas compression modules on the opposite corner of LDPI from the living quarters. The location of the surface facilities has been selected to reduce the likelihood of the living quarters being affected by a gas release, fire and/or smoke.

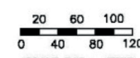
The living quarters, heliport, emergency generators, control room, and warehouses are located northwest of the well row. The living quarters, emergency equipment, and heliport are sited on the most northern point of LDPI to provide separation from the process equipment and gas injection and production wells.

Figure 9-5. Conceptual 3-D Rendering of Proposed LDPI

Figure 9-6. LDPI Site Plan (Conceptual)



AREA 1	1	HELI–PAD	AREA 14	34	TRAIN #7 PRODUCTION MODULE
	4	HANGER/ARKTOS STORAGE		35	TRAIN #6 PRODUCTION MODULE
	5	FREEZER/DRY STORAGE MODULE	AREA 15	36	TRAIN #5 PRODUCTION MODULE
	6	MAIN CAMP		37	TRAIN #4 PRODUCTION MODULE
	19	GRAVEL STORAGE		65	PRODUCTION MANIFOLD MODULE
AREA 2	7	RELIEF WELL LOCATION	AREA 16	38	TRAIN #3 PRODUCTION MODULE
AREA 3	2	FIRE & RESCUE		39	TRAIN #2 PRODUCTION MODULE
	3	POTABLE WATER STORAGE MODULES		66	GAS LIFT/INJECTION MANIFOLD MODULE
	8	SEWAGE PLANT	AREA 17	40	TRAIN #1 PRODUCTION MODULE
	11	STANDBY GENERATOR MODULE		41	FG & INJECTION COMPRESSION MODULES
	12	DIESEL STORAGE	AREA 18	42	SALES OIL PUMP & LACT MODULES
	18	INCINERATOR		43	PIPELINE/PIGGING MODULE
AREA 4	10	WELDING SHOP		46	FIRE WATER TANK–5000BBL
	14	GENERAL SHOP		47	SALES OIL TANKS–15000BBL
	15	WAREHOUSE STORAGE	AREA 19	44	PRODUCED WATER & SEA WATER
	17	ELECTRICAL SHOP			TANKS–15000BBL
	–	RELIEF RIG RESERVED SPACE		45	SLOP TANK
AREA 5	16	DRILLERS' CAMP		48	UTILITY MODULE
	21	VEHICLE SHELTER & STORAGE		49	CHEMICAL TANK FARM
AREA 6	22	CONTROL ROOM MODULE #1	AREA 20	51	P.W. TREATMENT MODULES #1 – #3
	23	CONTROL ROOM MODULE #2		52	P.W. TREATMENT MODULES #4 – #7
	62	MICROWAVE COMMUNICATION TOWER		53	VRU
	68	DIESEL TANK FARM		57	WATER INJECTION/OFFSPEC PUMP MODULE
AREA 7	–	RIG SKID BEAMS		59	S.W. TREATMENT MODULES
AREA 8	–	RIG SKID BEAMS			(BY ACCELERATED)
AREA 9	31	DRILLING RIG/UTILITY MODULE	AREA 21	54	COMPRESSION TRAIN #1 MODULE
AREA 10	24	SWITCHGEAR		55	COMPRESSION TRAIN #2 MODULE
	25	MCC #1		56	COMPRESSION TRAIN #3 MODULE
	26	MCC #2		60	FLARE BOOM
	27	POWER GENERATOR #1		61	FLARE KNOCK–OUT DRUM
	28	POWER GENERATOR #2		67	COMPRESSION TRAIN #4 MODULE
	29	POWER GENERATOR #3	-	9	C–CAN LAYDOWN AREA
	30	POWER GENERATOR #4		13	C–CAN LAYDOWN AREA
	58	POWER GENERATOR #5		63	SEA WATER INTAKE CAISSON
AREA 11	33	PRODUCTION & INJECTION WELL AREA		64	SEA WATER INJECTION PUMP MODULE
	69	DRILLING CEMENT SILOS			
AREA 12	32	DRILLING SUPPORT BUILDING			
	33	PRODUCTION & INJECTION WELL AREA			
	70	DRILLING MUD SILOS			
AREA 13	20	GRIND INJECTION FACILITY			



10 ONSHORE FACILITIES AND SUPPORT RESOURCES

This section describes support utilities and infrastructure associated with production and pipeline operations, as well as other facilities and resources that will be used to support construction of this project. In addition to the major project components described earlier (gravel island, production facilities and infrastructure, and pipeline system), a system of project support facilities will also be required to construct and operate this project. These include:

- System of winter ice roads
- Gravel mine site
- Onshore freshwater sources

10.1 Ice Roads

A system of ice roads will be built to support project construction, refer to Figure 10-1.

- Winter Season (4Q Execute Year 1) – Island Construction
    - Badami Ice Road
    - Badami Ice Road to Shore Crossing/Material Site Interconnect
    - Sea Ice Material Source/Pipeline Road
- Winter Season (4Q Execute Year 2) – Offshore Pipeline Construction and Material Delivery to Island
    - SDI to Liberty
    - Badami Ice Road to Shore Crossing/Material Site
    - Material Source/Pipeline Road

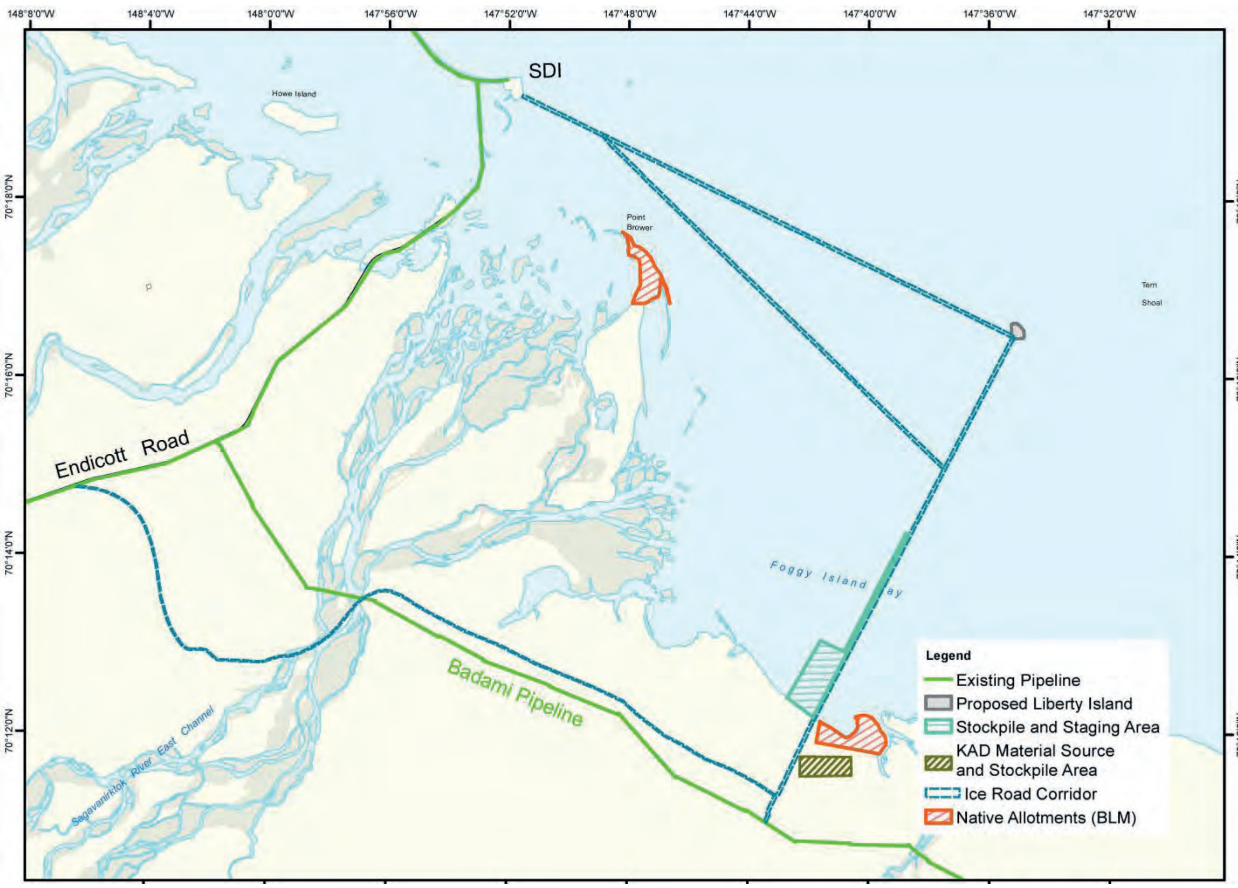
The use of ice roads allows on-ice trench excavation and pipe laying activities, and the bulk hauling of gravel and other materials to the island and pipeline route locations. The ice roads will extend from the Endicott Road, along the Badami Pipeline, and from the island to the Badami Pipeline tie-in to support pipeline construction. An ice road will also extend from the island to the proposed mine site to support island construction. Additional ice road spurs will be constructed as necessary to interconnect the ice road system, and to access existing permitted water sources. During all phases of construction and operations, an ice road will extend from the SDI to the LDPI. Ice roads have been demonstrated to have limited impact on marine or terrestrial environments.

The road built on grounded sea ice and ice roads constructed onshore will have a traveled surface approximately 40 feet wide. The annual ice road between SDI and LDPI will be approximately 11 miles long and between 70 inches and 96 inches (8 feet) thick. The road will be approximately 120 feet wide with a driving lane width of 40 feet, and will cover approximately 160 acres of sea ice in total. The actual width and depth of the ice in a given year will be based upon that year's activities and the required loads. Typically, ice roads constructed on the tundra to access water sources will be approximately 6-inches thick with a traveled surface width of approximately 30 feet.

The ice road built in support of pipeline construction in the pipeline corridor will be contained within the pipeline construction right-of-way and will be sufficiently thick to support numerous passes of heavy construction equipment. The ice road connecting the mine site to the island will be about 50 feet wide and approximately 6-inches thick onshore. Offshore, this road will consist of two distinct segments: a section constructed on grounded sea ice and a floating section. The floating section of the sea ice will be thickened approximately 8 feet (96 inches) to support heavy loads required for island construction.

In addition to the ice road system, three ice pads are also planned to support construction. These include the pipe stringing and two stockpile/disposal areas needed for pipeline construction (see Section 7). During the winters when production well drilling is occurring, an additional storage area of approximately 350 by 700 feet will be built on the sea ice on the east side of the island. This site would be used to store tubulars and other clean materials.

Figure 10-1. Proposed Ice Road Routes to Support Liberty Construction and Re-Supply



Onshore ice roads will be constructed by using snow cover and water to form an initial trail. Snow fence may be required to gather snow. Ice thickness will be increased by spraying additional water until the road is the desired thickness (about 6 inches onshore). Additional water will be added as necessary for road maintenance. Ice road construction begins by building a grounded ice ramp departing the Endicott road system. Ice rubble in the path of the planned road is knocked down, and the rough areas are flooded or sprayed with sea water, as required, to allow for tracked vehicles, Rolligons, and hovercraft travel to and from the island. Flooding is continued to improve the road until sufficient ice is present to support project resupply as well as provide carrying capacity in the event of a blowout during winter operations. Imported ice chip aggregate flooded with fresh water can also be used. Freshwater can be sprayed onto the road to form a cap over the main road structure.

Following the removal of the rubble, the ice road will generally be constructed by pumper units equipped with an ice auger to drill holes in the sea ice and then pump water from under the ice to flood the surface of the ice. The ice augers and pumping units will continue to move along the ice road alignment to flood the entire alignment, returning to a previous area as soon as the flooded water has frozen. The ice road will be maintained and kept clean of gravel and other solids as solar radiation will deteriorate a dirty ice road quickly.

Construction will be scheduled to begin as soon as conditions are appropriate. The ice roads and pads will thaw in the summer season.

In subsequent years, an ice road system will be constructed to access the island. The location of the ice road from SDI to LDPI will remain essentially the same from year to year during operations (see Figure 5-2).

10.2 Water Sources

Existing permitted water sources will be used for ice road construction and other water needs. These sources include existing and abandoned gravel mine sites, as well as several tundra lakes and ponds. It is estimated that the total quantity of freshwater required for project construction is approximately 120 million gallons over a period of two construction seasons. During operations, an estimated 20 million gallons would be needed for ice road construction.

10.3 Gravel Sources

A source of approximately 1,250,000 cubic yards of gravel is required to meet immediate and potential long-term project needs. Approximately 833,000 cubic yards will be needed for the island, approximately 3,500 cubic yards for the Badami tie in pad, and approximately 1,500 cubic yards for the Badami ice road crossing. The remaining yardage would be used for pipeline select backfill, maintenance, and contingency needs. The mine site operation is planned for one season.

The proposed source of gravel is a new mine site, developed specifically for this project, west of the Kadleroshilik River. The plan would be similar to those used for other mine sites developed on the North Slope, including the Put 23 Mine Site, East Badami Mine Site, and the Kuparuk Dead Arm Mine Site. The general approach of these mining and reclamation plans is to minimize the effects of mining and to create conditions that improve aquatic habitat. The detailed Liberty Mining and Reclamation Plan will be developed in coordination with the state and federal agencies, and will meet Alaska Department of Natural Resources (ADNR) criteria for mine site development.

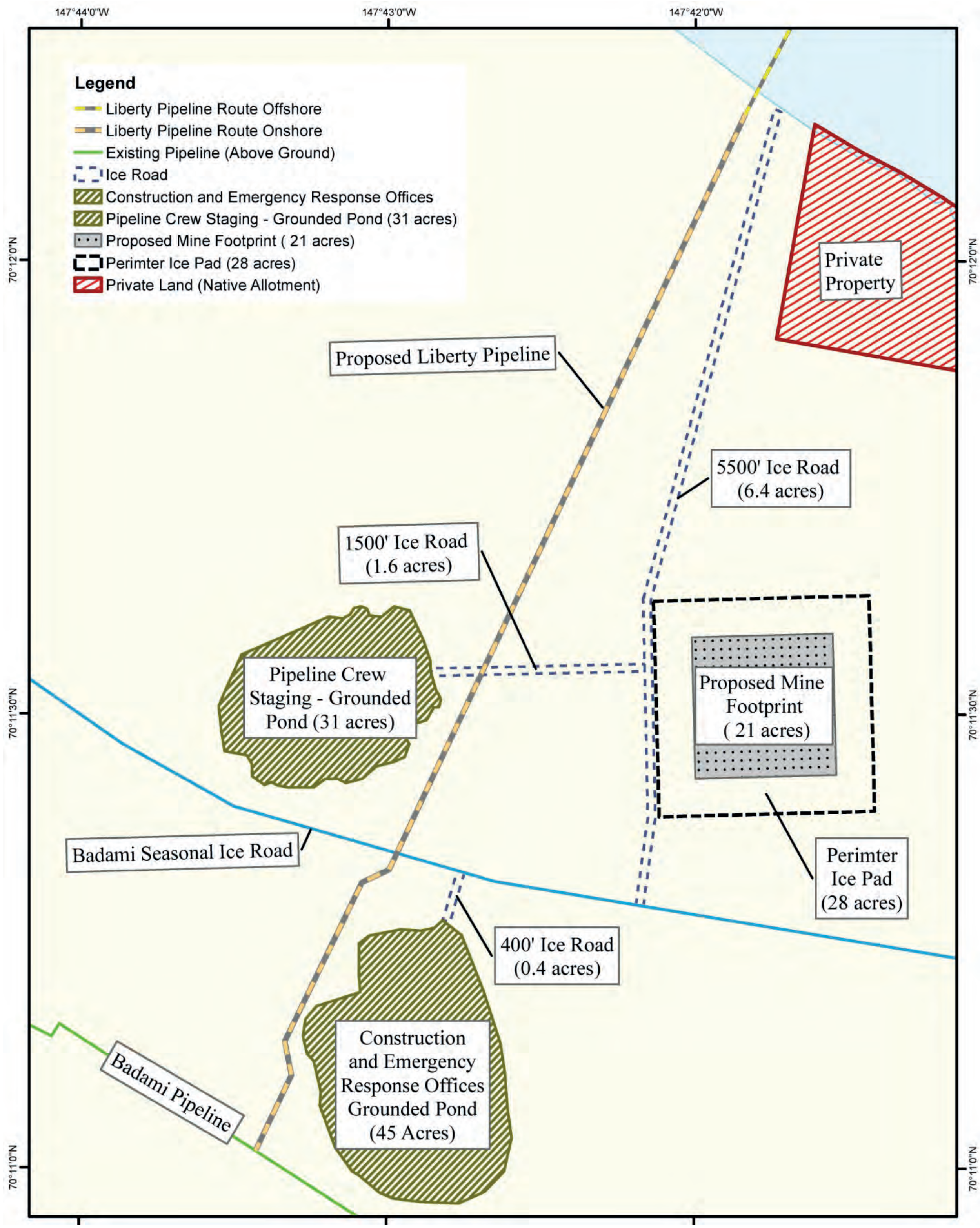
The mine site, shown in Figure 10-2, lies approximately 0.5 miles south of Foggy Island Bay, west of the Kadleroshilik River. The development mine site is approximately 21 acres in size, with the primary excavation area developed as one cell. A 28-acre ice pad perimeter is planned.

The gravel mining and rehabilitation plan will be developed with the objective of minimizing environmental impacts through mitigation features incorporated into the project design.

Mining is scheduled to begin in 1Q Execute Year 2. Unusable material will be stripped from the site and stockpiled on an ice pad in a designated reserve area. After useable gravel has been removed from the mine, materials unsuitable for construction will be placed back in the excavation to slope one side of the cell and create a shallow shelf area to improve future habitat potential of the site.

Upon rehabilitation, the mine site will provide several benefits. The excavation will create potential overwintering habitat for fish in an area where this type of habitat is limited. Rehabilitation planning will be coordinated with Alaska Department of Fish and Game (ADF&G) and ADNR to create the most useable habitat. The pit may also provide a source of water for ice road construction.

Figure 10-2. Proposed Mine Site



10.4 SDI Dock and Hovercraft Hangar

Similar to the support facilities on West Dock that support the Northstar Island, there will be facilities located on SDI used to support the LDPI. Included on SDI will be a small dock face, hovercraft hangar, and staging or laydown area. A 2,000-gallon fuel tank will be located on the SDI to support hovercraft operations. There is no expansion of the SDI footprint planned at this time.

10.5 Onshore Construction Camp Support

Construction during the period from 4Q Year 1 to 3Q Year 3 will be staged from existing or on-site facilities. HAK plans to house the majority of the summer work force in existing onshore facilities until the on-island camp is available. After installation of the infrastructure modules, the permanent living quarters will be ready for occupancy. An additional temporary camp housing unit up to 125 workers may also be installed during the 3Q Year 2; sanitary and domestic wastewater from this camp may be discharged in accordance with the NPDES permit.

Waste categories and quantities for the project are provided in Section 11.11. Waste categories for activities on the SDI during construction include construction debris, wood waste, minor amounts of oily waste, municipal solid waste, treated sanitary wastewater from a construction camp wastewater treatment plant, and minor amounts of hazardous and universal wastes. After construction, only minor amounts of oily waste from hovercraft maintenance and minor amounts of municipal waste from hovercraft operations is expected.

Temporary diesel storage capacity will be required on the island to support drilling and construction. Temporary tank storage would be mobilized to the site over the ice road after island construction and filled by truck just before breakup. Once facilities modules are installed and operational, this temporary storage capacity will no longer be needed. An estimated maximum of 21,000 barrels of temporary diesel storage will be required, and the largest single tank volume would be 5,000 barrels. Tanks will meet all relevant industry and regulatory agency requirements for leak prevention and secondary containment.

Diesel will need to be delivered to the site as needed to maintain the supply needed to support construction and drilling. Approximately 5,000 gallons of diesel will be transported at any one time. Seven deliveries are estimated (one by trucks in ice road season Year 2, two by barge in open-water season Year 2, two by trucks in ice road season Year 3, and two by barge in open-water season Year 3). Temporary diesel storage will no longer be required after the facilities plant begins operating. At the pipeline tie-in pad, propane will be resupplied approximately every 3 months via ice road. No summer transportation of propane is anticipated.

Chemicals that may be stored onshore and used to support Liberty Development Project activities are presented in Table 10-1.

Table 10-1. Onshore Chemical Storage and Usage for Liberty Production Operations

PRODUCT, DESCRIPTION	TYPICAL USE	VOLUME USED (ESTIMATE)	STORAGE VOLUME	STORAGE METHOD
Propane	Heaters at the pipeline tie-in pad	As needed	(3) 500 gal tank(s) at the Badami tie-in pad	Pressurized tank
Diesel fuel at the SDI	Hovercraft fuel	As needed	2,000 gal tank	Double walled above-ground storage tank

10.6 Onshore Air Emissions

The EUs that are planned for operating at the Badami Pipeline Tie-in Pad to support the Liberty Development Project include four propane-fired thermoelectric generators (TEG) with a maximum power output of 120 watts each. Table 10-2 shows the projected annual emissions in tons per year based on the conservative assumption that each EU operates at maximum capacity during the entire year. As shown, the cumulative projected emissions from the onshore support facility are approximately 1 tpy and insignificant in comparison to the projected emissions from the OCS facility presented in Section 9.4.

Table 10-2. Badami Tie-In Pad Projected Annual Emissions

DESCRIPTION	MODEL	QUANTITY	MAXIMUM POLLUTANT EMISSION RATE (TPY)				
			SO_2	PM[1]	NO_X	CO	VOC
Thermoelectric Generator (TEG)	Global Thermoelectric Model 5120	4	<0.0001	0.04	0.7	0.39	0.04

Note:

1. PM_{10} or $PM_{2.5}$. PM_{10} emission rates are used to conservatively estimate $PM_{2.5}$ emissions.

11 OPERATING MANAGEMENT SYSTEMS, PRACTICES, PROCEDURES

This section covers the operations management systems and procedures that will be put in place to construct the island and facilities, drill the wells, and operate the field. The previous sections described what is proposed; this section describes how the project will be executed and operated. This includes statements on how HAK manages its contractors and the level of performance expected. This is followed by a discussion of the skillsets and tasks necessary to operate and maintain the field. The latter half of the section gives a brief overview of several standard operating procedures that are utilized to manage activities on the island including such topics as freeze protection, spill prevention, and waste management.

11.1 Contractor Oversight

To execute this project, HAK will employ the services of several dozen contractors including the following:

- Gravel haulers
- Barge owners/operators
- Module fabricators
- Drilling contractors
- Construction contractors
- Drilling service contactors
- Skillset contractors including welders, pipefitters, mechanics, electricians
- Suppliers for equipment, materials, and supplies
- Others

In every situation where a contractor is performing a service for HAK, a HAK staff person will directly oversee the efforts of contractor personnel to ensure that performance standards are met in terms of quality, safety, and environmental stewardship. HAK has found that layers of management between the HAK directives and the actual work being performed are not conducive to high quality work. It is a HAK practice to supervise the work as assertively as necessary to ensure performance and safety standards are met.

All contractor companies who perform work on HAK's behalf must review and adhere to Hilcorp Minimum Contractor Safety Requirements. This includes the use of safe work practices, personal protective equipment (PPE), safety meetings, Job Safety Analyses (JSAs) as well as a contract company's own safety standards and programs. HAK expects contractors to have the necessary training and systems in place for work they will be conducting. HAK will perform an assessment of contractor Environmental, Health, and Safety (EH&S) performance and management systems to verify the necessary training, policies, and procedures are implemented as needed for a given activity. In addition to the initial assessment of contractor EH&S systems, HAK conducts ongoing contractor oversight in the form of field audits, periodic training, and contractor safety meetings.

HAK believes strongly that contractors must have ownership and accountability for their safety performance while operating at HAK facilities. One initiative that HAK has instituted to ensure accountability to safety performance is the company's Safety Watch program. The Safety Watch program mandates certain actions be implemented in the event of an OSHA recordable incident. The Safety Watch program includes OSHA Recordable injuries and Positive/Failed Drug Screenings that result from HAK's periodic facility wide drug tests. All incidents (including those under the purview of the Safety Watch program) are managed through HAK's incident reporting and investigation process. All incidents are reported to immediate supervisors. Supervisors document incidents on an initial incident reporting form that is sent to HAK's Safety Department. The initial report includes an initial level of investigation to identify causes and implement corrective actions. Incidents are classified consistent with the industry accepted "Safety Pyramid" by the Safety Department as to type (i.e. injury, fire, near miss, etc.) and severity (i.e. 1-7, near miss, minor incident, first aid, lost time injury). Depending on the level of severity or the potential severity of the incident, an investigation level is assigned to each incident, ranging from 0 (the initial incident report and investigation) to 3 (investigation conducted by outside third party entity is required). Incident and investigation results are tracked in a database through which HAK can produce summary reports and trended data. Required contractor response includes an incident root cause analysis, increased oversight by contractor safety professionals at a job site, and participation in an incident review meeting with Hilcorp Operations and EH&S Staff.

11.2 Production Operations and Maintenance (O&M)

11.2.1 Routine Production Operations

The Liberty production facility design is based on proven, off-the-shelf equipment and standard control systems. Facilities will be staffed with minimal on-site personnel consistent with safe, efficient, environmentally sound operations. This requires that the equipment be reliable and able to operate without full-time direct intervention. The project will be staffed with multi-skilled craftsmen and technicians trained to perform all operations and maintenance (O&M) duties in order to manage the flow of oil, water, and gas and maintain equipment to ensure long and reliable service.

Routine operations required to maintain flow from wells and through the plant include monitoring the status of fluid movement, pressures, and equipment status, as well as making adjustments to flow control equipment. Operators are assigned certain duties within the overall system, which include the following:

- Monitor flow of oil, water, and gas from each producer using the multi-phase flow meter assigned to each well or the use of a dedicated separation train for each well.
- Monitor temperatures and pressures at the wellhead of all producers.
- Monitor flow of gas and/or water into all injectors.
- Monitor height of fluids and the temperatures and pressures in all vessels. Look for signs of unstable flow and adjust accordingly.
- Monitor flow rates, inlet pressure, exhaust pressure, and temperatures of all compressors and pumps in the various flow streams of oil, water, and gas.
- Look for signs of upsets that may cause vessels or rotating equipment to operate outside their intended range.
- Make adjustments to well chokes and/or equipment operating parameters to move the process flows back to the ideal operating range.
- Make routine inspections of all vessels, piping, and equipment for signs of leaks or malfunctions in equipment.

11.2.2 Routine Equipment Maintenance

In addition to the day-to-day operations of the wells and plant, a staff of mechanics, electricians, and instrument and electronics (I&E) technicians will be employed to maintain process equipment and rotating equipment, and repair as necessary. A maintenance management system will be used to determine the frequency and type of periodic maintenance or overhauls necessary to sustain equipment and ensure reliability. A series of periodic inspections will be used to examine vessels, tanks, and piping for signs of corrosion, erosion, or abnormal wear. Duties that the maintenance staff members perform include the following:

- Perform overhauls of major rotating equipment including turbines, compressors, internal combustion engines, and pumps to ensure long and reliable service life.
- Take periodic emission measurements to ensure turbines, engines, boilers, and other emissions sources are operating within the specified range according to original equipment manufacturer (OEM) guidelines.
- Monitor temperatures and pressures of all rotating equipment.
- Monitor flow of gas or water into all injectors.
- Monitor function of all valves and control systems to ensure the process flow is functioning properly.
- Monitor, troubleshoot, and replace as necessary all instrumentation that measures and controls the process flow.
- Look for signs of upsets that may cause vessels or rotating equipment to operate outside their intended range. Troubleshoot as necessary.
- Make routine inspections of all vessels, piping, and equipment for signs of leaks or malfunctions in equipment.

11.2.3 Major Overhauls, Major Inspections

On a less frequent basis than routine maintenance, all major rotating equipment including turbines, compressors, and large pumps will be rebuilt or overhauled to replace worn parts and inspect for signs of corrosion, cracks, or significant wear. Frequencies of major overhauls are based on recommendations of the manufacturer, as well as the operating conditions and results of routine inspections and prior overhauls.

In addition to the work on major rotating equipment, all vessels and critical piping and pressure relief systems are subject to a robust inspection program to find and repair signs of potential failure. These programs are administered in accordance with applicable regulations.

11.2.4 Unscheduled Equipment Maintenance

In addition to planned maintenance and inspections, there will be instances of equipment breakdowns or cases where equipment needs to be replaced on an unplanned basis. These instances could result in plant slowdowns or shutdowns, so having contingency plans in place to ensure a timely delivery of materials, replacement equipment, and labor support must be in place to minimize the downtime. Many of the tasks performed for unplanned repairs and maintenance are the same tasks as routine maintenance and planned overhauls. If specialists are required, they will be brought to the island as quickly as possible.

11.2.5 Plant Turnarounds

As described above, most inspection, repair, replacement, alteration, and minor maintenance work can be done while the plant is in operation. However, there will times when a plant shutdown is required to undergo a scheduled process outage for maintenance work of multiple systems in the plant. Plant turnarounds for scheduled major maintenance work may result in loss of production while the plant is down. The benefits are increased equipment asset reliability, continued production integrity, and reduced risk of unscheduled outages or failure.

11.3 Mechanical Integrity Management

Significant time, effort, and financial commitments are made in the wells, plants, and labor pool to ensure that all piping and equipment has the mechanical integrity to meet the requirements and prevent failures that may result in an accident or spill. The two main ways to prevent failures in well tubulars and plant piping are proper material selection and corrosion inhibition with chemical treatments.

11.3.1 Materials Selection

Due to the high content of carbon dioxide in the crude oil and chloride content in the produced water, duplex corrosion-resistant alloy piping will be used for well production flowlines. Stainless steel piping will be used for all wet gas services. Production and wet gas separators will either use stainless steel and/or will be internally coated for corrosion protection. Chemicals will also be used to treat the fluid stream to prevent corrosion caused by carbonic acid, galvanic corrosion, and oxidation (rust) of carbon steel surfaces.

11.3.2 Corrosion Inhibition Treatments

In addition to the use of stainless steels on critical flow surfaces, corrosion inhibitors be will used to help neutralize the corrosive characteristics of produced crude, wet gas, and oxygen impregnated water. Chemicals are typically injected at the wellhead so that they can coat surfaces throughout the flow path including flowlines, vessels, and pressurized equipment. The effectiveness of chemical treatments are measured by the use of corrosion coupons, which are placed in the flow stream. On a periodic basis, the coupons are pulled and weighed to measure the material loss due to corrosion. Treatment recipes and concentrations are then adjusted to maximize the effectiveness of the treatments.

11.4 Chemical Treatments

Other chemicals that are injected into the flow stream at various locations include agents that facilitate the separation process and inhibitors that prevent the precipitation of mineral scales from produced water. Typical of all waterflood fields on the North Slope, chemicals are often needed to facilitate the separation of oil from water in the vessels of the oil section. Chemicals that are injected to improve the separation process include emulsion breaker and defoaming agents. These are injected upstream of the first separation vessel and can also be injected into subsequent vessels. Scale inhibitor primarily impacts downhole tubing and can be most efficiently carried out via periodic downhole squeezes or capillary injection strings. Other chemicals that are needed to treat the fluid streams include biocides to prevent bacteria growth in seawater, oxygen scavengers to minimize corrosion, and methanol and diesel for freeze protection. A table showing the name, description, and storage volumes of all chemicals that will be stored on the island was shown in Table 10-1.

11.5 Winterization, Freeze Protection Practices

Ambient temperatures in the -20°F to -30°F are typical for North Slope winters. Extreme low temperatures, as low as -50°F to -60°F, have been known to occur for weeks at a time. As a result, heat tracing alone, in many cases will not prevent the freezing of lines exposed to the elements during planned or unplanned shut-down. A few statements regarding the design and operational concerns of freeze protection are included here. This section is intended to emphasize that freeze protection is a primary design criteria; and considerable thought has been applied at the design stage to ensure that the freezing, plugging, and/or bursting of pipe, vessels, and/or equipment will be prevented.

11.5.1 Above-Ground Piping

The standard North Slope facility design incorporates the necessary piping and looping of lines to displace lines with diesel, methanol, and/or gas as necessary to prevent freezing. Jumpered warm-up loops and sufficient drain points and associated containment are designed into the facilities to prevent freezing in the event of a plant shut-down. It is preferable to heat trace only those lines and equipment that are required for operation and not rely on heat tracing to prevent freezing. With the help of a thermal engineering specialist, freeze-back curves will be generated during final engineering phase to understand minimal response times for various portions of the facilities, including producer wells, injector wells, on-pad piping, and the sales oil pipeline.

For planned shutdowns where and when gas is available as a displacement media, gas is the preferred alternative as it is available at the site as needed. The alternative is to purchase methanol and/or diesel and store it on site. A drawback to using gas as a freeze-protection fluid is that gas sweep may not fully evacuate the lines, leaving water and/or production fluids in low spots that may freeze. As long as this eventuality is considered in design plans, and heat tracing is available where necessary, gas can be the preferred alternative for displacing fluids that may freeze.

11.5.2 Freeze Protection of Producer Well Bores

Wells producing from the depths of the Kekiktuk reservoir will arrive at the surface at temperatures of approximately 160°F before waterflood breakthrough, and as high as 200°F when water cuts are high in the latter years of field life. Well bore freezing should not be an issue unless a shutdown event is expected to last for several days. Production wellbore tubing will have to be displaced with diesel below the permafrost to prevent well bore freeze-up if the well is shut-in for an extended period of time. Alternatively, gas lift can be used to displace the top section of the well to place a gas cap on the well. In some cases methanol will have to be injected to prevent hydrate formation. At this time, HAK does not contemplate using electric submersible pump (ESP) wells at Liberty, but ESP wells can also be displaced as long as the pump’s internal backflow preventer is neutralized.

11.5.3 Freeze Protection of Injector Well Bores

Depending on the temperature of the injected water (seawater, produced water, or mixture), a thawed area around the well (thaw bulb) may be present to slow the freezing time if a water injector needs to be shut-in. The primary method of freeze protection for injectors will be injection of plant gas. All injectors will be plumbed and manifolded to the gas injection compressors. If a well is planned to be shut-in, the well can be lined up with the gas injection manifold and displaced with gas. If the well is subject to an extended unplanned shutdown, the wellbore may have to be displaced with a methanol-water mix to prevent freezing.

11.6 Process Safety Systems; Plant Shutdown Philosophy

As a subset of the operations manual, a written, formalized set of procedures shall be put in place to initiate a plant shutdown in the event of a major process upset or an emergency condition. These procedures will comply with SEMS (Appendix D) and are described in part below per the requirements of 30 CFR 550.251 (b)-(c). Additional details on emergency procedures are included in Section 11.8.

The facility shutdown system consists of sensors, programming logic, and equipment combined into configurations that constitute specific shutdown levels based on the severity of the disturbance, potential danger to personnel or equipment, and to the facility itself. The process safety systems for Liberty are designed to automatically return the wells and the processing facilities to a safe state following an upset. The system will be designed to automatically activate increasing levels of isolation and depressurization as required.

The detailed set of procedures will be drafted once all the details of the plant have been confirmed and the equipment installation is nearing completion. As a general rule, a plant shutdown philosophy is configured into several levels of severity. Described below are the proposed levels of plant shutdown, with a distinction made between Process Shutdowns (PSDs) and ESDs. The reason for increasing levels of response, as configured in accordance with API RP 14C, is to isolate only those subsystems or systems that require shutdown to ensure personnel or environmental safety. The overall system consists of field mounted sensors, valves and trip relays, and a system logic unit for processing incoming signals, alarm and human machine interface (HMI) units. The system is able to process all input signals and activating outputs in accordance with the applicable Cause and Effect charts. In accordance with the philosophy, the system will initiate and notify personnel of several different types of shutdowns as follows:

- PSD1 or USD – Unit Shutdown
- PSD2 or OSD – Operational Shutdown
- PSD3 or FSD – Full Shutdown including pipeline shutdown
- ESD1 – Emergency Shutdown
- ESD2 – Emergency Shutdown with complete evacuation

11.6.1 PSD1 – Unit Shutdown

The lowest level of plant shutdown is a PSD1 or unit shutdown (USD), which shuts in a module or small portion of the plant, such as a compressor, pump or heater, or closes the inlet or outlet valves from a vessel or tank. When activated by an operator, a USD does not cause or force other shutdowns. Process upsets resulting from the USD, however, may trigger other USDs or an Operational Shutdown (OSD) depending on the impact to connected subsystems.

11.6.2 PSD2 – Operational Shutdown

The second level of plant shutdown is an OSD, which is initiated in the control room, through alarm criticality, which requires the shutdown or slowdown of incoming produced fluid at operator discretion. An example of a condition that would initiate an automatic OSD would include a low-low level in the main gas compressor seal oil tank. This condition will result in the depressurization of the compressor. During an OSD, the wells feeding the produced fluid train will have their surface safety valve (SSVs) shut-in; inlet shut-down valves (SDVs) to the corresponding first stage vessel will close after 10 seconds.

11.6.3 PSD3 – Full Shutdown

The third level of plant shutdown is a full shutdown (FSD) including a pipeline shutdown, which shuts in all wells (SSVs) on the island, all inlet SDVs on all first stage vessels, shuts down the dehydrator feed pumps as well as the booster and main shipping pumps, and finally the compression trains.

11.6.4 ESD1 – Emergency Shutdown

The fourth level, and first order emergency shutdown at Liberty is an Emergency Shutdown Level 1 (ESD1). This is initiated through alarm criticality, fire detected in the Process Module, or high gas concentration (40 percent lower explosive limit [LEL]) detection. An ESD requires the entire facility to be shut down and isolated. Activation of an ESD initiates a predetermined shutdown sequence, which includes, but is not limited to, shutdown of well fluid production, normal fuel gas system, gas-handling system, and production and booster pumps. Additionally, all fired heaters and normal electrical power generation systems soon shutdown because of a lack of fuel gas. The emergency generators then activate to power the facility.

11.6.5 ESD2 – Emergency Shutdown and Island Evacuation

In the event of a catastrophic event or uncontrolled fire, a Level 2 Emergency Shutdown would be initiated, which results in all the shutdowns of the ESD1 and complete evacuation of the island via vessels or Arktos™ emergency escape vehicles.

11.6.6 Shutdown Systems

The primary shutdown device is the actuated wellhead surface safety system, which will stop incoming fluids. All production wells will be equipped with actuated surface and subsurface safety valves, which will be activated in the case of a depressurized shutdown. The Liberty process facilities will be equipped with SDVs to isolate the facilities from the pipelines in the case of an emergency.

Instruments for continuously monitoring for the presence of flammable gas and fire will be installed in all areas where there is risk of leakage that could lead to a dangerous condition. Smoke detection will be installed in the control room/control module as necessary. Fire detection systems will provide alarms at key locations. Protective action will be by manual control, remote control, or computer generated automatic control.

All plant shutdown and safety systems will be designed in accordance with API Recommended Practices 14 C, Design, Installation and Testing of Surface Safety Systems for Offshore Production Platforms. To assure safe operation of the facilities, complete piping and instrument diagrams and Safe Charts will be developed. See Section 9.1.3 for additional details on LDPI Control Philosophy and Section 9.5.1 for additional details on safety systems and equipment, as well as F&G systems and related equipment.

LDPI is an approximately 833,000-cubic-yard gravel island placed in approximately 19 feet of water and will be armored with reinforced concrete mats with geotextile fabric to resist the effects of ice movements. The island design and armoring have been installed and tested on the North Slope for over 20 years at other gravel islands and similar project sites. LDPI is also landward of the barrier islands, which provide some protection from ice sheet movements. The working areas on the island are protected by approximately 15- to 20-foot-high sheet pile walls that are approximately 130 feet from the water line. Due to its design and location, the Critical Operations and Curtailment Plan for the LDPI is integrated with the basic facility emergency design and plans as described in this section.

In addition to the above, HAK will constantly monitor North Slope weather and oceanographic conditions to assure conditions that could threaten the LDPI mechanical integrity and/or personnel safety are identified. Pre-incident decision making criteria will be developed and the consequent decision making process established prior to construction and/or drilling. An example to the curtailment procedures used on the North Slope is the well-established foul weather "Phase" system and subsequent restrictions on travel. Phase I is a warning to exercise additional caution due to reduced visibility or deteriorating road conditions. Phase II is a restricted level, where visibility and/or road conditions are compromised further, travel is restricted to only approved events, and vehicles must travel in pairs. Phase III is the closure of all routine travel. Any travel must be arranged in convoys lead by a loader. Aircraft, vessel, and heavy equipment operations follow similar curtailment of operation as weather conditions (temperature, winds, and visibility) deteriorate.

In addition to weather-related travel restriction, LDPI will operate with designated progressive restrictions of operations due to ice ride up or wave run up conditions.

LDPI uses a mixture of transportation types to service the island. In the winter, normal road vehicles will travel over ice roads. In the summer vessels and barges will be used. During periods of unsound ice or break up, hovercraft and helicopters will be used. The LDPI is designed to store drilling, production, maintenance, and housing supplies sufficient to last through break-up or freeze-up. If a vessels or barge were damaged, the LDPI would have: (1) Its designed storage capacity; (2) Alternative means of travel (hovercraft or helicopters); and (3) Alternative contractors and the vessels operated by ACS as alternative means of maintaining safe operations. Emergency plans to respond to a blowout, and loss or disablement of a drilling unit are discussed in Sections 8.7 and 14.

11.7 Hydrogen Sulfide Information, Concentration

During the Liberty No. 1 flow back test in the field, there was an indication of a hydrogen sulfide (H_2S) content up to 8 parts per million (ppm) in the produced gas. The Liberty Reservoir will be developed with a waterflood using de-aerated seawater. Based on the Endicott history, which was developed with a similar waterflood, there is expected to be some increase in H_2S over time. The actual amount of H_2S increase at Liberty is unknown.

11.7.1 H_2S Classification

Fluid analysis of produced fluids from the Liberty test wells currently meet the definition of H_2S absent [30 CFR 250.490(b)]. HAK requests that the Regional Supervisor classify the Liberty area as "H2S Absent."

11.7.2 H_2S Contingency Plan

In the event that the field classification changes, BSEE will be consulted and an H_2S contingency plan will be developed.

11.7.3 Modeling Report

If HAK determines that the concentration of H_2S at LDPI may be greater than 500 ppm, a modeling report containing the information required in 30 CFR 550.245(d) will be provided.

11.8 Safety Assurance Procedures

The design of the island and facilities will be suited to the safe execution of operational requirements as written in the *Alaska Safety Handbook* (ASH). The following points list measures that will be taken to reduce emissions and/or leaks:

- A regular, systematic walk-through of the plant will enable the operators to identify leaking components and plan their repair or replacement.
- Gas detectors will be located around the plant to detect and warn of gas leakage.

11.8.1 Control and Monitoring

The Liberty facility design utilizes a central control philosophy that facilitates unattended operation. The technology being proposed will allow remote access to process control functions that will enable offsite control supervision and maintenance. Remote control supervision will allow a person at any other site equipped with a data link to monitor the control system operations. An additional option for this type of system allows remote instrument calibration and trouble shooting. The facilities will have supervisory control and data acquisition (SCADA) systems capable of all production control functions, including well testing, volume accounting, and pipeline leak detection. The control system will have an HMI allowing operator control of the plant operation.

11.8.2 Shutdown Systems

Standalone shutdown systems will be provided to generate safe and logical plant shutdowns from field shutdown inputs, manual shutdown stations, and the F&G system. These systems will have the capability to generate first out alarm and shutdown sequence, and be able to record the sequence of events. A hard wired manual push-button ESD system will be provided for selected critical shutdowns. This will be separate from the main Programmable Logic Computer (PLC) based shutdown system. Redundant F&G PLCs will be provided with inputs from the F&G detectors and manual stations, and with appropriate outputs to the ESD/plant shutdown systems. The design of any depressuring system will take full account of temperature effects on equipment metallurgy.

Shutdown systems will have on-line test facilities unless the related equipment can be taken off-line without disruption to production, or the test can be made on line. Use of test facilities will be protected and all test overrides will be alarmed in the central computer system. After the activation of a shutdown system, the facility must be restarted following a standard reset philosophy. The resets will be activated from the HMI, but will not allow equipment start-up without human intervention. The resets will not activate until specific permissives, as required for the equipment and plant, are met.

11.8.3 Flares and Vents

The flare system will be designed in accordance with the required relief capacity for the plant. The flare systems are required to be smokeless in their operation, and have the capability for remote ignition or instantaneous ignition. Flare and vent systems will have heat tracing to a level appropriate to prevent ice plugging of the flare or vent. Attention will be paid to the metallurgy of any vent subject to the cryogenic effect of high pressure depressurization.

11.8.4 Telecommunications

Operational telecommunications requirements are:

- Communication system providing access to the national telephone network
- Communication links (tie line) with local HAK network
- Data transmission capability for PC and Internet connections
- Mobile radio system with effective coverage over the facility area, and
- Mobile radio system linked to Alaska Clean Seas (ACS) or other spill response contractor.
- Safety System Testing

All pressure and level shutdown field devices and SDV actuators will be tested once per month. The ESD circuit will be tested once per month to verify operation of the system actuates the surface and subsurface safety valves in accordance with BSEE regulations. All testing will be done in accordance with API RP 14H. Relief valves certification will be done annually in accordance with BSEE regulations.

11.8.5 Equipment Identification, Documentation, Information Management

The plant, equipment and critical instruments will be identified by a site tag numbering system. Equipment that can be changed out on a like-for-like basis (e.g., relief valves) should use the manufacturers' serial numbers as the identifier in addition to the above. The tagging identification convention will be consistent with the information management system.

A documentation and information management philosophy will be prepared. The following information will be prepared for the facility:

- Operations Manual

- Operating Procedures
- Design Dossier
- Safety Manual Emergency Procedures
- Engineering Manuals
- Maintenance Manuals
- Training Manuals

11.9 Standard Operating Procedures

This section provides descriptions of standard operating practices for the Liberty Development project. References that will be used to support safe and environmentally-sound Arctic operations include the current *Alaska Safety Handbook* and the *North Slope Environmental Field Handbook*.

11.9.1 General Procedures

All management processes, operating procedures, and documentation that will be developed to conduct the Liberty Development operations in a safe, efficient, and environmentally sound manner will be implemented according to internal HAK guidelines and all applicable API, BSEE, and Occupational Safety and Health Administration (OSHA) regulations. Operations personnel will be properly trained to perform their project-specific duties. Processes and procedures for Liberty will be based on a set of best practices and operating experience, which will be modified to address specific Arctic conditions of the North Slope. Implementation of these will ensure that all necessary systems are in place and that the startup organization benefits from "best practices" derived from all prior developments.

11.9.2 Road and Pad Maintenance

Routine inspection and maintenance of ice and gravel facilities will be conducted on a periodic basis. Ice roads used for gravel haul will be cleared of gravel spills to minimize discharges to the ocean. Care will be taken not to damage the adjacent tundra, particularly during snow removal operations. Snow fences may be installed to reduce snow drifting onto roads and pads.

11.9.3 Snow Removal and Storage

During winter months, snow removal activities will be conducted on an as-needed basis. Personnel and equipment, such as front-end loaders and motor graders, will be available to handle snow removal requirements.

Operating procedures for snow removal and handling will adhere to the snow removal Best Management Practices (BMPs) associated with the Stormwater Pollution Prevention Plan (SWPPP). The BMPs will address handling and disposing of snow, which will be visually inspected for contamination before removal. Contaminated snow will be collected and stored in a designated area for proper disposal. Contaminated snow may be allowed to melt in tanks or a containment area, or a snowmelter will be used and contaminated meltwater will be injected into the disposal well. Uncontaminated snow will be pushed onto surrounding tundra and/or placed on the sea ice, where it will be allowed to melt. Pad clearing activities will be conducted to avoid gravel and debris entrainment in snow moved off the pads and roads, and will consider prevailing wind direction. Snow storage and disposal will be undertaken in a manner to avoid creating potential hiding places for polar bears.

11.10 Spill and Pollution Prevention Procedures

Liberty project planning includes pollution and spill prevention measures, as well as spill response preparedness. Applicable spill prevention and response requirements may include:

- 30 CFR, Part 550, Subpart C – Pollution Prevention and Control
- 30 CFR, Part 254 – Oil Spill Response Requirements

BSEE Pollution Prevention regulations require the lessee to take measures to "prevent unauthorized discharge of pollutants into offshore waters," and require the lessee to "not create conditions that will pose unreasonable risk to public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean." These regulations also require that "all hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters shall be designed, installed, and operated to prevent pollution" and that "maintenance or repairs which are necessary to prevent pollution of offshore waters… be undertaken immediately." These regulations also include requirements for secondary containment and control of surficial drainage.

The proposed project has incorporated design measures to assure that the potential for spills and leaks has been minimized to the extent practicable. These features include:

- Island grading plan – surface drainage controlled by flowing to sumps with oil/water separators to handle minor spills
- Storage tanks and process facilities located in lined, bermed areas
- Pipeline leak detection systems
- Pipeline valving plan
- Well control design

In addition to spill and leak prevention measures incorporated in design and operations planning, HAK will apply for approval of an Oil Spill Response (OSRP) addressing activities in federal waters, as well as an Oil Discharge Prevention and Contingency Plan (ODPCP) if required for activities in state waters and lands. The plans require demonstration of the ability to identify, respond, and cleanup spills with the appropriate equipment in all conditions expected at the site, including open-water conditions, broken ice conditions, and frozen conditions.

Prevention of spills is core to Liberty operations and environmental performance. Construction, drilling, and operating activities include numerous prevention, design, detection, reporting, response, and training measures that are, or will be, described in the spill prevention and response plans for various Project activities.

A high level overview of the spill prevention and response program is presented below. A description of what is detailed in the Liberty Development project OSRP is provided in Section 14 of this DPP.

11.10.1 Spill Prevention and Response Plans

HAK developed comprehensive spill prevention and response plans, including an ODPCP, Spill Prevention Control and Countermeasure (SPCC) Plans, and Facility Response Plans (FRPs) for operations on the North Slope and at Northstar and Endicott. These plans provide the overall framework for spill prevention and response measures for HAK-operated fields on the North Slope. Key requirements under these plans include:

- All facilities and pipelines will be designed to ensure safe containment of all hydrocarbons.
- North Slope-based Project workers will attend the Project-specific training program and the North Slope Training Cooperative (NSTC) "Unescorted Course," covering environmental excellence (among other topics) to ensure best practices of spill prevention.

Special spill prevention programs will be developed for specific Liberty operations where a need is identified. Examples include:

- **A Special Barging Spill Management Program.** An element of this program is that every crew member is expected to be a steward of the environment, looking out for leaks on equipment, or for any other environmental hazards present during work activities.
- **A Targeted Ice Road Spill Management Program.** This includes a "Drips and Drops" Program to identify the causes/sources of small drips and drops, and learn from these observations to both reduce their number and avoid potentially larger spills. This program also includes strict vehicle maintenance and inspection requirements, and limiting the use of older vehicles. Construction equipment will be inspected to help identify/prevent leaks or other mechanical defects of vehicles prior to leaving the staging area.

As they do for other North Slope oil production operations, ACS will serve as the primary Oil Spill Removal Organization and Response Action Contractor, as approved by the U.S. Coast Guard (USCG) and the Alaska Department of Environmental Conservation (ADEC), respectively. ACS technicians will help assemble, store, maintain, and operate the Project's spill response equipment.

The OSRP prepared for drilling and construction will be expanded to include Improvement Plans (IPs) from Preparedness for Response Exercise Program (PREP) operations. This has not been completed, but it is expected that the OSRP will provide for response equipment to be pre-positioned as described below.

Spill response equipment will be primarily stored at SDI and LDPI, and in strategically placed containers near the coastline. The equipment is expected to include: containment and absorbent boom, skimmers, portable tanks, pumps, hoses, generators, and wildlife protection equipment. Snow machines and other vehicles for off-road access will also be stored at SDI and LDPI. Equipment normally will not be staged at the remote locations but may be stored there during certain operations to provide timely response.

Spill response vessels and equipment will be maintained at SDI during the summer open-water season to respond to potential spills into streams and the near-shore marine environment. Day-to-day normal operations equipment, such as front end loaders, not dedicated to oil spill responses will be available to supplement the dedicated spill response equipment, as required. A boat launching area has been incorporated into the design of the SDI to facilitate oil spill response access by ACS. Section 14 describes the HAK spill response plan in greater detail.

In addition to the OSRP, HAK will prepare a detailed Well Control Blowout Contingency Plan. This plan addresses all aspects of primary well control, which includes well control planning, well control training, and well control during drilling. The plan also addresses secondary well control means, including blowout preventers, means of actuating them, and ancillary equipment that would be used in a well control situation. The primary and secondary means of well control are intended to ensure that control of the well is maintained at all times to prevent blowouts. Additionally, this plan prescribes the equipment that would be required and actions that would be taken in the unlikely event of a blowout.

11.10.2 Design, Construction, and Operations Measures

Containment of hydrocarbons and prevention of spills is a major focus during the Liberty Development Project design efforts. Construction and operations phases of the Liberty Development Project will employ numerous measures to prevent spills and to rapidly respond to any that may occur. Some of the general measures include:

- Formal Hazard and Operability for Process Hazard Analyses (HAZOPs), risk assessment, facility site reviews, design readiness review, independent project review, and constructability reviews will be used to identify potential spill risks and associated prevention or response measures.

- Storage tanks for oil and hazardous substances will be located within impermeable secondary containment areas.
- Spill response equipment and materials will be readily available at designated locations throughout the facility.
- Hazardous waste storage will also be located within impermeable secondary containment areas.
- Fuel transfers will follow BMPs, including using secondary containment devices.
- The Liberty pipeline will be based on proven Arctic designs, specifically tailored for the Project. Prevention and leak detection measures common to pipeline systems will include:
    - Pigging facilities to allow running in-line inspection, maintenance, and cleaning tools.
    - Internal corrosion monitored through the use of corrosion coupons and Electrical Resistance (ER) probes that provide a measure of corrosion rate and activity. The ability to inject a corrosion inhibitor will be provided.
    - External corrosion prevention for onshore pipeline segments through use of shop-installed polyurethane foam insulation covered with a roll-formed, interlocked, and galvanized metal jacket.
    - Visual inspections of the pipelines will typically be conducted weekly during operations via aerial surveillance, unless precluded by safety or weather conditions.

11.10.3 Spill Prevention During Oil Transport, Storage, and Use

Fuel transport, storage, and use will be conducted in accordance with applicable federal, state, and North Slope Borough (NSB) requirements, as well as the operator's fuel transfer guidelines contained in the Liberty OSRP. The BMP for spill prevention during fuel transfer draws upon the guidelines and operating procedures applicable to North Slope operations developed by other operators and included in the *North Slope Environmental Field Handbook Unified Operating Procedures* (UOP).

The UOP describes general fluid transfer guidelines, including conducting equipment inspections and checks, and positioning of equipment and hoses. The UOP has detailed descriptions of the proper use of surface liners and drip pans. The use of liners is mandated for: vacuum trucks, fuel trucks, sewage trucks, fluid transfers, all heavy and light duty parked vehicles, and support equipment (heaters, generators, etc.) within facilities. The UOP also describes secondary containment requirements for hydrocarbon storage containers as well as for fluid transfers.

Visual monitoring is the primary method to determine fluid levels in tanks during loading and to detect leaks or spills during fuel transfers. All fuel transfers will be continuously staffed and visually monitored. Typically, diesel tanks will be filled via transfer of fuel from trucks using a fuel hose. Personnel involved in fluid transfers will be specifically trained in accordance with fluid transfer guidelines. Personnel involved in the transfer will have radios and will be able to communicate quickly if a transfer needs to be stopped.

Diesel storage tanks at the site may be filled by fuel trucks travelling via ice road in winter or by fuel trucks via barge in the summer open-water season. Direct fuel transfers from fuel barge may also occur. These activities will comply with applicable BSEE, ADEC, and USCG requirements.

Tanks within state regulatory authority with capacities of 10,000 gallons (238 barrels) or more will conform to state regulations provided in 18 AAC 75.065. As required, inspections will be conducted in accordance with 18 AAC 75.065(b).

As described in the OSRP, oil storage tanks will be located within secondary containment areas. The main storage tanks for fuel and hazardous substances are located on LDPI to maximize the distance from waterbodies. These tanks will be located in secondary containment areas constructed of bermed/diked retaining walls and will be lined with impermeable materials resistant to damage and weather conditions. Secondary containment for smaller tanks may also be provided using metal basins. The containment areas will be kept free of debris, including excess accumulated rainwater and snow accumulation during the winter season. They will be visually inspected by facility personnel as required by applicable regulations.

It is not practicable to locate and resupply fuel tanks associated with generators on ice roads, water pumps on lakes, and light plants at areas greater than 100 feet from bodies of water or 1,500 feet from the current surface drinking water source. In these cases, fuel tanks will be located in lined containment areas and visually inspected. If it is necessary for other storage tanks to be located within 100 feet of bodies of water, appropriate regulatory approval will be obtained.

Onshore vehicle refueling sites, if required, will generally be located outside the annual floodplain. During operations, vehicle refueling will be set back at least 100 feet from stream banks and shorelines to avoid impacts to the floodplain. During winter construction and maintenance activities, some vehicles may require refueling on ice roads and ice pads located within the floodplain. If it is necessary to refuel vehicles in the annual floodplain, appropriate regulatory approval will be obtained.

Equipment and supplies appropriate for responding to a release will be available on site during transfer or handling of fuel or hazardous substances. Fuel and hazardous substance containers will be marked with the contents and the Operator's or contractor's name, using paint or permanent labeling, and stored within secondary containment.

To ensure proper reporting of spills and to improve spill prevention and response performance, HAK monitors and addresses all spills or potential incidents as follows:

- Reportable spills based on external guidelines and regulatory requirements (BSEE, ADEC, ADNR, Alaska Oil and Gas Conservation Commission [AOGCC], NSB, and National Response Center).
- Spills that are not agency reportable, but are internally reportable based on HAK's internal guidelines.
- Near misses based upon internal company guidelines where no spill occurred, but an unintended or uncontrolled loss of containment could have led to a spill.

11.11 Discharges and Emissions

Planned discharges and emissions will be in accordance with federal, state, and local laws, regulations, and permits. Permitted discharges include discharge of fill, wastewater, and stormwater into wetlands and other waters of the U.S., all of which will be completed under terms and conditions of NSB, state, and federal permits.

Most of the Liberty Development Project area and surrounding areas are waters of the U.S. (e.g., wetlands, streams, lakes, and marine waters). Liberty Development Project mitigation of impacts to wetlands and other waters of the U.S. includes both measures that significantly avoid impacts (e.g., through use of existing infrastructure) and reduce impacts (e.g., optimization of facility layouts to reduce footprints). A detailed discussion on environmental measures incorporated into the Liberty Development Project to mitigate the discharge of fill is provided in Section 5 of the EIA (Appendix A). Wastewater and stormwater will be managed either by injection into a waste disposal well or, where allowed, discharged to waters of the U.S. under terms of an Alaska Pollutant Discharge Elimination System (APDES) or National Pollutant Discharge Elimination System (NPDES) permit. While spills are not planned, they are planned for. Spill prevention and response, addressed in Section 14, is a crucial factor in the environmental performance of the Project.

The project will generate air emissions from operation of construction equipment, including marine vessels, from drilling activities, and from operations. Emission sources are inventoried and effects of the project on air quality are detailed in this DPP and the EIA. Associated emission sources (including composition, frequency, and duration of emissions) on State of Alaska lands and waters are included in the EIA. These include temporary construction sources (concrete manufacturing, gravel mine operations, and pipeline construction), as well as permanent sources (power generation equipment and a heater at the tie-in pad).

Emissions of environmental concern include air pollutant emissions, dust, noise, and external light. The type and amounts of air emissions expected from the Liberty Development will differ during the drilling, construction, and operations phases. Air emissions will be in accordance with applicable federal and state regulations. HAK has adopted several Project improvements that will result in an overall reduction of air emissions, as described further in Sections 4.1.4 and 5.2.4, and Attachment 1 of the EIA. Environmental concerns associated with noise are type, magnitude, and frequency of noise generated during construction, drilling, and operations. HAK has incorporated a number of design and operations measures into the project to reduce the amount of noise, as described further in Sections 4.1.5 and 5 of the EIA (Appendix A).

11.12 Waste Management

HAK will implement a comprehensive Liberty Development Waste Management Plan. Integral parts of the overall plan will incorporate proven measures, including: avoiding the generation of waste (where possible), waste minimization, product substitution, beneficial reuse, recycling, and proper disposal. The Liberty Waste Management Plan will address storage, transportation, and disposal of wastes generated during construction, drilling, and operations. No unusual solid or liquid wastes are expected from Liberty Development onshore facilities. In general, waste streams generated at onshore support facilities due to the Liberty Development will be similar to existing waste streams (e.g., domestic waste, sanitary waste, fire water, produced water). Waste streams from the onshore facilities are managed in compliance with regulatory requirements and are included in Tables 11-1 through 11-5. Waste disposal options and alternatives will emphasize subsurface injection, where practicable. Additional options that are identified as development progresses will be evaluated for incorporation into the Waste Management Plan.

Wastes will be handled in accordance with the North Slope industry standard, *Alaska Waste Disposal and Reuse Guide* (Red Book), and in full compliance with applicable federal, state, and NSB regulatory requirements.

Elements of the Waste Management Plan will include:

- Recycling/reusing drilling mud to the extent practicable, with spent drilling muds and cuttings injected into an on-site or offsite disposal well. Temporary storage of drilling muds and cuttings will be conducted in accordance with an approved plan.
- Segregating and storing wastes using appropriate containers, including dumpsters, hoppers, bins, etc. for food waste, burnable (non-food) waste, construction debris, oily waste, and scrap metal.
- Segregating and securing hazardous waste in a hazardous waste Central Accumulation Area. Satellite Accumulation Areas will also be provided, as needed.
- Incinerating camp waste (including food waste).
- Identifying recyclable materials and associated proper handling and storage methods.
- Providing recyclable Accumulation Areas, as needed.
- Providing storage hoppers and bins for contaminated snow.
- Providing domestic wastewater treatment system(s).
- Providing an industrial waste disposal well for approved liquid waste disposal.

Hauling waste off site is transportation limited. During the open-water season, waste hauling from the Liberty Development project area is available by barges/vessels. During the winter, waste hauling may occur via an ice road or tundra travel. Waste may also be removed by air.

A variety of facilities will be available for collecting, storing, recycling, and disposing wastes on LDPI. Wastes and recyclable materials will be segregated, consolidated, and stored on site prior to disposal. Most waste fluids from drilling, production, O&M, and domestic sources will be injected into the on-site waste disposal well.

Alternate means of disposal for some wastes may be needed, and will be subject to appropriate permit conditions and handling methods. Some wastes and recyclable materials will be transported to other North Slope locations, or transferred to other facilities in Alaska or the Lower-48 states for treatment, disposal, or recycling. Onshore wastes will be temporarily stored at the Badami pipeline tie-in pad until those wastes can be transported via ice road in winter to an authorized waste facility for disposal or hydrocarbon recycling as appropriate. Minimal wastes are expected throughout all operations at the tie-in pad.

A major goal of Liberty project planning has been to minimize waste generation, minimize air emissions (both regulated pollutants and greenhouse gases), and have zero surface discharges of drilling wastes. As described in Section 8.5, drilling muds will be recycled and reused to the extent practicable. Spent drilling muds and cuttings will be re-injected down the cuttings disposal well or hauled off site for disposal at authorized locations. Leftover, unused drilling products will be returned to the vendor or drilling contractor for reuse.

Hydrostatic test waters may be treated and discharged under applicable NPDES or APDES permits, injected down the waste disposal well, or disposed of off site. Of particular concern is the handling of food wastes and food-related garbage to prevent attracting wildlife to Liberty Development Project facilities. Food wastes and garbage that could attract wildlife will be incinerated on a regular basis. Such wastes will temporarily be stored indoors until incinerated. If the incinerator is out of service for an extended period, food waste may be stored in designated dumpsters with animal-proof lids or cages. Treated wastewater from the operations camp will generally be injected down the waste disposal well; however, a NPDES permit allowing for surface discharge of treated camp wastewater will be maintained for use before the disposal well is in service and when the disposal well is unavailable. Sewage sludge will be incinerated on-site regularly, or stored in enclosed tanks prior to shipment to the NSB treatment plant in Deadhorse. Food wastes will be managed carefully to avoid attracting wildlife.

In conjunction with the DPP submittal, HAK has prepared an application for an Individual NPDES Permit, which is included as Appendix E. Discharge modeling was not performed during the development of this DPP. The NPDES permit application contains detailed information about the quantity and types of potential discharges.

Table 11-1 through Table 11-5 list projected wastes and management options. The Projected Wastes information provided in Tables 11-1 through 11-5 is based on previous North Slope oil and gas development projects, such as the BP Northstar Development Project, knowledge of existing waste management infrastructure on the North Slope, and best management practices. Waste management objectives, strategies, and management plans will be detailed in the Liberty Waste Management Plan.

Table 11-1. Projected Early Construction Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO OFFSITE DISPOSAL
Construction debris	Electrical wire Flexible duct Liner (clean/oil free) Piping (plastic) Visqueen Welding rod Wood waste (low quality)	160,000 lbs	Deposit in NSB Oxbow Landfill	NA	No treatment Storage in dumpsters
Wood waste	Wood waste (high quality)	40,000 lbs	GPB Cold Storage Pad Solid Waste Site West	NSB Landfill or approved management methods	Dedicated wood waste dumpsters
Oily waste	Sorbents/rags[2] Oil filters	8,000 lbs	Incinerator operated by NSB at Oxbow Landfill	Offsite disposal at permitted waste management facility	Double bag, seal, and tag with generator information Store in dedicated oily waste dumpster prior to transport off site
Municipal solid waste	Cardboard Plastic Paper	40,000 lbs	NSB landfill	Recycle or other approved management methods	No treatment Storage in dumpsters, cover prior to transport
LDPI wastewater discharge [3]	Treated sanitary/domestic wastewater Construction dewatering Stormwater Mine site dewatering for ice roads and pads Secondary containment dewatering	Sanitary/domestic wastewater 9,400 gpd (3.3 MG/yr)	Backhaul to NSB wastewater treatment facility	Discharge of treated effluent under NPDES permit	Secondary treatment for domestic waste
SDI wastewater discharges	Construction dewatering Stormwater	Depends on weather	Managed under APDES construction and stormwater general permits	Disposal by injection at permitted disposal well	No treatment Pollution prevention by application of SWPPP and BMPs

Table 11-1. Projected Early Construction Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO OFFSITE DISPOSAL
Spill cleanup material	Contaminated snow/ice/ gravel[3]	200 cy	Disposal at permitted injection well	Discharge under NPDES permit	No treatment for injection. Use of oil/water separator for discharge. Storage in water-tight containers prior to transport off site
Hazardous and UW	Aerosol cans[4] Lead acid batteries (damaged or broken) Paint waste Solvents/thinners Rags with solvents/thinners UW lamps UW batteries	1,000 lbs	Offsite disposal or recycled at permitted facility	NA	Temporary storage in containers meeting the requirements of 40 CFR 262
Mine Site discharges	Mine site discharges from snow melt (Not expected to occur if mine site open a single season).	TBD	Discharge under APDES general permit	NA	Pollution prevention by application of BMPs

Notes:
1. The list of waste types is not intended to be all inclusive; it is representative of the major waste types that will be generated during this phase of the project.
2. Lab analysis may be required to document that the waste is non-hazardous prior to disposal, depends on type, volume, and season of spill.
3. Based on NPDES application.
4. Aerosol cans (empty or unusable) will be managed as hazardous waste until they are punctured, drained, and placed in a scrap metal dumpster for metal recycling. Residue from the cans will be collected and managed as hazardous waste.

Key: APDES = Alaska Pollutant Discharge Elimination System; BMPs = best management practices; CFR = Code of Federal Regulations; cy = cubic yard; gal = gallons(s); G&I = Grind and Inject Facility; GPB = Greater Prudhoe Bay; gpd = gallons per day; lbs = pounds; LDPI = Liberty Drilling and Production Island; MG = million gallons; NA = not applicable; NPDES = National Pollutant Discharge Elimination System; NSB = North Slope Borough; SDI = Satellite Drilling Island; SWPPP = Storm Water Pollution Prevention Plan; TBD = to be determined; UW = universal waste.

Table 11-2. Projected Final Construction Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
Construction debris	Electrical wire Flexible duct Incinerator ash[2] Liner (clean/oil free) Piping (plastic) Visqueen Welding rod Wood waste	350,000 lbs	Deposit in NSB Oxbow Landfill	NA	No treatment Storage in dumpsters
Fluids from hydrotesting new pipelines	Water-based mixture	100,000 bbl	Disposal by injection at permitted disposal well	Store for future use or return to supplier for recycling or discharge under NPDES	No treatment May be temporarily stored in tank
Oily waste	Sorbents/rags[2] Oil filters	40,000 lbs	Incinerator operated by NSB at Oxbow Landfill	Some, but not all, could potentially be incinerated on site depending on air permit	No treatment Double bag, seal, and tag with generator information Store in dedicated oily waste dumpster
Municipal solid waste	Food waste Cardboard/paper	200,000 lbs	Incinerate on site	NSB landfill	No treatment Storage in dumpsters
LDPI wastewater discharge[3]	Treated sanitary/domestic wastewater Construction dewatering Stormwater Mine site dewatering for ice roads and pads Potable water desalination backwash	Sanitary/domestic wastewater 9,400 gpd (3.4 MG/yr)	Discharge under NPDES permit of treated effluent	Backhaul to NSB wastewater treatment facility	Secondary treatment

Table 11-2. Projected Final Construction Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
SDI wastewater discharges	Construction dewatering Stormwater	Depends on weather	Managed under APDES construction and stormwater general permits	Disposal by injection at permitted North Slope disposal well	No treatment Pollution prevention by application of SWPPP and BMPs
Non-exempt, non-hazardous fluids[2]	Snowmelt/rainwater from containments Glycol (spent)	165,000 gal	Disposal by injection at permitted North Slope disposal wells	Offsite disposal at permitted waste management facility or discharge under NPDES	No treatment Storage in totes or drums prior to transport off site or Collect using vacuum truck during summer barging and winter ice road
Spill cleanup material	Contaminated snow/ice/gravel[2]	500 cy	Disposal by injection at permitted North Slope disposal well	Offsite disposal at permitted waste management facility or discharge under NPDES	No treatment Storage in water-tight bins prior to transport off site
Hazardous and UW	Aerosol cans[4] Lead acid batteries (damaged or broken) Paint waste Solvents/thinners Rags with solvents/thinners UW lamps UW batteries	2,500 lbs	Offsite disposal or recycled at permitted facility	NA	Temporary storage in containers meeting the requirement of 40 CFR 262
Recyclable hydrocarbons	Used oil Contaminated fuel	20,000 gal	Hydrocarbon recovery through GPB production facility	Temporary storage in containers prior to transfer to facility for hydrocarbon recycle	Storage in containers

Table 11-2. Projected Final Construction Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
Recyclable scrap metal	Cable Conduit (metal) and fittings Piping (metal), oil free Stainless steel, copper, or aluminum Valves Wiring	200,000 lbs	Scrap metal recycler in Alaska	Store in dumpster designated for scrap metal	NA

Notes:

1. The list of waste types is not intended to be all inclusive; it is representative of the major waste types that will be generated during this phase of the project.
2. Lab analysis may be required to document that the waste is non-hazardous prior to disposal, depends on type, volume, and season of spill.
3. Based on NPDES application.
4. Aerosol cans (empty or unusable) will be managed as hazardous waste until they are punctured, drained, and placed in a scrap metal dumpster for metal recycling. Residue from the cans will be collected and managed as hazardous waste.

Key: APDES = Alaska Pollutant Discharge Elimination System; BMPs = best management practices; CFR = Code of Federal Regulations; cy = cubic yard; gal = gallons(s); G&I = Grind and Inject Facility; GPB = Greater Prudhoe Bay; gpd = gallons per day; lbs = pounds; LDPI = Liberty Drilling and Production Island; MG = million gallons; NA = not applicable; NPDES = National Pollutant Discharge Elimination System; NSB = North Slope Borough; SDI = Satellite Drilling Island; SWPPP = Storm Water Pollution Prevention Plan; TBD = to be determined; UW = universal waste.

Table 11-3. Projected Drilling and Operations Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
E&P exempt waste	Drilling fluids and cuttings from downhole Completion fluids Cement returns Freeze protect fluids from downhole or from surface production piping Rinse water in contact with fluids/ cuttings from downhole	3,780,000 gal per well	Disposal by injection in on-site waste disposal well	Disposal at permitted injection facility	Temporary storage on site
Non-exempt, non-hazardous waste[2]	Boiler blow down Cement reinstate Waste from drilling disposal well Unused drilling and completion fluids Glycol (spent) Snowmelt/rainwater from containments	840,000 gal	Disposal by injection in on-site waste disposal well	Disposal by injection at permitted disposal well	Temporary storage on site
Construction debris	Electrical wire Flexible duct Incinerator ash[2] Liner (clean/oil free) Piping (plastic) Visqueen Welding rod Wood waste	200,000 lbs	Landfill at NSB Oxbow Landfill	NA	No treatment Storage in dumpsters

Table 11-3. Projected Drilling and Operations Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
Oily waste	Sorbents/rags[2] Oil filters	50,000 lbs	Incinerate on site	Incinerator operated by NSB landfill	Double bag, seal, and tag with generator information Store in dedicated oily waste dumpster
Municipal solid waste	Food waste Paper/Cardboard	224,000 lbs	Incinerate on site	NSB landfill	Plastic waste bag and bear-proof dumpsters
LDPI wastewater discharge[3]	Treated sanitary/domestic wastewater Construction dewatering Stormwater Mine site dewatering for ice roads and pads Potable water desalination backwash	Sanitary/domestic wastewater 9,400 gpd (3.4 MG/yr)	Downhole disposal on site (waste disposal well)	Marine discharge under NPDES permit or disposal by injection at permitted disposal well	Secondary treatment of domestic wastewater
STP[3]	Natural suspended solids concentrated by filter Residual chlorine Heat	1.0 MG/day (365 MG/yr)	NPDES	None	Minimize chlorine use and temperature increases
SDI wastewater discharges	Stormwater	Depends on weather	Managed under APDES stormwater general permit	Disposal by injection at permitted disposal well	No treatment Pollution prevention by application of SWPPP and BMPs
Spill cleanup material	Contaminated snow/ice/gravel	500 cy	Downhole disposal on site (waste disposal well)	Disposal by injection at permitted disposal well or discharge under NPDES permit	Temporary storage in water-tight containers

Table 11-3. Projected Drilling and Operations Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (IF APPLICABLE)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
Hazardous and UW	Aerosol cans[4] Lead acid batteries (damaged or broken) Paint waste Solvents/thinners Rags with solvents/thinners UW lamps UW batteries	3,000 lbs	Offsite disposal or recycled at permitted facility	NA	Temporary storage in containers meeting the requirement of 40 CFR 262
Recyclable hydrocarbons	Used oil Contaminated fuel Pigging waste	33,600 gal	Hydrocarbon recovery through Endicott production facility	Hydrocarbon recovery through Endicott production facility	Temporary storage in drums or totes prior to recycle
Recyclable scrap metal	Cable Conduit (metal) and fittings Piping (metal), oil free Stainless steel, copper, or aluminum Valves Wiring	200,000 lbs	Scrap metal recycler in Alaska	NA	Store in dumpster designated for scrap metal

Notes:
1. The list of waste types is not intended to be all inclusive; it is representative of the major waste types that will be generated during this phase of the project.
2. Lab analysis may be required to document that the waste is non-hazardous prior to disposal.
3. Based on NPDES Application.
4. Aerosol cans (empty or unusable) will be managed as hazardous waste until they are punctured, drained, and placed in a scrap metal dumpster for metal recycling. Residue from the cans will be collected and managed as hazardous waste.

Key: APDES = Alaska Pollutant Discharge Elimination System; bbl = barrel(s); BMPs = best management practices; CFR = Code of Federal Regulations; cy = cubic yard; G&I = Grind and Inject Facility; gal = gallons(s); GPB = Greater Prudhoe Bay; gpd = gallons per day; lbs = pounds; LDPI = Liberty Drilling and Production Island; MG = million gallons; NA = not applicable; NPDES = National Pollutant Discharge Elimination System; NSB = North Slope Borough; SDI = Satellite Drilling Island; SWPPP = Storm Water Pollution Prevention Plan; UW = universal waste.

Table 11-4. Projected Operations Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (if Applicable)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
E&P exempt waste	Solids from vessel cleanout Flowline/pipeline pigging waste Sandjet solids Freeze protection fluids from downhole or from surface piping	420,000 gal	If generated at LDPI, downhole disposal on site If generated onshore, disposal by injection at permitted Class I disposal well	Disposal by injection at permitted disposal well	May be temporarily stored in drums, tanks, or containers
Non-exempt, non-hazardous waste[2]	Glycol (spent) Snowmelt/rainwater from containments	210,000 gal	Injection at LDPI disposal well	Transport to Endicott Snowmelt tank for injection in a Class II enhanced oil recovery well or Dispose in permitted injection well or Discharge under NPDES permit	No treatment
Construction debris	Electrical wire Flexible duct Incinerator ash[2] Liner Plastic piping Visqueen Welding rod Wood waste	440 cy	Landfill at NSB Oxbow Landfill	NA	No treatment Storage in dumpsters
Oily waste	Sorbents/rags[2] Oil filters	50 cy	Incinerate on site at LDPI or oily waste dumpster at SDI	Incinerator operated by NSB at the Oxbow Landfill	No treatment Double bag, seal, and tag with generator information Store in dedicated oily waste dumpster
Municipal solid waste	Food waste Paper/cardboard Plastics	30,000 lbs	Incinerate on site at LDPI or dumpster at SDI	NSB Oxbow Landfill	No treatment Store in dumpsters Store food waste inside or in animal-proof container

Table 11-4. Projected Operations Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (if Applicable)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
LDPI wastewater discharge[3]	Treated sanitary/domestic wastewater Construction dewatering Stormwater Mine site dewatering for ice roads and pads Potable water desalination backwash	Sanitary/domestic wastewater 9,400 gpd (3.4 MG/yr)	Downhole disposal on site (waste disposal well)	Marine discharge under NPDES permit or Disposal at permitted injection well	Secondary treatment
STP[3]	Seawater with total suspended solids	1.0 MG/day (365 MG/yr)	NPDES	None	Natural suspended solids concentrated by the filter systems Chlorine residual – minimize use of chlorine Temperature – minimize temperature increases
SDI wastewater discharges	Stormwater	Depends on weather	Managed under APDES stormwater general permit	Disposal by injection at permitted disposal well	No treatment Pollution prevention by application of SWPPP and BMPs
Spill cleanup material	Contaminated snow/ice[2]	40 cy	Injection at LDPI disposal well	Disposal by injection at permitted disposal well or discharge under NPDES	Melt prior to injection Store liquid in tank or container
Spill cleanup material	Contaminated gravel[2]	20 cy	Disposal by injection at disposal well	Other offsite permitted facility	No treatment Store in water-tight bins or containers

Table 11-4. Projected Operations Wastes

TYPE OF WASTE[1]	TYPICAL COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	PREFERRED MANAGEMENT METHOD	ALTERNATE METHOD (if Applicable)	TREATMENT/ STORAGE PRIOR TO DISPOSAL
Hazardous and UW	Aerosol cans[4] Lead acid batteries (damaged or broken) Paint waste Solvents/thinners Rags with solvent/thinners UW lamps UW batteries	2,000 lbs	Offsite disposal or recycled at permitted facility	NA	Temporary storage in containers meeting the requirement of 40 CFR 262
Recyclable hydrocarbons	Used oil Contaminated fuel Pigging wastes[2]	12,600 gal	Hydrocarbon recovery through Endicott production facility	Hydrocarbon recovery through GPB production facility	Temporary storage in drums or totes prior to recycle
Recyclable scrap metal	Cable Conduit and fittings Piping Stainless steel, copper, aluminum Valves Wiring	Variable	Scrap metal recycler in Alaska	NA	Store in dumpster designated for scrap metal

Notes:

1. The list of waste types is not intended to be all inclusive; it is representative of the major waste types that will be generated during this phase of the project.
2. Lab analysis will be required to document that the waste is non-hazardous prior to disposal.
3. Based on NPDES Application.
4. Aerosol cans (empty or unusable) will be managed as hazardous waste until they are punctured, drained, and placed in a scrap metal dumpster for metal recycling. Residue from the cans will be collected and managed as hazardous waste.

Key: APDES = Alaska Pollutant Discharge Elimination System; bbl = barrel(s); BMPs = best management practices; CFR = Code of Federal Regulations; cy = cubic yard; G&I = Grind and Inject Facility; gal = gallons(s); GPB = Greater Prudhoe Bay; gpd = gallons per day; lbs = pounds; LDPI = Liberty Drilling and Production Island; MG = million gallons; NA = not applicable; NPDES = National Pollutant Discharge Elimination System; NSB = North Slope Borough; SDI = Satellite Drilling Island; SWPPP = Storm Water Pollution Prevention Plan; UW = universal waste.

Table 11-5. Offsite Waste Transportation Information by Project Phase

TYPE OF WASTE[1]	Typical COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	DESTINATION	TRANSPORTATION METHOD[2]: ICE ROAD AND OPEN-WATER SEASONS	TRANSPORTATION METHOD[2]: SHOULDER SEASON
Early Construction Phase (prior to camp on location)					
Construction debris	Electrical wire Flexible duct Liner (clean/oil free) Piping (plastic) Visqueen Welding rod Wood waste Sandy blasting media Fusion bonded epoxy powder	200,000 lbs	NSB Oxbow Landfill (NSB landfill), Deadhorse	Dumpster transported by truck via ice road (winter) and barge (open water) to SDI. Dumpsters transferred to truck and transported to landfill.	Storage on site
Oily waste	Sorbents/rags[3] Oil filters	8,000 lbs	NSB burner units	Oily waste transported by truck via ice road (winter) and barge (open water) to SDI. Dumpsters transferred to truck and transported to burners.	Hovercraft (small quantities only)
Municipal solid waste	Cardboard Plastic Paper	40,000 lbs	NSB landfill	Dumpster transported by truck via ice road (winter) and barge (open water) to SDI. Dumpsters transferred to truck and transported to landfill.	Storage on site
Sanitary and domestic wastewater	Sludge	182,000 gal	NSB wastewater treatment facility	Vacuum trucks access LDPI via ice road during winter, collect sludge, and transport it to Deadhorse for treatment/ disposal.	Storage on site
Non-hazardous fluids[3]	Snowmelt/rainwater from containments Construction dewatering	33,600 gal	GPB G&I Facility or Pad 3 or alternative Class I disposal well or discharge under NPDES permit[4]	Fluids will be accumulated in containers until transportation is available. Vacuum trucks access LDPI via ice road during winter, collect fluids, and transport them to GPB G&I facility for disposal.	Storage on site

Table 11-5. Offsite Waste Transportation Information by Project Phase

TYPE OF WASTE[1]	Typical COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	DESTINATION	TRANSPORTATION METHOD[2]	
				ICE ROAD AND OPEN-WATER SEASONS	SHOULDER SEASON
Spill cleanup material, non-hazardous	Contaminated snow/ Ice/gravel[3]	200 cy	GPB G&I Facility or Pad 3 or alternative Class I disposal well or discharge under NPDES permit[4]	Supersuckers or vacuum trucks access LDPI by ice road or on barge, collect material and transport it to disposal well.	Storage on site
Hazardous and UW	Lead acid batteries (damaged or broken) Paint waste Solvents/thinners Rags with solvents/ thinners UW lamps UW batteries	1,000 lbs	A licensed facility Specific disposal/recycle facility will vary depending on waste type	Containers transported by truck via ice road (winter) and barge (open water) to SDI. Containers transferred to truck and transported to a licensed facility for disposal/recycling.	Storage on site
Final Construction (with camp on location, prior to completion of waste disposal well)					
Construction debris	Electrical wire Flexible duct Incinerator ash[3] Liner (clean/oil free) Piping (plastic) Visqueen Welding rod Wood waste	350,000 lbs	NSB Oxbow Landfill (NSB landfill), Deadhorse	Dumpster transported by truck via ice road (winter) and barge (open water) to SDI. Dumpsters transferred to truck and transported to landfill.	Storage on site
Non-exempt, non-hazardous fluids	Snowmelt/rainwater from containments Glycol (spent)	165,000 gal	GPB G&I Facility or Pad 3 or alternative Class I disposal well or discharge under NPDES permit[4]	Vacuum trucks access LDPI via ice road during winter, collect sludge, and transport it to GPB G&I facility for disposal. Removal in summer would be by vessel.	Storage on site
Fluids from hydrotesting new pipelines	Water-based mixtures	174,000 gal	Endicott snowmelt tank for enhanced oil recovery well, permitted North Slope well or discharge under NPDES permit[4]	Vacuum truck	NA – No testing during shoulder season

Table 11-5. Offsite Waste Transportation Information by Project Phase

TYPE OF WASTE[1]	Typical COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	DESTINATION	TRANSPORTATION METHOD[2]	
				ICE ROAD AND OPEN-WATER SEASONS	SHOULDER SEASON
Spill cleanup material, non-hazardous	Contaminated snow/ice/gravel	500 cy	GPB G&I Facility or Pad 3 or alternative Class I disposal well[4]	Supersuckers or vacuum trucks access LDPI by ice road or on barge, collect material, and transport it to GPB G&I facility for disposal.	Storage on site
Hazardous and UW	Aerosol cans[5] Lead acid batteries (damaged or broken) Paint waste Solvents/thinners Rags with solvents/ thinners UW lamps UW batteries	2,500 lbs	A licensed facility Specific disposal/recycle facility will vary depending on waste type	Containers transported by truck via ice road (winter) and barge (open water) to SDI. Containers transferred to truck and transported to a licensed facility for disposal/recycling.	Storage on site
Recyclable hydrocarbons	Used oil Contaminated fuel Pigging waste[3]	20,000 gal	Endicott production facility	Vacuum truck comes to LDPI to collect fluids and transport to Endicott Snowmelt Tank. Vacuum trucks access LDPI via ice road during winter, collect fluids, and transport to Endicott Snowmelt Tank for recycling. Transportation during summer would be by vessel. If at tie-in pad, stored drums transported via truck over ice road in winter.	Storage on site
Recyclable scrap metal	Cable Conduit (metal) and fittings Piping (metal), oil free Stainless steel, copper, or aluminum Valves Wiring	200,000 lbs	Scrap metal recycler in Alaska	Dumpster transported by truck via ice road (winter) and barge (open water) to SDI. Dumpsters transferred to truck and transported to Investment Recovery yard in Deadhorse and consolidated with other scrap metal for transportation to metals recycler.	Storage on site

Table 11-5. Offsite Waste Transportation Information by Project Phase

TYPE OF WASTE[1]	Typical COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	DESTINATION	TRANSPORTATION METHOD[2]	
				ICE ROAD AND OPEN-WATER SEASONS	SHOULDER SEASON
Drilling and Operations Phases					
Construction debris	Electrical wire Flexible duct Incinerator ash[3] Liner (clean/oil free) Piping (plastic) Visqueen Welding rod Wood waste	200,000 lbs	Landfill at NSB Oxbow Landfill (NSB landfill)	Dumpster transported by truck via ice road (winter) and barge (open water) to SDI. Dumpsters transferred to truck and transported to landfill.	Storage on site
Hazardous and UW	Aerosol cans[5] Lead acid batteries (damaged or broken) Paint waste Solvents/thinners Rags with solvents/ thinners UW lamps UW batteries	3,000 lbs	Approved hazardous waste treatment and disposal facility Specific disposal/recycle facility will vary depending on waste type	Containers transported by truck via ice road (winter) and barge (open water) to SDI. Containers transferred to truck and transported to a licensed facility for disposal/recycling.	Storage on site
Recyclable scrap metal	Cable Conduit (metal) and fittings Piping (metal), oil free Stainless steel, copper, or aluminum Valves Wiring	200,000 lbs	Scrap metal recycler in Alaska	Dumpster transported by truck via ice road (winter) and barge (open water) to SDI. Dumpsters transferred to truck and transported to Investment Recovery yard in Deadhorse and consolidated with other scrap metal for transportation to metals recycler.	Storage on site

Table 11-5. Offsite Waste Transportation Information by Project Phase

TYPE OF WASTE[1]	Typical COMPOSITION	ESTIMATED ANNUAL AMOUNT UNLESS OTHERWISE NOTED	DESTINATION	TRANSPORTATION METHOD[2]	
				ICE ROAD AND OPEN-WATER SEASONS	SHOULDER SEASON

Notes:

1. The list of waste types is not intended to be all inclusive; it is representative of the major waste types that will be generated during this phase of the project.
2. All wastes generated onshore south of LDPI (such as at the Badami pipeline tie-in pad) will be temporarily stored on site and transported by truck via ice road in winter. Small amounts of wastes may be transported via helicopter as necessary.
3. Lab analysis will be required to document that the waste is non-hazardous prior to disposal.
4. Examples include Class I wells at Endicott, Prudhoe Bay G&I, and Pad 3.
5. Aerosol cans (empty or unusable) will be managed as hazardous waste until they are punctured, drained, and placed in a scrap metal dumpster for metal recycling. Residue from the cans will be collected and managed as hazardous waste.

Key: cy = cubic yard; gal = gallons(s); G&I = Grind and Inject Facility; GPB = Greater Prudhoe Bay; lbs = pounds; LDPI = Liberty Drilling and Production Island; NA = not applicable; NSB = North Slope Borough; SDI = Satellite Drilling Island; UW = universal waste.

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12 ENVIRONMENTAL PROTECTION AND MONITORING

Hilcorp (HAK) believes that strong environmental performance is integral to the overall success of the Liberty Development. Every key decision on the design of the island, pipeline, wells, and process facilities is based on the unique environmental setting of this project. This section of the DPP provides an overview of how HAK intends to protect the environment surrounding the Liberty Development.

HAK has access to a vast body of knowledge about the nearby environment, which is key to designing and achieving protections. In addition, HAK has updated that knowledge base with project-specific studies over the last 2 years. This knowledge has been incorporated into project engineering and design to mitigate potential impacts of development.

The Environmental Impact Analysis (EIA; Appendix A) is referenced for a detailed analysis of the affected environment, potential environmental effects, and mitigation measures. The following discussion focuses more on the environmental objectives, planning, and protective measures that underpin the proposed project and how environmental performance of the project will be monitored. Mitigation integrated into project design and operations is addressed in Section 13.

12.1 Hilcorp Corporate Initiatives

HAK has a set of core values that represent how the company conducts business. The most important of these values is *Integrity*, which is interpreted as “do the right thing.” In the context of environmental stewardship, it is up to every HAK employee and contractor to protect the environment. HAK is committed to building and operating a safe, clean project, while minimizing environmental impacts to the extent practicable.

Toward that end, HAK culture and expectations demand excellence from executive management, supervisory management, and first line workers in the performance of their everyday work processes and habits. Ways in which these processes are implemented include:

- Lead by example with a consistent message of commitment and accountability to do the right thing.
- Diligently and constantly evaluate the potential for risk. When failures occur, find the root cause and implement ways to prevent a similar occurrence in the future.
- Utilize a Management of Change (MOC) process to manage changes in processes, equipment, personnel, and procedures.
- Design, construct, and operate facilities to the highest level of performance by enforcing accountability to best practices and relevant codes and standards.
- Hire individuals and select contractors whose core values are consistent with HAK’s.
- Educate the workforce with proper technical, health, safety, environmental, and compliance training.
- Directly and assertively manage the behaviors and processes of third-party contractors.
- Prepare for possible emergencies. Develop effective response plans and conduct drills to be proficient.
- Communicate openly and effectively. Develop documentation, plans, procedures, and programs that convey accurate and useful information.

HAK is committed to operating in an environmentally responsible manner by implementing technically sound, practical solutions to meet the energy needs of this country. HAK seeks to drive the number and severity of incidents with real environmental impact to zero by committing to a policy of continuous improvement throughout our operations.

12.2 Project Environmental, Health, and Safety Plans

Project-wide and site-specific EH&S plans will be implemented to ensure that development and operational activities are conducted in full compliance with regulations and permits, and fully implement agreed-to environmental mitigation measures to protect human health and the environment. HAK corporate practices, along with best practices developed by other Alaska North Slope operators, will be used to develop plans specific for the Liberty Development project. Sources that will be used to support EH&S issues associated with working on the North Slope include the *Alaska Safety Handbook and North Slope Environmental Field Handbook.*

12.3 EH&S Training Program

The Liberty Development project will have a robust training system in place to ensure employee safety, regulatory compliance, and outstanding environmental performance. General environmental, sociocultural, and regulatory awareness training is planned for employee and contractor personnel assigned to the North Slope, and must be completed prior to on-site arrival. Additional training required by an individual's work assignment will also be provided.

The Liberty project's training program will span different levels, from new worker orientation to technical training for the specialized workforce, to periodic refreshers for experienced workers. The two primary components of this training program include the North Slope Training Cooperative (NSTC) Unescorted Program and the Liberty-specific training (see also Section 17.2). Both programs ensure that personnel assigned to the Liberty Development project are aware of applicable regulatory conditions and requirements, as well as safety, health, environmental, sociocultural, and security expectations and requirements related to working on the North Slope. NSTC training was developed by other operators on the North Slope. It is a 1-day training seminar that is mandatory for all personnel working in, and unescorted visitors to, any operating field on the North Slope.

Liberty project-specific training includes components related to environmental and cultural awareness, permit and regulatory compliance, wildlife interaction, the OSRP, and compliance with HAK expectations. Components of the training program include, but are not limited to:

- Site Orientation and Unique Working Conditions
- Regulatory Compliance and Expectations
- Alaska Native Cultural Awareness
- Environmental Awareness
- Waste Management Plans
- Spill Prevention and Reporting
- Polar Bear and Wildlife Interaction Plans
- Job Safety Analysis
- Eye, Hand, and Back Safety
- Behavior-Based Safety Processes
- Driving/Road Rules; Winter Driving/Ice Road Rules
- Cold Water Survival
- First Aid/Emergency Medical Treatment

12.4 Environmental Stewardship

HAK has incorporated a number of measures into the Liberty Development project to accommodate local environmental conditions and protect the local environment, including: oceanographic resources; air quality; biologic resources; cultural, historical, and archaeological resources; and subsistence. HAK has also taken into account the experience at other North Slope developments and other offshore gravel islands in the Beaufort Sea and experience gained that can be used to enhance environmental performance of the Liberty Development.

12.4.1 Application of Proven Technology and Lessons Learned

The Liberty Development benefits from significant technical and operational experience and lessons learned from recent Beaufort Sea oil and gas developments. These include: Endicott (1985), Northstar (2001), Oooguruk (2008), and Nikaitchuq (2011)[3]. The latter three projects have successfully demonstrated the installation and operation of subsea pipelines in the Beaufort Sea. Island slope protection systems developed from experience with exploration gravel islands and causeways in the 1970s and 1980s in the Beaufort Sea have been proven in actual use in the Beaufort Sea.

The Northstar experience provides information on such issues as the performance of island slope protection system and necessary maintenance in a more severe location than Liberty (i.e., outside the barrier islands). It also provides practical lessons on logistical support including the use of hovercraft. Other examples of relevant experience from other island projects include:

- Need for a conservative design basis for the island design storm event;
- Design of slope protection system to include simplifying slope maintenance;
- Waste management; and
- Applying lessons from successful installation according to design and construction plans and how further optimizations can be accomplished.

Extensive environmental studies and monitoring related to the Northstar Project, as well as West Dock and Endicott seawater treatment plants, contribute to a better understanding of potential environmental impacts of the proposed Liberty Development. Northstar's environmental studies and monitoring programs, including the effects of industrial noise on whales and the passage of migrating whales, are summarized in the EIA (Appendix A).

A comparative description of the design of Alaska Beaufort Sea subsea pipelines and flowlines of the Northstar, Oooguruk, and Nikaitchuq projects is provided by Lanan, Cowin, and Johnston in Offshore Engineer article entitled *Bundled for the Beaufort* (May 2011). That paper also describes the construction, operation, and monitoring systems of those pipeline and flowline bundles, and maintenance requirements of the Northstar pipelines. With respect to oceanographic conditions, Endicott is the most analogous to the planned LDPI where a linked concrete mat slope protection system on the exposed portions of the causeway and at MPI have operated successfully for nearly 30 years with minimal maintenance and repair.

12.4.2 Consideration of Existing Environmental Information

The environmental considerations for the Liberty Development have been identified, analyzed, and documented in over two decades of deliberations about developing oil in the Beaufort Sea, and specifically Stefansson Sound. The current scope of Liberty Development is almost identical to the project proposed in 2000. The broad history of environmental issue evaluation related to leasing and development of the Liberty reservoir and the general project area provides a substantial database that was considered in the proposed Liberty Development. A summary follows.

The Liberty Unit is comprised of two OCS leases: Y-1650, acquired in OCS Lease Sale 144, and Y-1585, originally acquired in OCS Lease Sale 124. The environmental impacts of Lease Sale 124 were evaluated in *Beaufort Sea Planning Area Oil and Gas Lease Sale 124 Final Environmental Impact Statement* (EIS),

[3] Years of first production.

completed by BOEM's predecessor agency, the MMS in 1990. In 1996, the environmental impacts of Lease Sale 144 were evaluated by MMS in *Beaufort Sea Planning Area Oil and Gas Lease Sale 144 Final EIS*. Both of these NEPA documents were subject to public review and comment. In both documents, MMS notes that lease sales in an area proceed only if it is determined that leasing and development would be environmentally and socially acceptable as well as technically feasible.

In 2000, BPXA submitted a DPP to MMS to develop the Liberty reservoir from a gravel island constructed on the OCS. In accordance with NEPA, the MMS prepared the *Liberty Development and Production Plan Final EIS*. The Final EIS analyzed the environmental impact of the project as proposed, as well as the impacts associated with three project alternatives. The proposed project that HAK is presenting is very similar to the MMS preferred alternative, based on that analysis. In the same timeframe, the *Beaufort Sea Oil and Gas Development/Northstar Project Final Environmental Impact Statement* was being completed by U.S. Army Corps of Engineers (USACE) for a proposed offshore production island with a subsea pipeline to shore. With some OCS lease wells included in the development plan, MMS was a cooperating agency in that EIS.

In 2003, MMS released the *Beaufort Sea Planning Area Oil and Gas Lease Sales 186, 195 and 202 Final Environmental Impact Statement.* Follow-on Environmental Assessments (EAs) were completed for Proposed OCS Lease Sale 195 in 2004 and Proposed OCS Lease Sale 202 in 2006 – both with Findings of No Significant Impact (FONSIs) issued. In 2007, BPXA submitted to MMS a DPP for the revised Liberty Development concept of ultra-extended-reach drilling (uERD) from the Endicott SDI. An EA was completed in 2007 by MMS.

In November 2008, the MMS released the *Beaufort Sea and Chukchi Sea Planning Areas Oil and Gas Lease Sales 209, 212, 217, and 221 Draft Environmental Impact Statement,* but it was not finalized. Instead, a Draft Supplemental EIS for the Chukchi Sea Planning Area Oil and Gas Lease Sale 193 was released in 2010, with a final Supplemental EIS released in 2011. In June 2014, BOEM published a Notice of Intent to prepare a Supplemental EIS to provide an updated oil and gas exploration, development, and production scenario and associated environmental effects analysis. In November 2014, Notice of Availability for the Chukchi Sea Oil and Gas Lease Sale 193 draft Supplemental EIS was published in the Federal Register.

On a 5-year schedule, the *OCS Oil and Gas Leasing Program: 2012-2017 Final Programmatic EIS* was issued by BOEM in July 2012. The Beaufort Sea OCS Planning Area was included in the analysis of potential impacts, with notable updates on oil spills and climate change, as well as updated data and analyses in other resource areas. Most recently, BOEM completed an *Environmental Assessment of the 2014 Liberty Ancillary Activities Shallow Geohazard Seismic Survey, Beaufort Sea, Alaska*.

In addition to the extensive collection of environmental analyses described above, baseline data has been collected by BOEM and other governmental agencies and universities over the past few decades, much of it focused on future development of OCS resources, including Liberty.

12.4.3 Update of Project-Specific Environmental Information

HAK has built upon and updated the vast body of existing information to prepare this DPP and to provide relevant data needed to complete the EIA (Appendix A) and assist BOEM in complying with NEPA in making permit decisions for Liberty Development. A brief overview of this information update and re-assessment process follows.

The Liberty project team reviewed the documents cited in Section 12.4.1 and 12.4.2, as well as other scientific studies and reports published since the 2002 Liberty FEIS and 2007 Liberty EA were completed. Where information gaps were determined to exist, the Liberty project team undertook new studies. Additionally, a number of engineering-related technical studies were completed that also provided environmental information useful for the assessment of potential impacts and development of mitigation.

Project-specific measures undertaken to update the existing environmental database are summarized below.

- Evaluated the previous 18 gravel islands constructed in the Beaufort Sea for design and environmental performance.
- Completed slope protection testing at Oregon State University to evaluate the effectiveness of slope armoring methods, which also affect potential for erosion and sedimentation (described in Section 6.2).
- Re-assessed oceanography and benthos to support design and assure resource protection. This included: seabed reconnaissance to determine extent of Boulder Patch; extensive modeling to predict dispersion of excess total suspended solids (TSS) from pipeline and island construction, and robust modeling of kelp growth, photosynthetic active radiation, and TSS to evaluate potential effects on the Boulder Patch.
- Re-assessed marine and terrestrial mammals, fish, and birds to better understand local resources and potential effects of project development.
- Assessed project area wetlands in siting the gravel mine.
- Performed onshore and offshore archaeological studies to identify and protect cultural and historic resources.
- Performed socio-economic modeling using the MAG-PLAN Alaska, a region-specific economic impact model used by BOEM to estimate potential economic impacts of development in the Alaskan OCS.
- Re-assessed air quality (existing and potential), meteorology, and global warming to support design and assure resource protection.
- Compiled the latest information of subsistence activities, focused on Cross Island whaling.

New studies undertaken specifically for this Liberty Development project are listed in Table 12-1, with a cross reference to those sections of the DPP/EIA in which additional information is provided. This list is not all-inclusive, but reflects the major information gathering efforts with associated environmental issues.

Building on the past environmental analyses, and updating them to include the most recent information placed HAK in a unique position to incorporate substantial environmental and sociocultural information into the design and operational planning of the proposed Liberty project.

12.4.4 Environmental Resource Protection

Understanding local resources is the first step in environmental protection. Each resource must then be evaluated for ways in which it can affect or be affected by the proposed project. Different resources present different issues of concern. Siting, design, and operations mitigation measures can be implemented to avoid or reduce potential impacts on or by the various resources. The Liberty Development EIA (Appendix A) is referenced for a detailed analysis of the affected environment, potential environmental effects, and mitigation. A summary of resource-specific mitigation incorporated in the Liberty project is provided in Section 13.

One way to measure the status of environmental resources and/or the success of environmental resource protection is monitoring, as discussed below.

Table 12-1. Environmental Study Information

STUDY	REFERENCE
BIOLOGICAL ENVIRONMENT	
Updated assessment of existing biological resources and potential effects	EIA Section 3.7 – 3.13; 4.1.7-4.1.13
Seabed reconnaissance: side-scan sonar and underwater photography to locate and characterize Boulder Patch	DPP Section 6.1.1.4; 13.3.1
Modeling TSS dispersion from island and pipeline construction as the basis for evaluating impacts of TSS on Boulder Patch	EIA Section 4.1.6 and 4.1.7
Projected Kelp Production in the Boulder Patch	EIA Section 4.1.7
PHYSICAL ENVIRONMENT	
Updated assessment of existing physical conditions and potential effects	EIA Section 3.1 -3.6; 4.1.1-4.1.6
Ocean Waves and Currents	DPP Section 6.1.1.1; EIA Section 3.2.3, 3.2.5. 3.2.6
Sea Ice	DPP Section 6.1.1.2
Ice Gouging	DPP Section 7.2.3
Strudel Scour	DPP Section 7.2.4
Climate Change Trends	DPP section 6.1.1.3
Offshore geology: bathymetry and side-scan sonar studies	DPP Section 6.1.1.4
Coastal Erosion Rate Study:	EIA Sections 3.2.9.3, 4.1.2.1
Soils and Permafrost	DPP Section 7.2.5, 7.2.6; 7.2.7 EIA Sections 3.3.2, 4.1.3.2
Gravel Mine Site Geology	EIA Section 2.2.4
Air Quality	DPP Section 9.4, 10.6 and Appendix F; EIA Sections 4.1.4; Attachment 1
Archaeological Surveys (Reports submitted to BOEM)	DPP Section 16.1; EIA Section 3.14
SOCIOECONOMICS	
Updated assessment of existing socioeconomic resources and potential effects	EIA Section 3.15; 4.1.15-4.1.18
MAG-PLAN Economic Impact Modeling	EIA Section 4.1.15
Subsistence and Traditional Land Use Patterns	EIA Section 4.1.18 and Attachment 2

12.5 Environmental Monitoring

The nearshore Beaufort Sea is a well-studied area. The Liberty Development benefits from the significant body of information from monitoring and environmental studies conducted over the past 30 years, including BOEM's environmental studies program. The Outer Continental Shelf Lands Act requires the U.S. Department of the Interior (USDOI) to conduct environmental studies to obtain information pertinent to sound leasing decisions as well as to monitor the human, marine, and coastal environments. The Alaska Environmental Studies Program was initiated 40 years ago when the federal government decided to propose areas of Alaska for offshore gas and oil development. Local meteorological data are collected at the National Weather Service (NWS) Automated Surface Observing System (ASOS) station located at the

Deadhorse Airport, and site-specific meteorological data was collected at the Endicott SDI as part of the USDOI Beaufort Sea Meteorological and Data Synthesis Project. The National Ocean Service maintains a tide station located in Prudhoe Bay that collects tidal data applicable to conditions in Foggy Island Bay. Various North Slope operators have produced study and monitoring data on water quality, permafrost, polar bear and other marine mammals, sea ice dynamics, erosion control, and underwater noise. These and other monitoring data related to Liberty Development are described in the associated EIA (Appendix A).

Liberty Development will continue to monitor various physical features of the Liberty Development. These monitoring plans are listed in Table 12-2, with a cross reference to location in the DPP.

Table 12-2. Environmental Monitoring Plans

ENVIRONMENTAL CONDITION MONITORED	DPP REFERENCE (SECTION)
Weather	11.6; EIA 4.1.1
Oceanographic conditions	11.6
Sea level	12.5; EIA 4.1.1 and 5.2.1
Strudel scour	7.2.4, 7.2.8, and 12.5; EIA 4.1.1.1
Ice conditions	EIA 4.1.1
Ice gouging	7.2.8
Permafrost	EIA 4.1.3.2
Bathymetry	EIA 4.1.3.2
Pipeline trench rehabilitation	13.3.1
Climate change trends	7.2.8

Biological monitoring will be developed with agency input on an activity-specific, site-specific basis. Some related monitoring is described in Section 12.5.2. HAK will also implement pipeline monitoring systems that can indicate changes in environmental conditions (Sections 7.2.2 and 7.10).

Additional environmental monitoring of Liberty Development will likely be required under various permits and authorizations issued (summarized in Section 15.4, Tables 15-1, 15-2, and 15-3 of this DPP). Table 12-3 lists the anticipated monitoring requirements for the major permits and authorizations required for the project. The type of monitoring requirements can be estimated based on past project experience related to both shallow water Beaufort Sea, onshore North Slope projects, and the environmental issues related to the Liberty Development.

12.5.1 Expected Monitoring Requirements

The list in Table 12-3 is not intended to be comprehensive of all monitoring that may be required; it focuses on the monitoring HAK expects. To address requirements of 30 CFR 550.252(a), Table 12-3 reflects environmental monitoring; it does not include engineering/operational monitoring for engineering, safety, or process integrity and operations (see Appendix D, SEMS).

Table 12-3. Major Permits and Approvals with Potential Environmental Monitoring Requirements

AGENCY	PERMIT/APPROVAL	POSSIBLE MONITORING
Federal Permits and Authorizations		
U.S. Department of the Interior Bureau of Ocean Energy Management (BOEM)	Development and Production Plan (DPP), Environmental Impact Statement (EIS), and Record of Decision Post Approval of the DPP	To be developed through planning, scoping, and public comments on draft EIS. Monitoring may be required for bird strikes, and marine mammal sightings.
U.S. Department of the Interior Bureau of Safety and Environmental Enforcement (BSEE)	Post Approval of the DPP	To be determined. Possibly pipeline integrity, coastal erosion.
U.S. Army Corps of Engineers (USACE)	Section 404 (33 CFR Part 320-330)	Mine site revegetation and other rehabilitation success, as-built surveys, erosion of islands and pipeline landfall.
U.S. Environmental Protection Agency (EPA)	National Pollutant Discharge Elimination System (NPDES; 40 CFR Part 122)	Discharge quality (e.g., total residual chlorine, pH, fecal coliform) discharge monitoring reports.
U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration	Safety Certification	Pipeline surveillance.
U.S. Fish and Wildlife Service (USFWS)	Endangered Species Act (ESA) Section 7 Consultation – Biologic Opinion (BO) - polar bears, Steller's eiders, and spectacled eiders	Monitor and record marine mammal observations; identify and avoid bird nesting/molting areas.
USFWS	Marine Mammal Protection Act (MMPA) Letter of Authorization (LOA) for Incidental Take and Intentional Take – polar bear, Pacific walrus – See Tables 15-1, 15-2, 15-3	Polar bear dens and other monitoring in cooperation with USFWS; annual polar bear monitoring reports.
National Marine Fisheries Service (NMFS)	ESA, Section 7 Consultation – bowhead, ringed seals	Monitoring is typically included under MMPA requirements as noted below.
NMFS	MMPA Authorization – whales and seals	Monitoring of marine mammals in vicinity of project construction areas and facilities (ice roads, islands, vessels, etc.).
State Permits and Authorizations		
Alaska Department of Environmental Conservation (ADEC)	Alaska Pollutant Discharge Elimination System (APDES)	Discharge quality (e.g., total residual chlorine, pH, fecal coliform) discharge monitoring reports.
Alaska Department of Fish and Game (ADF&G)	Title 16 Fish Habitat Permit	Water withdrawal procedures, reporting on mine site rehabilitation success.
Alaska Department of Natural Resources (ADNR), Division of Mining, Land, and Water (DMLW)	Temporary Water Use	Source description, water withdrawal quantities, and accounting.
ADNR, DMLW	Material Sales Contract (gravel extraction)	Gravel use accounting, revegetation, and other mine site rehabilitation success.
ADNR, DMLW	Land Use Permit	Post-season tundra inspection and remediation (if required).
Alaska State Pipeline Coordinator's Office (SPCO)	Right-of-Way Application Approval and Lease	Pipeline surveillance.

Table 12-3. Major Permits and Approvals with Potential Environmental Monitoring Requirements

AGENCY	PERMIT/APPROVAL	POSSIBLE MONITORING
North Slope Borough		
North Slope Borough (NSB)	Development Permit and Administrative Approvals (NSB Code Title 19)	Implement permit requirements (e.g., post-season ice road monitoring). NSB development permits for large oil and gas projects typically have multiple stipulations related to monitoring environmental performance but focus on mitigating subsistence impacts.

12.5.2 Monitoring Associated with Protected Species

12.5.2.1 Threatened and Endangered Species under the Endangered Species Act

Several Threatened and Endangered species may occur in the Liberty Development area: polar bear (Threatened), ringed seal (Threatened), bowhead whale (Endangered), and spectacled eider (Threatened). Other listed species that may possibly, but are unlikely to, occur in the Liberty Development area are: humpback whale (Endangered; extralimital), and Steller's eider (Threatened; casual). One candidate species may occur in the Liberty Development area: Pacific walrus (extralimital, but occurs occasionally). In implementing their authority under the Endangered Species Act (ESA), the U.S. Fish and Wildlife Service (USFWS) and National Marine Fisheries Service (NMFS) will prepare Biological Assessments and issue Biological Opinions as part of the DPP NEPA review and for decisions in issuing Letters of Authorization (LOAs) for incidental take of marine mammals.

Planned methods of protecting the identified animal resources will be included in the Biological Opinions, as applicable. Specific protection measures will also be included in the required Polar Bear and Walrus Interaction Plan and other wildlife management plans.

Potential impacts to threatened and endangered species and associated mitigation are described in EIA Section 4.1.12. No more than negligible to minor effects are expected from the Liberty Development.

Authorization of the Liberty Development will require further analysis under the NEPA. Additional environmental monitoring may be included in the final NEPA document and/or relevant permits and authorizations (shown in Tables 15-1, 15-2, and 15-3).

12.5.2.2 Marine Mammals

HAK may choose to apply for authorizations under the Marine Mammal Protection Act (MMPA) from the NMFS for impacts to whales and seals and/or from the USFWS for impacts to polar bear and Pacific walrus, as noted in Table 12-3. Environmental monitoring of marine mammals will be outlined in these permit applications and authorizations issued by the relevant federal agency.

Planned methods of protecting the identified marine mammal resources will be included in the Letter of Authorization/Incident Harassment Authorization (LOA/IHA) and Biological Opinions, as applicable, HAK will have procedures in place for approved marine mammal monitors. Because the majority of bearded seal, spotted seal, gray whale, and beluga whale populations occur outside of Foggy Island Bay, noise and activity-related impacts to these overall populations are expected to be negligible (EIA Section 4.1.8.6).

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13 ENVIRONMENTAL MITIGATION MEASURES

HAK has identified actions that can be taken to avoid, minimize, or further mitigate potential effects the Project may have on the physical, biological, and human environment. Mitigation measures, including specific features, physical controls, and management practices, have been integrated into every major aspect of the Project including design, logistics, construction, and operations. Section 5 of the EIA (Appendix A) describes in detail the mitigation measures by resource. This section provides a brief summary of the more notable environmental protection and mitigation measures incorporated into the Project.

13.1 Approach

Mitigation measures that reduce, avoid, or eliminate environmental and social impacts may take a number of forms including:

- Specific engineering design, construction, and operations measures or practices intended to provide impact mitigation;
- Engineering design, construction, and operations practices that, while not necessarily intended as mitigation, nevertheless have positive environmental or social impact benefits;
- Environmental studies and monitoring (see Section 12) can also be considered as mitigation since understanding impacts allows adaptive management of the project to adjust practices to further reduce impacts or assure that impacts are being appropriately managed and mitigated;
- Mitigation may also be implemented through compliance with regulatory-mandated requirements at the federal, state, and local levels as outlined in Section 15; and
- Mitigation as required by OCS lease sale stipulations (as outlined in Section 16).

A number of regulatory programs with jurisdiction over the project activities require mitigation, such as:

- The National Environmental Policy Act (NEPA) regulations require Lead and Cooperating agencies to address mitigation in their review of the proposed action and alternatives, and to consider mitigation measures not already incorporated into the project as part of their decision-making. The U.S. Bureau of Ocean and Energy Management (BOEM) will conduct a NEPA review in conjunction with their review of this DPP and the EIA.
- Under the Clean Water Act Section 404 (b)(1) Guidelines, the U.S. Army Corps of Engineers (USACE) and U.S. Environmental Protection Agency (EPA) require application for a Section 404 permit to follow a "mitigation sequence" whereby a demonstration is made of how impacts have been avoided or minimized with respect to wetlands and other waters of the United States.
- An applicant for a Section 404 permit must also demonstrate that the project is the least environmentally damaging practicable alternative (LEDPA) to meet the project's purpose. The applicant has to conduct a 404(b)(1) Alternatives Analysis to provide this information.
- The State of Alaska (e.g., ADNR, ADF&G and ADEC) and North Slope Borough (NSB; Title 19 code) regulatory programs will condition its permits, leases, easements, etc., with extensive mitigations contained in stipulations.

Understanding the project's environmental mitigation is aided by an appreciation of the project's design basis as well as the implementation of Arctic best management practices (BMPs) and applicable engineering codes. Equally important is the data and experience gained from similar projects (e.g., Northstar, Oooguruk, Nikaitchuq) related to design, construction, operations, and environmental performance lessons learned.

13.2 Mitigation Features of the Project

This section of the DPP focuses on design features and measures proposed by HAK that have the effect of avoiding or reducing potential environmental impacts. The EIA addresses a broader range of mitigation, including specific regulatory controls and permit requirements, and is referenced for additional information.

Substantial mitigation measures have been incorporated into the Liberty Development. More importantly, HAK has selected a development option that minimizes the environmental impact while safely meeting project needs, including maximizing resource recovery. The process of evaluating alternatives is summarized in Section 2 of the EIA. Potential environmental impacts led to the exclusion of some alternatives from further consideration. The environmental mitigation benefits and features of the proposed Liberty Development Project are summarized below:

- Use of directional drilling tools and techniques to limit the number of drilling pads (i.e., islands) to one.
- Access to a remote offshore site by seasonal ice roads, barges, hovercraft, and aircraft to avoid need for a causeway to the island.
- Selection of a southern pipeline route that avoids sensitive eco-systems and risks of strudel scour to the north.
- Processing on LDPI will use modern and efficient air emission sources, as compared to using existing, older, less-efficient processing facilities.
- The selection of a pipeline route and design that is similar to the two most recent developments in the Beaufort Sea and has been proven to be safe and reliable.
- The selected pipeline route avoids areas of mapped high density (≥ 25%) Boulder Patch.
- Pipeline design features will minimize the depth and size of the trench and thus the impacts from excavation and backfill. Engineering optimization has reduced the size of the production pipeline to 12-inch diameter; the minimum backfill thickness required to avoid upheaval buckling has also been optimized. The single phase, pipe-in-pipe design maximizes leak detection sensitivities.
- The selected LDPI location is outside (inshore) of the mapped Boulder Patch while still facilitating maximum resource recovery and minimizing directional drilling requirements.
- LDPI size and layout, while accommodating worker safety and spill prevention and response, minimizes the gravel requirements and seabed footprint.
- LDPI will have a mat slope armor protection system that will extend from the island bench to the sea floor with a 3:1 (horizontal to vertical) profile and sheetpile wall. This system minimizes the seabed footprint and overall gravel requirements as well as the need for long-term maintenance. The slope protection may provide substrate for population by kelp and other Boulder Patch organisms.
- Process modules on LDPI will employ a fit-for-purpose design that matches equipment sizing and emissions sources to the reservoir and production needs of the Liberty reservoir.
- The selection of the routing of the onshore pipeline minimizes impacts to water resources and coastal erosion, and avoids areas of known archaeological sensitivity.
- The process design philosophy of using proven, off-the-shelf designs results in minimal operational staffing to operate and maintain equipment. The smaller staff size reduces logistical support needs and, therefore, environmental impacts related to logistics.
- Ocean discharge of wastewaters will be minimized. Drilling muds will not be discharged but will be stored on site and disposed via injection when the disposal well is operational. Wastewater from LDPI sewage treatment and potable water plants will also be discharged to the waste disposal well when the well is operational. Temporary and contingency discharge of wastewater under NPDES will be required when the waste disposal well is not available.

- The waste disposal well will be the first well drilled and completed to facilitate waste water injection instead of discharge.
- Optimization of the project gravel needs and construction schedule minimizes the size of gravel pit needed and length of time it is operated.

In addition to proposed design parameters and mitigation measures, HAK will comply with mitigation stipulated in the BOEM Liberty Development Record of Decision and in permits for project development.

13.3 Mitigation by Resource

Following are examples of the types of mitigation incorporated into the Liberty Development by environmental resource of particular concern, with reference to the related discussion of impacts in the EIA for additional information. A more detailed description of mitigation to reduce impacts on all major environmental resources is provided in the Section 5 of the EIA (Appendix A).

Note that some measures avoid or reduce impacts to more than one resource (e.g., island armoring protects water quality, benthic communities, and fish), and are listed in more than one subsection to show the extent of environmental protection provided.

13.3.1 Physical Oceanography and Coastal Processes

There is an extensive meteorological database from the Prudhoe Bay area and 20 years of tidal gauge data to support project design with respect to oceanographic parameters. Oceanographic conditions (bathymetry, waves, storm surge, sea ice, strudel scour, etc.) in Stefansson Sound that affect the design basis for the project (mainly LDPI and pipeline) are summarized in EIA Section 3.2.

Oceanographic data have been collected in the Beaufort Sea for over 30 years, providing a sound database for engineering design. Recent Beaufort Sea oil and gas developments, including Endicott (1985), Northstar (2001), Oooguruk (2006), and Nikaitchuq (2008), provide a sound engineering design basis that will be incorporated into the design of LDPI.

Project concerns about oceanographic disturbance generally focus on disturbing currents in the project area. The Liberty Project's use of a sound, conservative design, based upon available and site-specific data and application of lessons learned from other Beaufort Sea projects will provide substantial environmental mitigation of oceanographic impacts.

Mitigation Measures

The project components have been sited with the following design considerations:

- The LDPI is setback from the Boulder Patch to minimize the potential for oceanographic current changes affecting the Boulder Patch.
- The LDPI is located beyond the 10-ft isobath, which avoids disturbing the ocean current in important summer fish habitat.
- The LDPI is located well away from the coastline (approximately 5.6 miles) and Endicott causeway (approximately 7 miles), to avoid constricting normal current patterns.
- The LDPI is smaller than most barrier islands (about ¼ the size of the SDI), minimizing oceanographic current disturbance.
- The LDPI is very small compared to the approximately 170,400-acre coastal lagoon bounded by Tigvariak Island, the offshore barrier islands, and Cross Island. The approximately 20-acre LDPI will cover less than 0.01% of this lagoon area. The small size relative to the overall current

patterns in these bodies of water greatly minimizes any potential effect of the general oceanographic current patterns.
- The pipeline bundle will be sufficiently buried to avoid impacts from natural loading conditions such as ice gouges.
- Pipeline trench backfill mound would be monitored to confirm return to sea floor level.

13.3.2 Geology

This section addresses geology (reservoir geology and shallow hazards) and permafrost. In addition to seismic studies and marine hazard surveys, six exploratory wells have been drilled in the Liberty Reservoir area, and extensive drilling has occurred at the Endicott oil field approximately 7 miles to the west. This provides a detailed description and understanding of the marine geology, shallow hazards, reservoir geology, and permafrost. In addition, drilling and producing oil in the Arctic for over 30 years has created a vast knowledge of permafrost and the design, construction, and operations basis for protecting permafrost. Additional information is provided in EIA Section 4.1.3.

Project impact concerns on the area's geology include safely penetrating through the geological strata above the reservoir and then into the reservoir, encountering shallow hazards (gas pockets, pipelines, etc.), or creating hazards (submarine pipelines, cables, etc.). Shallow hazards and other subsurface geology issues are discussed in Section 4 of the DPP, and are not addressed again here. Permafrost thawing can cause mechanical integrity issues and lead to impacting maintenance or repairs, and related mitigation is summarized below.

Mitigation Measures (Permafrost)

HAK will apply the extensive knowledge base acquired from building and operating North Slope facilities on permafrost to the design, construction, and operations of Liberty Development.

- Land-Based Design
  - LDPI, gravel pads, and gravel mine site are all designed to manage the risk of permafrost thaw. LDPI will be a gravel island and small gravel pads will be created onshore at the junction with the Badami pipeline and at the Badami ice road crossing location. Gravel roads and pads have been used on the North Slope for over 30 years to prevent thaw subsidence.
  - Heated facilities will be designed to preserve permafrost using proven methods such as elevation above the gravel on pilings or insulated floors to minimize building heat transmission to the permafrost.
  - Thermo-siphons will be installed where needed to prevent thaw subsidence.
- Pipeline Design, Installation, and Operation
  - Geotechnical borings have been collected along the pipeline corridor to provide information on the presence of thaw-sensitive versus stable permafrost.
  - Permafrost characteristics of the pipeline route are incorporated into computer modeling to determine pipeline design that will minimize the impact from permafrost below the buried pipeline.
  - Modeling is used to determine the most effective means of preventing unwanted permafrost changes, including insulation design and heat transfer within the pipeline.

13.3.3 Air Quality

The air quality discussion in EIA Section 4.1.4 uses meteorological data models and ambient air data to evaluate current and potential air quality conditions, as well as potential impacts to air quality that may result from the proposed project. Potential project impacts include degrading air quality.

Mitigation Measures

HAK has selected a development option that allows the installation of up-to-date emissions sources rather than the use of older, less efficient emission units at existing facilities for processing.

Air quality permitting requirements for oil and gas projects on the North Slope are very prescriptive at the state (ADEC – program delegated by EPA) and federal (BOEM – OCS) levels as well as the modeling protocols, ambient data used, and pollutant thresholds triggered for Prevention of Significant Deterioration and best available control technology (BACT). Requirements may include emission controls. The applicant has some flexibility in proposing BACT, operational restrictions, and other ways to meet regulated emission limits as well as the overall development strategy. As a result, the identification of specific mitigation measures regarding air quality ultimately depends upon a lengthy iterative modeling process, vendor consultations, and BACT analyses.

13.3.4 Acoustic Environment

Information on the acoustic environment noise propagation in the nearshore is provided in EIA Section 3.5, and an assessment of the potential environmental consequences of noise from the project and acoustic effects on marine mammals is provided in EIA Sections 4.1.5.1 and 4.1.8.1, respectively.

One of the important environmental concerns of Liberty Development is the impact of project noise, particularly underwater noise transmission, on marine mammals in the project area including seals (several species) and whales. Bowheads are of particular concern due to their importance for subsistence.

Mitigation Measures

A preliminary list of mitigation measures, focusing on minimizing disturbance from project noise to marine mammals, includes:

- Winter construction noise from the pipeline installation and gravel placement for the island (bowhead whales will be absent but ringed seals will be present in the project area).
- Managing the potential for acoustic disturbance by vessels with a strategy that includes choice of vessel route, timing of vessel traffic, reduction of vessel speed, and operational procedures to maintain appropriate distance.
- Scheduling impact pile driving to avoid or minimize effects on fall bowhead migration and subsistence hunting.

13.3.5 Water Quality

This section includes a discussion of mitigation measures to reduce potential impacts to water quality in both freshwater and marine environments. A discussion of freshwater and marine water quality can be found in EIA Section 4.1.6. Concerns about project impacts to water quality relate to the potential to discharge or create pollutants and introduce them to a waterbody. Liberty Development will need to discharge camp wastewater until the disposal well is operational and STP effluent for the life of the project. Construction of LDPI, pipeline installation, gravel mine development and hauling all have the potential to introduce TSS to waterbodies. Fuel transfers over water have the potential to create small spills.

Mitigation Measures

- HAK will not discharge drilling waste to the land or waters in the Alaskan Arctic.
- HAK has included a number of mitigation measures in its design, construction, and operations of Liberty to minimize potential for TSS generation and related impacts. These include:
    - LDPI will be located in water depth of approximately 19 feet, inshore and east of the main mapped areas of Boulder Patch. This location was selected for optimal reservoir development and to minimize direct long term impacts (coverage) and short term impacts (increase in TSS) to the Boulder Patch.
    - Selected pipeline route corridor that minimizes direct impacts to the Boulder Patch, as mapped.
- Gravel construction will be conducted in winter from the sea ice when most wildlife is absent from the project area. Ocean currents (under the ice) will be at a minimum, thus limiting the entrainment and transport of TSS away from the island. Winter construction will also minimize the excavation required.
- Construction practices related to handling material excavated from the pipeline trench will seek to minimize the time that excavated material will be temporarily staged on the sea ice surface to minimize the backfill of frozen soils.
- LDPI and onshore gravel pads will be designed to manage runoff.
- The slope protection system, which will extend to the seabed with a 3:1 (vertical to horizontal) slope, essentially eliminates the potential for entrainment of TSS into the water column after installation.
- The sheetpile wall around the island (except the dock and ramps) reduces overall gravel quantities needed for the island.
- Installation of the slope protection in the summer following gravel placement will be prioritized to protect the east slopes of the island most prone to impacts from the predominant easterly storms and wave run up.
- Drilling muds, which can create TSS, will not be discharged. They will be stored until the waste disposal well is operational, and then injected for disposal or hauled off site.
- Mining operations will only occur in winter, minimizing the potential for operations to introduce TSS to waterbodies.

Other potential pollutants will be controlled to minimize their introduction to the waters of Stefansson Sound, including:

- HAK will apply for an NPDES permit for temporary domestic wastewater discharges until the waste disposal well is in operation and when backhaul of wastewater is infeasible (and also as a contingency if the disposal well is unavailable). Such NPDES permits specify treatment requirements, effluent limitations, monitoring, and compliance with a Best Management Practices (BMP) Plan.
- The waste disposal well will be the first well drilled and constructed on LDPI, minimizing the time camp wastewater must be discharged.
- Once operational, camp wastewaters will be injected unless the waste disposal well is not operating or otherwise unavailable.
- Produced water will be separated from the oil and gas on the LDPI and will be used for oil recovery, eliminating the need to discharge produced waters.
- The STP discharge will consist primarily of slightly warmed seawater, with a higher concentration of TSS (all from the Beaufort Sea's natural TSS materials) and minor amounts of total residual chlorine. The potential for the STP discharge to impact the Beaufort Sea has been

monitored extensively at the Prudhoe Bay and Endicott STPs. All impacts were found to be minor to negligible.
- HAK will have strict control over what chemicals can be brought on site. Less hazardous chemicals are chosen when there is an option for substitution.
- HAK will implement strict waste management practices (e.g., waste segregation and designation of dedicated temporary storage systems, waste minimization, etc.), which prevent waste from coming in contact with snow or rainwater.
- HAK will implement strict practices of using drip pads beneath fuel transfers and engines to prevent drips or spills from contacting water or wetlands.

13.3.6 Benthic Communities

Mitigation measures for protection of macrofaunal communities, infaunal communities and flora (algae), including species in the Boulder Patch, are described below.

The key benthic alga in the Boulder Patch is *Laminaria solidungula*, with this kelp community existing at the extreme range of its distribution. Impacts to light through turbidity can impact *Laminaria solidungula* by decreasing photosynthetic rate. This could lead to benthic community impacts since *Laminaria solidungula* produces a significant amount of biomass for the community. Water pollution also has the potential to change growth rate in benthic communities. Additional information, including an in-depth analysis of effects of TSS, is included in EIA Section 4.1.7.

Mitigation Measures

Several mitigation measures in LDPI design, construction, and operation minimize potential impacts to the Boulder Patch. These include mitigations to minimize impacts to oceanography and water quality, such as:

- LDPI and pipeline route location to minimize direct disturbance and sedimentation from construction.
- LDPI and pipeline design to minimize size and footprint impacts.
- Island armoring to reduce erosion.
- The expectation that lower portions of the armor at LDPI may serve as hard bottom habitat that is likely to attract Boulder Patch community colonization.
- Winter construction that provides a stable work platform (ice), with reduced water turbulence and currents
- Winter construction avoids the time when the Boulder Patch needs clearer water to fix carbon by photosynthesis (during the Arctic summer).

13.3.7 Marine Mammals and Acoustic Environment

Marine mammals that would most likely be present in the summer are polar bears, bearded seals, ringed seals, and whales. In the winter, the two species expected to be present are polar bear and ringed seals.

Marine mammals can be disturbed by vessel traffic, noise, and human presence. Disturbance can vary from fatalities for vessel-marine mammal collisions to altering movement and feeding behavior. Marine mammals can be disturbed by loud acoustical signals. Potential impacts to marine mammals are described more fully in EIA Sections 4.1.8 (non-ESA listed) and 4.1.12 (ESA listed).

Mitigation Measures

The following mitigation measures avoid or minimize impacts to marine mammals:

- The project is located inshore of the barrier islands and inshore of the main fall migration path of the bowhead.
- The principal construction activities—island gravel laying and pipeline installation—are scheduled to occur in the winter when whales are not present.
- As agreed to on similar North Slope projects, unmitigatable impact pile driving at LDPI that place sounds in the water above 120 decibels (dB) will not be conducted during the bowhead whale migration in the project area – late August through September.
- Barging and other support marine traffic to LDPI will utilize routes in relatively shallow water inshore of the barrier islands and the main migration path of the bowhead.
- Operational procedures that minimize the risk of contact and noise generation will be in place for project support vessels in transit during bowhead migration.
- HAK's polar bear interaction plan will be implemented, which includes commitments to survey potential denning habitat for maternal dens (e.g., forward-looking infrared [FLIR], or similar technology, aerial surveillance) along ice road routes to avoid active denning areas. Protection, agency reporting, and a stop work order will occur in the event of the discovery of previously unidentified polar bear dens, unless alternative action is approved by the USFWS.
- The steel sheetpile wall protecting the LDPI work surface will deter access of polar bears to the island work surface.
- Procedures will be in place for approved marine mammal monitors and those licensed to haze and conduct other intentional takes to defend workers.
- Food handling and waste management procedures (to avoid creating attractants) will be in place, such as secure storage of food and proper disposal of chemicals and wastes.
- Training and procedures will be provided to assure safety of worker and animals when working where marine mammals may occur.
- Setback (activity) from active polar bear dens will be 1 mile or as otherwise approved by the USFWS.
- The subsea pipeline route was selected to provide separation from historical polar bear denning site at Point Brower.
- Ice road management (e.g., traffic controls, re-routings, etc.) will control access in areas where marine mammals may be encountered.

HAK will enter into a Conflict Avoidance Agreement with the Alaska Eskimo Whaling Commission (AEWC) and Nuiqsut Whaling Captains' Association to mitigate impacts to subsistence whaling and bowhead; and HAK will consult the Nuiqsut Whaling Captains' Association on specific routes and traffic frequency for Liberty support vessels.

13.3.8 Coastal and Marine Birds

The principal concerns with respect to coastal and marine birds from the Liberty Development relate to: potential collisions with LDPI structures (e.g., towers), particularly during the fall migrations; lighting attraction; impacts of predatory birds (e.g., ravens) on other birds due to nesting opportunities on structures; loss of nesting habitat (e.g., onshore gravel mine site); disturbance from air traffic; and disturbance to molting waterfowl in Stefansson Sound, as described further in EIA Section 4.1.9.

Mitigation Measures

Experience related to these potential impacts has been gained from Northstar and other projects on the North Slope. Mitigation measures may include:

- A lighting plan to minimize the potential for bird strikes.
- Towers and other structure on LDPI designed to reduce opportunities for predatory bird nesting.

- Strict food waste control (e.g., animal-proof dumpsters) to avoid attracting predators.
- Marine traffic procedures to avoid encountering concentrations of molting waterfowl.
- Seasonal air traffic controls (e.g., routing and minimum altitudes) over specific nesting and brooding areas (e.g., Sagavanirktok River Delta, Howe Island).
- Consideration of bird use and wetlands mapping in the vicinity of the onshore gravel mine site and gravel pads to avoid high quality habitat, particularly for spectacled eiders and snow geese.

13.3.9 Fish and Shellfish

Fishes inhabiting the Beaufort Sea and the adjoining coastal plain fall into three groups based on life history and salinity tolerance: (1) marine fish that complete their entire life cycle in the marine environment; (2) anadromous and amphidromous fish that migrate between fresh water and marine or brackish waters at some stage of their life cycle; and (3) freshwater fish that are limited primarily to freshwater habitats. Marine fish (arctic cod and fourhorn sculpin) combined with four anadromous fish (arctic cisco, least cisco, Dolly Varden, and broad whitefish) account for most of the total nearshore community. Fish fauna in the Liberty area vary greatly from summer to winter. During the winter the anadromous fish are not present, and fish habitat from about the 6-foot isobath shoreward is not present due to land and bottomfast ice.

Projects in the marine environment affect fish by exchanging soft-bottom habitat for gravel island edge habitat. If ocean currents are disrupted and the pattern of brackish water changes, anadromous and amphidromous fish movements and access to food may be altered. Water pollution has the potential to make polluted areas more attractive or less attractive to fish. Potential impacts to fish are further discussed in EIA Section 4.1.10.

Mitigation Measures

Several mitigation measures in LDPI design, construction, and operation minimize potential impact to the Stefansson sound fish community. These include measures that minimize impacts to the oceanography and water quality including:

- LDPI and pipeline location to avoid impact to habitat and alteration of ocean currents.
- LDPI design to minimize size and footprint, decreasing impacts to fish habitat.
- Seawater intake structures designed to prevent fish entrainment.
- Island armoring to reduce erosion and the spread of silt or gravel over fish habitat.
- Winter construction with fewer fish species present and low water currents, which reduce TSS distribution.

13.3.10 Vegetation Wetlands and Terrestrial Mammals

This section contains information on vegetation, wetlands, and terrestrial mammals. Detailed information on these resources is provided in EIA Section 3.11, and potential impacts from the proposed project are discussed in EIA Section 4.1.11. Species of terrestrial mammals that are present vary greatly from winter to summer in the Arctic. In the winter only red and arctic fox are typically active. Grizzly bears are hibernating. Caribou migrate into the coastal areas in summer. Most Liberty Development facilities, construction activities, and operations are located offshore. Further, most construction will be conducted in winter when many terrestrial mammal species are not expected to be in the Liberty Development area, including caribou.

The proposed gravel mine site in the vicinity of the Kadleroshilik River and the onshore elevated pipeline and associated pads are the only project components with expected impacts to tundra wetlands. Access to the mine site will be via onshore and offshore ice roads (no gravel road is planned). It is not possible to avoid impacts to the tundra wetlands from mining at the proposed mine site. There are no existing gravel sources within an economical hauling distance and no upland gravel sources near the project.

Access to the onshore pipeline will also be via ice roads, and no gravel access road is planned. The location of the gravel pad at the Badami ice road crossing will be sited to avoid higher value wetland types to the extent feasible. The gavel pads will be minimal in size, reducing impacts to wetlands and terrestrial mammals. The onshore pipeline will be placed on vertical support members (VSMs) and elevated approximately 7 feet above tundra after daylighting, allowing free passage of terrestrial mammals and reducing impacts to tundra.

Mitigation Measures

Mitigation measures in LDPI design, construction, and operation features that reduce wetlands and terrestrial wildlife impacts include:

- Wetlands mapping conducted in the vicinity of candidate mine sites and gravel pad sites to avoid higher value wetland types to the extent feasible.
- Winter construction that avoids conflict with summer migrants, the majority of animals that utilize the North Slope.
- Controlled access and strict anti-hunting, anti-harassment, and anti-feeding policies to restrict impacts during summer.
- No overland access to LDPI in summer (it is surrounded by water).
- Implementation of North Slope BMPs to provide long-term habitat enhancement by converting the former mine site into a water resource for fish and wildlife.
- Elevation of the pipeline onshore approximately 7 feet to reduce impediments to terrestrial mammals.

13.3.11 Threatened and Endangered Species

Threatened and Endangered Species (TES), including Candidate species, likely to occur in the project are described in EIA Section 3.12. They include one species of marine birds (spectacled eider) and three marine mammals (polar bear, ringed seal, and bowhead whale). Other TES have the potential to occur but are typically outside their normal range and not likely to occur (Steller's eider, Pacific walrus, and humpback whale). Concerns about impact to these species include disturbance through noise; human presence; collision with structures, vehicle, or vessels; alteration of predator-prey balances; and habitat changes. Potential impacts to TES are described in EIA Section 4.1.12.

Mitigation Measures

Several mitigation measures in LDPI design, construction, and operation that minimize potential impact to the project area also serve as measures that minimize impact to TES. These mitigations are described in the following EIA sections: 5.2.8 Marine Mammals, 5.2.9 Coastal and Marine Birds, and 5.2.11 Vegetation Wetlands and Terrestrial Mammals. These measures may include:

- Siting for LDPI, the gravel mine site, pipeline, gravel pads, ice road, vessel, and aircraft routes to avoid or minimize potential to disturb TES.
- Construction timing to lessen the potential to disturb TES. Winter construction avoids the time period when the TES birds and whales are present.
- Foregoing sealift of modules to avoid conflict with TES by designing truckable modules.
- Enhanced detection and surveys of TES and TES habitat (e.g., route survey for den habitat).
- Procedures and worker training to reduce impacts in areas where TES may be encountered.

- Food handling and waste management procedures to avoid creating attractants (i.e., secure storage of food, chemicals, and wastes).
- Ice road management (e.g., traffic controls, re-routings) to control access to areas where TES may be encountered.
- Lighting plans to minimize the potential for bird strikes.
- Towers and other structure on LDPI designed to reduce opportunities for predatory bird nesting.
- Wetlands mapping in the vicinity of the onshore gravel mine site and gravel pads to avoid impacts to high quality habitat.

13.3.12 Archaeological Resources

Archaeological surveys of marine and onshore (ice road and potential mine site) project locations have been conducted. Archaeological surveys of the onshore ice roads and gravel pad associated with the pipeline will be conducted. The results of the marine survey and onshore archaeological surveys will be provided to BOEM and the State Historic Preservation Office.

No archaeological resources were identified that would be impacted by the Liberty Development, including ice road routes (onshore and offshore), gravel mine site, and offshore pipeline and LDPI. In the event of an unanticipated archaeological discovery, HAK will develop an Archaeological Discovery Plan prior to construction. The Plan will include monitoring policies and procedures, staffing requirements, training and preconstruction briefing requirements, communication protocols, and work stoppage protocols. The Plan will provide for discovery, documentation, and notification procedures; specific protocols related to the discovery of human remains; prohibited activities (including removal of cultural materials without consultation);, confidentiality requirements; and contact information for HAK, Agency, and Tribal Officials.

13.3.13 Sociocultural Resources – Subsistence

This section discusses the mitigation measures for potential subsistence impacts. EIA Section 3.16.2 describes subsistence issues of the project area. Liberty is primarily offshore, and the only onshore components are the single season gravel mine and elevated pipeline with associated two small gravel pads. The closest communities are Nuiqsut and Kaktovik, approximately over 80 and 90 miles away respectively. The nearest infrastructure and population is the North Slope oil production area. Subsistence activities in the Liberty Development area are mainly limited to the hunting of bowhead, as reported in EIA Section 3.16.2. Impacts to bowhead are discussed in EIA Section 4.1.8 and 4.1.12. Impact to subsistence activity is discussed in EIA Section 4.1.16.2.

HAK will take measures to avoid impacts from vessel traffic (marine and aircraft) to the Cross Island bowhead whale hunt. HAK has consulted with subsistence users, including potentially affected whaling captains' associations and the Alaska Eskimo Whaling Commission (AEWC) to obtain input about how to carry out proposed activities in a manner to avoid impacts to the hunt. In addition, HAK plans to sign Conflict Avoidance Agreements (CAAs) between Industry Participants and the AEWC during Liberty construction, operation, and production activities. The CAA identifies measures to be taken to mitigate impacts from oil and gas operations on the subsistence bowhead whale hunt, including limitations on activities during the whale hunt and using agreed upon communication protocol.

Mitigation Measures

Project-specific subsistence mitigation measures will be developed during consultations with the NSB, AEWC, and community of Nuiqsut. These may include:

- Describe criteria for island siting and design with Nuiqsut Whaling Captains' Association and consult on supporting marine traffic (routes, frequency, schedule).

- Employ local subsistence representatives during appropriate project phases.
- Execute and implement a Conflict Avoidance Agreement, which may include supporting communications centers during the whaling season and operational procedures, among other mitigation measures.
- Employ personnel skilled at protected species identification on support vessels when warranted, to prevent vessel-marine mammal interaction during the open-water season.
- Establish preferred marine routes for transport of facilities and supplies to LDPI.
- Establish minimum aircraft altitudes and routes for helicopters and other support aircraft to avoid disturbing bowhead whales and other subsistence resources, consistent with safety requirements and weather considerations.
- Train HAK and contract personnel on the importance of subsistence and measures to avoid conflicts.

14 OIL SPILL RESPONSE PLAN

This section summarizes key elements of the Liberty Oil Spill Response Plan (OSRP), which has been submitted to the U.S. Department of the Interior (USDOI) in conjunction with this DPP, meeting the requirements of 30 CFR 550.250(a)(1), 30 CFR 254 Subpart B, and NTL No. 2012-N06. The Liberty OSRP describes the steps HAK will take to prevent, prepare for, and respond to potential oil spills, including a description of the strategies and tactics to respond to a Worst Case Discharge (WCD).

In addition to a summary of what is detailed in the OSRP, the section below and Section 8.7 describe how HAK intends to prevent a spill resulting from the uncontrolled release of hydrocarbons from a flowing well, commonly referred to as a blowout. If a blowout were to occur, a WCD response will include ignition of the oil plume and methane gas vapor cloud. Well ignition is a common practice for source control specialists, allowing safe access for responders to stop the flow via traditional source control methods (e.g., well capping) without the threat of accidental ignition of the surrounding vapor cloud. Subsequently, the volume of oil to be recovered from the environment using traditional mechanical or non-mechanical methods is significantly reduced.

The discussion below has been broken into three components: prevention, preparedness, and response with additional information provided on waste management and wildlife protection procedures.

14.1 Blowout Prevention

It is HAK's first priority to prevent a blowout from happening. Prevention measures include:

- A management system that stresses accountability to best practices
- Proper drilling fluids design criteria and procedures
- Engineered casing and cementing procedures
- Fit for purpose diverter system equipment specifications and procedures
- Properly designed blowout preventer with engineered and tested blowout preventer systems
- Well completion procedures and equipment selection that are designed for the anticipated conditions
- Proper safety systems while drilling
- A well control and production safety training system that is properly administrated

There is substantial experience with drilling wells in this area, including four exploration wells into the Liberty Reservoir, more than 80 wells drilled in the nearby Endicott Reservoir, and over 5,000 wells drilled on the North Slope. The knowledge and procedures developed from this experience greatly reduce the risk of a blowout.

Blowout preventer equipment, measures, and procedures are fundamental to the drilling program of any development. The measures that HAK will implement to prevent a blowout from occurring are described in detail in Section 8.7 of the Drilling section of this DPP.

14.1.1 Prevention of a Pipeline Spill

The pipeline between LDPI and the Badami pipeline will fall under federal and state jurisdiction. Mass balance and pressure monitoring leak detection systems will be incorporated into the export pipeline design. These systems work in parallel and provide redundant measurements to insure accuracy. It is expected that under optimal conditions, these systems would be capable of detecting a leak of 1% of volumetric flow in the pipeline over a 24-hour period.

Pipeline flow at the Liberty pipeline, as well as all HAK crude oil pipelines on the North Slope, can be stopped within 1 hour after verified detection of a spill, as required by 18 AAC 75.055(b). If the leak detection system alarms, the control board operator proceeds through a series of steps to determine the cause of the alarm. Emergency shutdown of the crude oil transmission pipeline can be activated at the control room. Pipeline emergency shutdown will result in a complete pipeline shutdown. See further descriptions of the pipeline systems in Section 7.

HAK will conduct long-term monitoring and surveillance of the pipeline system to assure mechanical and operational integrity and as required by SPCO and BSEE. The purpose of this monitoring and surveillance program will be to assure design integrity and to detect potential problems. The program will generally include visual inspections, aerial surveillance, and pig inspections. The program is detailed in Section 7-10.

14.1.2 Prevention via Training

HAK employees and contractors with job duties directly involving inspection, maintenance or operation of oil storage and transfer equipment on the Liberty leases will be trained to successfully fulfill their duties in spill prevention and spill response. This training provides instruction in state and federal oil spill requirements applicable to personnel and regulated equipment on the North Slope. Topics include the following: spill prevention regulations, training requirements, inspections recordkeeping, truck-to-tank transfers, well cellars, tank design and inspections, secondary containments design and inspection, crude oil transmission pipeline leak detection, and inspections of flow lines and facility oil piping. The training program involves a list of HAK personnel by name and job who are authorized to inspect, maintain, and operate regulated oil tanks and truck-to-tank transfer equipment, and their training histories.

Facility personnel also receive training on the SEMS. The training outlines how to report oil spills. The HAK Liberty SEMS promotes continual improvement in HSE performance. The system uses direct input from technical specialists and field personnel, and information developed through routine loss control and incident investigations, to minimize the potential recurrence for incidents which promote continuous EH&S performance.

Environmental communications and bulletins are regularly distributed to ensure specific safety and environmental issues are communicated. Supervisors shall discuss environmental communications and bulletins with their crews during daily and weekly safety meetings.

14.2 Preparedness

Section 8.7 and the previous section describe preventative measures that will be taken to prevent a blowout or spill from occurring. Although BOEM has stated: *"In general, historical data show that loss of well control events resulting in oil spills are infrequent and that those resulting in large accidental oil spills are even rarer events"* (BOEM 2012 p. 4-78), there is a small but finite chance that such an event could happen. Therefore, there are preparedness measures that will be implemented to insure an effective response. LDPI has been designed to facilitate rapid source control in all seasons.

The Liberty development project has incorporated spill preparedness into the project design and will continue preparedness activities throughout the project life. Preparedness maximizes the effectiveness of a successful response, should it be required. The design includes:

- Well spacing was set at to 15 feet to allow heavy equipment to access and facilitate excavation around the affected well, and to minimize affects to neighboring wells.
- The well row is aligned parallel to the prevailing wind to allow access to a side least affected by spill/fire.
- A large laydown area north of the well row is provided to allow room for blowout responders to

clear the area around the well and to facilitate oil removal from the work area.

- The island's long axis and orientation is perpendicular to prevailing wind, which facilitates:
  - Relief drilling rig and drilling facilities located outside of oil spill plume and heat radiation zone
  - A spill response staging area located outside of oil spill plume and heat radiation zone, and
  - A large space available for permanent storage of oil spill response equipment.
- The 30-foot-perimeter road inside seawall and 60-foot-wide shelf outside of seawall and shelf equipment ramps allows:
  - Responder equipment access to blowout well from any side, inside or outside of the seawall,
  - Ice road access to multiple points on the island, and
  - Space for additional staging area.

The oil-bearing reservoir will only be drilled in open water and solid ice (winter) seasons when response is greatly facilitated.

14.2.1 Response Management Preparedness

HAK's response organization is consistent and compatible with the Alaska Incident Management System (AIMS) as well as the National Incident Management System (NIMS). HAK team leaders and managers serve the roles of Qualified Individual (QI) as well as Incident Commander (IC). QIs/ICs have the authority to obligate funds on behalf of HAK, implement response actions, including source control, and to notify federal officials and response organizations as applicable.

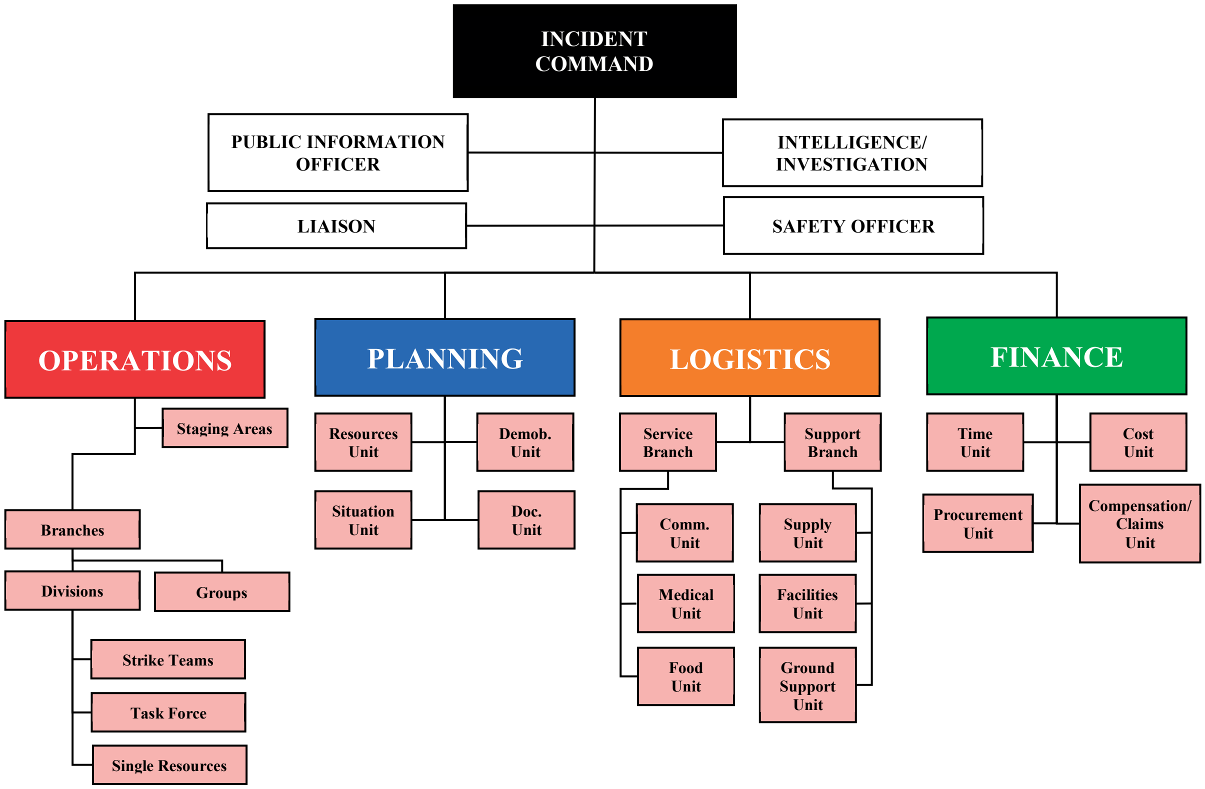
The Incident Management Team (IMT) includes the Command Staff comprised of an IC, Deputy IC, Safety Officer, Public Information Officer, Liaison Officer and Legal Officer, as well as the General Staff comprised of four Section Chiefs (Figure 14-1). During an incident, the IC is initially responsible for each function until he/she assigns appropriate personnel into Command or General Staff positions. Each position shown in Figure 14-1 has assigned roles and responsibilities. Weekly IMT rosters provide a list of personnel available 24 hours a day on the North Slope, their associated IMT role and contact information. These rosters are maintained within an internal database. Training for IMT members responsible for spill response management and source control decision-making and coordination can be found in Appendix B of the OSRP.

HAK is a member of Alaska Clean Seas (ACS), which is an USCG-approved oil spill removal organization (OSRO). ACS is supplemented by the North Slope Spill Response Team (NSSRT), which consists of workers available on a 24-hour basis who serve as emergency spill response personnel. Each team member is required to have initial emergency response training and annual refresher training, which meets or exceeds the requirements in the HAZWOPER regulations, 29 CFR 1910.120(q). Annual requirements for HAZWOPER refreshers, medical physicals, and respiratory fit tests are tracked by ACS through weekly reports from the database. The NSSRT training program is provided to responders from all production units on the North Slope.

14.2.2 Spill Response Operations Center and Forward Operating Bases

The location of the spill response operations center (also known as the Incident Command Post [ICP]) depends on the location, type, and size of an incident. The ICP for an oil spill from LDPI would be located on the North Slope and/or Anchorage headquarters. Mobile command centers are also available for additional field operations support or as forward operating bases.

Figure 14-1. Incident Command System Organization Chart



14.2.3 Pre-Staged Response Equipment

Equipment would be pre-staged where effective at LDPI, SDI, the Endicott causeway, and along the shoreline of Foggy Island Bay. ACS will maintain pre-staged equipment during the open-water season as environmental (and regulatory) conditions allow.

14.2.4 Oil Spill Detection and Tracking

In the event of a release of oil, determining the location and predicting the movement of the spilled oil will aid in directing initial planning and cleanup operations. HAK will use established tactics to locate spills and will have remote sensing capabilities. The Liberty development is located close to shore within Foggy Island Bay and therefore the initial spill location, and predicting spill movement is easier than if the spill occurred further offshore.

For a winter spill event, initial delineation of the oil on top of the ice is straight forward. Spill delineation will be conducted visually, and the spill area will be staked out. Blowing snow can cover spilled oil, so delineation will be conducted as soon as possible following an event. Oil under the sea ice will be located either by drilling holes through the ice or by using remote sensing techniques such as ground-penetrating radar (refer to ACS *Technical Manual* Tactics T-2 and T-3). ACS also has an inventory of 24 ice beacons that can be deployed by teams using helicopters, vessels, and vehicles. The beacon system consists of a global positioning system (GPS) receiver, antenna, and beacon equipped with a transmitter. Beacon positions are transmitted to the Command Center via e-mail and incorporated into the common operating picture (ACS Tactic T-4A: *Discharge Tracking in Ice*).

Spill location and tracking can be conducted using aircraft outfitted with forward-looking infrared (FLIR) sensors that detect temperature differences between the oil and the surrounding environment. The aircraft provides radio reports and FLIR video images. The thicker areas of oil within an oil slick emit more thermal radiation than the surrounding water and show up in the image as white or hot spots. The FLIR system works day or night. The data is superimposed over existing maps in Geographic Information System (GIS) format.

14.2.5 Waste Management Capabilities

The oil discharged from a potential WCD well control event would be classified as *exemp*t. This term is used to describe waste materials that are not regulated as hazardous waste under the Resource Conservation and Recovery Act (RCRA). Exemptions are based on the source of the waste, not its properties or composition.

In the event of a WCD, the Unified Command will determine the appropriate management method based upon the specific waste stream. The preferred management option for recovered oil is to recycle it back into the production stream at a nearby process facility. The recovered fluids would be processed at Endicott by one of the following methods:

- Some of the recovered fluids would be transferred from mini-barges to the MPI snowmelt tank. These fluids would be transferred by vacuum truck or pumps and hoses in a series. Once the recovered fluids were in the snowmelt tank, they could be processed and sent to the production pipeline system.
- Some recovered fluids would be offloaded by a large (12,000-barrel) barge. The barge would be tied off at the MPI dock or near, and probably need a dedicated pipe system into the processing plant.

If the material is not suitable for recycling, it would be disposed of downhole in one of several disposal wells on the North Slope. These are listed in Table 14-1 and Table 14-2 below. Class I is regulated by EPA and allows injection of industrial waste. Class II is regulated by the Alaska Oil and Gas Conservation Commission and is limited to oil production waste. Recovered fluids could also be reused downhole at injection wells as a part of enhanced oil recovery (EOR) process.

Table 14-1. Class I Disposal Facilities

LOCATION	FACILITY	OFFLOADING LOCATION (TRUCK)
Greater Prudhoe Bay Area (requires Ballot Agreement)	Pad 3	Pad 3 injection skid
	G&I (Grind and Inject) Facility (DS-4)	DS-4 injection skid
Milne Point Unit	MPU Class I Well B-50	B-50 injection skid

Table 14-2. Class II Disposal Facilities (Liquids)

LOCATION	FACILITY	OFFLOADING LOCATION (TRUCK)
Kuparuk River Unit (requires Ballot Agreement)	CPF-1 oily waste disposal facility	CPF-1 oily waste injection skid
Greater Prudhoe Bay Area (requires Ballot Agreement)	Flow Station 1	Injection skid
	GC 2	Dirty water tank
Endicott	Well P-18/2-02	2-02 injection skid

If recovered residue (or another material) could not be disposed on the North Slope, HAK would use an intermodal approach (truck, rail, and/or barge) to dispose of waste to the lower 48 states. For example, roll-on-roll-off containers could be hauled down the Dalton Highway to an Alaska Railroad Corporation (ARRC) facility (nearest one is Fairbanks) where the cars are then stacked and staged at either Whittier or the Port of Anchorage for final transport to the contiguous United States. Waste management options are detailed in the LDPI OSRP.

14.3 WCD Response

The Blowout scenario for the Liberty Development is based on guidelines provided by BOEM and BSEE in Notice to Lessees and Operators (NTL) No. 2015-N01 and NTL No. 2015-N01: Frequently Asked Questions. The worst-case discharge (WCD) rate estimation is based on the current understanding of the Liberty Reservoir and the status of the project. The WCD rate is intended to represent the highest rate of discharge from any well that might be drilled into the reservoir. Because the well locations that are initially proposed in this DPP do not necessarily correspond to the thickest and best rock properties in the reservoir, and because the locations that are proposed may be adjusted once core and log data from actual wells are gathered, analyzed, and re-incorporated back into the geologic model, a "virtual well" is chosen to represent the highest potential well. A numerical model (reservoir simulator) was used to calculate the WCD rate. The WCD estimate was modeled using a gridded numerical model and a set of hydrologic correlations; the reservoir simulator that was used in an industry accepted program called IMEX, developed and supported by Computer Modeling Group Ltd. (CMG). The modeling input and assumptions are provided in Appendix G. The model predicted a first day volume of oil and gas as shown in the Table 14-3 below.

Table 14-3. Worst-Case Discharge Characteristics (Based on Modeling Approach and Assumptions)

REQUIRED PREDICTION	UNITS
Estimated WCD flow rate (first day), Oil	91,219 bbl/day
Estimated WCD flow rate, Gas	84,538,512 scf/day
Total volume over 30 days[1]	2.02 MMbbl
Total volume over 90 days[1,2]	4.61 MMbbl

Note:
1. 30 day and 90 day discharge volumes represent the modeled oil discharges only.
2. Estimated time to mobilize a second rig, drill a relief well, and kill the blowout well is 90 days.

Key: bbl = barrel; MMbbl = million barrels; WCD = Worst Case Discharge.

The calculations that were used to arrive at the first day rates shown above were based on the following assumptions:

- The drill string has been removed.

- The surface and intermediate casing strings are set.
- Shoe of the 9-5/8” intermediate casing is just above the reservoir interval
- Bit size used to drill the reservoir section is 8-1/2”
- There is a complete blowout preventer (BOP) systems failure
- The BOP stack are out of the line of flow and not obstructing flow
- Drilling mud is completely removed from wellbore
- These conditions allow open flow to atmospheric pressure
- The open hole does not collapse, restricting flow (i.e., no bridging).
- The entire section (Zone 2) of the reservoir has been penetrated by a slant well
- There is no rig structure overhead that prevents the oil from blowing into the air

The WCD calculated for the Liberty Development is within the ranges that BOEM (2012) terms “An Unexpected Accidental Event and Spill – Catastrophic Discharge Event.” Several factors that BOEM describe as increasing the risk of a blowout (e.g., drilling in frontier vs. mature areas, drilling at greater water depth, operator lack of familiarity with well bore parameters, complication of subsea BOP operation, etc.) are absent at Liberty because it is a drilling island, using land-based drilling techniques with a surface BOP system in a mature, shallow area, with well-understood well bore parameters and knowledge from drilling other wells into the Liberty Reservoir and surrounding area. That being stated, a description of how the scenario could unfold is given below.

- <u>Maximum Duration of Potential WCD</u>. The maximum duration of a potential blowout is difficult to predict as there are multiple complex factors that determine the response period, and these factors vary from blowout to blowout. Boots & Coots has found that most wells are capped in 20 days.
- <u>Potential for the Well to Bridge Over</u>. Mechanical failure/collapse of the borehole in a blowout scenario is influenced by several factors, including in-situ stress, rock strength, and fluid velocities at the sand face. Given the substantial fluid velocities inherent in the WCD, and the scenario as defined where the formation is not supported by a cased and cemented wellbore, it is likely that the borehole may fail/collapse/bridge over within the span of a few days, significantly reducing the outflow rates. However, this WCD scenario does not include any bridging.
- <u>Likelihood of Surface Intervention to Stop the Blowout.</u> It is highly likely that a surface intervention (“well capping”) would be the mechanism to successfully stop a blowout at LDPI. Well capping is the primary mechanism that is deployed to control land well blowouts. Using a surface BOP stack on a gravel island allows for the same equipment and techniques to be used on LDPI. Based on dozens of case studies researched by Boots & Coots, the time it takes to regain control of the well via well capping is expected to be in the range of 10 to 20 days. The WCD has been calculated without considering the likelihood or time to cap the well.
- <u>Availability of Relief Well Drilling Rigs.</u> Several rigs or rig designs have been identified that meet the requirements to drill a relief well on LDPI. The relief well rig would either be under contract or mutual aid agreements would be in place prior to Liberty Drilling.
- <u>Relief Well Rig Constraints.</u> The primary rig package constraint is the need for the rig to be broken down into smaller modules for transport over an ice road or via barge in open water to LDPI.
- <u>Estimated Time to Drill a Relief Well.</u> Rig mobilization time is estimated to range from 10 to 30 days. The duration of the relief well drilling is estimated to be from 30 to 60 days. Total time ranges from 40 to 90 days.

In the event of a WCD, the HAK IMT will implement well ignition as the best available response measure for well control and oil spill response. Ignition of an uncontrolled well allows safe access for responders to stop the flow of the well via traditional source control methods (e.g., capping) without a threat of accidental ignition of the surrounding vapor cloud. This strategy also significantly reduces the volume of oil to be recovered from the environment using traditional mechanical or non-mechanical methods. Well ignition would result in an excess of 90% of the discharged oil being lost to combustion and converted to particulates. Well ignition would be augmented with mechanical recovery and possibly in-situ burning.

The scenarios below demonstrate HAK ability to respond to a WCD during winter, summer, and shoulder seasons. Each scenario outlines mitigation measures that are implemented before drilling and maintained throughout the drilling season. The mitigation measures are followed by response tactics, including mechanical recovery, in-situ burning (ISB), waste management, and wildlife response.

14.3.1 Winter WCD Scenario

In the event of a winter WCD (well blowout), the HAK IMT will implement well ignition as the best available response measure for safety and oil spill response. Mechanical recovery and ISB operations would also be conducted.

14.3.1.1 Winter Trajectory

Once the uncontrolled well is ignited, in excess of 90% of the oil would be combusted and the remaining volume would be soot that would be dispersed mostly downwind. In the winter, the prevailing winds are generally to the southwest and northeast.

Before well ignition, the discharged oil takes the form of an aerial plume extending from the well to the direction of prevailing winds (southwest and northeast). An un-ignited and unobstructed surface well blowout oil distribution can be modeled using ACS Tactics T-6 (based on modeling by SL Ross Environmental Research Ltd. [SL Ross]). The distribution of oil falling from the aerial plume depends upon the height that the oil is propelled and the size of the oil droplets. The gas flow rate controls the plume height and subsequent fallout distribution.

Modeling indicates that prior to ignition, the majority of oil would settle within 2 miles of the discharge site. This area would be landfast ice in mid-winter. Modeling also indicates that before ignition, very small droplets may be created, which can be held aloft by atmospheric turbulence. Ignition destroys the oil and prevents both the settling near the island and very small droplets from becoming airborne.

Prior to well ignition, the discharged oil would have a high viscosity in the colder temperatures. The discharged oil would rapidly stop spreading and gel. The oil's slow evaporation rate indicates it will not lose its light ends as quickly as it would during summer months. Given these properties, including a tendency for this oil to form a waxy skin encapsulating fresher oil within, Liberty oil is particularly amenable to ISB during winter months.

14.3.1.2 Mechanical Recovery

The oil discharged prior to well ignition would be recovered using heavy equipment (i.e., loaders, bulldozers, trimmers, skid steers, dump trucks, and snow machines). Mechanical recovery would be augmented by ISB and manual methods (where only a thin layer or minimal volume of oil is available to recover).

14.3.1.2.1 Mechanical Recovery of Oil-Saturated Snow on Ice

Snow is a highly effective sorbent material for oil and forms a mulch-like mixture that is relatively easily removed. Heavily oiled snow may contain up to 100 gallons of oil per cubic yard at 3.7 gallons of oil per cubic feet of snow. When the ice thickness is greater than 18 inches, heavyweight response teams (with tracked dozers, front-end loaders, backhoes, and dump trucks) would be deployed. Once deployed, response personnel would assess ice competency continuously.

The tracked vehicles make piles of the oil and oiled snow. If heavily oiled snow needs blending to ease recovery, loaders and dozers push nearby lightly oiled snow into the heavily oiled snow area for recovery. Clean snow can also be used for blending.

14.3.1.2.2 Remove Lightly Oiled Snow

Distal portions of the fallout plume receive less oil, resulting in lightly oiled snow. ACS tactics provide options for lightly oiled snow removal, whether mechanical or manual. Task forces use mechanical and manual methods to recover the lightly oiled snow. Shovels, brooms, rakes, and snow blowers collect the snow into small storage assets such as cans, totes, etc. Snow machines with trailers transport the containerized oiled snow to either SDI, the causeway, or another staging point. Loaders then transfer the oiled snow to dump trucks. See ACS Tactics R-1A: *Use of a Snow Blower to Remove Lightly Misted Snow* and R-2: *Manual Recovery of Lightly Oiled Snow*.

Snow fences can be erected on the downwind side of the lightly oiled snow to prevent the wind from dispersing the oiled snow. The fence would be a minimum of 4 feet high and can be double stacked to reach 8 feet high with a minimum of 50% porosity. T-bars, rebar, and other type posts can be used to anchor the fence in place along with wire ties. Snow fences also guard cleaned areas to prevent re-oiling from blowing oiled snow (see ACS Tactic C-19: *Containing Oiled Snow Using Snow Fence*).

14.3.1.2.3 Ice Mining

In the event that oil becomes embedded within the ice, oiled ice can be mined when trimming is inadequate. There are several types of equipment that can be used to break and mine oiled ice (e.g., backhoes, amphibious backhoes, dump trucks, etc.). This tactic can be used in winter and into breakup as long as the ice is thick enough to support the weight of vehicles and heavy equipment. An ice-miner grinds up the ice and deposits it in a pile that can be picked up with a front-end loader and hauled away by dump truck, ACS Tactic R-29: *Ice Mining*.

14.3.1.2.4 Direct Suction

When the ice is thick enough to support heavy machinery, any oil pooled in the pre-constructed trenches, sumps, dikes, or natural depressions can be directly removed via viscous oil pumps and recovered directly into tanker and vacuum trucks. Vacuum trucks typically can pull up to 200 feet radius of the truck in order to ensure viscous oil recovery. See ACS Technical Manual Tactic R-6: *Recovery by Direct Suction*.

Hoses and pumps can also be placed in series to collect oil from further distances. Trash pumps are placed approximately 1,000 feet apart. Liquids are pumped to a storage tank or vacuum trucks. The trash pumps are towed behind an Argo all-terrain vehicle or 4-wheeler. A 4-inch trash pump weighs 825 pounds and has an axle and wheels under its skid mount. An all-terrain vehicle towing a trailer carries the hose. See ACS Tactic R-24: *Hoses and Pumps in Series*. The oil will be directly pumped into tanker trucks, which are comprised of one truck with an attached tank trailer. Steam heat could also be added to facilitate pumping and transfer operations.

14.3.1.2.5 Containment Curtain

A containment curtain can be installed in designated areas to prevent the spreading of oil during a spill. The curtain is a barrier frozen in place, which prevents oil from spreading under the ice pack. The design curtain depth is determined by the distance needed between the oil under the ice and the bottom of the curtain. This depth required varies throughout the year as the ice thickness increases.

The installation of the containment curtain involves cutting a trench through the ice once a safe working ice thickness of 18 inches has been achieved. This can be done through the use of a Ditchwitch trench digger. A small mobile trencher can be mounted on skis and maneuvered using small trailers and snow machines and a small crew. The containment curtain can be lowered though the trench and anchored in place. The containment curtain is made of a robust high-density polyethylene (HDPE) fabric or, alternatively, freezing in plywood or metal barriers can provide additional containment.

14.3.1.3 On-Ice In-Situ Burning

Oil can be burned on snow and ice when the following minimum thicknesses are met:

1. 1 mm (0.08 to 0.12 inch) for fresh crude oil
2. 2 to 5 mm (0.12 to 0.2 inch) for weathered crude

When the ice is between 12 to 18 inches thick, lightweight response teams are deployed. The response teams use snow machines, tracked vehicles, or all-terrain vehicles. Small or thinly oiled areas would be ignited by propane weed burners. Large or heavily oiled areas are ignited using hand-held igniters. Typical equipment and personnel used to support ISB are detailed in the LDPI OSRP.

When the ice is thicker than 18 inches, heavyweight response teams would be deployed using rubber tracked or wide/tracked dozers and front-end loaders to create snow berms and concentrate oil, and act as fire breaks. (Fire breaks are not necessarily needed, as the extent of the burn will be limited by the thickness of the oil). A snow berm is built around the heaviest oiled areas on the ice (ACS Tactic C-1: *Containment Using Snow Berm*). Front-end loaders and Bobcats create berms when the larger front-end loaders or wide-tracked machinery cannot access an area.

When oil is initially spilled on the ice surface and mixed with snow, burning of oiled snow piles can be conducted even throughout the winter season. Depending on the initial concentration of the oil, plowing oiled snow into concentrated piles is an effective tactic to achieve ignition and burning. See ACS Tactic B-5: *Burning Oil Pools on Any Surface*.

Many of the mitigation measures implemented for a winter response also support ISB on ice operations. Pre-digging partial trenches or through-ice slots to direct oil flow to a collection point or freezing in barriers provide additional containment pockets, which may not be accessible for mechanical response assets but yet are still candidates for burn operations. Trenches cut into the oil can allow oil under the ice to float to the surface and be burned. (Refer to ACS Tactic C-11: *Containment on Ice with Trenches and Sumps*.) Ice trenches can be configured in "U" shapes or herringbone patterns to contain oil for burn operations. Ice blocks removed from the trenches would also serve as fire breaks surrounding the pooled oil (ACS Tactic R-13: *Cutting Ice Slots for Recovery*).

Residue is the material remaining on the surface of the ice following ISB operations. Residue would be recovered using established tactics. Residue recovery teams would collect the residue as quickly as possible using mechanical and manual methods. Residue is loaded in totes positioned on snow machines with trailers. Residue may also be collected in oily waste bags that are loaded into front-end loaders or directly into waste bins. Once recovered, residue is transported to staging at SDI or on North Slope pads.

14.3.1.4 Winter Waste Management

In the event of a winter WCD, tracked dozers and skid steers would be used to create berms made with snow and ice in the lagoon between SDI and the causeway. This temporary waste staging area would allow oil spill recovery vehicles to transfer their load rapidly without having to take the time to access the North Slope road system. Recovered oiled snow and ice would be transferred to one of the following locations:

1. Existing lined storage cells (examples include cells on MPI and at Milne Point Unit). Other locations exist in Greater Prudhoe Bay but would require Unit permission to use.
2. Temporary storage would be constructed in accordance with regulations.

The recovered oiled snow and ice would be transferred from these temporary staging areas to disposal sites.

14.3.1.5 Wildlife Response

In the event of a WCD, wildlife responders would work with state, federal, and local agencies to deploy the equipment, expertise, and infrastructure needed to create and sustain an effective wildlife response. Wildlife responders would be supported with airboats, helicopters, snow machines, and/or Rolligons.

A detailed discussion of the wildlife response priorities and tactics is provided in the LDPI OSRP. The response would be consistent with the state Unified Plan, which lists three response strategies to protect wildlife in order of priority:

1. Containment and recovery of oil (as close to the source as possible),
2. Wildlife hazing, and
3. Capture, stabilization, and treatment of oiled wildlife (when necessary).

All marine mammals (polar bears, seals, and whales) are protected by the MMPA, which gives these animals protection under federal law. Some whales and seals are also listed as threatened or endangered under the ESA. Field personnel should report encounters (including sightings) of marine mammals to HAK, Security, or ACS personnel, who will determine the appropriate communications or actions, depending on the situation.

All polar bear sightings, interactions, and known or suspected polar bear dens must be reported to security personnel immediately. This policy applies during a spill response or normal operations. The USFWS requires that sightings of and interactions with all polar bears be reported as soon as possible, but not longer than 24 hours after the occurrence. The USFWS will be the lead agency for polar bear response activities; ADF&G will assist on a case-by-case basis.

Ringed seals could be encountered in the Liberty area year-round. In general, adult male pinnipeds may be too aggressive to safely capture and clean. If a seal, regardless of its age, takes to the water when approached, it should be left alone. If the seal is moribund and does not try to escape when approached, it may be feasible to pick up the animal and attempt treatment.

In the event of a spill response, ACS is permitted to haze terrestrial mammals. ADF&G is responsible for overseeing and providing guidance for ACS hazing personnel and may assist ACS with hazing. The minimum amount of hazing required to move animals away from a spill site will be used.

14.3.2 Summer (Open Water) WCD Response

In the event of a summer WCD (well blowout), the HAK IMT will implement well ignition as the best available response measure for well control and oil spill response. Mechanical recovery and ISB operations would also be conducted.

14.3.2.1 Summer Trajectory

When the well is ignited, the combustion efficiency would be similar to the winter scenario – in excess of 90% of the discharged oil would combust. The discharge plume would extend from the well to the direction of prevailing winds (southwest). In the event of an un-ignited, unobstructed blowout, the SL Ross model would produce a similarly sized plume as the winter scenario.

NOAA's GNOME model can also be used to predict the movement of oil once it lands on the surface of the Beaufort Sea. Using the model in standard mode with regionally specific location files allows responders to predict the movement. As applied to a blowout on a drilling island, the GNOME model treats the discharge as a point source. Figure 14-2 illustrates the oil trajectory at Hour 24 under one set of adverse conditions (i.e., wind out of the east and northeast at 20 knots). Under this wind regime, first landfall of oil would be approximately 6 hours.

In 2000, MMS conducted an oil-spill risk analysis to provide oil spill statistics spanning for 30 days after a spill for the Liberty DPP (MMS 2000b). This modeling report was used as guidance for developing the response options in the OSRP. The conditional probabilities of landfall from a summer release on Day 1 were 1% to 17%.

14.3.2.2 Mechanical Recovery

Discharged oil (prior to well ignition) would be recovered using several systems, including:

1. One oil-spill response barge (OSRB) system,
2. Nearshore skimming vessels with mini-barges,
3. Static collection at Endicott causeway breaches,
4. Shore-based recovery using mini-barges or fast-tanks, and
5. Shoreline recovery

The location of the OSRB would be dependent upon weather. In general it would be located within Foggy Island Bay, upwind of LDPI and in sufficient water depth. It may also be involved in operations support between West Dock, SDI, and LDPI. Skimming vessels, mini-barges, and airboats used in the initial response would be stored at SDI. Mechanical response teams would be prepared to commence response operations within 4 hours of notice.

14.3.2.2.1 OSRB System

One OSRB and associated tug would be moored or on anchor in Foggy Island Bay. The barge will be outfitted with high-volume skimmers and Ocean Busters® to recover oil within safe operating environments.

14.3.2.2.2 Nearshore Skimming Vessels with Mini-Barges

Response teams utilize smaller vessel skimming systems consisting of two boom boats, a skimmer vessel, and temporary storage such as mini-barges or bladders. The vessels recover oil with conventional boom in “U” or “J” configurations or Buster® boom systems (ACS Tactics R-17: *J-boom to Skimmer and Mini-Barge* and R-19: *J-boom to Large Barge or OSRV*. Recovered oil is transferred to mini-barges or storage bladders.

14.3.2.2.3 Static Collection at Endicott Causeway Breaches

Equipment is deployed at the Endicott causeway breaches (bridges). Buster® systems and high-capacity skimmers or pumps recover oil into a mini-barge or directly to shore-based storage such as vacuum trucks or tanker trucks. For additional details refer to ACS Tactic R-33: *Swift Water Recovery – Harbour Buster®*.

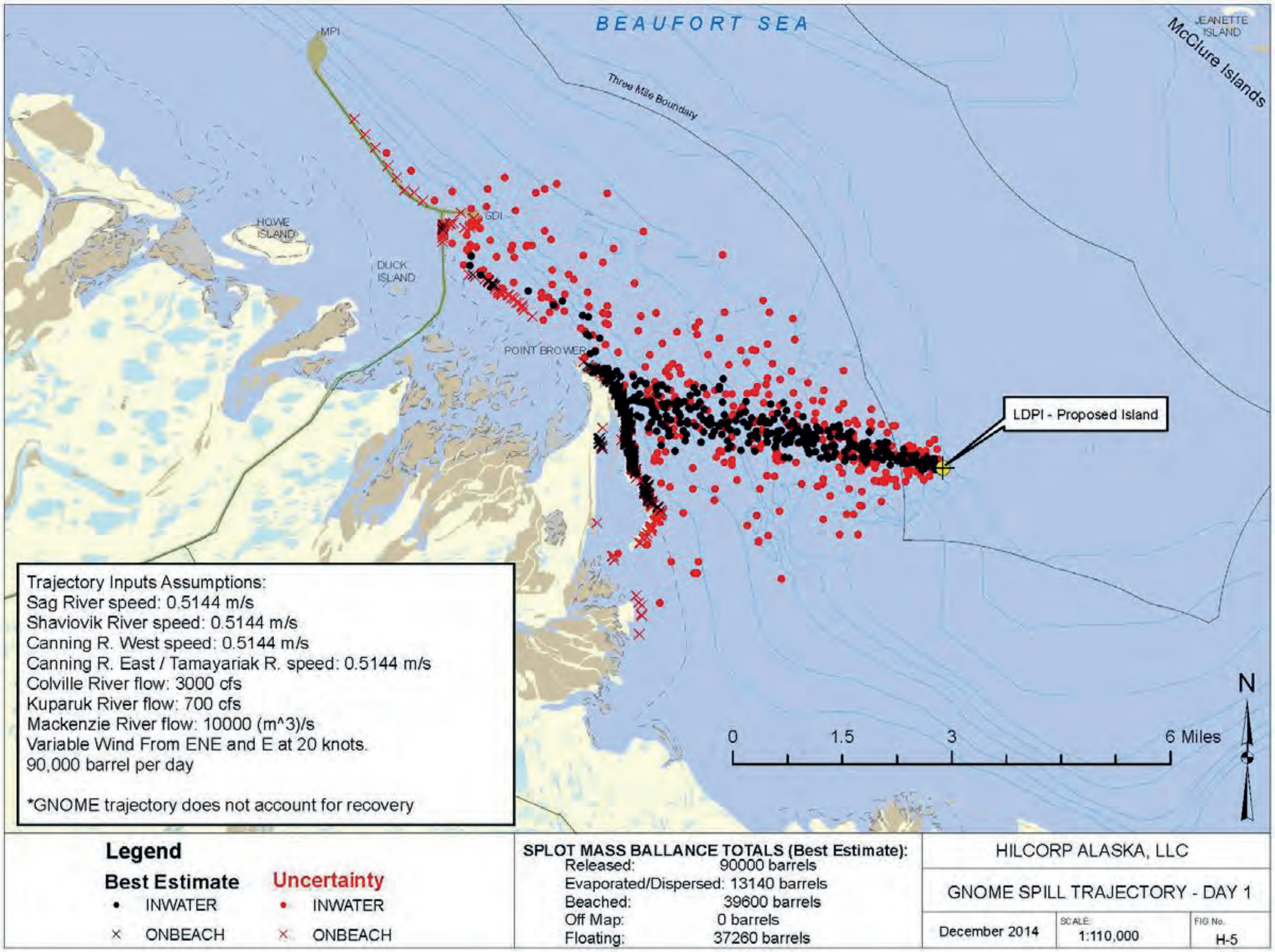
14.3.2.2.4 Shore-Based Recovery Using Mini-Barges

Mini-barges are deployed to locations along the shoreline of Foggy Island Bay. The mini-barges are intentionally grounded to provide an operations platform in shallow water (2 feet or less). Small skimmers and boom are deployed from the mini-barge using airboats. Sheet metal can be deployed in shallow water instead of conventional boom. Recovered fluids are transferred 1,000 to 3,000 feet to workboats shuttling mini-barges. If the shore-based recovery is close enough (within approximately 3,000 feet) of the road system, recovered fluids could be transferred to a vacuum truck with hoses and pumps in a series.

14.3.2.2.5 Shoreline/Onshore Recovery

Airboats are able to access nearshore and shoreline areas in water depths of 0 to 3 feet. Responders using workboats and airboats deploy boom and anchors along the shoreline of the Foggy Island Bay in lengths of approximately 50 to 300 feet. Skimmers are deployed in the boom apex. Diesel power packs onshore would power the skimmer (ACS Tactic R-16: *Hook Boom to Skimmer and Storage*). This tactic can be augmented with the use of static recovery with snare boom and/or sorbents.

Figure 14-2. Potential Trajectory of an Un-Ignited WCD During Summer at Hour 24



14.3.2.3 On-Water In-Situ Burning

Task forces will either tow boom that was pre-deployed within the path of the trajectory or will tow fire boom deployed from SDI. Vessels tow the fire boom in a U-configuration to a safe area for ignition. To use the full holding capacity of the boom, oil should fill the lower one-third of the boom's apex while the boom is towed.

During a burn, the oiled area may be expanded by slowing down. This increases the size of the burn and the oil elimination rate. The oil can be released from the boom and allowed to spread until it is too thin to burn. (The potential spread area is possibly as large as ten contained fire diameters.)

Collection, ignition, and sustained burning are monitored from both the surface and the air (when possible) to provide guidance on the most effective position of the burn teams relative to surrounding oil slicks, other vessels, and wind direction.

Each pair of boats will work with approximately 150 meters (approximately 500 feet) of fire boom and will spread it apart to a swath opening of approximately 50 meters (approximately 150 feet), maintaining a speed of approximately 0.5 to 0.75 knots. The open end of the "U" will be maneuvered through the oil slick so that the oil is collected in its apex.

Task forces collect oil until there is a sufficient volume and thickness of oil within the booms for ignition. When the appropriate oil thickness is contained, a small igniter boat positions itself outside and near the fire boom on the upwind side of the contained oil. A hand-held igniter, containing gelled diesel in a 0.5-gallon plastic bottle with a float and road flare attached, is activated and released onto the contained oil.

ACS Tactic B-4 (*Deployment and Use of Fire Containment Boom*; B-7: *Burn Extinguishment on Water*) and the LDPI OSRP contain for more information concerning ISB operations.

Residue recovery tactics would be used to support ISB. The type and amount of residue from an in-situ burn of oil on water depend on several environmental conditions, including how the oil is contained throughout the burn. If wind or currents are available to push burning oil against a barrier (boom, ice, steel structure, etc.), adequate combustion thicknesses will be maintained for a much more efficient burn. The residue may be an inch or more thick.

The residue may continue to thicken and reach an average thickness of several inches. Most burns result in taffy-like layers of weathered, viscous material that is relatively buoyant. Some residues, however, may become negatively or neutrally buoyant because of combustion and/or sediment uptake.

Response teams would recover residue before collecting and burning additional oil. The residue can be released to secondary collection booms or nets. Whether recovered from secondary booms or the fire containment boom, the burn residue can normally be picked up with large strainers or hand tools, with viscous oil sorbents, or with standard viscous-oil skimmers.

14.3.2.4 Summer Waste Management

In the event of a summer WCD, skimming vessels with mini-barges and the OSRB transit to SDI and/or MPI for offloading. Fluids offloaded to the holding tank at SDI could be transferred (by vacuum truck or pumps and hoses in a series) to other storage tanks before ultimate recycling or disposal.

14.3.2.5 Wildlife Response

In the event of a WCD, wildlife responders would work with state, federal and local agencies to deploy the tools, expertise, and infrastructure needed to create and sustain an effective wildlife response. Wildlife responders would be supported with transportation equipment, including workboats, airboats, and helicopters.

The response would be consistent with the state Unified Plan. The priorities would be the same as described in Section 14.3.1.5. Marine mammal protocols would also be the same as a winter response. Polar bears, ringed seals, bearded seals, and possibly whales would be in the project area during summer (open water) season.

In the event operations or response personnel encounter a dead or injured bird, responders will immediately notify Security, who will call ACS or Environmental Advisors. The spectacled eider and Steller's eider are listed as threatened by the USFWS. The USFWS requires that injured or dead birds listed as threatened or endangered be reported to the USFWS Office of Law Enforcement within 24 hours of discovery (regardless of cause of the event). The USFWS will then provide guidance regarding the bird.

14.3.3 Response During Shoulder Seasons

The period spanning mid-May through July is characterized by warming temperatures, overflood of the rivers, the formation of melt ponds, and the degrading surface ice (break-up). October to November is characterized by thin (and mobile) ice slowly thickening (freeze-up). These periods are referred to as the shoulder seasons. Drilling through the reservoir section will be limited to the open-water season (~July 15 through ~October 1) or during frozen ice season, which begins with 18 inches of sea ice (~November 15) and ends June 1 as prescribed in the OSRP.

In the event an oil spill response extended into the shoulder seasons, responders would continue mechanical recovery tactics and ISB. Responders would also prioritize tracking and surveillance of the discharged oil in order to efficiently recover it when conditions improve.

Many of the tactics in winter and summer scenarios are appropriate well into the shoulder seasons (e.g., mechanical removal of oiled snow with snow machines and trailer, and ISB with hand ignition devices). The following specialized equipment is available for response during break-up or freeze-up in varying ice conditions:

- Hovercraft
- Amphibious Haagland Personnel/Small Equipment Carriers
- Airboats
- Amphibious Ditchwitch Trencher
- Amphibious Backhoe

Hovercraft and amphibious vehicles similar to the Haagland have been used to transport personnel and light equipment on the Slope in a variety of conditions for many years. Airboats have also been used to transport personnel and can be used to transport anchors and tow boom.

14.3.3.1 Use Helitorch for Aerial Ignition

Helicopter-supported ISB can be used during spring break-up and fall freeze-up when responders cannot access the oil with tracked vehicles or snow machines. The Simplex Model 5400 Helitorch owned by ACS is a helicopter-slung device for delivering measured amounts of burning gelled fuel to an oil slick for purposes of igniting the slick. The helitorch can also be used to ignite inaccessible oil pockets collected in quiet-water areas or on ice melt pools. Typical equipment and personnel used to support ISB with a helicopter are detailed in the LDPI OSRP.

14.3.3.2 Setting Boom in Decaying Ice Conditions

Before overflood, containment boom, absorbent boom, and fire boom would be deployed via airboats in a stationary mode (either anchored to the shore or to the ice) to direct the oil to locations where it can be burned in situ.

During overflood (typically the end of May) the rivers flood out onto the ice. The water can reach a depth of 3 feet and can spread as far as 3.7 miles offshore into Foggy Island Bay. Airboats can continue to deploy boom during overflood. As conditions allow, boom can be towed in a standard U-configuration to collect oil on water and concentrate it for burning within the boom. During June, there is 24 hours of sunlight.

After overflood, the ice begins to decay. Using airboats, response crews would continue to mobilize boom and initiate ISB. As strudel holes developed, responders would prioritize the holes, booming the sites hindering oil from entering the Beaufort Sea. Responders can also recover burn residue from airboats using hand tools.

In early to mid-July, the ice would deteriorate enough to allow responders to deploy free skimming tactics. Skimmers (e.g., brush skimmer and rope mops) would be deployed from the Endicott breaches (by crane), vessels, and/or barges deployed from SDI or West Dock.

14.3.3.3 Fall Freeze-Up

Freeze-up begins around October 1 in the area south of the Endicott causeway, when the ice is considered shorefast for the season. Ice becomes shorefast for the season north of Endicott on approximately October 25. Air temperatures range from 5 to 15°F. Daylight is 9 to 10 hours per day.

In the event a response in fall, responders would use skimming tactics for as long as possible. Workboats utilize various skimmers (e.g., rope mops) to navigate the spill area, collecting oil in pockets of broken sea ice. During collection/recovery, the vessels maintain no forward speed and are not using boom. Onboard cranes place the skimmers into the deepest pools of oil for recovery. The encounter rate can be enhanced by using prop wash and hoses to direct the oil to skimmers.

Skimmers can also be deployed from the bridges along the Endicott causeway until ice precludes operation. Eventually ice thickens to the extent that marine operations stop. ISB would be conducted by helicopter and airboats. Remote sensing techniques are extended to map areas where discharged oil may be encapsulating. As the ice thickens naturally, pumps and water trucks would be deployed to increase ice thickness and allow increasingly heavier equipment to be mobilized.

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15 REGULATORY COMPLIANCE

The LDPI Project will include three major elements of construction: the artificial island, the subsea and onshore pipeline, and the process and support facilities, as described in Section 6 through 10. The artificial island will be constructed on the outer continental shelf (OCS), in the federal jurisdiction of the United States of America (USA). The subsea pipeline beginning from the new artificial island to the shore of Alaska will traverse federal and the State of Alaska waters. The onshore pipeline and onshore facilities will be located within the jurisdiction of the State of Alaska. Due to the locations of each element of construction, each element is subject to different regulations and jurisdictions. This section provides a list of the permits and approvals required for the LDPI Project. It also discusses the BSEE approvals that are required. Finally, a list of Design Codes and Standards that will be used to guide the efforts is provided in the Section 15.6.

15.1 Liberty Drilling and Production Island

Liberty Drilling and Production Island will be an artificial island constructed on the OCS, about 5 miles offshore of the north coast of Alaska. As such it falls under the jurisdiction of federal regulations and is outside of the jurisdiction of the State of Alaska.

The federal jurisdictional authority for regulating oil exploration, development, and production on the OCS is the Bureau of Safety and Environmental Enforcement (BSEE). The applicable regulations are contained in Title 30 of the Code of Federal Regulations (CFR) 30, Chapter II, Subchapter B, Part 250 – Oil and Gas and Sulphur Operations in the Outer Continental Shelf.

Permits and Approvals by Regulating Authority for the LDPI are shown in Table 15-1.

15.2 Subsea and Onshore Pipeline

The oil pipeline will be routed between Liberty Island and an existing onshore pipeline on State lands. Therefore the subsea and onshore pipeline is located in both federal and State of Alaska waters and State of Alaska mainland.

Permits and approvals by regulating authority for the pipeline are shown in Table 15-2.

15.3 Onshore Facilities

The onshore support facilities will be located on the north coast of Alaska, and fall under the jurisdiction of the State of Alaska and the North Slope Borough.

Permits and approvals by regulating authority for the onshore facilities are shown in Table 15-3.

15.4 Permits

Hilcorp Alaska, LLC (HAK) will conduct Project activities and operations in compliance with applicable federal, state, and local laws and regulations and in a manner compatible with the environmental, socioeconomic, and cultural concerns of the local communities. Major permits, authorizations, and regulatory reviews required for construction and operation of the project are listed in Table 15-1, 15-2, and 15-3. This list is not comprehensive but represents the broad range of regulatory authorizations needed for Project development. Permit applications will address information needs identified during the pre-application and NEPA processes.

Table 15-1. Permits and Approvals Required for LDPI Development[1]

AGENCY	PERMITS AND APPROVALS[2]	REGULATORY AUTHORITY[3]	STATUS
FEDERAL			
Federal Agencies U.S. Department of the Interior Bureau of Ocean Energy Management (BOEM) expected to be lead agency	Evaluation of potential impacts and decision on proposed action under the National Environmental Policy Act, as amended (NEPA)	40 CFR 1500-1508 43 CFR 46; 30 CFR 550. 269	Initiated by Federal agency after submission of DPP and other requests for authorization.
BOEM	Development and Production Plan (DPP) Approval	30 CFR 550.202; 550.241-262	Agreement with agency requires submittal by year-end 2014.
BOEM	Ancillary Activities Permit	30 CFR.550.207-210	As needed.
BOEM	Certificate of Oil Spill Financial Responsibility	30 CFR Part 553	Included in DPP.
BOEM	Air Quality approval	30 CFR 550.218, 550.245, 550.249, 550.257, 550.258, 550.302-304	Included in DPP.
U.S. Department of the Interior Bureau of Safety and Environmental Enforcement (BSEE)	Oil Spill Response Plan (OSRP) Approval	30 CFR 254	Submit concurrently with DPP.
BSEE	Pipelines and Pipeline Rights-of-Way	30 CFR 250 Subpart J	Apply for and obtain prior to construction.
BSEE	Application for Permit to Drill	30 CFR 250 Subpart D	Apply for and obtain prior to drilling.
BSEE	Pollution Prevention	30 CFR 250.300(b)(2)	Obtain approval of method of disposal of drill cuttings, sand, and other well solids from the District Manager.
BSEE	Platform Verification	30 CFR Part 250.900, 902	"Design Verification Plan" submitted with or subsequent to DPP submittal. "Fabrication Verification Plan" and "Installation Verification Plan" submitted prior to start of operations.
U.S. Army Corps of Engineers (USACE)	Clean Water Act (CWA), Section 404 Permit	33 CFR 323	Apply for and obtain prior to construction.
USACE	Rivers and Harbors Act, Section 10 Permit	33 CFR 322	Apply for and obtain prior to construction.
USACE U.S. Environmental Protection Agency (EPA)	Ocean Dumping Permit	33 CFR 324 40 CFR 220-229	If needed, apply for and obtain prior to construction and pipeline installation. Contingency for excavated trench materials.
EPA	National Pollutant Discharge Elimination System (NPDES) Individual Permit (or General Permit if available)	40 CFR 122	Apply for and obtain before construction; submit application information in DPP.
National Oceanic and Atmospheric Administration National Marine Fisheries Service (NMFS)/U.S. Fish and Wildlife Service (USFWS)	Authorization for Incidental Take of Marine Mammals	Marine Mammals Protection Act of 1972, as amended (MMPA)	Apply for and obtain prior to activity.

Table 15-1. Permits and Approvals Required for LDPI Development[1]

AGENCY	PERMITS AND APPROVALS[2]	REGULATORY AUTHORITY[3]	STATUS
NMFS	Essential Fish Habitat (EFH) Consultation	Magnusson-Stevens Fisheries Conservation and Management Act	Federal agency consultation.
NMFS/USFWS	Endangered Species Act (ESA) Consultation and Biological Opinion (BO)/ Incidental Take Statement	Section 7(a) ESA	Agency consultation; BOEM may designate Liberty Operator as "designated non-federal representative" in drafting BO for NMFS review.
U.S. Coast Guard (USCG)	Facility Response Plan	33 CFR 154 Subpart F	Submitted as part of the OSRP.
USCG	Letter of Adequacy for Operation Manual	33 CFR 154 Subpart B	Submit and obtain Letter of Adequacy prior to activity.
USCG/USACE	Aid to Navigation	33 CFR 66.01	Apply concurrently with USACE permit.
STATE OF ALASKA			
ADNR, Office of History and Archaeology	National Historic Preservation Act, Section 106, as amended. Review and concurrence that no historic properties affected.	36 CFR 800	Required by USACE for issuing 404 permit. BOEM may lead consultation for activities requiring BOEM authorization.

Notes:

1. Listed are key permits/authorizations/reviews required for Liberty Development based on information available at this time. Until the conclusion of the NEPA process, the project, laws and regulations, and baseline information may change regulatory requirements. As needed, this table will be updated. Coastal Zone Consistency determination is not listed because Alaska does not currently have a Coastal Zone Management Program.
2. AAC = Alaska Administrative Code; AS = Alaska Statute; CFR = Code of Federal Regulations.
3. Other state and local government agencies may serve as cooperating agencies, based on their interest in the proposed action.
4. This assumes that U.S. Department of Transportation regulatory authority will be coordinated through the SPCO and the State-Federal Joint Pipeline Office.

Table 15-2. Permits and Approvals Required for Liberty Pipeline Development[1]

AGENCY	PERMITS AND APPROVALS[2]	REGULATORY AUTHORITY[3]	STATUS
STATE OF ALASKA			
Alaska Department of Natural Resources (ADNR), Division of Oil and Gas (DOG)	Right-of-Way Easements	11 AAC 51	Apply and obtain prior to construction.
ADNR DOG	Land Use Easement	AS 38.05.850 and/or 11 AAC 51	Apply and obtain prior to construction activity.
ADNR State Pipeline Coordinator's Office (SPCO)[4]	Right-of-Way Leases	AS 38.35	Apply and obtain prior to construction activity.
FEDERAL			
BOEM	Development and Production Plan (DPP) Approval	30 CFR 550.202; 550.241-262	Agreement with agency requires submittal by year-end 2014.
BSEE	Pipelines and Pipeline Rights-of-Way	30 CFR 250 Subpart J	Apply for and obtain prior to construction.
USACE U.S. Environmental Protection Agency (EPA)	Ocean Dumping Permit	33 CFR 324 40 CFR 220-229	If needed, apply for and obtain prior to construction and pipeline installation. Contingency for excavated trench materials.
National Oceanic and Atmospheric Administration National Marine Fisheries Service (NMFS)/U.S. Fish and Wildlife Service (USFWS)	Authorization for Incidental Take of Marine Mammals	Marine Mammals Protection Act of 1972, as amended (MMPA)	Apply for and obtain prior to activity.
NMFS	Essential Fish Habitat (EFH) Consultation	Magnusson-Stevens Fisheries Conservation and Management Act	Federal agency consultation.
NMFS/USFWS	Endangered Species Act (ESA) Consultation and Biological Opinion (BO)/Incidental Take Statement	Section 7(a) ESA	Agency consultation; BOEM may designate Liberty Operator as "designated non-federal representative" in drafting BO for NMFS review.
LOCAL GOVERNMENT			
North Slope Borough (NSB)	Development Permit	NSB Municipal Code 19.50	Apply and obtain prior to construction.
OTHER			
Private Landowners	Land Easement		Obtain prior to activity on privately owned land.

Notes:

1. Listed are key permits/authorizations/reviews required for Liberty Development based on information available at this time. Until the conclusion of the NEPA process, the project, laws and regulations, and baseline information may change regulatory requirements. As needed, this table will be updated. Coastal Zone Consistency determination is not listed because Alaska does not currently have a Coastal Zone Management Program.
2. AAC = Alaska Administrative Code; AS = Alaska Statute; CFR = Code of Federal Regulations.
3. Other state and local government agencies may serve as cooperating agencies, based on their interest in the proposed action.
4. This assumes that U.S. Department of Transportation regulatory authority will be coordinated through the SPCO and the State-Federal Joint Pipeline Office.

Table 15-3. Permits and Approvals Required for Liberty Onshore Development[1]

AGENCY	PERMITS AND APPROVALS[2]	REGULATORY AUTHORITY[3]	STATUS
FEDERAL			
BOEM	Development and Production Plan (DPP) Approval	30 CFR 550.202; 550.241-262	Agreement with agency requires submittal by year-end 2014.
STATE OF ALASKA			
Alaska Department of Natural Resources (ADNR), Division of Oil and Gas (DOG)	Right-of-Way Easements	11 AAC 51	Apply and obtain prior to construction.
ADNR DOG	Land Use Easement	AS 38.05.850 and/or 11 AAC 51	Apply and obtain prior to construction activity.
ADNR State Pipeline Coordinator's Office (SPCO)[4]	Right-of-Way Leases	AS 38.35	Apply and obtain prior to construction activity.
ADNR DOG	Geophysical and Seismic Surveys	11 AAC 96.030(a)	As needed.
ADNR, Division of Mining, Land, and Water	Land Use Permit	11 AAC 96	Apply and obtain prior to construction activity.
ADNR, Division of Mining, Land, and Water	Temporary Water Use Permits	11 AAC 93	Apply and obtain prior to activity.
ADNR, Division of Mining, Land, and Water	Material Sales Contract (including Mining and Rehabilitation Plan)	11 AAC 71	Modify Existing Material Sale Contract as needed prior to construction; coordinate with USACE permitting.
ADNR, Office of History and Archaeology	National Historic Preservation Act, Section 106, as amended. Review and concurrence that no historic properties affected.	36 CFR 800	Required by USACE for issuing 404 permit. BOEM may lead consultation for activities requiring BOEM authorization.
Alaska Department of Environmental Conservation (ADEC)	Existing Endicott Title V Operating Permit Modification	18 AAC 50	Modify Endicott permit if required by SDI tank volume.
ADEC	Oil Discharge Prevention and Contingency Plan	18 AAC 75	Apply and obtain prior to activity.
ADEC	Section 401 Water Quality Certificate of Reasonable Assurance	18 AAC 15 18 AAC 70 CWA	Automatic review during federal permitting.
ADEC	Short-Term Water Quality Variance or Zone of Deposit (variance)	18 AAC 70.200 Or 18 AAC 70.210	Optional, depending on potential effects of island and/or pipeline construction.
ADEC	Alaska Pollutant Discharge Elimination System (APDES) discharges from facilities on state land or water	18 AAC 83	Apply and obtain prior to activity; file Notice of Intent under General Permit, if available.
Alaska Department of Fish and Game (ADF&G)	Fish Habitat Permit	AS 16.05 (Title 16)	Apply and obtain prior to construction, including ice roads.
ADF&G	Public Safety Permit	AS 16.05.930	Apply for and obtain prior to activity.
Department of Public Safety	Fire Marshal Plan Review	13 AAC 50	Submit plans, if needed.
LOCAL GOVERNMENT			
North Slope Borough (NSB)	Development Permit	NSB Municipal Code 19.50	Apply and obtain prior to construction.

Table 15-3. Permits and Approvals Required for Liberty Onshore Development[1]

AGENCY	PERMITS AND APPROVALS[2]	REGULATORY AUTHORITY[3]	STATUS
NSB	Rezoning – Conservation District to Resource Development District – Master Plan	NSB Municipal Code 19.60	Apply and obtain prior to construction.
NSB	Traditional Land Use Inventory (TLUI) Archaeology Clearance/ Form 500	NSB Municipal Code 19.50 and 19.60	Apply and obtain prior to activity.
OTHER			
Private Landowners	Land Easement		Obtain prior to activity on privately owned land.

Notes:

1. Listed are key permits/authorizations/reviews required for Liberty Development based on information available at this time. Until the conclusion of the NEPA process, the project, laws and regulations, and baseline information may change regulatory requirements. As needed, this table will be updated. Coastal Zone Consistency determination is not listed because Alaska does not currently have a Coastal Zone Management Program.
2. AAC = Alaska Administrative Code; AS = Alaska Statute; CFR = Code of Federal Regulations.
3. Other state and local government agencies may serve as cooperating agencies, based on their interest in the proposed action.
4. This assumes that U.S. Department of Transportation regulatory authority will be coordinated through the SPCO and the State-Federal Joint Pipeline Office.

15.5 Agency Design Reviews

In addition to review and approval of this Development and Production Plan, there are several detailed design review processes that must be completed before project construction can begin. These include BSEE and State of Alaska review and approval of pipeline design; BSEE review and approval of the island structural design through the Certified Verification Agent process; and various BSEE approvals for drilling and safety systems design and installation features.

15.5.1 Pipeline Design Review

Both BSEE and the Alaska State Pipeline Coordinator's Office (SPCO) must review pipeline right-of-way applications and issue a lease before pipeline construction. Under the terms of an agreement between BSEE (formerly MMS) and SPCO, it is planned that SPCO will complete design review to assure compliance with both state and federal pipeline design and operating standards.

The State has very broad statutory authority and scope of review over applications for rights-of-way. In making a decision to issue a lease, the Commissioner of Natural Resources must consider whether or not:

- The proposed use of the right-of-way would unreasonably conflict with existing uses of the land involving a superior public interest
- Applicant has the technical and financial capability to protect state and private property interests; and
- Applicant has the technical and financial capability to take action to the extent reasonably practical to:
    - Prevent any significant adverse environmental impact, including but not limited to, erosion of the surface of the land and damage to fish and wildlife and their habitat
    - Undertake any necessary restoration or revegetation
    - Protect the interests of individuals living in the general area of the right-of- way who rely on fish, wildlife, and biotic resources of the area for subsistence purposes

- Applicant has the financial capability to pay reasonably foreseeable damages for claims arising from the construction, operation, maintenance, or termination of the pipeline; and
- Applicant has agreed that in the construction and operation of the pipeline, the applicant will comply with, and require contractors and their subcontractors to comply with, applicable and valid laws and regulations regarding the hiring of residents of the state.

As part of its decision process, the SPCO will conduct an extensive review of the application to assure the technical integrity of the design. As part of this review, SPCO will likely evaluate structural and mechanical design, proposed leak prevention and detection methods, geotechnical information, ice gouge potential, strudel scour potential, adequacy of the proposed quality assurance program, pipeline operations procedures, monitoring and surveillance, and other factors affecting the overall technical performance of the pipeline system. SPCO will probably require assistance through third-party reviewers for certain aspects of the technical review. BPXA submitted an initial pipeline design basis document to SPCO for review in March 1998; this document supplements information provided in the August 8, 1997, application. In addition, the Liberty Quality Assurance Plan has been approved. A Construction Plan must be reviewed and approved before construction may begin, and a Surveillance and Monitoring Plan must be reviewed and approved before pipeline operation begins.

BSEE will also require submission of detailed pipeline design information for review and approval prior to construction. The design basis document to be provided to SPCO will provide the basis for the BSEE detailed pipeline application.

15.5.2 Island Design Review (Platform Verification)

Island structural design must be reviewed and approved by BSEE prior to construction through the third-party Certified Verification Agent (CVA) process. Under this process, an Island Design Plan will be prepared and submitted to BSEE. An independent third-party CVA will then review the gravel island and slope protection design to assure integrity over the life of the project, including:

- Wave heights and periods
- Currents
- Winds
- Water depth
- Tide data
- Storm surge
- Ice effects
- Air and sea temperatures
- Geotechnical conditions
- Loadings, soil stability
- Seafloor survey results (shallow hazards surveys)
- Design loadings
- Material specifications

15.5.3 Other BOEM, BSEE Reviews

In addition to the major BOEM DPP and the pipeline design approvals, there are numerous other major and minor authorizations required before drilling and/or construction can commence. These are summarized in Table 15-4.

Table 15-4. Required Project Approvals

Regulatory Authority (30 CFR PART 250)	Description
250.204	Development and Production Plan (this document)
250.301(b)(2)	Approval of the method of disposal of drill cuttings
250.401(a)(3)	Fitness of drilling unit
250.402(b)(2)	Welding, burning, and hot tapping plan
250.414	Application for Permit to Drill (includes detailed safety and operational information)
250.415	Sundry Notices (minor changes in drilling plans)
250.417(h)(1)	Hydrogen sulfide contingency plan
250.513	Well completion
250.613	Well workovers
250.802(e)	Safety-systems design and installation features (requires detailed design review of process facilities)
250.803	Firefighting system
250.901(b)(8)	Application for approval of platform
250.909	Foundation (soils investigations; site investigation; including shallow hazards and geological surveys)
250.1007 and .1010	Application for approval of pipeline right-of-way grant
250.1102(b)(2)	Oil and gas production rates
250.1105(c)	Bottomhole pressure survey
250.1107	Enhanced oil and gas recovery operations
250.1200(b)	Measurement of liquid hydrocarbons
250.1201(b)	Gas production
250.1501	Application for approval of training program
250.1503(f)	Submission of training programs for well completion, well work-overs, and well control
250.1504(d)	Submission of training programs for production safety systems course

15.6 Design Codes and Standards

15.6.1 Regulated Codes and Standards

The codes and regulations BSEE has incorporated by reference are listed in 30 CFR Part 250.198. HAK intends to utilize those codes and references that are applicable to the design, construction, and operation of the facility.

Part 250 Subpart I is primarily written to regulate offshore platforms and ocean structures. The regulation is vague regarding artificial islands, where many of the referenced codes and standards are not applicable to islands or the land-based facilities that will be installed on the island.

HAK is in the process of determining which codes apply to an OCS gravel island. Listed below in Table 15-5 are applicable design codes and standards listed in Part 250.198 determined to be applicable for an artificial island design. Referenced standards and/or codes that are not applicable to the project have been noted with the proposed replacement document.

Table 15-5. CFR 30, Chapter II, Subchapter B, Part 250.198 Applicable Codes and Regulations

Standard	Description	Use	Notes
American Concrete Institute (ACI)			
ACI Standard 318-95	Building Code Requirements for Reinforced Concrete (ACI 318-95)	Yes	Concrete is not part of the island structural system but may be used in facility foundations and armoring
ACI 318R-95	Commentary on Building Code Requirements for Reinforced Concrete	Yes	Concrete is not part of the island structural system but may be used in facility foundations and armoring
ACI 357R-84	Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997	No	Concrete is not part of the island structural system
American Institute of Steel Construction			
ANSI/AISC 360-05	Specification for Structural Steel Building	Yes	Structural steel is not part of the island structural system but will be used in facility foundations and superstructures
American National Standards Institute (ANSI)			
ANSI/ASME Boiler and Pressure Vessel Code	Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations Volume 55	Yes	N/A
ANSI/ASME Boiler and Pressure Vessel Code	Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations Volume 55	Yes	N/A
ANSI/ASME Boiler and Pressure Vessel Code	Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1 and 2, and all Section VIII Interpretations Volumes 54 and 55	Yes	N/A
ANSI/ASME B 16.5-2003	Pipe Flanges and Flanged Fitting	Yes	N/A
ANSI/ASME B 31.8-2003	Gas Transmission and Distribution Piping System	Yes	N/A
ANSI/ASME SPPE-1-1994	Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations	Yes	N/A
ANSI/ASME SPPE-1d-1996 Addenda	Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations	Yes	N/A
ANSI Z88.2-1992	American National Standard for Respiratory Protection	Yes	N/A

Table 15-5. CFR 30, Chapter II, Subchapter B, Part 250.198 Applicable Codes and Regulations

Standard	Description	Use	Notes
American Petroleum Institute (API)			
API 510	Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006	Yes	N/A
API Bulletin 2INT-DG	Interim Guidance for Design of Offshore Structures for Hurricane Conditions, May 2007	No	Not applicable to this facility type or location
API Bulletin 2INT-EX	Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, May 2007	No	Not applicable to this facility type or location
API Bulletin 2INT-MET	Interim Guidance on Hurricane Conditions in the Gulf of Mexico, May 2007	No	Not applicable to this facility type or location
API MPMS	Chapter 1—Vocabulary, Second Edition, July 1994 API Manual of Petroleum Measurement Standards	Yes, TBD	Metering and measurement of oil, gas and produced liquids will occur but is not yet fully defined. The appropriate chapters of MPMS will be applied to the detailed design.
API RP 2A-WSD	Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design, Twenty-first Edition, December 2000; Errata and Supplement 1, December 2002; Errata and Supplement 2, September 2005; Errata and Supplement 3, October 2007	No	Facility is a gravel island, not a platform
API RP 2D	Operation and Maintenance of Offshore Cranes, Sixth Edition, May 2007	No	No fixed offshore cranes are used
API RP 2FPS	RP for Planning, Designing, and Constructing Floating Production Systems; First Edition, March 2001	No	Facility is a gravel island, not a platform
API RP 2I	In-Service Inspection of Mooring Hardware for Floating Structures; Third Edition, April 2008	No	Facility is a gravel island, not a platform
API RP 2RD	Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009	No	Facility is a gravel island, not a platform
API RP 2SK	Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008	No	Facility is a gravel island, not a platform
API RP 2SM	Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007	No	Facility is a gravel island, not a platform

Table 15-5. CFR 30, Chapter II, Subchapter B, Part 250.198 Applicable Codes and Regulations

Standard	Description	Use	Notes
API RP 2T	Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms, Second Edition, August 1997	No	Facility is a gravel island, not a platform
API RP 14B	Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005, also available as ISO 10417: 2004, (Identical) Petroleum and natural gas industries—Subsurface safety valve systems—Design, installation, operation and redress	Yes	N/A
API RP 14C	Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, reaffirmed: March 2007	Yes	N/A
API RP 14E	Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; reaffirmed, March 2007	Yes	N/A
API RP 14F	Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations, Fifth Edition, July 2008	Yes	N/A
API RP 14FZ	Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, First Edition, September 2001, reaffirmed: March 2007	Yes	N/A
API RP 14G	Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007	No	N/A
API RP 14H	Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007	Yes	N/A
API RP 14J	Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; reaffirmed: March 2007	Yes	N/A
API RP 53	Recommended Practices for Blowout Preventer Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004	Yes	N/A

Table 15-5. CFR 30, Chapter II, Subchapter B, Part 250.198 Applicable Codes and Regulations

Standard	Description	Use	Notes
API RP 65	Recommended Practice for Cementing Shallow Water Flow Zones in Deepwater Wells, First Edition, September 2002	No	N/A
API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997; reaffirmed November 2002	Yes	N/A
API RP 505	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; reaffirmed November 2002	Yes	N/A
API RP 2556	Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993; reaffirmed November 2003	No	Fluids are not expected to result in any incrustation
ANSI/API Spec. Q1	Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Eighth Edition, December 2007, Effective Date: June 15, 2008	TBD	Quality Standards to be developed
API Spec. 2C	Specification for Offshore Pedestal Mounted Cranes, Sixth Edition, March 2004, Effective Date: September 2004	No	No offshore pedestal cranes
ANSI/API Spec. 6A	Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009; Addendum 1, February 2008; Addendum 2, 3, and 4, December 2008	Yes	N/A
API Spec. 6AV1	Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed January 2003	Yes	N/A

Table 15-5. CFR 30, Chapter II, Subchapter B, Part 250.198 Applicable Codes and Regulations

Standard	Description	Use	Notes
ANSI/API Spec. 6D	Specification for Pipeline Valves, Twenty-third Edition, April 2008; Effective Date: October 1, 2008, Errata 1, June 2008; Errata 2, November 2008; Errata 3, February 2009; Addendum 1, October 2009; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 14313:2007 (Identical), Petroleum and natural gas industries—Pipeline transportation systems—Pipeline valves	Yes	N/A
ANSI/API Spec. 14A	Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Effective Date: May 1, 2006; also available as ISO 10432:2004	Yes	N/A
ANSI/API Spec. 17J	Specification for Unbonded Flexible Pipe, Third Edition, July 2008; Effective Date: January 1, 2009, Contains API Monogram Annex as Part of U.S. National Adoption; ISO 13628-2:2006 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 2: Unbonded flexible pipe systems for subsea and marine application	No	Unbonded flexible pipe not used
API Standard 2552	USA Standard Method for Measurement and Calibration of Spheres and Spheroids, First Edition, 1966; reaffirmed, October 2007	No	No spheres used
API Standard 2555	Method for Liquid Calibration of Tanks, First Edition, September 1966; reaffirmed March 2002	No	Conventional strapping will be used
API RP 90	Annular Casing Pressure Management for Offshore Wells, First Edition, August 2006	Yes	N/A
API Standard 65—Part 2	Isolating Potential Flow Zones During Well Construction; Second Edition, December 2010	TBD	N/A
API RP 75	Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, Third Edition, May 2004, Reaffirmed May 2008	Yes	N/A
API RP 86	API Recommended Practice for Measurement of Multiphase Flow; First Edition, September 2005	Yes	N/A
American Society for Testing and Materials (ASTM)			
ASTM Standard C 33-07	approved December 15, 2007, Standard Specification for Concrete Aggregates	Yes	Concrete is not part of the island structural system but may be used in facility foundations and armoring

Table 15-5. CFR 30, Chapter II, Subchapter B, Part 250.198 Applicable Codes and Regulations

Standard	Description	Use	Notes
ASTM Standard C 94/C 94M-07	approved January 1, 2007, Standard Specification for Ready-Mixed Concrete	Yes	Concrete is not part of the island structural system but may be used in facility foundations and armoring
ASTM Standard C 150-07	approved May 1, 2007, Standard Specification for Portland Cement	Yes	Concrete is not part of the island structural system but may be used in facility foundations and armoring
ASTM Standard C 330-05	approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete	No	No lightweight concrete used
ASTM Standard C 595-08	approved January 1, 2008, Standard Specification for Blended Hydraulic Cements	No	Using C 150
American Welding Society (AWS)			
AWS D1.1:2000	Structural Welding Code—Steel, 17th Edition, October 18, 1999	Yes	N/A
AWS D1.4-98	Structural Welding Code—Reinforcing Steel, 1998 Edition	No	Welded reinforcing not used
AWS D3.6M:1999	Specification for Underwater Welding (1999)	No	Underwater welding not used
National Association of Corrosion Engineers (NACE)			
NACE Standard MR0175-2003	Standard Material Requirements, Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments, Revised January 17, 2003	Yes	Possible, depending on H2S levels
NACE Standard RP0176-2003	Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production	No	Gravel island structure
American Gas Association (AGA Reports)			
AGA Report No. 7	AGA Report No. 7	No	No custody transfer of natural gas
AGA Report No. 9	Measurement of Gas by Multipath Ultrasonic Meters; Second Edition, April 2007	No	No custody transfer of natural gas
AGA Report No. 10	AGA Report No. 10	No	No custody transfer of natural gas
ISO/IEC (International Electrotechnical Commission)	Conformity assessment—General requirements for accreditation bodies accrediting conformity assessment bodies, First edition 2004-09-01; Corrected version 2005-02-15	No	No custody transfer of natural gas
Center for Offshore Safety (COS)			
COS Safety Publication COS-2-01	Qualification and Competence Requirements for Audit Teams and Auditors Performing Third-party SEMS Audits of Deepwater Operations, First Edition, Effective Date October 2012	TBD	N/A

Table 15-5. CFR 30, Chapter II, Subchapter B, Part 250.198 Applicable Codes and Regulations

Standard	Description	Use	Notes
COS Safety Publication COS-2-03	Requirements for Third-party SEMS Auditing and Certification of Deepwater Operations, First Edition, Effective Date October 2012	TBD	N/A
COS Safety Publication COS-2-04	Requirements for Accreditation of Audit Service Providers Performing SEMS Audits and Certification of Deepwater Operations, First Edition, Effective Date October 2012	TBD	N/A

15.6.2 Voluntary Codes and Standards

The codes and standards referenced in Part 250.198 are applicable to a portion, but not all, of the facilities that will be designed and constructed in the Liberty project. A significant portion of the project design and construction is not covered by the listed codes and standards. Those portions of the work not covered will use codes and standards selected by HAK to be applicable and appropriate.

In selecting codes and standards, HAK will take into account the goals for the design, construction, and operation of the facility, including:

- A facility that protects the environment to a comparable level as other similar onshore facilities in the State of Alaska.
- A facility that protects workers to a comparable level as other similar onshore facilities in the State of Alaska.

HAK recognizes that most workers at this facility will have been trained and gained experience at onshore or offshore oil drilling and production facilities located in Alaska. Therefore, HAK intends to construct a similar facility by utilizing similar standards and practices.

HAK intends to utilize the following codes and standards not incorporated by reference by Part 250.198 in the design, construction, and operation of the facility. Most of these codes and standards are adopted by the State of Alaska, and are commonly used for similar facilities.

- U.S. Department of Labor Occupational Safety and Health Administration (OSHA) – for design and construction of exterior stairs and walkways, ladders, stairs in process facilities, guarding of openings (CFR 29, Part 1910).
- U.S. Environmental Protection Agency – for air quality, oil pollution prevention measures.
- International Code Council (ICC) Series (IBC, IPC, IFC, IFGC) – for facility design related to architecture, space planning, egress, access, fire safety, structural, mechanical, and fuel gas to appliances.
- National Fire Protection Association (NFPA) – for facility design related to electrical (NEC) and fire safety.
- International Association of Plumbing and Mechanical Officials (IAPMO) – for facility design related to plumbing systems (UPC).
- American Society of Mechanical Engineers (ASME) – for process piping design (B31.3) up to pipeline flange.
- API – for above-ground storage tanks (RP-650).
- Underwriters Laboratory (UL) – above-ground storage tanks (UL 142).
- American Water Works Association – above-ground water storage tanks (D 100).

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16 LEASE STIPULATIONS, BONDING, TESTAMENTS

HAK will meet the requirements of lease stipulations associated with the two federal leases upon which the Liberty Development is located. There are two relevant lease sales: Beaufort Sea OCS Lease Sale 144 (Lease OCS-Y1650) and Beaufort Sea OCS Lease Sale 124 (Lease OCS-Y1585). In general, the stipulations for the two lease sales are the same. It will be noted where the lease sale stipulations differ by lease sale.

16.1 Protection of Archeological Resources

Protection of Archaeological Resources is Stipulation No. 1 of Lease Sale 124.

Stipulation Summary: If the Regional Supervisor, Field Operations (RS/FO), believes an archaeological resource may exist in the lease area, the lessee shall prepare a report to determine the potential existence of any archaeological resource that may be affected by operations prior to commencing operations. The report will be prepared by an archaeologist and geophysicist, and will be based on an assessment of data from remote-sensing surveys and other pertinent archaeological and environmental information. This report will be submitted to the RS/FO.

If evidence suggests that an archaeological resource may be present, the lease shall locate operations so as to not adversely affect the area where the archaeological resource is located; establish that an archaeological resource does not exist or will not be adversely affected by operations; or, if an archaeological resource is likely to be present and be adversely affected by operations, take no action that may adversely affect the archaeological resource until the RS/FO has told the lessee how to protect it.

If the lessee discovers an archaeological resource while conducting operations in the lease area, the lessee will report the discovery to the RS/FO. The lessee shall make every reasonable effort to preserve the archaeological resource until the RS/FO has told the lessee how to protect it.

Compliance: An archaeological survey was completed in both onshore and offshore areas potentially affected by Liberty Development. No cultural resources, of either historic or prehistoric origin, were identified in any of the coring materials or remote-sensing data collected in the offshore environment. The Archaeological Resources reports were provided to BOEM under separate cover.

Several onshore cultural/archaeological resources were documented, and onshore components of Liberty Development (mine site, water supply sources, and ice roads/pads) have been located to avoid them. A Cultural Resources/Archaeology Report on survey results will be submitted to the Alaska Department of Natural Resources, Office of History and Archaeology, State Historic Preservation Office (SHPO) for their Section 106 (under the National Historic and Preservation Act) review and to the NSB Inupiat History, Language, and Culture (IHLC) Division.

HAK will have procedures and training in place to recognize, report, and protect cultural/archaeological resources encountered during construction and operations. BOEM will be notified if any archaeological resources are discovered during project activities. The SHPO and the North Slope Borough (NSB) will also be notified if the discovery is within State jurisdiction. Project activities at the site of a new archaeological discovery will be suspended until proper evaluation occurs, and plans to proceed are developed and approved by BOEM and/or the SHPO and NSB, depending on location.

HAK will comply with requirements of Section 550.194, NTL No. 05-A03 and concurrences issued by SHPO and NSB.

16.2 Protection of Biological Resources

Protection of Biological Resources is Stipulation No. 2 of Lease Sale 124 and Stipulation No. 1 of Lease Sale 144.

Stipulation Summary: The RS/FO may require the lessee to conduct biological surveys needed to determine the extent and composition of biological populations and habitats requiring additional protection. As a result of these surveys, the RS/FO may require the lessee to relocate the site of operations, establish that operations will not have adverse effects or ensure that special biological resources do not exist, operate during times that do not adversely affect the biological resource, or modify the operation. In addition, the lessee is required to report any area of biological significance discovered during the conduct of any operations on the lease, and make every reasonable effort to preserve and protect the biological resource from damage until the RS/FO provides direction with respect to resource protection.

Compliance: The Liberty Project area has been studied extensively, and Liberty Development has been designed to avoid or mitigate potential impacts to biological resources (see Section 13 for proposed mitigation measures). The EIA provided as Appendix A of this DPP describes the biological resources in the project area. Planned methods of protecting the identified animal resources will be included in the Letter of Authorization/Incident Harassment Authorization (LOA/IHA) and Biological Opinions if applicable or in other mitigation plans. Specific protection measures will also be included in the required Polar Bear and Walrus Interaction Plan and other wildlife-specific management plans. The subsea pipeline bundle has been routed to minimize impacts to the Boulder Patch, based on past and recent project-specific studies. Additional protection strategies for biological resources may be developed as a part of the permitting and NEPA processes.

16.3 Orientation Program

The lessee shall include in any exploration or development and production plans a proposed orientation program for all personnel involved in exploration or development and production activities (including personnel of the lessee’s agents, contractors, and subcontractors) for review and approval by the RS/FO.

Orientation Program is Stipulation No. 3 of Lease Sale 124 and Stipulation No. 2 of Lease Sale 144.

Stipulation Summary: The lessee must develop a proposed orientation program for all personnel involved in the Liberty Development. The program must address environmental, social, and cultural concerns that relate to the area, including the importance of not disturbing archaeological and biological resources and habitats. The program shall be designed to increase the sensitivity and understanding of the personnel to community values, customs, and lifestyles in areas in which such personnel will be operating. The orientation program also shall include information concerning avoidance of conflicts with subsistence, commercial fishing activities, and pertinent mitigation. The program shall be attended at least once a year by all personnel involved in on-site exploration or development and production activities. The lessee shall maintain an on-site record of all personnel who attend the program for as long as the site is active, for a period not to exceed 5 years.

Compliance: HAK will require all North Slope field workers to complete an 8-hour “unescorted” training program provided by the North Slope Training Cooperative. The North Slope Training Cooperative Offshore Safety Awareness Modules include an introduction to lifestyle and culture of Alaska Native people. The program includes an explanation of the applicable laws protecting cultural and historic resources, and stresses the importance of not disturbing archeological, cultural and historic resources, and biological resources and habitats while providing guidance on how to avoid disturbance. A Polar Bear interaction plan will also be included in environmental training.

In addition, a Liberty-specific training module covering environmental, social, and cultural concerns related to the Liberty Project area will be developed and delivered to personnel assigned to the Liberty Development.

16.4 Transportation of Hydrocarbons

Transportation of Hydrocarbons is Stipulation No. 4 of Lease Sale 124 and Stipulation No. 3 of Lease Sale 144.

Stipulation Summary: Pipelines are required for transportation of hydrocarbons if the pipeline right-of-way can be obtained, if laying the pipeline is technologically feasible and environmentally preferable, and if pipelines can be laid without social safety net loss. No crude oil production will be transported by surface vessel from the offshore production site except in cases of emergency.

Compliance: HAK plans to develop a subsea pipeline from the LDPI to shore to transport Liberty single-phase production. At the shore day-lighting location, LDPI production will be tied into the Badami pipeline and be transferred to the TAPS. No crude oil production will be transported by surface vessel from LDPI except in the case of an emergency.

16.5 Industry Site-specific Bowhead Whale Monitoring Program

Industry Site-Specific Bowhead Whale-Monitoring Program is Stipulation No. 5 of Lease Sale 124 and Stipulation No. 4 of Lease Sale 144.

Stipulation Summary: Lessees proposing to conduct exploratory drilling operations, including seismic surveys, during the bowhead migration will be required to conduct a site-specific monitoring program approved by the RS/FO.

Compliance: This is a development project. This stipulation applies to exploration projects. No compliance activity is required. However, other measures designed to protect bowhead whales are planned, as described in Section 13.3.7.

16.6 Subsistence Whaling and Other Subsistence Activities

Subsistence whaling and other subsistence activities is Stipulation No. 6 of Lease Sale 124 and Stipulation No. 5 of Lease Sale 144.

Exploration and development and production operations shall be conducted in a manner that prevents unreasonable conflicts between the oil and gas industry and subsistence activities (including, but not limited to, bowhead whale subsistence hunting).

Prior to submitting an exploration plan or development and production plan (DPP; including associated oil-spill contingency plans) to the MMS for activities proposed during the bowhead whale migration period, the lessee shall consult with the potentially affected subsistence communities, Barrow, Kaktovik, or Nuiqsut, the North Slope Borough (NSB), and the Alaska Eskimo Whaling Commission (AEWC) to discuss potential conflicts with the siting, timing, and methods of proposed operations and safeguards or mitigating measures that could be implemented by the operator to prevent unreasonable conflicts. Through this consultation, the lessee shall make every reasonable effort to assure that exploration, development, and production activities are compatible with whaling and other subsistence hunting activities and will not result in unreasonable interference with subsistence harvests.

A discussion of resolutions reached during this consultation process and plans for continued consultation shall be included in the exploration plan or the development and production plan.

Stipulation Summary: The lessee must conduct operations in a manner that prevents unreasonable conflicts between industry activities and subsistence activities. Prior to submitting a DPP, the lessee shall consult with the potentially affected communities, the NSB, and the AEWC to discuss potential conflicts with the siting, timing, and methods of proposed operations and safeguards or mitigation measures that could be implemented to prevent unreasonable conflicts. The lessee shall make every reasonable effort to assure that development and production activities are compatible with whaling and other subsistence hunting activities, and will not result in unreasonable interference with subsistence harvests.

A discussion of resolutions reached during this consultation process and any unresolved conflicts shall be included in the DPP. The lessee shall show in the DPP how mobilization of the drilling unit and crew, and supply boat routes will be scheduled and located to minimize conflict with subsistence activities. Those involved in the consultation shall be identified in the plan. The lessee shall notify the RS/FO of all concerns expressed by subsistence hunters during the operations and of steps taken to address such concerns.

Compliance: Subsistence activities conducted in the vicinity of the Liberty Development are described in Section 3.16 of the EIA (Appendix A). Fall bowhead whaling is conducted by Nuiqsut whalers from Cross Island located about 17 miles north-northwest of the Liberty prospect. A number of North Slope organizations, including the AEWC and the communities of Nuiqsut and Kaktovik, have been previously consulted about the project, and will be included in further discussions as the project is further defined and evaluated during the NEPA review. Updated information on subsistence use near the project area was collected from interviews conducted in Nuiqsut and Kaktovik, as documented in the EIA, Sections 3.16. and 18 and EIA Attachment 2. In addition, consultations were conducted with whaling captains, with the AEWC, and the NSB. A listing of consultations with regulatory agencies and other stakeholders are contained in Section 6 of the EIA (Appendix A). These consultations will continue through other phases of the project.

HAK is proposing to incorporate measures into design, construction, and operations to minimize potential conflicts with subsistence use in the project area, such as those described in Section 13 of this DPP and Section 5 of the EIA (Appendix A). These measures include using a community liaison, protected species observers and subsistence advisors, and implementing a Conflict Avoidance Agreement with the AEWC and Nuiqsut Whaling Captains' Association, when warranted. Most major construction activities are planned for winter when there is no subsistence whaling. Marine traffic to/from the LDPI during subsistence whaling season will be routed inside the barrier islands, inshore of the typical fall bowhead whale migration path and Nuiqsut whaling activities. The Conflict Avoidance Agreement will also include consultation with the whalers on marine traffic and routing concerns.

Section 5 of the EIA (Appendix A) fully describes these measures, which include employment of a community liaison, development of a Conflict Avoidance Agreement with the AEWC, scheduling major construction activities to avoid conflicts with subsistence, and generally limiting vessel transit to LDPI to routes inside the barrier islands.

16.7 Oil Spill Response Preparedness

Oil Spill Response Preparedness is Stipulation No. 7 of Lease Sale 124.

Stipulation Summary: Lessees will submit OSRPs in accordance with 30 CFR 250.42. The OSRP must address all aspects of oil spill response readiness, including an analysis of potential spills and spill response strategies; type, location, and availability of appropriate oil spill equipment; response times and equipment capability for the proposed activities; and response drills and training requirements. The lessee will conduct drills as necessary to demonstrate readiness and response capabilities. For production operations, drills will be conducted at least semiannually.

Compliance: Oil spill response is discussed in Section 14 of this DPP. In addition, an OSRP has been developed for the Liberty Development and will be submitted to BSEE concurrent with DPP submittal.

16.8 Agreement between United States of America and the State of Alaska

An agreement between the United States of America and the State of Alaska is Stipulation No. 6 of Lease Sale 124 and Stipulation No. 5 of Lease Sale 144.

Stipulation Summary: This stipulation is an advisory regarding the terms of an agreement between the United States of America and the State of Alaska and applies to blocks or portions of blocks referred to in the notice as disputed.

Compliance: No compliance activity is required.

16.9 Agreement Regarding Unitization

An agreement between the United States of America and the State of Alaska regarding unitization is Stipulation No. 9 of Lease Sale 124 and Stipulation No. 7 of Lease Sale 144.

Stipulation Summary: This stipulation is an advisory regarding the terms of an agreement between the United States of America and the State of Alaska and applies to blocks or portions of blocks referred to in the notice as disputed.

16.10 Bonds, Oil Spill Financial Responsibility, Well Control Statements

Hilcorp Alaska, LLC (HAK) attests that:

- The activities and facilities proposed in this DPP will be or are covered by an appropriate bond under 30 CFR Part 556, subpart I;
- HAK has or will demonstrate oil spill financial responsibility for facilities proposed in the final DPP, according to 30 CFR part 553; and
- HAK has the financial capability to drill a relief well and to conduct other emergency well control operations.

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17 EMPLOYMENT AND TRAINING

The Liberty Development will have a measurable and lasting positive economic impact within the State of Alaska and beyond. Construction jobs, full-time operations positions, and an increased need for support industry services and supplies will all be a direct result of this development.

17.1 Employment

The Liberty Project workforce will vary. Workforce demands will shift as the project progresses from construction to drilling, and ultimately to continuous operations. The number of jobs is expected to peak during the construction phase with approximately 200 full-time equivalent positions. Construction crews will be contracted for: ice road construction, pipeline construction, civil construction, facility installation, and drilling unit installation. Island and pipeline construction activities will be scheduled 24 hours per day. Each work day will be split into two 12-hour shifts. Liberty activity will be constrained to seasonal work and short duration construction projects, and should not create a permanent population increase on the North Slope.

Drilling activity will also be scheduled around the clock and is expected to last approximately 2 years. Two drilling crews are planned to be on site at all times. Twelve-hour shifts are the Company standard. Drilling crews are anticipated to change out every 14 days. Each drilling position, 20 to 25 positions total, will require four full-time workers (two 12-hour shifts, rotating on-off the North Slope). During periods of drilling activity, the drilling unit crew and associated personnel are estimated to fluctuate between 60 and 80 full-time people.

Following construction and drilling, Liberty will move into the operations phase. At the appropriate time, HAK will develop staffing plans to support safe and responsible operations at Liberty. HAK will determine the necessary number of full-time employees, their job descriptions, as well as the timing for recruiting and hiring activities. Once production begins, one operations crew will be on the island at all times. The majority of operations personnel on the island will work day shift, with minimal staff required on night shift. Operations crews will be employed through the duration of field life, which has been estimated to be 15 to 20 years.

An economic analysis of the Liberty Development, including total workforce projections both direct and indirect, is presented in Section 4.1.15 of the EIA.

Please note the employment numbers presented in this section are in the terms generally understood and used by the general public. They may vary from the numbers and terms in EIA Section 4.1.15, which are terms of employment used in economic modeling.

17.2 Personnel Training

As part of existing Alaskan operations, HAK has a robust training system in place in order to ensure employee safety, regulatory compliance, and environmental stewardship. General environmental, socioeconomic, and regulatory awareness training is required of all employee and contractor personnel assigned to the North Slope. Additional training may be provided, depending on the individual work assignments.

Alaska's university, college, and vocational training facilities provide programs focused on employment in the oil and gas industry. The process technology program provided under the University of Alaska is one potential recruiting source. Additionally, individuals with oil and gas experience in O&M will be provided with an opportunity to apply for experienced-hire positions. For individuals hired from both the technical college and experienced-hire groups, HAK will provide additional training specific to Liberty operations and island logistics.

HAK will develop a new comprehensive training program for the unique aspects of the LDPI. The training module will be modeled after the program developed and implemented at the Northstar Island. Training will include sections on environmental awareness, environmental compliance, comprehensive safety issues, and operational details. All construction, drilling, and operations personnel will receive an appropriate level of training in pertinent subject areas. Training will be in compliance with 30 CFR Part 250, Subpart O - Training, as well as 30 CFR Part 250, Subpart S – Safety and Environmental Management Systems (SEMS), and with the stipulations of Lease Sale 144.

In addition to what is discussed in EH&S training (Section 12.3), other topics will be taught as part of general Liberty personnel training and discipline-specific training. Those topics are under development and currently include but are not limited to:

- Archaeological resource protection
- Protection of biological resources and habitats
- Subsistence and other socioeconomic issues
- Drilling well control
- Well completions
- Well work-over control
- Production safety systems
- Facility Control Systems
- Cold weather safety

18 COMMUNITY INVOLVEMENT

HAK's Alaska-based External Affairs Manager ensures that HAK remains in open communication with the stakeholders, regulators, and the general public in the State. HAK will continue to keep neighboring community members informed of planned activities via various means of communication including: community visits, meetings with community leadership and elders, general community meetings, bulk mailings, local newspaper postings, local radio broadcasts, and local government or tribal meetings.

Effective, consistent, and ongoing consultation with North Slope constituents is a priority for HAK and the Liberty partners. Such consultation will help to execute the Liberty project in a way that is right for both industry and the community. It will also ensure that concerns of the NSB and communities closest to Liberty are identified and addressed in a timely manner.

18.1 Communications and Coordination with Local Residents

The Liberty Development project has been studied for more than 15 years, with input from North Slope residents and a wide variety of subject matter experts. HAK will continue the tradition of developing the project with input from local residents and performing scientific studies as needed. Based on this foundation of development planning and mitigation measures, protocols have been developed to avoid or minimize the adverse impacts to subsistence resources and activities.

HAK has committed to take part in the Conflict Avoidance Agreement (CAA) with the Alaska Eskimos Whaling Commission (AEWC), and will continue to abide by the CAA each year that marine operations are conducted in support of Liberty operations.

Dialogue with local stakeholders including local residents, the NSB, AEWC, Alaska Native tribal organizations, local whaling captains, the Inupiat Community of the Arctic Slope (ICAS) and relevant Alaska Native Claims Settlement Act (ANCSA) corporations will be ongoing. HAK will strive to maintain open and transparent communications at all times.

Meetings with federal and state agencies, including BOEM, BSEE, USACE, EPA, USFWS, ADNR, ADF&G, and ADEC, are taking place. Information on the associated permitting actions and NEPA analysis will be provided through the public notice process in selected publications. As permitting progresses, additional public notices will be provided under NEPA for comments on the federal applications, as well as individual state and local permits requiring public notice.

18.2 Local and Alaska Hire

HAK has made the commitment to hire local workers to support North Slope operations and other activity within Alaska. New projects like Liberty will require several additions to our existing workforce including: construction and fabrication crews, additional operations personnel, drilling crews, maintenance, and a number of other support staff positions. HAK understands the unique challenges that operating on the North Slope presents and prefers to hire Alaskan workers with local experience and knowledge. HAK welcomes and encourages the opportunity to bring traditional knowledge to the field. The vast majority of current HAK employees are Alaska residents.

HAK estimates that approximately 90% of all labor costs associated with this project will be contracted with Alaska-based companies and Alaska resident labor. Qualified Alaska-based firms that provide necessary goods and services will be given special consideration. However, HAK will search for and evaluate contractors that meet our requirements for competitiveness, competency, and safety performance. Those who are best suited to perform the stated work will be selected. North Slope residents will be encouraged to apply for jobs that become available through contractors at the appropriate time.

Seasonal-hire positions (e.g., Protected Species Observers and bear monitors) represent additional opportunities for local employment at Liberty. Guidance from Subsistence Representatives will also be needed. Seasonal positions offer an abbreviated work schedule that doesn't conflict with subsistence hunting, fishing, and whaling activities. For both year-round and seasonal employment, reasonable administrative leave requests by Alaska Natives to fulfill subsistence and cultural activities will be considered and granted on a case-by-case basis.

19 PROJECT TERMINATION, DECOMMISSIONING, ABANDONMENT

The expected life of the Liberty field is 15 to 20 years, and the minimum project operational life is determined to be 25 years for the basis of design to assure acceptable island, pipeline, well, and facility performance for the life of the field. However, the actual service life of the project will depend on several factors. Once the island is constructed, infill drilling or possible delineation success could extend the service life of the island, production facilities, and pipeline system. Likewise, since the pipeline system will be operated as a common carrier, HAK or another entity could continue to use the pipeline for other future purposes after the Liberty reservoir has been depleted.

HAK will decide when to abandon the project facilities based on the need for continued use of the facilities. At the time the project is no longer economically viable, HAK would either begin abandonment procedures according to the permit conditions and regulations in force at that time, or enter into negotiations to transfer ownership of the project to another entity.

BSEE regulations provide specific requirements for well abandonment, but those are not prescriptive for island abandonment (removal is required to a depth approved by the Regional Supervisor). The buried subsea pipeline will be abandoned in place. Laws and regulations pertaining to ADNR and U.S. Army Corps of Engineers (USACE) approvals for this project also provide for discretion in termination and abandonment procedures.

Some precedent has been set through approved abandonment of several islands built for exploratory drilling in state and federal Beaufort Sea waters. These abandonment procedures have involved removing island slope protection, removing island facilities, removing wellheads, pilings, and other structures to below the mudline, and plugging and abandoning wells. Natural wave, ice, and current forces then gradually erode the island surface. This procedure was used for Tern Island, which is located about 1.5 miles from the proposed LDPI. HAK anticipates decommissioning LDPI at the end of field life (EOFL) and cessation of production, as defined by operating agreements, permits, and regulations. HAK will obtain approval of its decommissioning plan by submitting an application pursuant to regulation in effect at that time. Title 30 CFR 250.1703(a) and 30 CFR 250.1704 currently require the application be submitted to BSEE and meet the applicable requirements of 30 CFR Subpart Q, Decommissioning Activities.

The majority of the Liberty Development decommissioning will be focused on the production and transportation facilities. The decommissioning of these facilities is expected to occur in approximately 25 to 30 years. Following is a brief description of the key aspects of decommissioning at the EOFL. Given the time until actual decommissioning, and the permits that must be obtained for project construction and operation that may contain decommissioning stipulations, the actual decommissioning plan may vary from what is currently envisioned and described here.

In addition to LDPI facilities, the gravel mine developed to support the Liberty Development is expected to be rehabilitated and abandoned much earlier, typically within 5 years of completing gravel removal. The gravel mine will be on state land, and rehabilitation and abandonment is regulated primarily by USACE and ADNR. A number of gravel mines have been rehabilitated and abandoned on the North Slope. The standard steps for North Slope mine abandonment include requiring contouring portions of the mine pit, redistributing top soil from the site, and allowing the site to fill with water to create a lake or water reservoir.

For this brief description of decommissioning, assume the following divisions of development assets:

- Surface Facilities
- Surface Pipelines and Vertical Support Members (VSMs)
- Wells

- Subsurface/Subsea Pipelines
- Offshore Gravel Islands
- Gravel Mine
- Onshore Gravel Roads and Pads

These descriptions would be consistent with reasonable general assumptions unless there are specific conflicting stipulations defined in the relevant permits or other controlling documents required for development.

19.1 Surface Facilities

For purposes of this brief description, surface facilities include all equipment and structures associated with drilling, development, and production of the Liberty asset. All modules, stick-built structures, pipelines, and supports are considered in the inventory of surface facilities.

All installed surface facilities associated with the Liberty Development will have to be removed. All surface facilities would be de-energized, flushed of any oil and chemical residues if necessary (not all the lines carry oil), and removed. Modules will be removed in a reverse process from installation and transported to an offsite location for recycle or final disposition. Other installations would likely be removed by dismantlement, similar to the reverse of their construction process.

19.2 Onshore Pipelines and Vertical Support Members

For the purposes of this brief description, HAK will assume that all surface pipelines and well lines used exclusively by Liberty Development will be removed following EOFL. All surface lines would be de-energized and flushed (if necessary) prior to removal. The processes and standards for flushing are expected to be site-specific and become a key element of the final decommissioning plan. Additionally, a likely expectation is that VSMs will be removed.

19.3 Wells

Well abandonment is assumed to follow the applicable requirements in 30 CFR 250, Subpart Q. Once abandoned, either a well marker will be welded to the remaining cemented casing to identify the well, or casing may be welded closed, as determined by requirements at the time of decommissioning.

19.4 Subsea, Subsurface Pipelines

The marine pipelines will be abandoned in place, which is the environmentally preferable method of decommissioning. The normal process of abandoning buried pipelines is an extensive flushing and verification that all hydrocarbons or other contaminants have been removed, cutting the ends of the pipeline off at the appropriate elevation, and permanently sealing the ends. Marine lines would likely need to be identified to the U.S. Coast Guard (USCG) for proper chart designations or aid to navigation marking, as appropriate. The details of decommissioning the subsea buried pipeline will be determined in the permitting and/or decommissioning approval process.

19.5 Offshore Gravel Island

Offshore gravel exploration islands in the Beaufort Sea have traditionally been allowed to remain in place, after armoring and structures were removed, and become gravel islands that may be useful as habitat or to support regional non-industrial activities. For purposes of this brief description, HAK assumes the same decommissioning for LDPI. The process of decommission typically would include removal of armoring and sheet pile, testing the island(s) for any contamination, remediating any contamination, and then allowing the waves and currents to reshape the island by natural processes. The removed armor may be used to enhance hard bottom habitat, which is rare in the Beaufort Sea, or removed from the project area and recycled to another use or disposed of in an approved manner. If Boulder Patch communities have colonized the lower portions of concrete slope armor, BOEM will be consulted prior to removal. Aids to Navigation requirements, if any, would be established with the USCG.

19.6 Gravel Mine

Abandonment and rehabilitation of the gravel mine site for Liberty will be described in a Mining and Rehabilitation Plan submitted for approval to the ADNR and USACE.

19.7 Onshore Roads and Pads

Liberty Development does not include construction of onshore gravel roads; two small gravel pads will be developed for onshore pipeline support at the Badami pipeline tie-in location and at the Badami seasonal ice road crossing location. Temporary onshore and offshore ice roads connecting the mine site, construction areas, and LDPI will melt at breakup; stream and river crossings will be slotted to facilitate stream flow. As is standard procedure, onshore ice road routes will be inspected the following summer for tundra damage, which will be remediated, as needed. Abandonment and rehabilitation of the onshore gravel pads will be completed according to applicable regulatory requirements.

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20 CONTACTS, LIST OF PREPARERS

20.1 Hilcorp Contacts

A Hilcorp Alaska LLC designated representative will be on site at all times during construction, drilling, and production operations. A 24-hour phone service will be available at construction camps and later at the Operations Camp while activities are being performed.

During the planning and permitting phase, persons or positions that are designated contacts for the Liberty Project are listed in Table 20-1. The mailing address for all contacts is 3800 Centerpoint Drive, Anchorage, AK 99503.

Table 20-1. Hilcorp Alaska, LLC, Contact Personnel

NAME	TITLE	EMAIL	PHONE
Kate Kaufman	Permitting Manager Primary Contact	kkaufman@hilcorp.com	Office (907) 777-8329 Mobil (907) 244-8292
Mike Dunn	Operations Manager Secondary Contact	mdunn@hilcorp.com	Office (907) 777-8382 Mobil (907) 351-4191
Walton Crowell	Operations Engineer Secondary Contact	wcrowell@hilcorp.com	Office (907) 777-8402 Mobil (907) 570-8177

This contact list will be updated and provided to the applicable agencies, as appropriate.

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21 ADMINISTRATIVE INFORMATION

21.1 Exempted Information

Appendix C. Geochemical Reports

Appendix G. Worst Case Discharge (WCD) Modeling Report

21.2 Bibliography

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