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BP EXPLORATION (ALASKA) INC.

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

LIBERTY DEVELOPMENT AREA
NORTH SLOPE, ALASKA

June 2000

Contents

MANAGEMENT APPROVAL AND MANPOWER AUTHORIZATION

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN
LIBERTY DEVELOPMENT AREA
NORTH SLOPE, ALASKA

This Oil Discharge Prevention and Contingency Plan has been prepared for BP Exploration (Alaska) Inc. operations at Liberty. These operations include drilling, production, storage, transfer, and field maintenance.

This plan is approved for implementation as herein described. Manpower, equipment, and materials will be provided as required in accordance with this plan.

BPXA's approach to spill response will be based on the following priorities:

1. Safety of personnel
2. Protection of the environment
3. *Protection of facilities*

______________________________ ______________________________

Greg Mattson Date
Alaska New Developments Business Unit Leader
BP Exploration (Alaska) Inc.
Anchorage, Alaska

ENGINEER SPCC CERTIFICATION

Incorporated into this ODPCP is the Spill Prevention, Control, and Countermeasure (SPCC) Plan for the Liberty Development Area required by 40 CFR (Code of Federal Regulations) 112. Regulation 40 CFR 112.3(a) requires a SPCC plan to be stamped by a professional engineer to be considered in effect. Specifically, 30 CFR 112.3(d) states:

> No SPCC Plan shall be effective to satisfy the requirements of this part unless it has been reviewed by a Registered Professional Engineer and certified to by such Professional Engineer. By means of this certification the engineer, having examined the facility and being familiar with the provisions of this part, shall attest that the SPCC Plan has been prepared in accordance with good engineering practices . . .

Because the ODPCP integrates many aspects of spill response planning, including response and prevention, the engineer must certify that only those sections that apply directly to SPCC requirements have been prepared according to good engineering practice. Sections of the ODPCP plan which do not apply directly to SPCC requirements, such as information on the biology, geology or climate of the area, or to response activities, need not have engineering certification because no engineering practice is involved.

I hereby certify that I have examined the facility and, being familiar with the provisions of 40 CFR Part 112, attest that the sections of this plan applicable to SPCC requirements have been prepared in accordance with good engineering practice.

____

Printed Name of Registered Engineer

____

Signature of Registered Professional Engineer

Registration No. ____________

State ____________

RECORD OF REVISIONS

REVISION NUMBER	REVISION DATE	DATE ENTERED	SIGNATURE OF PERSON ENTERING CHANGES

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[30 CFR 254, Subpart B)]

REGULATION SECTION (30 CFR)	SECTION TITLE	PLAN SECTION
254.22	**Introduction and Plan Contents**	
(a)	Identification of Facility, Including Location and Type	Sections 1.8 and 3.1
(b)	Table of Contents	Table of Contents
(c)	Record of Changes	Page iii
(d)	Cross-Reference Table	This section
254.23	**Emergency Response Action Plan**	Section 1.1
(a)	Designation of Trained Qualified Individual (with full authority to implement removal actions and notify federal officials and response personnel)	Section 1.1
(b)	Designation of Trained Spill Management Team Available 24 Hours (including organizational structure and responsibilities and authorities of team members)	Figure 1-2, Section 3.3
(c)	Description of Spill Response Operating Team, Including Numbers and Types of Personnel (trained and available on 24-hr basis)	Figures 1-2, Section 1.6.14
(d)	Locations and Primary and Secondary Communications for Spill Response Operations Center (including phone numbers and radios)	Section 1.4
(e)	List of Types of Oil Handled, Stored, or Transported	Section 3.1, Table 3-1
(f)	Procedures for Early Detection of a Spill	Section 2.5
(g)	Procedures for Spill or Substantial Threat of a Spill for Differing Spill Sizes	Section 1.6
(g)(1)	Notification Procedures (including reporting form from Area Plan)	Section 1.1, Figure 1-4
(g)(1)(i)	Contact Information for Qualified Individual, Spill Response Coordinator and Alternates, and Other Spill Response Management Team Members	Section 1.1
(g)(1)(ii)	Names and Addresses for Oil Spill Response Organizations (OSROs) and Regulatory Agencies to be Notified and Contacted for Environmental Information	Section 3.8, Table 1-2 Section 1.1, Tables 1-3A and 1-3B
(g)(2)	Methods to Monitor and Predict Spill Movement	Sections 1.6.4; 3.10.1
(g)(3)	Methods to Identify and Prioritize Sensitive Areas	Sections 1.6.5 and 3.10
(g)(4)	Methods to Protect Sensitive Areas	Sections 1.6.5 and 3.10

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CROSS REFERENCE TO U.S. MINERALS MANAGEMENT SERVICE RESPONSE PLAN REQUIREMENTS [30 CFR 254, Subpart B)]

REGULATION SECTION (30 CFR)	SECTION TITLE	PLAN SECTION
254.23 (Cont'd)	**Emergency Response Action Plan (Cont'd)**	
(g)(5)	Methods to Mobilize and Deploy Equipment and Personnel	Section 1.5
(g)(6)	Methods for Storage of Recovered Oil (to allow containment and recovery to continue without interruption)	Section 1.6.14
(g)(7)	Procedures to Remove Oil and Oiled Debris from Shallow Areas and Along Shorelines and to Rehabilitate Oiled Waterfowl	Section 1.6.14
(g)(8)	Storage, Transfer, and Disposal Procedures	Sections 1.6.9 and 1.6.10
(g)(9)	Methods to Implement Dispersant Use Plan and In Situ Burning Plan	Sections 1.7
254.24	**Equipment Inventory Appendix**	
(a)	Inventory of Spill Response Materials and Supplies, Services, Equipment, and Response Vessels Available Locally and Regionally (identify supplier, location, and phone number)	Sections 3.6 and 3.8, Table 3-2
(b)	Procedures for Inspecting and Maintaining Spill Response Equipment (inspected monthly; records of inspections and maintenance kept for at least 2 years)	Section 3.6.2
254.25	**Contractual Agreements Appendix (copies of contracts or membership agreements or certification that they are in effect; must ensure 24-hr availability)**	Section 3.8
254.26	**Worst-Case Discharge Scenario Appendix**	Section 1.6.14
(a)	Volume and Assumptions/Calculations	Sections 1.6.13 and 1.6.14
(b)	Trajectory Analysis (including maximum extent of oil travel)	Section 1.6.14
(c)	List of Sensitive Areas That Could be Affected (from Area Contingency Plan) and Strategies for Protecting Them	Sections 1.6.5 and 1.6.14
(d)	Response to Worst-Case Scenario in Adverse Weather Conditions	Section 1.6.14
(d)(1)	Response Equipment Used for a 30-day Blowout (types, locations, owners, quantity, capabilities, and daily recovery capacities using 20% derate)	Section 1.6.14
(d)(2)	Personnel, Materials, and Support Vessels (Locations, Owners, Quantities, and Types)	Section 1.6.14

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REGULATION SECTION (30 CFR)	SECTION TITLE	PLAN SECTION
254.26 (Cont'd)	**Worst-Case Discharge Scenario Appendix (Cont'd)**	
(d)(3)	Description of Oil Storage, Transfer, and Disposal Equipment (Location, Owners, Quantities, and Capacities)	Section 1.6.14
(d)(4)	Estimate of Response Times	Section 1.6.14
(d)(4)(i)	Procurement of Identified Containment, Recovery, and Storage Equipment	Section 1.6.14
(d)(4)(ii)	Procurement of Equipment Transportation Vessels	Section 1.6.14
(d)(4)(iii)	Procurement of Personnel to Load and Operate the Equipment	Section 1.6.14
(d)(4)(iv)	Equipment Loadout	Section 1.6.14
(d)(4)(v)	Travel to Deployment Site	Section 1.6.14
(d)(4)(vi)	Equipment Deployment	Section 1.6.14
(e)	Equipment, Materials, Support Vessels, and Strategies Must be Suitable to Range of Environmental Conditions. Discussion in (d) Must Use Standardized Defined Terms in ASTM F625-94 and F818-93	Section 3.4
254.27	**Dispersant Use Plan Appendix**	Not Applicable
(a)	Inventory and Location of Dispersants and Other Spill Response Chemicals	Not Applicable
(b)	Summary of Toxicity Data	Not Applicable
(c)	Application Equipment and Time to Deploy	Not Applicable
(d)	Application Procedures	Not Applicable
(e)	Conditions Under Which Product Use May be Requested	Not Applicable
(f)	Outline of Procedures for Obtaining Approval	Not Applicable
254.28	**In Situ Burning Plan Appendix**	Section 1.7
(a)	Description of Equipment, Including Availability, Location, and Owner	Section 1.7.4
(b)	In Situ Burning Procedures, Including Ignition	Section 1.7
(c)	Environmental Effects of Burn	Section 1.7
(d)	Guidelines for Well Control and Personnel Safety	Section 1.6.3
(e)	Circumstances When Burning is Appropriate	Sections 1.6.14 and 1.7
(g)	Outline of Procedures for Obtaining Approval	Sections 1.7

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CROSS REFERENCE TO
U.S. MINERALS MANAGEMENT SERVICE RESPONSE PLAN REQUIREMENTS
[30 CFR 254, Subpart B)]

REGULATION SECTION (30 CFR)	SECTION TITLE	PLAN SECTION
254.29	**Training and Drills Appendix**	
(a)	Training: Describe Dates and Types of Training Given to Response Team Personnel; Location of Certificates: • Annual hands-on training of spill response operating team • annual training for spill response management team, including locations, intended use, deployment strategies, and operation and logistics of response equipment; spill reporting; trajectory analysis; responsibilities • qualified individual sufficiently trained • keep training certificates and attendance records at least 2 years	Section 3.9
(b)	Exercise Plans for Annual Spill Management Team Tabletop, Annual Deployment of Equipment Staged Onshore, Annual Notification Exercise, Semiannual Deployment for Equipment at Facility (entire plan must be exercised once every 3 years). National Preparedness for Response Exercise Program [PREP] can be used	Section 3.9

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WORST CASE DISCHARGE

MMS regulations 30 CFR 254.47 require worst case discharge (WCD) calculations for an oil production platform facility. Liberty will be a gravel island, not a production platform. However, the WCD for Liberty is calculated based on the formula provided in 30 CFR 254.47 and is provided below. Scenarios describing the response to a WCD are provided in Section 1.6.14.

$WCD_{production}$ = Maximum capacity of all oil storage tanks and flowlines on the facility plus the volume of oil from a pipeline break, considering shutdown times, hydrostatic pressure, and other factors, plus the daily production volume from an uncontrolled blowout of the highest capacity well.

Capacity of all storage tanks	*19,350 barrels (bbl)*
Capacity of all flowlines[1]	9 bbl
Pipeline leak[2]	1,764 bbl
Daily production volume	15,000 bbl
$WCD_{production}$	**36,123 bbl**

[1] Based on a 6-inch flowline, approximately 250 feet long. Subject to change pending final construction

[2] See Section 1.6.13 for the pipeline leak volume calculation.

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CROSS REFERENCE TO U.S. DEPARTMENT OF TRANSPORTATION RESPONSE PLAN REQUIREMENTS [49 CFR 194, Subpart B)]

REGULATION SECTION (49 CFR 194)	SECTION TITLE	PLAN SECTION
194.103	Significant and substantial harm; operator's statement	This section
194.105 (a)	Worst case discharge and the methodology, including calculations used to arrive at the volume.	This section
194.107 (a)	Resources for responding to the worst case discharge and the substantial threat of a discharge.	Sections 1.6.14, 3.5, 3.6, and 3.8
194.107 (c)	Certification that the plan is consistent with the NCP	This section
194.107 (d) (1) (ii)	Immediate notification procedures	Section 1.1
194.107 (d)(1)(iii)	Spill detection and mitigation procedures	Sections 1.6 and 2.5
194.107 (d) (1) (iv)	Name, address and phone number of Spill Response Organization	Table 1-2
194.107 (d)(1)(v)	Response activities and resources	Section 1.6.14
194.107 (d)(1)(vi)	Names and telephone numbers of federal, state, and local agencies with pollution control responsibilities or support	Section 1.2; Tables 1-3A and 1-3B
194.107 (d)(1)(vii)	Training procedures	Sections 2.1.1 and 3.9
194.107 (d)(1)(viii)	Equipment Testing	Section 3.6.2
194.107 (d)(1)(ix)	Drill types, schedules, and procedures	Section 3.9
194.107 (d)(1)(x)	Plan review and update procedures	Introduction
194.107 (d)(2)	Response zone	N/A, entire pipeline is a single response zone

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U.S. DOT CERTIFICATION OF PREPAREDNESS

CERTIFICATE OF RESPONSE PREPAREDNESS FOR LIBERTY DEVELOPMENT

BP EXPLORATION (ALASKA) INC.
LIBERTY DEVELOPMENT

Pipeline Response Plans Officer
Research and Special Programs Administration
U.S. Department of Transportation
Room 2335
400 Seventh Street, SW
Washington, DC 20590

BP Exploration (Alaska) Inc. hereby certifies to the Research and Special Programs Administration of the U.S. Department of Transportation that it has identified, and ensured by contract, or other means to be approved by the Research and Special Programs Administration, the availability of private personnel and equipment to respond, to the maximum extent practicable, to a worst-case discharge or a substantial threat of such a discharge.

______________________________ ____________________

Greg Mattson — Date
Alaska New Developments Business Unit Leader
BP Exploration (Alaska) Inc.
Anchorage, Alaska

This Certification of Response Preparedness was acknowledged before me on ______________, by ________________________ on behalf of said corporation.

____

My commission expires ________

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ACP/NCP CONSISTENCY CERTIFICATION FOR LIBERTY

BP EXPLORATION (ALASKA) INC.
LIBERTY DEVELOPMENT

BP Exploration (Alaska) Inc. hereby certifies to the Research and Special Programs Administration of the Department of Transportation that it has reviewed the National Contingency Plan (NCP) and applicable Area Contingency Plans (ACPs) and found the Liberty Development's Oil Discharge Prevention and Contingency Plan to be consistent with them. The NCP/ACPs reviewed include the NCP as set forth in the 40 CFR Part 300 as published in FR Vol. 59, No. 178, Final Rule, September 15, 1994, and the Alaska Federal/State Unified Preparedness Plan ACP (The Unified Plan), Volume I and Volume II (North Slope Borough), dated May 1994.

____
Ross Klie, Manager
Health, Safety, and Environment

____
Date

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U.S. DOT INFORMATION SUMMARY

Name and Address of Operator:

BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612
Phone: (907) 561-5111

Street Address:
900 East Benson Boulevard
Anchorage, AK 99508
Fax: (907) 561-5020

Response Zone Description:

The BP Exploration (Alaska) Inc. Liberty Development Area consists of a single response zone containing the Liberty sales oil line, running from the Liberty Development Island to the Badami pipeline tie-in, located in the North Slope Borough of Alaska.

Worst-Case Discharge

In accordance with 49 CFR 194.105(b)(1), the WCD for the pipeline is equal to the pipeline's maximum release time (RT_{max}) in hours plus the maximum shutdown response time (ST_{max}) in hours multiplied by the maximum flow rate (F_{max}) expressed in bbl per hour (bph) (based on maximum daily capacity of the pipeline) plus the largest pipeline drainage volume (PV_{max}) after shutdown of the line section(s) in the response zone expressed in bbl or:

$$WCD = [(RT_{max} + ST_{max}) * F_{max}] + Pv_{max}$$

Where:

RT_{max} = 0.092 hours (5.5 minutes)
ST_{max} = 0.142 hours (8.5 minute)
F_{max} = 2,708 bph[1]
PV_{max} = 1,130 bbl[2]

[1]The Liberty pipeline will have a handling capacity of 65,000 bbl of oil per day (bopd) (2,708 bph).
[2] PV_{max} =Maximum oil volume displaced by water intrusion.

Therefore, the Liberty sales oil pipeline DOT WCD is:

[(0.092 hrs + 0.142 hrs) * 2,708] + 1,130 bbl = **1,764 bbl**

Description of the Line Sections

The Liberty sales oil line will be 7.6 miles in length, running from Liberty Island to the Badami tie-in, approximately 1.5 miles west of the Kadleroshilik River.

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Basis for Determination of Significant and Substantial Harm

The Liberty sales oil line will have an outside diameter of 12 inches. The offshore section of the pipeline will be 6.1 miles long, located within the Foggy Island Bay and the onshore section will be aboveground and 1.5 miles long, located over tundra. The marine environment of Foggy Island Bay and the onshore tundra environment are sensitive areas that would be impacted if a release occurred. As such, the pipeline is determined to pose a significant and substantial harm to the environment.

Type of Oil and Volume of Worst-Case Discharge

Type of oil:	North Slope crude
Worst-Case Discharge	1,764 bbl

Certification of Necessary Response Personnel and Equipment for a Worst-Case Discharge

Sufficient response personnel and equipment is available to respond to a WCD or threat of such a discharge. This information is provided in sections 1.6.14, Spill Response Scenarios; 3.5, Logistical Support; 3.6, Response Equipment; and 3.8, Response Contractor Information.

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LIST OF FIGURES

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LIST OF ACRONYMS AND DEFINITIONS

AAC	Alaska Administrative Code
ACP	Area Contingency Plan
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ARCO	ARCO Alaska, Inc.
BAT	best available technology
bbl	barrel
BESD	blowdown emergency shutdown
BMP	Best Management Practices
BOP	blowout preventer
bopd	barrels of oil per day
boph	barrels of oil per hour
bpd	barrels per day
BPXA	BP Exploration (Alaska) Inc.
CFR	Code of Federal Regulations
CMT	Crisis Management Team
DOT	(U.S.) Department of Transportation
EPA	(U.S.) Environmental Protection Agency
ERT	Emergency Response Team
ESD	Emergency shutdown
ESDV	emergency shutdown valve
FBE	fusion-bonded epoxy
FOSC	Federal On-Scene Coordinator
GC	gathering center
H_2S	hydrogen sulfide
HAZWOPER	Hazardous Waste Operations and Emergency Response
HQ	headquarters
HSE	(BPXA) Health, Safety, and Environment (department)
ICS	Incident Command System
IMT	Incident Management Team
ISB	in situ burning
LEL	lower explosive limit
LEOS	Leck Erkennung und Ortungs System
LOSC	Local On-scene Coordinator
MAD	Mutual Aid Drill
MAOP	maximum allowable operating pressure
MB	mass balance
MBLPC	*mass balance line pack compensation*
MMS	Minerals Management Service
mstb	thousands of standard barrels
NCP	National Contingency Plan
NGL	natural gas liquids

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NPWM	negative pressure wave monitoring
NSSRPT	North Slope Spill Response Project Team
OCS	Outer Continental Shelf
ODPCP	Oil Discharge Prevention and Contingency Plan
OPA 90	Oil Pollution Act of 1990
OSD	operational shutdown
OSHA	Occupational Safety and Health Administration
OSRO	Oil Spill Response Organization
PLC	programmable logic controller
PPA	pressure point analysis
PPE	personal protective equipment
PREP	(National) Preparedness for Response Exercise Program
psi	pounds per square inch
psig	pounds per square inch gauge
RP	Recommended Practice
RPS	Response Planning Standard
RRT	Regional Response Team
RTTM	real-time transient model
SCADA	supervisory control and data acquisition
scf	standard cubic foot
SDI	Satellite Drilling Island
SDV	shutdown valve
SOSC	State On-Scene Coordinator
SPCC	Spill, Prevention, Control, and Countermeasures
SPTF	Shoreline Protection Task Force
SRT	Spill Response Team
SRTF	Shoreline Recovery Task Force
SSSV	subsurface safety valves
SSV	surface safety valves
stb	standard barrel
TBD	to be determined
UOP	Unified Operating Procedure
USCG	U.S. Coast Guard
USD	unit shutdown
USFWS	U.S. Fish and Wildlife Service
VHF	very high frequency
VSM	vertical support member
WCD	Worst Case Discharge

INTRODUCTION

This Oil Discharge Prevention and Contingency Plan (ODPCP) is for the Liberty Development Area. BP Exploration (Alaska) Inc. (BPXA) is the owner/operator of the facility, which will be located offshore in Foggy Island Bay about 6.5 miles east of the Endicott Satellite Drilling Island (SDI) and about 5 miles north of the Kadleroshilik River on Alaska's North Slope. The development will consist of an artificial drilling/production gravel island, with a crude oil pipeline to shore tying into the pipeline from the Badami Development Area. The island will be located in federal waters, but the pipeline will enter state waters and state lands. BPXA's address, phone, and fax numbers are provided below:

BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612
Phone: (907) 561-5111

Street Address:
900 East Benson Boulevard
Anchorage, AK 99508
Fax: (907) 561-5020

OBJECTIVES

The objective of this ODPCP is to provide BPXA with the background information and response planning guidelines necessary to implement an effective spill response. The following types of facilities and operations are covered by this plan:

- Facility and pipeline construction
- Drilling facilities
- Production facilities
- Storage operations
- Pipeline operations
- Transfer operations
- Field maintenance operations

The plan follows the format of oil discharge prevention and contingency plan regulations of the Alaska Department of Environmental Conservation (ADEC) (18 Alaska Administrative Code [AAC] 75.425); however, because the facility is located in federal waters, it is regulated by the U.S. Minerals Management Service (MMS). A cross-reference table is provided for the MMS regulations as well as the U.S. Department of Transportation (DOT) regulations, based on the Oil Pollution Act of 1990 (OPA 90). The USCG regulates barge fuel transfer operations, which are conducted in accordance with an USCG-approved Operations Manual. The plan has also been designed to address U.S. Environmental Protection Agency (EPA) SPCC regulations under 40 CFR 112. The various federal and state jurisdictions are summarized below:

• Crude oil production:	MMS
• Barge fuel transfer operations:	USCG
• Transportation of crude oil by pipeline:	MMS, DOT, ADEC
• Fuel storage:	MMS

A spill response operation on the North Slope falls into one of three categories:

- **Level I:** Small operational spills dealt with by on-scene personnel and equipment.
- **Level II:** Larger spills which could affect the area around the facility or operation that require equipment and/or trained personnel located in the other operating areas of the North Slope.
- **Level III:** A major spill requiring resources from off the North Slope.

Both Level II and III spills may result in the activation of the Incident Management Team (IMT) and/or the Crisis Management Team (CMT). As necessary, the responsible party will use the resources of other North Slope operators through Alaska Clean Seas (ACS), Mutual Aid, spill response cooperatives, and contractors. The response organization structure described in this plan is based on the Incident Command System (ICS) and will accommodate each level of response.

ACS TECHNICAL MANUAL

BPXA is a member of ACS, which serves as the primary response action contractor for operators on the North Slope. This ODPCP incorporates by reference, wherever applicable, the ACS *Technical Manual*, which consists of Volume 1, *Tactics Description*; Volume 2, *Map Atlas*; and Volume 3, *Incident Management System*. Volume 1 describes the tactics that can be used in responding to a variety of spill situations. Volume 2 provides maps and a narrative description of resources at risk and key response considerations. Volume 3 details the incident management system that will be used to respond to a spill.

PLAN CONTENTS ORGANIZATION

Following is a summary of the principal contents of this ODPCP:

- **Management Approval and Manpower Authorization**. Providing approval and authorizing resources as required to implement this plan.
- **Engineer SPCC Certification.** Sign-off by a registered professional engineer (once the facility has been constructed) stating that the ODPCP meets the requirements of SPCC regulations (40 CFR 112).
- **OPA 90 Section.** Addressing the federal spill planning regulations of MMS (30 CFR 254) and DOT (49 CFR 194), as applicable.
- **Part 1 - Response Action Plan**. The response action plan provides information to guide the Spill Response Team (SRT), IMT, and CMT in a response to an incident. Information includes reporting and notification procedures, basic safety procedures, a communications plan, deployment and response strategies, and initial response procedures. Company personnel are familiar with the contents of this plan and other manuals necessary to carry out a successful response.
- **Part 2 - Prevention Plan**. The prevention plan provides a detailed description of policies, best management practices, and prevention measures employed at the facility. Information is included on identified risks, historical spills, and measures being taken to minimize potential impacts.
- **Part 3 - Supplemental Information**. The supplemental information provides an overview of the facility operations, environmental information, and supporting response information.

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- **Part 4 - Best Available Technology**. The best available technology (BAT) analyzes spill prevention and response equipment of the facility to determine whether it meets performance standards in 18 AAC 75.

This plan relies heavily upon information that is provided in the ACS *Technical Manual*. Information from the Technical Manual is not repeated in this plan. On each page of this plan, the right-hand column contains references to specific tactics descriptions, maps, and IMT information contained in the ACS *Technical Manual*. In addition, the right-hand column references tables and figures contained in this plan. This format minimizes duplication of information.

The following BPXA manuals, which describe blowout prevention and additional support information, are located at facility response centers and in the BPXA Anchorage Health, Safety, and Environment (HSE) Department. The manuals are available for inspection on request.

- *Crisis Response Team Procedures Manual*
- *BPXA Arctic Well Control Contingency Plan*
- *Alaska Safety Handbook*

PLAN DISTRIBUTION

The plan is distributed to regulators, BPXA management, and staff as appropriate. Additional copies are located in the Anchorage Crisis Center, HSE Department, and ACS. A record of plan distribution is maintained by the HSE Department.

UPDATING PROCEDURES

A master copy of the plan is maintained by the HSE Department. The plan is reviewed and updated when major changes occur. In accordance with SPCC requirements, the plan is also reviewed periodically. Below is a list of key factors, which may cause revisions to the plan:

- New developments
- New pipeline construction
- Changes to response planning standards (RPS)
- Change in commodities transported
- Change in oil spill response organizations
- Change in Qualified Individual
- Changes in an NCP or ACP that have a significant impact on the appropriateness of response equipment or response strategies
- Change in response procedures
- Change in ownership

Modifications to the plan may also occur after spill response drills or incidents have been fully evaluated. In addition, all plan recipients are encouraged to provide comments on the plan, which could lead to updates or modifications to the plan.

Any significant amendment to the plan is submitted to the appropriate agency for review prior to implementation. MMS regulations require that revisions be submitted for approval with 15 days whenever significant changes occur.

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DOT regulation 49 CFR 194.121 requires that modifications that could substantially affect the implementation of the response plan be submitted for review within 30 days.

Revisions to the plan are logged on a Record of Revisions - Master Plan form. On receipt of revisions, the plan recipient replaces pages as instructed and records changes on the Record of Revisions form provided in the front of the document. This process indicates the completeness of the plan, as revisions are consecutively numbered. It is the responsibility of each plan recipient to verify that updates are promptly incorporated into the plan.

PLAN RENEWAL

The plan covers a number of state and federal approvals. The approvals covered by this Plan and their renewal cycles are provided below:

Regulating Agency	Renewal Cycle	Expiration Date
MMS	Biannual review by operator, with submittal of changes or written notification that there are no changes	
ADEC	3 years	
EPA	No more than every 5 years for facility response plan, 3 years for SPCC Plan	
DOT	5 years	

The Plan will be reviewed every 2 years and updated if necessary, in accordance with MMS regulations. If no changes are necessary, BPXA will provide MMS with written notification that the Plan is current.

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1. RESPONSE ACTION PLAN [18 AAC 75.425(E)(1)]

1.1 EMERGENCY ACTION CHECKLIST [18 AAC 75.425(e)(1)(A)]

Contact Information

Tables 1-1A & 1-1B. Figure 1-1

Tables 1-1A and 1-1B provide a checklist of the immediate response and notification actions to be taken for a spill at Liberty. Figure 1-1 provides a flow chart for immediate spill notification and reporting. The Qualified Individuals for Liberty are listed below:

Overall Responsibility:
Richard Campbell, President
Telephone: (907) 564-5422

Exploration and New Development Operations:
Greg Mattson, Alaska New Developments Business Unit Leader
Telephone: (907) 564-5798

Emergency and Crisis Response Organization:
Garry Willis, Crisis Manager
Telephone: (907) 564-5187

Environmental Issues:
Ross Klie, HSE Business Manager
Telephone: (907) 564-5580

Liberty Qualified Individual:
TBD
Liberty Operations Supervisor
Telephone:

Liberty Alternate Qualified Individual:
TBD
Telephone:

Note: The responsibilities of the Incident Commander are the same as the Qualified Individual under OPA 90 requirements.

Contents

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Contents

TABLE 1-1A
IMMEDIATE RESPONSE AND NOTIFICATION ACTIONS

LEVEL I SPILL	
PERSONNEL	ACTION TO BE TAKEN
FIRST PERSON TO SEE THE SPILL	Assess safety of situation, determine whether source can be stopped, and stop the source of spill if possible. Immediately notify your supervisor or BP Radio/Operator. **Phone number to be determined (TBD).** Provide information on: • Personnel safety • Source of the spill • Type of product spilled • Amount spilled • Status of control operations
RADIO DISPATCHER/ OPERATOR	Immediately notify the following (see Table 1-2 for phone numbers): • Operations Team Lead • Environmental Specialist
INCIDENT COMMANDER ENVIRONMENTAL SPECIALIST	Report to scene. Make an initial assessment of the spill and associated safety issues. Maintain a log of events, notifications, and actions taken. Stop the source of spill if possible. Mobilize SRT and on-site equipment required to control and clean up spill. Upon arrival on scene, begin response operations. Assess response activities. If response is adequate, remain at Level 1. If additional capabilities are needed, go to Level 2/3 response. Supervise control and recovery operations. Upon completion, verify appropriate storage and disposal of oily wastes/materials. Confirm success of cleanup and plan remediation if required. Report spill to Endicott HSE Supervisor.

If Environmental Specialist determines that the spill is a Level II or III event, the additional notifications identified in Table 1-1B should take place.

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TABLE 1-1B
IMMEDIATE RESPONSE AND NOTIFICATION ACTIONS

LEVEL II OR LEVEL III SPILL	
RADIO DISPATCHER/ OPERATOR	Notify the following (see Table 1-2 for phone numbers): • ACS • Safety Officer • Operations Team Lead (Incident Commander)
SAFETY OFFICER	Account for the safety of all personnel. Determine if a threat of fire or explosion exists. If a threat exists, suspend all control and/or response operations and notify Fire/Safety Department. Determine appropriate personal protective equipment (PPE) and brief site workers.
ON-SITE ENVIRONMENTAL TECHNICIAN	Contact Endicott HSE Supervisor to make agency notifications.
INCIDENT COMMANDER	Activate all or part of the IMT and the Command Post. Notify BPXA Security at Anchorage HQ **(907) 564-5954** or **7-521-5954** to alert the on-call Crisis Duty Officer. Provide Security with a contact name and phone number. Continue internal and external notifications. Maintain communications with Anchorage Crisis Center. Verify that Finance Section has completed agency notifications. Coordinate staff activity. Manage incident operations and approve release of major resources and supplies. Approve plan for demobilization. Approve final oil spill report.
Well Control Incident	For well control incident: • Determine if incident requires a well control specialist, and if so, contact Safety Boss. • Contact the on-call Crisis Duty Officer to initiate relief well planning.
OPERATIONS SECTION CHIEF	Activate ACS **659-2405** (24 hours). Activate Mutual Aid through ACS as necessary. Establish staging areas as required. Provide the Logistics Section Chief with information on initial equipment, manpower, material, and supply needs. Supervise control and recovery operations. Verify appropriate storage and disposal of oily wastes/materials. Confirm success of cleanup and prepare plan for remediation for Incident Commander.
Well Control Incident	For well control incident: • Identify well control options, based on circumstances of incident. • Notify rig contractors and coordinate activities. • Implement relief well planning process. • Implement logistics plan to provide Safety Boss support.
PLANNING SECTION CHIEF	Ramp up Planning Section. Verify that Agency Notifications have been made and updates are provided. Compile and display status information in Command Post. Assist in development of planning process. Document all aspects of the response. Provide environmental support as needed. Prepare final oil spill report.

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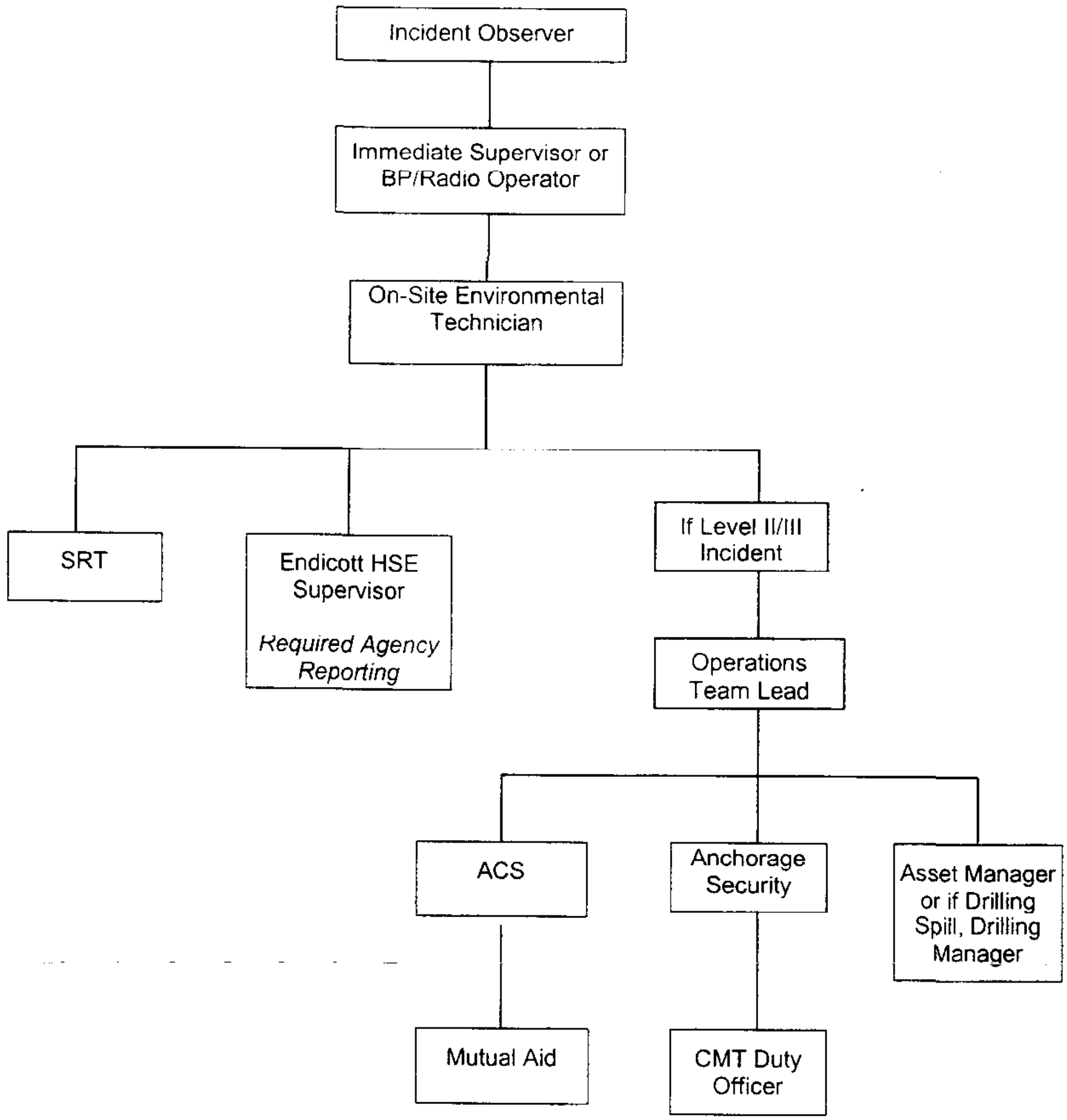
TABLE 1-1B (CONTINUED)
IMMEDIATE RESPONSE AND NOTIFICATION ACTIONS

page 2 of 2

LEVEL II OR LEVEL III SPILL	
LOGISTICS SECTION CHIEF	Order equipment, manpower, material, and supplies as requested. Provide all transportation support. Provide support for all field operations and Command Post operations.
FINANCE SECTION CHIEF	Issue cost code for tracking of expenses. Notify insurance representatives as warranted. Track all expenditures and provide audit function as needed.
CRISIS DUTY OFFICER	Activate CRT as needed to support operation. Coordinate with the Incident Commander to mobilize backup resources. Activate the Anchorage Crisis Center to provide information distribution support. Coordinate Government and Public Affairs notification and information effort.

Contents

FIGURE 1-1
IMMEDIATE SPILL NOTIFICATIONS AND REPORTING



Contents

TABLE 1-2
BPXA CONTACT LIST*

POSITION	NAME	TELEPHONE
BPXA MANAGEMENT		
Headquarters Security (24 hours)		(907) 564-5954
President BP Exploration (Alaska)	R. Campbell	(907) 564-5422
Central North Slope Business Unit Leader	T. Holt	(907) 564-4634
Alaska New Developments	G. Mattson	(907)-564-5798
CNS Production & Field Manager	N. McCleary	(907) 659-4452
Compliance Assurance & Cont.l Improve Mgr.	N. Ingram	(907) 659-6555
Western North Slope Business Unit Leader	M. Bly	(907) 564-5240
Alaska Exploration Business Unit Leader	FX O'Keefe	(907) 564-4246
FACILITY CONTACTS		
ANCHORAGE		
Headquarters Security (24 hours)		(907) 564-5954
HSE Business Manager	R. Kile	(907) 564-5560
Crisis Manager	G. Willis	(907) 564-5187
Environmental Manager	R. Vaseleski	(907) 564-5990
Permitting	P. Hanley	(907) 564-5202
Environmental Studies	D. Trudgen	(907) 564-5473
Health and Safety Manager	M. Senquefield	(907) 564-5542
BADAMI		
OperationsTeam Leader	J. Powers/J. Eckstein	(907) 659-1322
Lead Maintenance Operator	M. Warren/S. Beaty	(907) 659-1321
ACS Lead Technician	N. Hermon/R. O'Brien	(907) 659-1243
ENDICOTT		
Operations Support Supervisor	S. Gates/M. Goodwin	(907) 659-6570
Operations Supervisor	M. Krompack/Cleve Pogue	(907) 659-6520
HSE Supervisor	L. Swinehart/R. Jones	(907) 659-6666
Production & Wells Coordinator	D. Robertson/M. Sauve	(907) 659-6546
LIBERTY:	To be completed once Liberty is constructed.	
MILNE POINT		
Operations Manager	W. Kuykendall/G. Cooke	(907) 670-3323
Facility Operations Team Lead	H. Harrington/J. Scarbrough	(907) 670-3331
Well & Field Operations Team Lead	J. Bixby/J. Ketchum	(907) 670-3330
Maintenance Superintendent/Supervisor	T. Simpson/L. Cusack	(907) 670-3386
Fire Chief	P. Panter/V. Snell	(907) 670-3474
ACS Environmental Technician	B. Fletcher/D. Dawley	(907) 670-3473
NORTHSTAR:	To be completed once Northstar is constructed.	
PRUDHOE BAY		
Operations Manager	D. Blanchard/M. Werner	(907) 659-4514
Business Account Manager - Safety	M. Pye	(907) 564-4855
Business Account Manager - Environment	J. Platt	(907) 564-5501
GC-1 Ops. Team Leader	*D.Kruger/D. Blanchard - until filled*	*(907) 659-4087*
GC-2 Ops. Team Leader	C. Schlueter/G. Alexander	(907) 659-4902
GC-3 Ops. Team Leader	E. Ford/G Dyer	(907) 659-4951
Production Optimization Team Leader	K. Eager/T. French	(907) 659-4472
Field Optimization Team Leader	S. Piggott/J. Miller	(907) 659-4905
OI Field Support Team Leader	B. Herrin/ J. Barrett	(907) 659-4457

Contents

TABLE 1-2 (CONTINUED)
BPXA CONTACT LIST*

POSITION	NAME	TELEPHONE
PRUDHOE BAY (continued)		
Response Team Leader	J. Rychlinski/L. Christie	(907) 659-4458
N.S. Field Environmental Advisor	M. McDaniel	(909) 659-4789
SHARED SERVICES DRILLING		
Drilling Manager	F. Gunkel	(907) 564-5189
Drilling Superintendent -CNS	T. Bunch	(907) 564-5219
Drilling Superintendent – Northstar/AEX/WNS	D. Cocking	(907) 564-4896
CTD Superintendent	M. Stanley	(907) 564-5938
Wells Superintendent	S. Rossberg	(907) 564-5637
ALASKA CLEAN SEAS, OSRO		
Address: Pouch 340022, Prudhoe Bay, Alaska 99734		
Prudhoe Bay Office	N. Glover/R. Hocking	(907) 659-2405

* All numbers listed are 24-hour notification numbers. Headquarters Security provides notification to BPXA management and spill response teams on a 24-hour basis.

Note: Last updated 4-21-00

Contents

1.2 REPORTING AND NOTIFICATION [18 AAC 75.425(e)(1)(B)]

1.2.1 Internal Notification Procedures

It is BPXA policy for employees and contractors to report spills of oil or hazardous substances, regardless of size, to BPXA. Figure 1-1 is an immediate spill notifications and reporting flow chart. Figure 1-2 is the flow chart for the Immediate Spill Response Team at Liberty. Figure 1-3 shows the IMT structure for a Level II/III incident. Table 1-2 lists phone numbers for BPXA personnel and spill response teams. Qualified Individuals for Liberty are listed in Section 1.1.

Figures 1-1, 1-2, 1-3, Section 1.1, Table 1-2

At Liberty, all spills must be reported directly to the BPXA on-site Operations Team Lead. Notifications will follow procedures outlined in Figure 1-1.

There are two key points in the internal notification procedure:

- Activation of the Incident Command System for a Level II or Level III spill is accomplished through notification by the Operations Team Lead.
- Initiation of verbal agency notifications through the North Slope Environmental Advisor staff in a Level II or III spill will ensure overall agency notification and allow the BPXA on-site Liberty Operations Supervisor to devote his efforts to spill response.

A Spill Report Form, as shown on Figure 1-4, is completed for agency-reportable spills.

Figure 1-4

1.2.2 External Notification Procedures

The Incident Commander or his designee is responsible for notifying the appropriate regulatory agencies. Appropriate agency and community verbal notifications may include:

Tables 1-3A, 1-3B

- National Response Center
- U.S. Department of the Interior, Minerals Management Service
- U.S. Environmental Protection Agency
- U.S. Coast Guard
- U.S. Department of Transportation
- Alaska Department of Environmental Conservation
- Alaska Oil and Gas Conservation Commission (AOGCC)
- Alaska Department of Natural Resources (ADNR)
- U.S. Fish and Wildlife Service
- North Slope Borough
- Communities of Nuiqsut and Kaktovik

FIGURE 1-2
IMMEDIATE SPILL RESPONSE TEAM

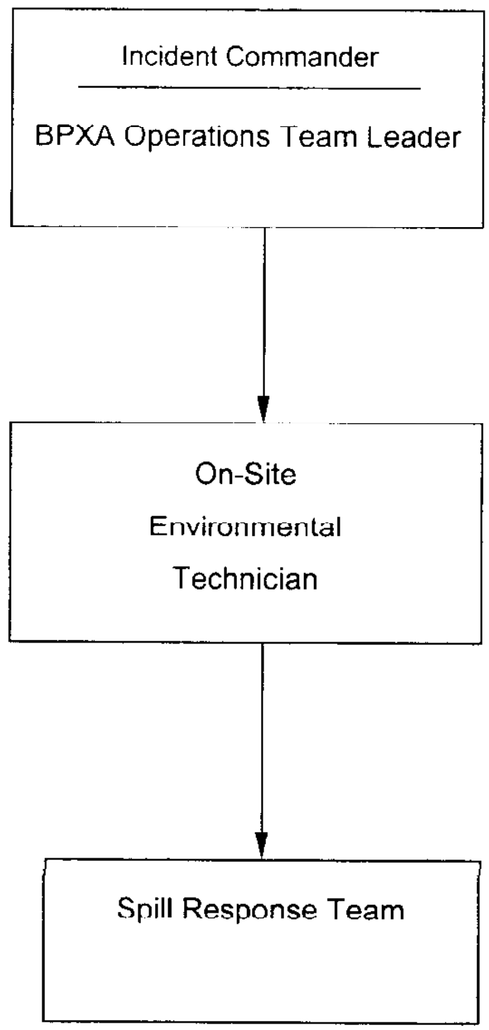
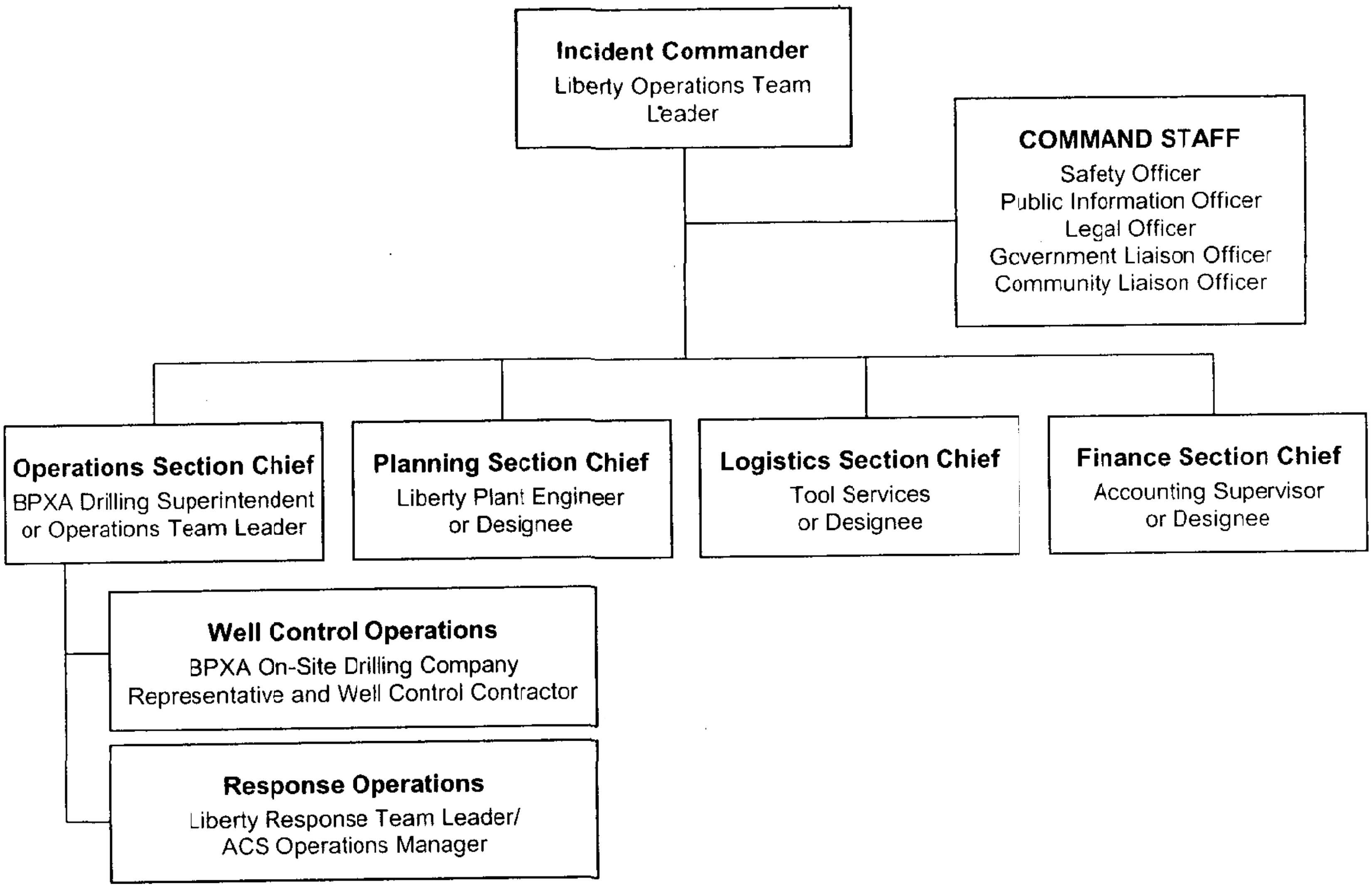


FIGURE 1-3
INCIDENT MANAGEMENT TEAM
LEVEL II / III RESPONSES



Contents

FIGURE 1-4

North Slope Spill Report

BP Exploration (Alaska), INC.
900 East Benson Blvd.
Anchorage, AK 99519 - 6612

BPX Spill Rpt # :	Total in Containment (Gal) :
Date Of Spill :	Total Outside Containment (Gal) :
Time :	Recycled/ Reused (Gal) :
Report Status :	Disposed(Gal):
Location :	Surface Area Impacted (Sq. Ft.) :
NRC Rpt # :	All Secondary Containment?
Company : Water Affected ?	Tundra Affected?
Material Name	Amount (Gal):

Cause:

Clean- Up:

Disposal:

Environmental Impact:

Preventative Action:

Additional Information:

Submitted By

Telephone

Contents

TABLE 1-3A
AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
National Response Center Notifies all appropriate federa agencies	See specific federal agency below for guidance on reportable spill size	Immediately	(800) 424-8802 (24 hr)	24 hour line	Not required as form is completed during phone notification process.
U.S. Environmental Protection Agency	Any size to navigable waters of the U.S. (includes tundra) or to land that may threaten navigable waters	Immediately	(907) 271-4306, M-F, 8 to 5 (206) 553-1263 (907) 271-3424 (FAX) (M-F, 8 to 5)	Carl Lautenberger Seattle office, 24-hour EPA fax number	For facility requiring SPCC Plan if spill is 1,000 gallons or more or if it is second spill in 12 months.
U.S. Coast Guard	Any size in or threatening navigable waters	Immediately	(907) 271-6700 (24 hr) (907) 271-6751 (FAX)	Marine Safety Office USCG fax number	Not required but requested.
U.S. Department of Transportation	Any size from a regulated pipeline	Immediately	(800) 424-8802	24 hour line	Required within 30 days on DOT Form 7000-I (see form for details).
U.S. Department of Interior, U.S. Fish & Wildlife Service	Any size that poses a threat to fish and wildlife	Immediately	(907) 271-2797	---	---
U.S. Department of the Interior, Minerals Management Service	All spills into marine waters	Immediately	(907) 271-6065 (24-hour) (907) 271-6504 (FAX)	Jeff Walker	Within 15 days after spill has stopped.
Pipeline Corridor Office (SPLO/DOT) - Anchorage, AK	Any size from a regulated pipeline	Immediately	(907) 271-4373	---	---
Alaska Department of Environmental Conservation, Northern Alaska Response Team	WATER - Any Spill LAND >55 gallons including cumulative discharge (outside impermeable area) >10 gallons but <55 gallons >55 gallons (inside impermeable area) 1 to 10 gallons (including cumulative discharge)	Immediately Immediately 48 hours none	(907) 451-2121 (907) 451-2362 (FAX) and (800) 478-9300 (M-F after 5, Sat, Sun)	Ed Meggert ADEC fax number or Alaska State Troopers	Interim reports until cleanup complete, as required by ADEC. If no written report is required by ADEC, a written report is required within 15 days of end of cleanup or if no cleanup, within 15 days after discharge. Monthly report
Alaska Department of Natural Resources	>55 gallons 10 to 55 gallons 1-10 gallons	Immediately 48 hours None	(907) 451-2678 (907) 451-2751 (FAX) and (907) 269-8815	Spill Report Number ADNR fax number and Kristina O'Connor	Monthly written record of any discharge, including a cumulative discharge, of oil solely to land for spills between 1 and 10 gallons.
Alaska Oil and Gas Conservation Commission	All spills from wells or involving any crude loss	Immediately	(907) 279-1433 (24 hr) 276-7542 (FAX) and (907) 659-3607 659-2717 (FAX)	Dan Seamount	Within 5 days of loss
North Slope Borough	All spills	>55 gallons as soon as possible (no verbals <55 gallons)	(907) 852-0390 (Barrow) (907) 852-0327 (FAX)	Oma Gilbreth, Occupational Safety & Environmental Affairs	Copy of any reports submitted as requested.

Contents

TABLE 1-3B
AGENCY NOTIFICATION REQUIREMENTS FOR HAZARDOUS MATERIALS

AGENCY	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
National Response Center	See specific federal agency below for guidance on reportable spill size	Immediately	(800) 424-8802 (24-hr)	24 hour line	Not required as form is completed during phone notification process.
U.S. Environmental Protection Agency	All hazardous substance releases that equal or exceed the reportable quantity (or release at RCRA facility) PCB Spill	Immediately 24 Hours	(907) 271-4306, M-F, 8 to 5 (206) 553-1263 (907) 271-3424 (FAX) (M-F, 8 to 5)	Carl Lautenberger Seattle office, 24-hour EPA fax number	Within 15 days to DOT for transportation-related release (DOT Form 5800.1) Within 15 days to EPA for release at RCRA facility.
U.S. Coast Guard	Any size in or threatening navigable waters	Immediately	(907) 271-6700 (24 hr) (907) 271-6751 (FAX)	Marine Safety Office USCG fax number	Not required but requested.
U.S. Department of Transportation	Any size from a regulated pipeline	Immediately	(800) 424-8802	24 hour line	Required within 30 days on DOT Form 7000-l (see form for details).
U.S. Department of the Interior, Minerals Management Service	All spills into marine waters	Immediately	(907) 271-6065 (907) 271-6504 (fax)	Jeff Walker	Within 15 days after spill has stopped.
Alaska Department of Environmental Conservation, Northern Alaska Response Team	All hazardous substance releases	Immediately	(907) 451-2121 (907) 451-2362 (FAX) (800) 478-9300 (M-F after 5, Sat, Sun)	Ed Meggert ADEC fax number or Alaska State Troopers	Within 15 days of end of cleanup
Alaska Department of Natural Resources	All spills	Immediately	(907) 451-2678 (907) 451-2751 (FAX) and (907) 269-8815	Spill Report Number ADNR fax number and Kristina O'Connor	---
North Slope Borough	All spills	>55 gallons as soon as possible (no verbals for <55 gallons)	(907) 852-0390 (Barrow) (907) 852-0327 (FAX)	Oma Gilbreth, Occupational Safety & Environmental Affairs	Copy of any reports submitted as requested.
Village of Nuiqsut and Kuukpik Corporation	All major spills	As soon as possible	(907) 480-6727 (Nuiqsut) (907) 480-6928 (FAX) (907) 480-6220 (Kuukpik)	Mayor of Nuiqsut and Kuukpik Corporation	BPXA Liaison officer will notify.

Note:

1. The National Response Center (800-424-8802) must be called even if the release is reported to the local number. Alternate phone number for the National Response Center is (202-267-2911).

Contents

1.2.3 Written Reporting Requirements

Depending on the type and amount of material spilled, individual government agencies have written reporting requirements which must be adhered to by BPXA.

Tables 1-3A, 1-3B

MMS

MMS requires immediate notification of all spills into marine waters (federal and state) regulated by the agency. A written report for any spill greater than 1 bbl must be reported within 15 days after the spillage has been stopped.

ADEC

State of Alaska regulations 18 AAC 75.300 requires notification to ADEC of any spill on state lands or waterways. After notification of the discharge has been made to ADEC, the department will, at its discretion, require interim reports until cleanup has been completed (18 AAC 75.307). A written final report must be submitted within 15 days of the end of cleanup operations, or if no cleanup occurs, within 15 days of the discharge (18 AAC 75.307). Interim and final written reporting requirements are specified in 18 AAC 75.307. The report must contain the following information:

ACS Tactic A-2

- Date and time of discharge
- Location of discharge
- Name of facility or vessel
- Name, mailing address, and telephone number of person or persons causing or responsible for the discharge and the owner and the operator of the facility or vessel
- Type and amount of each hazardous substance discharged
- Cause of the discharge
- Description of any environmental damage caused by the discharge or containment to the extent the damage can be identified
- Description of cleanup actions taken
- Estimated amount of hazardous substance cleaned up and hazardous waste generated
- Date, location, and method of ultimate disposal of the hazardous substance cleaned up
- Description of actions being taken to prevent recurrence of the discharge
- Other information the department requires to fully assess the cause and impact of the discharge

DOT

Spills from a DOT-regulated pipeline must be reported to DOT. DOT requires the following information:

- Name of pipeline
- Time of discharge
- Location of discharge
- Type of product
- Reason for discharge
- Estimated volume
- Weather conditions
- Actions taken or planned

Contents

1.3 SAFETY [18 AAC 75.425(e)(1)(C)]

The principal sources of information concerning safety procedures and practices to be followed in the event of a spill are:

ACS Tactics S-1 through S-6

- The ACS *Technical Manual*, which includes site entry procedures, site safety plan development, and personnel protection procedures.
- The *Alaska Safety Handbook* distributed to all North Slope employees and contractors.
- The BPXA *Arctic Well Control Contingency Plan* prepared for each drilling operation conducted on the North Slope and designed to ensure drilling activities are performed in a safe and environmentally sound manner. Each plan identifies the procedures, systems, and equipment employed in drilling; utilizes the best technical information available concerning subsurface formation characteristics and pressures; and provides information critical to the success and safety of the drilling program.

Section 1.4.2

As outlined in the North Slope Subarea Plan, the Local On-scene Coordinator (LOSC) will be involved in any spill that poses an immediate threat to public safety. The North Slope Borough Emergency Services Director or designee will typically integrate into the command structure through a LOSC liaison representing all affected communities.

1.4 COMMUNICATIONS [18 AAC 75.425(e)(1)(D)]

1.4.1 Equipment

BPXA's communications plan is designed for compatibility with the communications equipment available through BPXA's Anchorage office, ACS, the rig used for the drilling operations, and project facilities. Initially, Liberty will respond to an oil spill using the day-to-day communications system. Liberty will have the following radio equipment on site:

- Transmission line with connectors
- VHF antenna
- Tone remote controls (2 ea.)
- Marine private coast station
- MT2000 handheld radios (6 ea.)
- Backboarded Spectra mobile radio

The VHF transmitter and receiver frequencies for Liberty will be assigned before the facility begins operation.

With such repeaters installed across the North Slope, coverage is provided from Kuparuk to Badami. The range of each fixed repeater is approximately 30 to 50 miles, depending on topography. ACS solar-powered portable repeaters can also be deployed at the time of a spill. ACS will provide the repeater, coast station, antennas, handheld radios, and backboarded mobiles to allow for effective spill response, when necessary, in an emergency.

Contents

A detailed explanation of oil spill communications on the North Slope is provided in the ACS *Technical Manual.*

ACS Tactic L-5

1.4.2 Unified Command

When an incident occurs, the North Slope Operators view it as a single problem, requiring a single, highly focused response effort. Constructing such an effort can be difficult when multiple organizations exist with the authority to launch simultaneous, potentially divergent response operations. The Unified Command concept is designed to address this problem.

ACS *Technical Manual,* Vol. 3

The North Slope Operators view Unified Command as a structure that is created at the time of an incident to bring together the "Incident Commanders" of each major organization involved in response operations. In Alaska, the members of Unified Command are usually the Federal On-Scene Coordinator, the State On-Scene Coordinator, the LOSC, and the responsible party's Incident Commander.

The primary responsibilities of the Unified Commanders are to:

- Establish objectives and priorities.
- Review and approve tactical plans developed to address objectives and priorities.
- Ensure the full integration of response resources.
- Resolve conflicts.

These responsibilities are typically exercised through the conduct of periodic, highly focused Unified Command meetings with attendance typically restricted to the members of Unified Command.

The role of the agency representatives on the Unified Command is to fulfill their legal responsibilities (i.e., to direct and/or monitor response operations), while allowing the Responsible Party to manage emergency response operations.

When an incident occurs, the Unified Command structure is established and superimposed at the top of the IMT. *In this position, the Unified Commanders are ideally situated to carry out* the responsibilities cited above. They should provide overall direction by establishing Strategic Objectives and response priorities that must be addressed by the IMT through the planning process. Moreover, they should review and approve the products of the planning process (i.e., Incident Action Plans) developed by the IMT to address the objectives and priorities.

Their position at the top of the IMT also facilities the appropriate integration of response resources. For the agency representatives, it allows them to determine the appropriate role(s) for agency personnel and to position them optimally within the IMT structure. For the Responsible Party, it ensures members of the IMT have access to valuable expertise without diluting their ability to manage response operations.

Contents

1.5 DEPLOYMENT STRATEGIES [18 AAC 75.425(e)(1)(E)]

1.5.1 Transport Procedures [18 AAC 75.425(e)(1)(E)(i)]

BPXA daily operations provide an infrastructure for a spill response. For instance, the extensive transportation infrastructure for personnel and equipment can support a small response and can be enhanced for a major spill. Transportation options depend on the location, season, and weather, and include vessels, vehicles, Rolligons, helicopters, fixed-wing planes, and air cushion vehicles.

Table 1-4

TABLE 1-4
SEASONAL TRANSPORTATION OPTIONS
TO LIBERTY ISLAND

ACS Tactics
L-3, L-4

MODES OF TRANSPORTATION	SEASONS		
	SUMMER	WINTER	BREAK-UP/FREEZE-UP
Vessels	X		X
Helicopters	X	X	X
Fixed-Wing Aircraft		X	
Vehicles		X	
Heavy all terrain vehicles		X	
Air-Cushion Vehicle	X	X	X

The estimated response time from discovery of a spill at Liberty to the deployment of equipment varies depending on the incident causing the spill, the size of the spill, time of year, logistical support, and available information. Listed below are the estimated response times for the Liberty operations. These estimates do not include the time involved for a health and safety characterization or release of the site.

- There will be immediate response to a spill on the Liberty island with the pre-staged response equipment.
- The travel time from Endicott for marine equipment is approximately 1 hour. This is a potential staging area for response equipment and emergency services.
- The estimated response time to a spill along the Liberty pipeline route by either the Endicott SRT or Liberty SRT is within 1 hour by boat.
- The estimated response time to a spill at the Liberty location from Deadhorse is within 2 hours.
- The travel time from the West Dock for marine equipment is 6 to 8 hours after the vessel is underway.

All of the above mobilization times are general estimates based on ideal conditions. Actual response and mobilization times will vary depending on a variety of factors, such as weather, personnel safety, wildlife considerations, and terrain.

Contents

The ACS *Technical Manual* provides information on travel times on the North Slope for a variety of transportation equipment. The scenarios in Section 1.6.14 illustrate deployment strategies for spill response equipment.

ACS Tactic L-3

Pre-Staging

The Liberty SRT will respond immediately to any spill using on-site equipment. Equipment will be deployed in the manner appropriate to the type of spill, based on the containment tactics established in the ACS *Technical Manual*.

ACS Tactics C-1 through C-16

A list of pre-staged oil spill response equipment is provided in Section 3.6 of this plan.

Table 3-3

Air Access

Year-round air access to the Liberty field area is planned and a helicopter landing site is planned for Liberty Island. Air operations can be limited by weather conditions, as discussed in Section 3.4. In general, air access is best suited for movement of personnel and for emergency movement of supplies or equipment to the field.

Section 3.4

Land Access

The only overland/sea ice access will be by winter ice roads. Ice roads are commonly used on the North Slope for winter travel from late December through mid-April for specific projects. Nearly any vehicle can travel on an ice road.

ACS Tactic L-1

Marine Access

Marine access to the site will be available from July to October.

1.5.2 Notification and Mobilization of Response Action Contractor [18 AAC 75.425(e)(1)(E)(ii)]

ACS is the primary response action contractor for BPXA. The 24-hour phone number for ACS is listed in Table 1-2, BPXA Contact List.

Table 1-2

Section 1.1 of this ODPCP describes immediate response and notification actions, which include notification of ACS by the BPXA Operations Section Chief. While ACS is mobilizing personnel and equipment to the spill site, BPXA Liberty personnel will determine safety procedures, notify government agencies and BPXA personnel, and proceed with source control measures. In addition, if safe to do so, Liberty response personnel will deploy on-site spill containment equipment.

Table 1-1A and 1-1B

1.6 RESPONSE STRATEGIES [18 AAC 75.425(e)(1)(F)]

The following subsections provide information on the strategies utilized for responding to incidents at Liberty production facilities. This information supports the discussions in Section 1.6.14, Spill Response Scenarios. Where warranted, a narrative discussion has been provided; otherwise the reader is directed to the relevant portion of the scenarios.

Section 1.6.14

Contents

1.6.1 Procedures to Stop Discharge [18 AAC 75.425(e)(1)(F)(i)]

Module Shutdown

A module shutdown may occur from a number of causes such as hydrocarbon release, fire, operational activities or equipment failure or breakdown.

The process control system will be equipped with safety alarm systems to alert the operator of a potential problem prior to shutdown. Safety alarm systems will provide the control room operator with information on process control variables, allowing the operator to make adjustments or notify the local operator of required adjustments.

The process safety systems for Liberty will be designed to automatically return the wells and the processing facilities to a safe state following an emergency plant upset. The system will be designed to automatically activate increasing levels of isolation and depressurization as required. The system will initiate four different types of control action depending on the severity of the event. The four types of shutdowns are a Unit Shutdown (USD), Operations Shutdown (OSD), Emergency Shutdown (ESD) and Blowdown Emergency Shutdown (BESD). They are described as follows:

- **USD**: Initiated as required for the protection of an individual piece of equipment or area of the facility.
- **OSD**: Initiated through alarm criticality (which requires only the shutdown of the hydraulic wing valve to stop incoming oil) or at operator discretion. Controls the systems affected by the problem.
- **ESD**: 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 but remain pressured or, at operator discretion, depressurized.
- **BESD**: Initiated through alarm criticality, which requires the entire facility to be shut down, isolated, and depressured.

The Liberty process facilities will be equipped with a shutdown valve (SDV) to isolate the facilities from the pipelines in case of an emergency.

The process facility will have a high pressure and a low pressure flare to provide the safe and controlled release of safety emergency vents and pressure relief valve discharges during equipment failures. All pressure vessels will be protected with pressure relief valves and independent pressure and level shutdown instrumentation. The flare and relief system will be designed in accordance with American Petroleum Institute (API) Recommended Practices (RP) 520/521.

All plant shutdown and safety systems will be designed in accordance with API RP 14C, Design, Installation and Testing of Surface Safety Systems for Offshore Production Platforms.

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Gas Handling System

The gas handling system will consist of compressor trains and their associated vessels, coolers, and piping. For any shutdown, the turbines and compressors will follow an automatic sequence control. This shutdown will not automatically shut down incoming oil production, which may continue while incoming gas is burned in the flare system. The gas compression system may be shut down by manual initiation or equipment-related protective devices.

Crude Oil Handling System

The crude oil handling system will include the first- and second-stage separators, crude heater and cooler, dehydrator and stabilizer, pumps and metering facilities. Upon activation of the USD, all crude oil lines entering and leaving the plant will be isolated. In an ESD, all hydrocarbon lines entering and leaving the plant will be shut in, wells will be shut in to prevent overpressure of the pipelines, and the first-stage separator, pumps and motors will be turned off.

Well Pads/Pipeline/Manifolds

The primary shutdown device is the actuated wellhead surface safety system, which stops incoming fluids. In the event of a depressurized shutdown, the production wells' actuated surface and subsurface safety valves will be activated.

Activation of the process USD will close the shutdown valves upstream of the choke valves on producing wells. Activation of the process ESD will close the shutdown valves upstream of the choke valves and the surface safety valves on producing and gas injection wells. Water injection wells will remain operational during USD. Manual shut-in will occur if ESD is probable for a prolonged period. Freeze protection steps will be taken prior to shut-in.

Maintenance of Shutdown Systems

Systems will require periodic testing and maintenance. Provisions will be made to deactivate the shutdown system while testing and maintenance are in progress.

1.6.2 Fire Prevention and Control [18 AAC 75.425(e)(1)(F)(ii)]

The fire and gas detection systems in the process facility will use ionization smoke detectors, combination infrared/ultraviolet flame detectors, flammable-limit gas detectors, and thermal detectors. The systems will be electrically supervised against short and open wiring faults in the detection and alarm circuits. The electrical power supply is supported by the uninterruptable power system. Hydrogen detectors will be located in battery storage rooms. Hydrogen sulfide detectors will be located in modules with produced water.

Instruments for continuously monitoring for the presence of flammable gas and fire will be installed in all areas where there is risk of leakage, which could lead to a dangerous escalation. Smoke detection will be installed in the control room/control module as necessary. Detection systems will provide alarm only at key locations. *Protective action will* be by remote or local manual initiation.

Manual alarm indications will be located at strategic points throughout the facility and a fire protection panel will be programmed in the central computer system, provided with zone indication of detector points.

When activated, the fire alarm detection system will shut down and blowdown the facility through the BESD. The foam 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.

If the gas detection system detects a 20 percent LEL gas concentration, the emergency ventilation fans will start, increasing air changes to a minimum of one cubic foot per minute of outside fresh air per square foot of floor space but not less than six air changes per hour. If the gas concentration continues to rise to 40 percent LEL, a BESD will be activated, causing the facility to be shut down and isolated. The facility may be depressurized, at the operator's discretion. All production wells will be shut in.

1.6.3 Blowout Control/Relief Well Plan [18 AAC 75.425(e)(1)(F)(iii)]

All production wells at Liberty will be equipped with subsurface safety valves (SSSVs) and surface safety valves (SSVs) in accordance with BPXA policy and MMS regulations (30 CFR 250, Subpart D). This regulation requires SSSVs for all wells with an offshore surface location and that can flow to the surface unassisted.

If well control is lost, resulting in an uncontrolled flow of fluids at the surface, detailed planning will begin to regain control. A thorough evaluation of the situation will be necessary to determine the best course of action. Three primary considerations in developing a well control plan, based on specific well conditions are:

- Additional surface control measures
- Ignition of the blowout
- Drilling a relief well

Surface Control

Section 2.1.7

Section 2.1.7 outlines preventive and recovery measures to minimize hydrocarbon spill potential which are applied to development drilling operations and are applicable to onshore as well as offshore island facilities. All well control discussions in Section 2.1.7 are aimed at preventing spills (i.e., blowouts where hydrocarbons spill to the surface) from occurring during drilling operations. In the unlikely event that well control is lost while drilling a well, every effort would be made to provide control at the surface. Historically, regaining control at the surface is faster than drilling a relief well and has a high success rate. An uncontrolled flow at the surface presents a safety hazard. Safety procedures are employed to protect personnel, the environment and property.

Loss of surface control maximizes the pressure drop across the formations. Under these conditions, reservoir formations flow to equalize pressure, and the resulting bridging results in decreased flow at the surface. While surface control may be regained through natural bridging, additional mechanical methods are employed as soon as the well can be safely accessed. The exact surface control methods used depend on the type of situation. Potential mechanical surface control methods include:

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- Establishing primary control by pumping kill weight fluids (mud, cement, brine).
- Establishing secondary control by replacing, repairing or adding mechanical containment equipment.

Each of these methods may require removal of equipment around the rig, or the rig itself, to minimize damage, ensure personnel and environmental safety, and gain access to the wellhead. Once safe access is established, uncontrolled fluids at the surface would be diverted into a collection area.

Following the Iraq-Kuwait war, the techniques and experience for handling blowouts with surface control have improved. Operators have established relationships with well control specialist companies to assist in the intervention and resolution of any well control emergency. These companies would be notified immediately in the event of any well control situation that has the potential for escalation.

BPXA maintains a contract with a well-control firm to assist in the intervention and resolution of any well-control emergencies. The contractor will be notified immediately in the event of any well control situation that has the potential for escalation.

Blowout Well Ignition

Ignition of a blowout will be a decision made by BPXA management in conjunction with regulatory agencies. The decision to ignite a blowout will be made only after assessing the probability of implementing successful surface control, reviewing potential safety hazards, addressing pertinent environmental considerations, and obtaining necessary agency approvals. One potential justification for the ignition of a blowout would be a gas blowout where the hydrocarbon had a toxic component to it such as hydrogen sulfide (H_2S). In such instances, the blowout may be ignited to control the toxic gases while preparations are being made to kill the well. Once well kill preparations were in place, the fire would be put out and the kill operations would commence.

Relief Well

The lead time involved in relocating a rig to a surface location and drilling a relief well necessitates early planning. Due to long lead times associated with drilling a relief well, the relief well plan may be initiated concurrent with the implementation of surface control methods. If surface control measures fail, BPXA relief well plans are fully implemented as provided in the *BPXA Arctic Well Control Contingency Plan.* BPXA decisions are made by management in accordance with procedures contained in the relief well plan.

The following provides information on elements of relief well activities including identification of surface location, equipment, and time. The amount of time required to execute a relief well depends on the success of surface control techniques and well conditions, including any natural bridging that may occur.

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Relief Well Surface Locations

The optimum surface location for a relief well depends on several factors including the depth and direction of the wellbore, personnel safety, and weather conditions. The surface location would be selected so the relief well could be drilled in the most efficient manner. Other surface location considerations include hole angle, minimizing drilling time, and directional control.

Liberty Island itself offers the primary surface location providing that it is safe to work there. If the development drilling rig is still usable, then with certain replacement equipment (e.g., well control equipment), it may be possible to drill a relief well with this unit. Otherwise, an alternative rig would have to be deployed. The drilling side of the island (i.e., the eastern half) would be the first choice, assuming a rig could be located in a suitable position. Alternatively, an emergency drilling site could be made by carrying out local civil work, i.e., redistributing gravel around the dock/bench area on the south side of the island.

If the island was deemed unsuitable to locate a rig, then the following alternatives exist:

- **Gravel Island**: A gravel island would be located over the field as dictated by the requirements of the relief well location. For 21 feet of water (worst case), approximately 98,000 cubic yards of gravel would be required to construct an island with a 200-foot-diameter work surface and a 400-foot-diameter base extending 15 feet above mean sea level. From a location approximately midway from Liberty Island to shore, the water depth is 10 feet. An island could be constructed there with much less gravel, yet still allow for all current well targets to be reached with an estimated 3-mile maximum step-out.
- **Ice Pad:** Use of an ice pad is unlikely since the window of opportunity is limited. Operations in winter would concentrate on moving gravel over an ice road in order that sufficient time existed to site a rig and allow continued operations supported by helicopter after break-up.
- **Land Locations and SDI:** As extended-reach technology evolves at a rapid pace, it is possible that a land-based location could be used to drill a relief well to certain parts of the field. The land to the southwest of the field around Pt. Brower lies at a step-out of 3.75 to 4.75 miles from four-fifths of the well targets, while the Endicott SDI is over 5.5 miles from the northwest well targets. Depending on technology advances, it may be possible to drill relief wells from these locations.

To the extent practical in such an emergency situation, island placement would avoid high-value boulder patch habitat. Potential gravel sources for the above relief well options include North Slope and Prudhoe Bay Unit gravel sites, and Goose Island with an estimated 110,000 cubic yards. Also, the gravel pit identified for constructing Liberty Island has been planned to allow for sufficient gravel to construct an alternative relief well island (possible only in winter due to lack of road access). The selected source will depend on season and island location. Gravel would be hauled with trucks over an ice road in winter or by barge and tug during the open water season.

Relief Well Drilling Rig and Equipment

All necessary equipment to drill the relief well is located in BPXA's drilling stock either on the North Slope or in Fairbanks. Shared Services Drilling currently has rigs under contract, and will make a suitable rig available for relief well services if needed. If a relief well is to be drilled from Liberty Island and the development rig is not usable, then during ice road season both Hercable rigs (Pool #4, Pool #6) and truckable rigs (Nabors #33E, Pool #122 -- both currently being modified for BPXA North Slope operations) can be mobilized by ice road. During the open-water season, these rigs, plus North Slope modular wheeled rigs, can be mobilized by barge. If a relief well is to be drilled from an alternative gravel island, then the Hercable rigs would be the primary option by either ice road or barge.

A commitment as to the availability of a rig for the drilling of a relief well, signed by a responsible official from the drilling rig company, is submitted with the addenda package for individual wells before drilling. Depending on the season, it may be necessary to contract a helicopter-lift rig from the Lower 48 to allow for a rig to be mobilized during freeze-up or break-up. BPXA would locate, contract for, and handle all the transporting issues involved while the gravel island was being constructed.

Relief Well Timing

Preparation for a relief well will begin as early as possible. Earth-moving equipment is located on the North Slope to immediately begin building a relief well site. Under winter conditions (December through March), construction of an ice pad and necessary roads would begin. If conditions require gravel construction, gravel haul would be initiated from existing gravel mine sites. Mobilization planning for the rig and supporting relief well equipment would begin. When the site location was completed, the equipment would be staged for delivery. Movement of a rig and associated equipment would be accomplished via gravel or ice roads or via Hercules aircraft, supported when necessary by helicopter transport. The drilling of the well would begin as soon as the rig up was complete. The range of time for completing a relief well is 4 to 8 months:

1)	Mobilize gravel equipment	1 week
2)	Construct ice road	3 weeks
3)	Construct gravel island or modify Liberty island	2 weeks
4)	Set conductor; mobilize rig	3 to 4 weeks
5)	MMS inspect; spud; drill relief well	3 to 6 weeks
6)	Kill well and plug & abandon	1 to 2 weeks
7)	Demobilize rig	2 weeks
8)	Break-up/freeze-up factor	0 to 3 months
	TOTAL	4 to 8 months

A range of time is given for controlling a blowout by drilling a relief well due to a number of unpredictable circumstances that may occur, including weather, cause of blowout, choice of surface location, and depth of well.

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Permits

In the event of a well blowout, a series of federal, state, and local permits would be required to support the response effort. Permits would be needed to authorize construction of gravel and/or offshore or onshore support facilities (e.g., ice or gravel staging pads, temporary storage areas, temporary water uses).

Federal approval would be required in the form of a Section 404/10 permit from the U.S. Army Corps of Engineers for placement of gravel (fill) in waters of the United States (nearshore coastal waters). The Corps has issued Nationwide Permit #20 which authorizes placement of fill needed for cleanup of spilled oil. A request for this authorization would require approval from the Regional Response Team (RRT). This request would typically be approved very rapidly assuming the RRT is in agreement with the overall cleanup strategy for this specific spill event.

In addition to this federal permit, it is likely that State of Alaska and North Slope Borough permits will also be required. As part of overall North Slope oil spill preparedness, ACS holds a series of permits authorizing a variety of cleanup related activities, including excavation and placement of fill.

1.6.4 Discharge Tracking [18 AAC 75.425(e)(1)(F)(iv)]

ACS Tactics T-1 through T-7

Discharge tracking is discussed in the ACS *Technical Manual,* Volume 1.

1.6.5 Protection of Sensitive Areas [18 AAC 75.425(e)(1)(F)(v)]

ACS Map Sheets 74, 80, 83, 84, 85, and 86

Environmentally sensitive areas and areas of public concern include cultural resource sites, public use areas, Native allotments, bird nesting areas, etc. Initial strategies for protection and cleanup of these areas will be determined based on the data contained in the ACS *Technical Manual Volume II, Map Atlas*. The entire open water, nearshore, and offshore marine areas in Foggy Island Bay may be subject to oiling from potential unrecovered spills at Liberty.

Suggestions for shoreline sites for priority protection are based on three criteria:

- Relative value as wildlife habitat or as cultural resource, subject to confirmation by resource agencies.
- Distance from a potential oil spill, as a qualitative index of probability of oiling.
- Practicality of protection measures, to be determined by spill responders at the time of the response.

ACS Tactic W-6

As a spill progresses, priorities may change based on seasonal variations and assessments conducted at the time of the spill.

1.6.6 Containment and Control Strategies [18 AAC 75.425(e)(1)(F)(vi)]

ACS Tactics C-1 through C-16

Containment and control strategies are discussed in the ACS *Technical Manual,* Volume 1.

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1.6.7 Recovery Strategies [18 AAC 75.425(e)(1)(F)(vii)]

ACS Tactics R-1 through R-21

Recovery strategies are discussed in the ACS *Technical Manual*, Volume 1.

1.6.8 Lightering, Transfer, and Storage of Oil from Tanks [18 AAC 75.425(e)(1)(F)(viii)]

ACS Tactics R-22 through R-28

Lightering, transfer, and storage of oil from tanks are discussed in the ACS *Technical Manual*, Volume 1.

1.6.9 Transfer and Storage Strategies [18 AAC 75.425(e)(1)(F)(ix)]

ACS Tactics R-22 through R-28

Transfer and storage are discussed in the ACS *Technical Manual*, Volume 1.

1.6.10 Temporary Storage and Disposal [18 AAC 75.425(e)(1)(F)(x)]

ACS Tactics D-1 through D-5

The method of disposal for oil and contaminated materials from spill recovery operations or for oily waste from normal operations must be approved by the appropriate state and federal agencies. At the time of the spill, the Operations Chief, in consultation with the Environmental Unit Leader, will determine a reuse, recycle, or disposal method best suited to the state of the oil, the degree of contamination of recovered debris, and the logistics involved. Application for agency approvals will be completed before the method of disposal is used. An initial determination must be made regarding the classification of the waste as exempt, hazardous, or non-hazardous. This classification may be made on a case by case basis. The Environmental Unit Leader will provide assistance in determining the classification should the status of the waste material be in question. In general, the following guidelines apply:

- Spills from DOT lines are non-exempt and must be tested to determine if the material to be disposed of is hazardous.
- Spills from production lines are exempt.
- Spilled material that comes out of a well, either during drilling or workover operations, is exempt. Spilled material that did not come out of a well is non-exempt and must be tested to determine if the material to be disposed of is hazardous.
- Spills that occur from filling a tank (e.g., vehicle, storage, etc.) are non-exempt, even though they may occur on a well pad, and must be tested to determine if the material to be disposed of is hazardous.

Should materials need to be transported off the North Slope, truck, barge, and/or air transportation will be arranged.

The preferred method for handling recovered liquid oil is to recycle it through the plant. The preferred option for recovered diesel is to reuse it as freeze protection during drilling operations. In this case, the diesel would be stored on site. If the diesel is not suitable for freeze protection, it would be tested to determine if it is hazardous. If hazardous, it would drummed and stored on-site until it could be shipped to an approved hazardous waste disposal facility. If non-hazardous, it would be injected in the Liberty disposal well.

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During normal field operations, recovered spilled oil is processed using oil/water separators. Fluids recovered from a large oil spill will be either liquid oil or oil mixed with water, snow, or ice. Oil in excess of immediate processing capacity will be stored. Sources of tankage include:

ACS Tactic D-4

- ACS spill response equipment located in Deadhorse
- BPXA Prudhoe Bay spill response equipment
- BPXA Endicott spill response equipment

Additional sources of temporary storage tanks include oil companies and numerous service companies in the North Slope area. These storage tanks include 500-bbl Tiger tanks and 200- to 300-bbl vacuum trucks. Mobile tankage is estimated at 20,000 bbl in the North Slope area.

Depending on the magnitude of potential spill cleanup, temporary storage areas may be established for solid cleanup materials. Specific temporary site locations can be established at a number of suitable sites. Requisite land owner and agency approvals will be sought before specific sites are used.

Scenario-specific information is provided in Section 1.6.14.

1.6.11 Wildlife Protection [18 AAC 75.425(e)(1)(F)(xi)]

ACS Tactics W-1 through W-6

Wildlife protection strategies are discussed in the ACS *Technical Manual*, Volume 1.

1.6.12 Shoreline Cleanup [18 AAC 75.425(e)(1)(F)(xii)]

ACS Tactics SH-1 through SH-12

Shoreline cleanup strategies are discussed in the ACS *Technical Manual*, Volume 1.

1.6.13 Response Planning Standards [18 AAC 75.430]

For purposes of this plan, the applicable RPS volumes are as follows:

Storage Tank Failure (18 AAC 75.432)

The RPS volume for the oil storage tanks at Liberty is calculated below. The calculation is based on the largest tank to be installed at Liberty. All of this volume could reach open water.

Volume capacity of the produced water tank	5,000 bbl

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Well Blowout (18 AAC 75.434)

The Liberty RPS volume for a well blowout is based on the well with the largest daily oil production. The largest anticipated daily production from a Liberty well is 15,000 bopd *(barrels of oil per day), which is based upon reservoir characteristics and initial gas/oil ratios* appraised from the four discovery wells drilled. Once production well flow rates are established, the RPS volume may require adjustment.

The RPS volume for a Liberty well blowout is provided below:

Initial RPS volume during first 72 hours	45,000 bbl
20% evaporative loss[1]	(9,000 bbl)
Adjusted RPS volume	**36,000 bbl**
Portion to pad	1,200 bbl
RPS volume entering open water first 72 hours	34,800 bbl
Spilled over next 12 days	180,000 bbl
20% evaporative loss[1]	(36,000 bbl)
Adjusted RPS volume	**144,000 bbl**
Portion to pad	0 bbl
RPS volume entering open water	144,000 bbl
Total spilled over 15 days	225,000 bbl
20% evaporative loss[1]	(45,000 bbl)
Total adjusted RPS volume	**180,000 bbl**
Total portion to pad	1,200 bbl
Total volume entering open water	**178,800 bbl**

The receiving environment is a production well pad on fill surrounded by seawater. Oil travels from the well in an aerial plume. The portion of oil reaching open water was calculated using the SL Ross dispersion model for surface well blowouts.

ACS Tactic T-6

[1] Evaporative loss is an accepted North Slope Spill Response Project Team (NSSRPT) assumption.

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Offshore Pipeline Leak (18 AAC 75.436)

The RPS volume for a spill from the subsea portion of the Liberty sales oil line is provided below. The value was calculated using the following equation from 18 AAC 75.436:

RPS volume = (L - H) * C + FR * (TD + TSD)

Where:

L	=	pipeline length between pumping or receiving station valves,
H	=	pipeline hydraulic characteristics due to terrain profile,
C	=	pipeline capacity in barrels per linear measure,
FR	=	pipeline flow rate in barrels per time period,
TD	=	estimated time to detect a spill event, and
TSD	=	time needed to shut down the pipeline pump or system.

L	=	6.1 miles (32,208 feet) length, from Liberty Island to landfall valve or vertical loop
H	=	23,208 feet (32,208 feet minus 9,000 feet that would drain, based on a bathymetric survey)
C	=	0.126 bbl/ft (12.75 inches outside diameter WT = 0.688)
FR	=	65,000 bpd (45 bbl per minute)
TD	=	0.5 minute+ 5 minute to verify leak
TSD	=	8.5 minutes

Therefore:

RPS $\text{volume}_{\text{LIBERTY}}$ = (32,208 ft – 23,208 ft)(0.126 bbl/ft)+[(45 bbl/min)(5.5 min + 8.5 min)]

Pipeline RPS $\text{volume}_{\text{LIBERTY}}$ entering open water **1,764 bbl**

The estimated maximum spill volume is calculated as approximately 1,580 bbl, which is less than the ADEC RPS volume of 1,764 bbl. This volume difference is mainly a result of two factors. 1) In a shutdown, the oil pumps and the isolation valve on Liberty Island would be shut down immediately after a leak is confirmed, preventing additional volume losses. 2) The landfall valve is estimated to take 8.5 minutes to completely close. As the valve is closing, oil from the overland section could potentially drain back into the offshore section.

The RPS volume for a chronic leak in the offshore portion of the sales oil pipeline is 97.5 bbl; all of this volume would be released directly into water. This volume is based on the combined leak detection capability of the mass balance line pack compensation (MBLPC), pressure point analysis (PPA), and Leck Erkennung and Ortungs System (LEOS) leak detection systems. The MBLPC and PPA have a combined leak detection sensitivity of 0.15% of throughput, equal to 97.5 bbl per day. The LEOS leak detection system has a sensitivity of 0.05% of throughput or 32.5 bbl a day. Readings will be collected from the LEOS system once a day, so the maximum leak volume would be 97.5 bbl before detection.

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1.6.14 Spill Response Scenarios

This section contains spill response strategies to address the following spill scenarios:

Tables 1-5 through 1-21, Figures 1-5A through 1-5H

- Well Blowout in Open Water
- Well Blowout in Broken Ice (Freeze-up)
- Offshore Pipeline Spill in Solid Ice
- Offshore Pipeline Spill in Broken Ice (Break-up)

Qualifying Statement

The following scenarios are developed in accordance with 18 AAC 75.425(e)(1)(F) and 18 AAC 75.445(d). They describe equipment, personnel, and strategies that could be used to respond to an oil spill. The scenarios are for illustration only and are not performance standards or guarantees of performance. The scenarios assume conditions of the spills and responses only to display general procedures, strategies, tactics, and selected operational capabilities.

Some details in the scenarios are examples. Although some equipment is named, it may be replaced by functionally similar equipment in the future. The response timelines are for illustration only. They do not limit the discretion of the persons in charge of the spill response to select any sequence or take whatever time they deem necessary for an effective response without jeopardizing safety.

In situ burning could be used in a spill response to reduce the quantity of oil, regardless of whether a scenario hypothesizes in situ burning to help meet the RPS volume.

Actual response performance equal to the scenarios is not guaranteed. For example, oil from a large spill likely will go ashore. Weather, malfunctions and human performance can compromise efficiency. As a result, effectiveness may be less than illustrated in a theoretical, mathematical planning model. Experience shows that a catastrophic spill will result in a long-term cleanup program, which will be the "shortest possible time."

Actual responses in an oil spill emergency depend on personnel safety considerations, weather and other environmental conditions, agency permits and priorities, and other factors. In any accident, considerations to ensure the safety of personnel will be given highest priority. The scenarios assume the agency on-scene coordinators and other agency officials will immediately grant any required permits.

These scenarios were developed according to the guidelines established by the NSSRPT. These guidelines can be found in the front portion of Volume 1 of the ACS *Technical Manual*. Scenario parameters and assumptions regarding oil recovery rates are shown according to these guidelines. The scenarios include procedures for the following, as appropriate:

ACS *Tech. Manual* Volume 1

i. Procedures to Stop Discharge
ii. Fire Prevention and Control
iii. Blowout Control/Relief Well Plan
iv. Discharge Tracking
v. Protection of Sensitive Areas

Contents

vi. Containment and Control Strategies
vii. Recovery Strategies
viii. Damaged Tank Transfer
ix. Transfer and Storage Strategies
x. Temporary Storage and Ultimate Disposal
xi. Wildlife Protection
xii. Shoreline Cleanup

The oil distribution and spill response illustrations of Scenarios 1 and 2 for well blowouts of 15 days are directly applicable to spills of 30 days. Specifically, the oil movement and recovery efforts at the end of Day 3 in the scenarios would continue at that scale through Day 30 for spills of that duration. MMS representatives and other members of the NSSRPT agreed to apply the 15-day scenarios to also show how operations would be supported for a blowout lasting 30 days, as required in 30 CFR 254.27.

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SCENARIO 1

LIBERTY ISLAND BLOWOUT DURING OPEN WATER CONDITIONS

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TABLE 1-5
SCENARIO CONDITIONS FOR LIBERTY PRODUCTION WELL BLOWOUT TO OPEN WATER; AUGUST 1ST TO 15TH

PARAMETER	PARAMETER CONDITIONS	PROJECT TEAM ASSUMPTION?
Spill Location:	Liberty Production Facility	N/A
Spill Time:	15 days, August 1st to August 15th	N/A
Source of Spill:	Production Well	Yes
Cause of Spill:	Unobstructed blowout	Yes
Quantity of Spill:	1. Adjusted RPS volume = (15,000 bopd X 15 days) - (20% loss to evaporation) = 180,000 bbl 2. 180,000 bbl – 1,200 bbl (portion entering other than water) = 178,800 bbl entering open water	Yes
Type of Spilled Oil:	Liberty crude	No
Wind Speed:	20 knots	Yes
Wind Direction:	West southwest Day 1; shifting to east northeast Days 2-15	Yes
Surface Current:	0.6 knot	N/A
Air Temperature:	45° F	N/A
Visibility:	Unrestricted	N/A
Surface:	Open water	Yes
Spill Trajectory:	The discharged oil takes the form of an aerial plume of droplets (see Figure 1-5A). A blowout event was modeled with input parameters of 15,000 bopd, 6.3-inch surface casing, gas-to-oil ratio of 900 cubic feet of gas per bbl of oil, and a 20-knot wind. Approximately 50 percent of the oil remaining after evaporation falls within 100 meters of the source; 80 percent of the oil after evaporation falls within 615 meters of the source, and the plume is approximately 100 meters wide at this point. The remaining 20 percent spreads as a light fall-out as far downwind as 4,200 meters. On Day One, 1,200 bbl are retained in the surface gravel at a rate of one-half gallon per square foot. At Hour 2.5, the island surface becomes saturated and oil begins to run off. On Day 1, 10,800 bbl enters the water. On Days 2-15, 6,000 bopd falls directly to the water surface, and 6,000 bopd runs off the island to the water surface (Figure 1-5B). Floating oil moves at 0.6 knots, NE on Day 1, then SW with the wind shift on Day 2. Under the NE wind, floating oil moves northward past Pt. Brower.	Yes, ACS *Technical Manual* Tactics Description T-6

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TABLE 1-6
RESPONSE STRATEGY FOR LIBERTY PRODUCTION WELL BLOWOUT TO OPEN WATER

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	An unobstructed production well continues to blow out at a rate of 15,000 bbl per day. All other wells are shut in using surface and subsurface valves. The Drilling Supervisor notifies the Field Manager. All appropriate notifications are made, and the IMT is activated. The Drilling Supervisor calls Well Control in an initial effort to stop the discharge. Well Call is called out from Houston and arrives in 12 hours. Well Call initiates attempts to stop the blowout by means of subsurface mechanisms. Surface methods control the blowout on Day 15. In the meantime, a relief well rig is mobilized.	A-1 A-2 Vol. 3 ICS
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection.	S-1 through S-6
(iii) Well Control Plan	While potential surface control measures are evaluated, the relief well drilling plan is implemented such that a drill site is ready should surface control be ineffective.	Not applicable
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Blowout plume model is run. Oil movement is tracked using a combination of visual observation and remote sensing techniques. Tracking buoys are deployed, and the Kuparuk Twin Otter reports the oil to the on-water task forces. Vector addition and trajectory modeling forecasts oil movement	T-6 T-4 T-5
(v) Exclusion Procedures; Protection of Sensitive Resources	Potential oil impact areas and priority protection sites are identified with oil slick trajectory modeling. <u>Priority Site #</u> — <u>Map Atlas</u> — <u>Boom Length (ft)</u> — <u>Tactic</u> — <u>Task Force</u> 12 (Duck Is. 1) — 74 — 1500 — C-13 — STF#1 12 (Duck Is. 2) — 74 — 1500 — C-13 — STF#1 12 (Duck Is. 3) — 74 — 500 — C-13 — STF#2 12 (Pt. Brower) — 74 — 750 — C-13 — STF#3 4 Kad R. Delta — 86 — 1000 — C-14 — STF#4 A Shoreline Task Force (STF) member helps direct response workers away from the cultural sites, based on a shoreline cleanup plan approved by the Unified Command and the State Historic Preservation Officer.	Atlas Maps Nos. 74; 80; 83 to 86 W-6 C-13 (3) C-14 (1)
(vi) Spill Containment and Control Actions	<u>Days 1 to 3</u> The Nearfield Task Force (TF) deploys two skimming systems, including the *Arctic Endeavor* intermediate storage barge, 615 meters northeast of Liberty Island within 12 hours of blowout (see Figure 1-5C and Table 1-7). Objective: Recover oil that has reached the water upwind of the point where 80% of the mist has fallen out. The Farfield TF deploys two skimming systems & the *Beaufort 20* intermediate storage barge downwind of the Nearfield TF (see Figure 1-5D). Objectives: Recover scattered windrows of oil downwind of the Nearfield TF that entered the water during first 12 hours (4,800 bbl) and oil that falls downwind of the Nearfield TF (100 bph); on Days 3-15, recover windrows from falling mist in Foggy Island Bay. Two staging areas are established at West Dock for staging personnel & equipment for the response.	R-19 R-20 R-17 (2) L-2

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TABLE 1-6 (CONTINUED)
RESPONSE STRATEGY FOR LIBERTY PRODUCTION WELL BLOWOUT TO OPEN WATER

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures	TF1 recovery team faces the oncoming wind and positions itself 615 meters east northeast from the blowout source on Day 1, and 615 meters WSW from the blowout source on Days 2-15. Mini barges transfer liquids to the *Arctic Endeavor* storage barge shared with TF2. TF1 is comprised of two 'Bay Class' vessels, the *Big Dipper*, *Kiwi*, *Irene*, and the *Northstar*.	R-20 R-28
	The TF2 recovery team faces the oncoming wind and positions itself 615 meters ENE from the blowout source on Day 1, and 615 meters WSW from the blowout source on Day 2. The *Arctic Endeavor* storage barge is shared by the TF1 and TF2 for intermediate storage, but operates as part of TF2. The Nearfield Team is comprised of TF1 and 2 and targets 3,600 bbl of oil on Day 1, and 9,600 bopd on days 2-15. Decanting is approved by Unified Command. TF2 is comprised of two 'Bay Class' vessels.	R-19
	The Farfield Team is comprised of TF 3 and 4 and targets the area downwind of the Nearfield TF. The *Beaufort 20* receives liquids from both TF3 and 4 as a shared resource. Over the 15 day period, the Farfield Team targets 6,000 bbl of oil that falls NE of Liberty Island on Day 1, and 33,600 bbls of oil that falls SW of Liberty Island, beyond TF1 and TF2, on Days 2-15. Two 'Bay Class' vessels, the *Retriever*, *Deployer*, *Agviq*, and *Arctic Rose* comprise TF3 and 4.	R-17 (2) R-28
	A Shoreline Recovery TF (SRTF) places skimmers on the Endicott causeway. Two skimmers and 2 hook booms are deployed near the outer breach and 2 skimmers and 2 hook booms are deployed near the inner breach. Another pair is deployed at Pt. Brower. Each hook boom deployment uses 300 feet of delta boom. Recovery equipment is set up by Hour 24. SRTF targets 1,000 bbl that escapes the Farfield TF. Fastanks are emptied with vac trucks or freighter boats.	R-16 (6) R-22 and R-25
	<u>Recovery on Days 4-15</u> Recovery efforts proceed on Days 4 through 15 at the level established by the end of Day 3. The Farfield TF effort declines after the oil spilled from Hours 0 to 12 is recovered by Day 3. In subsequent days, the Farfield TF targets oil falling downwind of the Nearfield TF. APSC SERVS sends a TK6 lightering pump from Valdez via aircraft to Prudhoe Bay, and it is deployed at West Dock.	R-19 & R-20 R-17 (2) R-6
	<u>After Day 15</u> Once the well has been controlled, a task force is deployed to Liberty to *excavate oiled gravel from the pad. Vacuum trucks and super sucker* trucks remove pools of oil from the pad.	R-26
	After the free oil is removed, a backhoe removes 9,600 cubic yards of gravel contaminated to a depth of 2.6 feet with oil. Loaders place the gravel into end dumps which are transported via work barge to West Dock, and then hauled to Western Operating Area Pad 3. There, the gravel undergoes long-term treatment under a plan approved by ADEC for soil stockpiles.	
(viii) Lightering Procedures	Mini-barges carry collected liquids to the intermediate barges. See Table 1-8 for calculations of the mini barges' rates of transfer. The *Beaufort 21* storage barge is used to lighter the *Arctic Endeavor* and *Beaufort 20* barges in-place, transferring recovered fluids to the West Dock temporary tank farm.	R-28 L-4
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	A Fluid Transfer TF assembles a temporary tank farm on West Dock adjacent to Seawater Treatment Plant. The objective is to transfer oil and water from barges to the production pipeline to Lisburne Production Center. The Fluid Transfer TF Leader supervises teams to set up and operate six 400-bbl upright tanks. PZ pumps move the liquid from the tanks through a 3-inch hard-line and a flange connector into the production pipeline to Lisburne Production Center.	R-22

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TABLE 1-6 (CONTINUED)
RESPONSE STRATEGY FOR LIBERTY PRODUCTION WELL BLOWOUT TO OPEN WATER

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	• Fluids are piped and hauled by vacuum truck to GC1 and are recycled. GC2 is available to accept recyclable fluids, if GC1 becomes congested. • Used sorbents are collected in plastic bags or other leak-proof storage containers and disposed of by incineration. • Associated non oily waste is disposed of appropriately. • Oily gravel is stockpiled at Pad 3 and treated under a plan approved by ADEC.	D-1 D-2 D-3 D-4
(xi) Wildlife Protection Plan	Resources at risk are primarily birds. Exclusionary methods are implemented to keep oil away from bird habitat. Additionally, hazing operations are initiated and captive/treatment and stabilization as required. International Bird Rescue & Research is deployed to make the wildlife treatment facility operational on Day 2. The Nearfield TF retrieves three oiled waterfowl carcasses from boomed areas on Day 1. The Wildlife TF bags and tags them for deposition with the Alaska Department of Fish and Game (ADF&G) and the U.S. Fish and Wildlife Service (USF&WS).	W-1 to W-3 W5 W-4
(xii) Shoreline Cleanup Plan	Shoreline cleanup operations are initiated once the source of the oil has been stopped, based on a plan approved by Unified Command. A shoreline assessment is conducted to understand the nature and extent of oiling. Based on shoreline assessment, priorities are established for cleanup. Cleanup techniques chosen are based on shoreline type and degree of oiling. *NOTE: The following discussion is based on a purely speculative prediction of shoreline impact, and is presented for illustrative purposes only. Prior to commencement of any shoreline cleanup operation, the affected areas must be surveyed to determine the appropriate response. Specific cleanup techniques to be used will be based on field data obtained at the time of the spill on the shoreline habitats, type and degree of shoreline contamination, and spill-specific physical processes. It is not possible to presuppose the outcome of the Shoreline Cleanup Assessment Team process and/or the decisions of the Unified Command.* Wind and currents will continue to move the oil to the southwest until shoreline impact. The majority of predicted shoreline impact is along 6-8 miles of shoreline along the East Channel Sag River Delta to Pt. Brower. The majority of these shorelines consist of narrow sand beaches, mud flats, peat shorelines, and tundra cliffs. Impact to the outer barrier island chain is not anticipated, but some impact to the sand beaches of Foggy Island is anticipated. Shoreline assessment teams are deployed along the Endicott Causeway, but no stranded oil is found. Primary shoreline cleanup techniques would include: • Manual recovery of heavier pockets of oil stranded along the shoreline (limiting foot access on peat shores); • Deluge of minor to moderately oiled shoreline, including those areas where heavier concentrations were manually removed; • Passive recovery (use of sorbents) and oiled vegetation cutting for any vegetated areas impacted; • Natural recovery for those areas where residual staining may remain, but further recovery would cause more harm than good.	SH-1 SH-2 through SH-11 SH-5 (2-3) SH-3 (2-3) SH-7 (1-2) SH-2

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TABLE 1-7
OIL RECOVERY CAPACITY[1]
LIBERTY BLOWOUT DURING OPEN WATER SCENARIO

A SPILL RECOVERY TACTIC	B NUMBER OF SYSTEMS[1]	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE (boph)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)	F OPERATING TIME (hours in a 24-hour shift)	G DAILY DERATED OIL RECOVERY CAPACITY (bpd) B X D X F
Day 1 (Up to Hour 12) *No Recovery; Mobilization, Deployment and Transit Completed*						
Day 1 (After Hour 12)						
TF1, R-20[2]	1	LORI LSC-3	217	0	10	2,170
TF2, R-19[2]	1	2 LORI LSC-3	2 + 217 = 434	0	10	4,340
TF3 & TF4, R-17[3]	2	LORI LSC-3	217	0	10	4,340
Day 1 (After Hour 12) Total						**10,850**
Day 2-15						
TF1, R-20[2]	1	LORI LSC-3	217	0	20	4,340
TF2, R-19[2]	1	2 LORI LSC-3	2 + 217 = 434	0	20	8,680
TF3 & TF4, R-17[3]	2	LORI LSC-3	217	0	20	8,680
Shoreline TF, R-16[3]	6	MI30	10	0	20	1,200
Day 2-15 Daily Total						**22,900**
Total Capacity, Days 1-15						**331,450**

1 To determine the amount of equipment and personnel required, multiply the number of recovery systems by the equipment and personnel tables in the corresponding ACS *Technical Manual* Tactic.

2 TF1 and TF2 share the *Arctic Endeavor* intermediate storage barge (decreasing the combined number of barges shown in ACS Tactics Manual equipment/personnel table by 1).

3 TF3 and TF4 share *Beaufort 20* for an intermediate storage barge (decreasing the combined number of barges shown in ACS Tactics Manual equipment/personnel table by 1).

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TABLE 1-8
LIQUID HANDLING CAPABILITY
LIBERTY BLOWOUT DURING OPEN WATER SCENARIO

A SPILL RECOVERY TACTIC	B NUMBER OF STORAGE SYSTEMS	H STORAGE CAPACITY DESCRIPTION	I DERATED STORAGE CAPACITY VOLUME PER UNIT (bbl)	J OIL & EMULSION AVAILABLE[3] (bph)	K TIME ON LOCATION BEFORE OFFLOAD NEEDED (hrs) I/J	L OFF-LOADING MECHANISM	M OFF-LOADING RATE (bph)	N TRANSIT TIME - BOTH WAYS (hrs)	O OFFLOADING TIME (hrs) I/M	P OFFLOAD AND TRANSIT TIME (hrs) N+O
TF1 & TF2, R-19 & R-20[1]	1	*Arctic Endeavor*	21,000	646	32.5	R-28	5,024	N/A[4]	4.2	N/A
TF3 & TF4, R-17[2]	1	*Beaufort 20*	12,200	161	76	R-28	5,024	N/A[4]	2.4	N/A
Shoreline TF, R-16	6	Fastank	57	N/A	N/A	R-6 or R-25	200	N/A	N/A	N/A

[1] TF1 and TF2 share the *Arctic Endeavor* intermediate storage barge.

[2] TF3 and TF4 share the *Beaufort 20* intermediate storage barge.

[3] The total volume of oil/emulsion available for recovery is the volume of oil on water x 1.67 (emulsion factor).

[4] Barges are lightered in place with the *Beaufort 21* barge as needed (see ACS *Technical Manual* L-4, and R-28).

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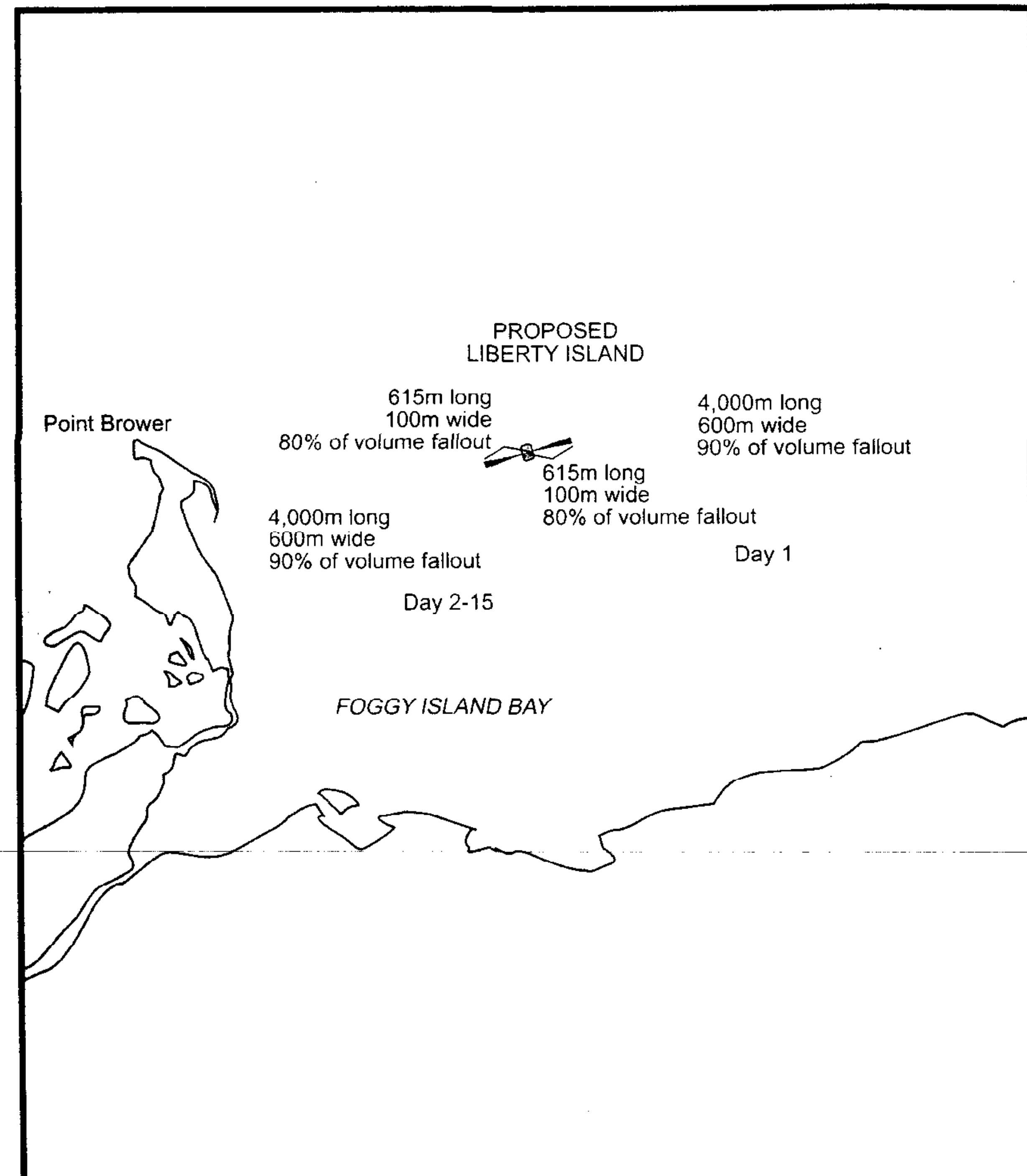

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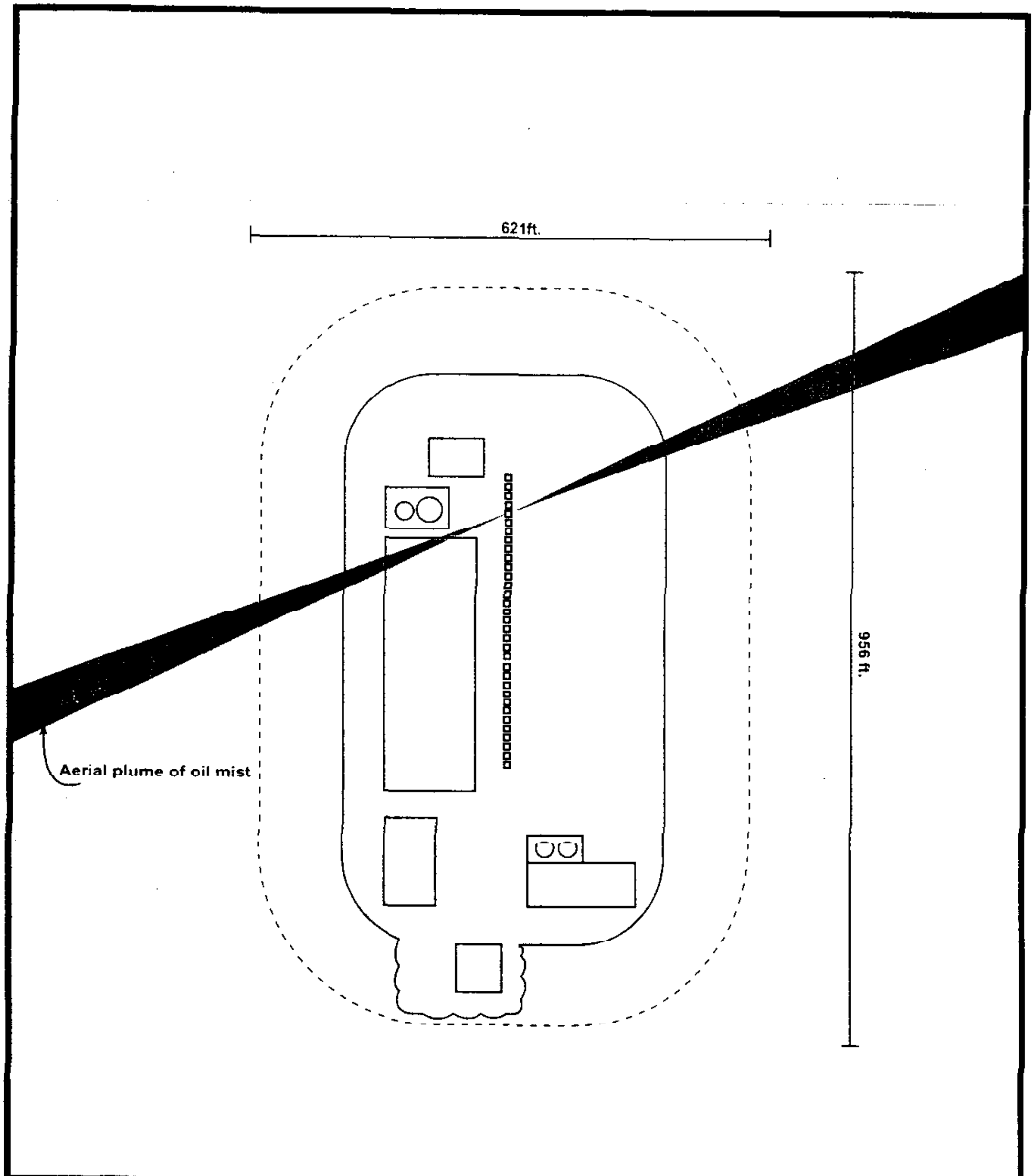
N

Liberty Development
Blowout Plume

Figure 1-5A

Contents



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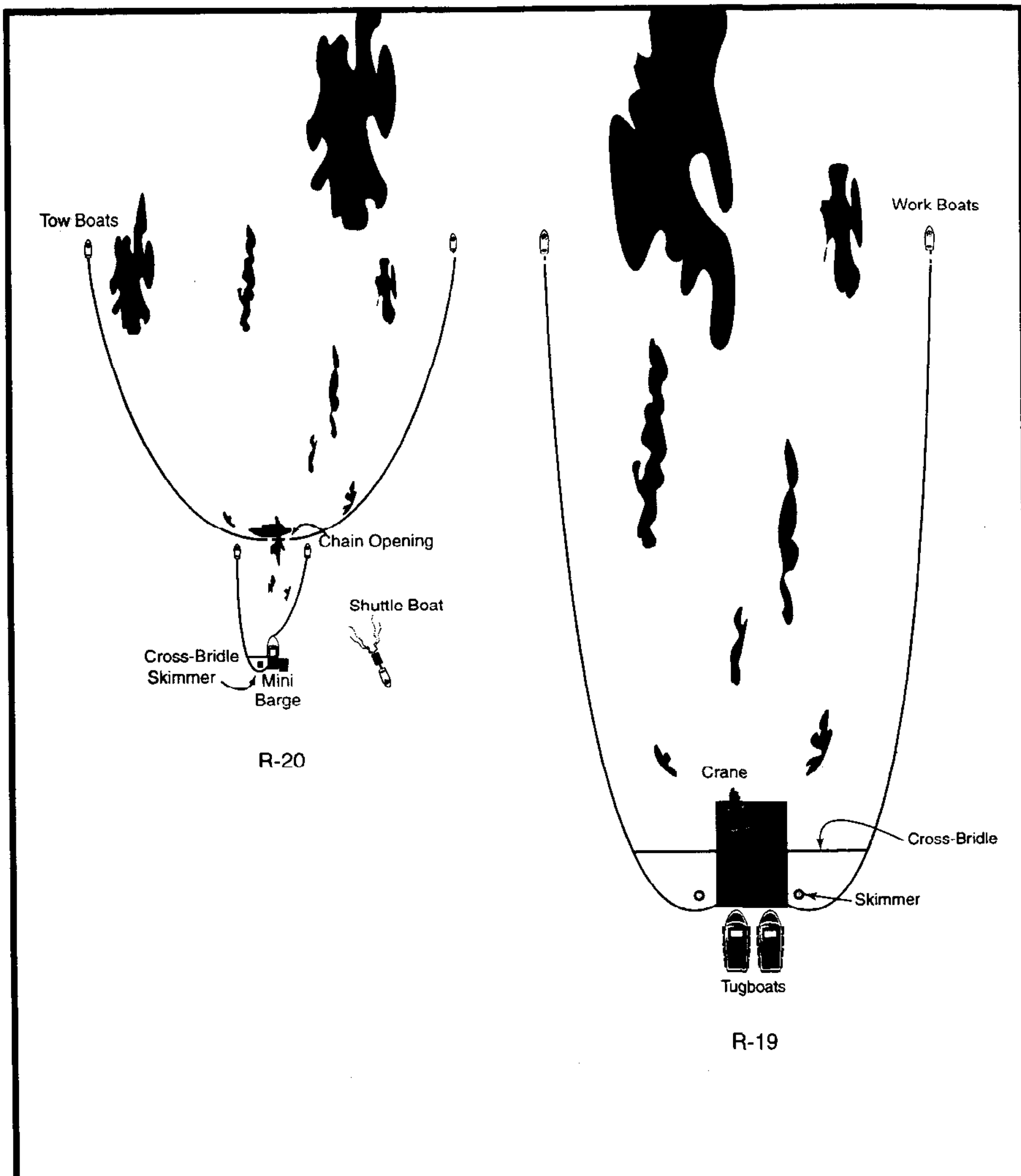
BP

Liberty Blowout Plume
Production Island Fallout

Figure 1-5B

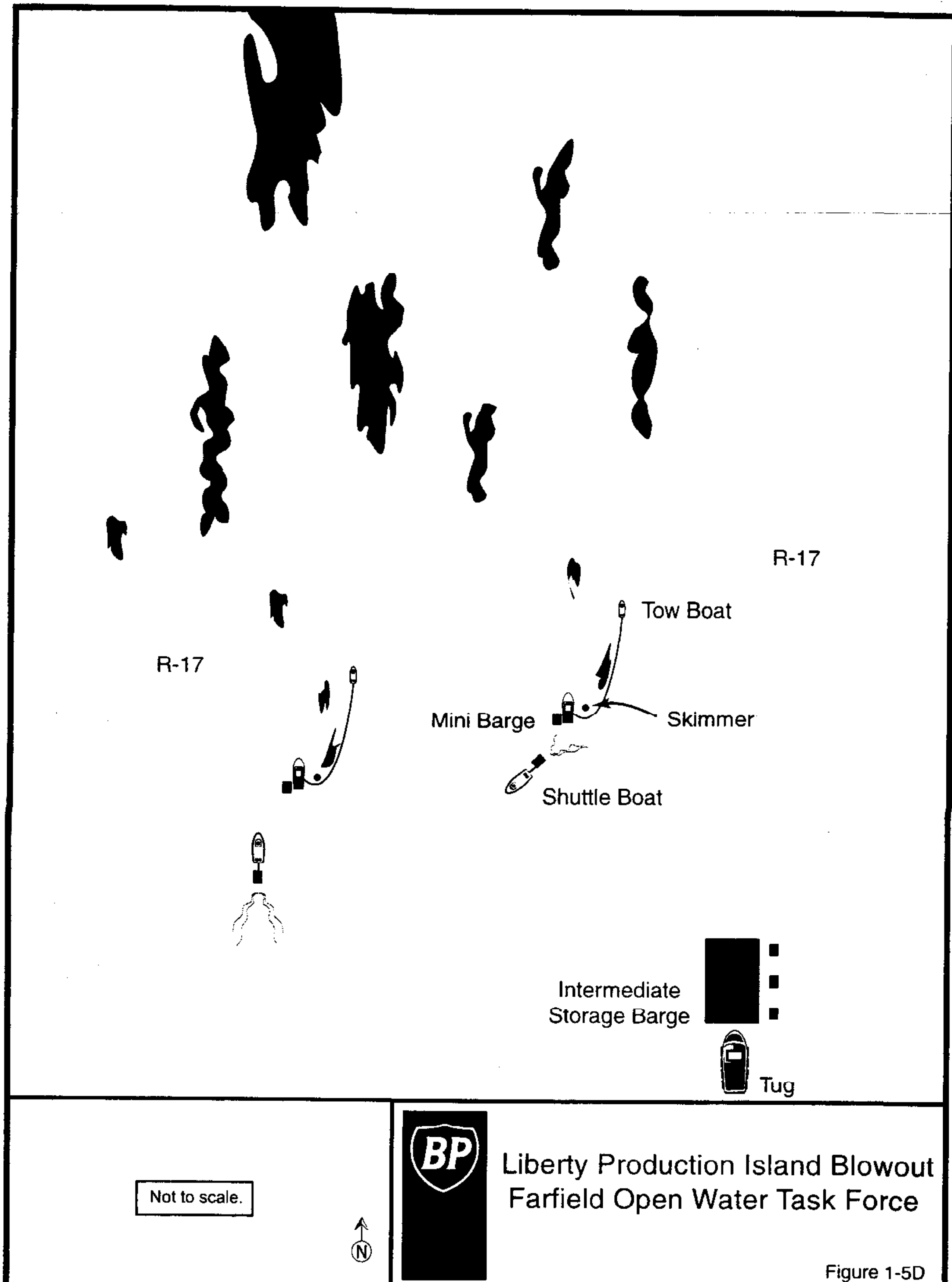
Contents



Liberty Production Island Blowout
Nearfield Open Water Task Force

Figure 1-5C

Contents



Liberty Production Island Blowout
Farfield Open Water Task Force

Figure 1-5D

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SCENARIO 2

LIBERTY ISLAND BLOWOUT DURING FREEZE-UP BROKEN ICE CONDITIONS

TABLE 1-9
SCENARIO CONDITIONS FOR LIBERTY PRODUCTION WELL BLOWOUT TO BROKEN ICE (FREEZE-UP); OCTOBER 5TH TO OCTOBER 19TH

PARAMETER	PARAMETER CONDITIONS	PROJECT TEAM ASSUMPTION?
Spill Location:	Liberty Production Facility (see Figure 1-5A)	N/A
Spill Time:	15 days; October 5th to October 19th	N/A
Source of Spill:	Production Well	N/A
Cause of Spill:	Unobstructed Blowout	Yes
Quantity of Spill:	1. Initial RPS Volume = 15,000 bopd x 15 days = 225,000 bbl 2. Adjusted RPS Volume = 225,000 bbl - (20% Evaporation) = 180,000 bbl 3. See Table 1-13 for portion of oil to water and to ice.	Yes
Type of Spilled Oil:	Liberty Crude	No
Wind:	13 knots Day / Wind From / Day / Wind From 1, 2 / SW / 9-11 / W-SW 3-7 / W-SW / 12,13 / SW 8 / NE / 14,15 / E-NE	Yes *(North Slope Spill Response Project Team, Aug. 10, 1998)*
Surface Current:	0.4 knots	N/A
Air Temperature:	10° F to 20°F	N/A
Visibility:	Unrestricted; 5% < 1/2 nautical mile	N/A

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TABLE 1-9 (CONTINUED)
SCENARIO CONDITIONS FOR LIBERTY PRODUCTION WELL BLOWOUT TO BROKEN ICE (FREEZE-UP); OCTOBER 5TH TO OCTOBER 19TH

Surface:	Snow depth averages 3 inches. Five-inch thick young ice covers 1/10 to 8/10 of the water. Open water wake in the lee of the island during heavy, moving ice. Broken ice coverage within 3 miles of the island varies as shown below.		
	Day	**Hours**	**Average Percent Coverage of Broken Ice within 3 miles of Island**
	1	12	70%
	1	12	10%
	2	24	10%
	3	24	20% & slush
	4	24	50% & slush
	5 to 7	72	70%
	8	12	50%
	8	12	10%
	9	24	30% & slush
	10 to 11	48	70%
	12	12	70%
	12	12	10%
	13	24	10%
	14	12	30%
	14	12	70% & slush
	15	24	70% & slush
Spill Trajectory:	The discharged oil takes the form of an aerial plume of droplets (see Figure 1-5A). Twenty percent evaporates before it reaches the surface. Some oil falls to the island. The remaining oil reaches the ocean surface. Eighty percent of the oil has fallen within 615 meters. Thicker oil accumulates in the center of the slick. (See SL Ross Environmental Research Ltd., DF Dickins and Associates Ltd., and Vaudrey and Associates, Inc. 1998. "Evaluation of Cleanup Capabilities for Large Blowout Spills in the Alaskan Beaufort Sea During Periods of Broken Ice," for NSSRPT.) Oil on water moves at a rate of 10 miles per day with the wind. Oiled broken ice rubbles against Tern Island, McClure and Stockton barrier islands, and the landfast ice edge along the East Sag River Delta and western Foggy Island Bay. Some minor ice rubble piles occur along the edge of the icesheet extending seaward from the east side of Endicott Causeway. Within days, solid ice conditions freeze the oil and oiled broken ice in place as rubble piles in the land fast ice.		

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TABLE 1-10
RESPONSE STRATEGY FOR LIBERTY
PRODUCTION WELL BLOWOUT TO BROKEN ICE (FREEZE-UP)

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	An unobstructed production well continues to blow out at a rate of 15,000 bopd. All other wells are shut in using surface and subsurface valves. The Drilling Supervisor notifies the Field Manager. All appropriate notifications are made and the IMT is activated. The Drilling Supervisor calls Well Control in an initial effort to stop the discharge. Well Call is called out from Houston and arrives in 12 hours. Well Call initiates attempts to stop the blowout by means of subsurface mechanisms. Surface methods control the blowout on Day 15. In the meantime, a relief well rig is mobilized.	A-1 A-2 Vol. 3 ICS
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection.	S-1 through S-6
(iii) Well Control Plan	While potential surface control measures are evaluated, the relief well drilling plan is implemented such that a drill site is ready should surface control be ineffective.	N/A
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Blowout plume model is run. Oil movement is tracked using a combination of visual observation and remote sensing techniques. Tracking buoys are deployed. A helicopter and the Kuparuk Twin Otter report the oil to the on-water task forces. Vector addition and trajectory modeling will be used to forecast oil movement. A surveillance unit is deployed by helicopter to delineate the areas along the McClure & Stockton Islands where the oiled ice from Days 1-8 has moved. By Day 15, additional rubble piles of oiled ice also extend around Tern Island, along the landfast ice edge from the East Sag River Delta and along western Foggy Island Bay, and along the seaward edge of the landfast ice extending out from the Endicott Causeway. Additional tracking buoys are deployed from the helicopter, and global positioning system coordinates are taken of the extent of the rubble piles. Oiled ice is spread along the McClure & Stockton Islands, around Tern Island, along the landfast ice edge from the East Sag River Delta and along western Foggy Island Bay, and along the seaward edge of the landfast ice extending out from the Endicott Causeway.	T-6 T-4 T-5 T-2 T-4
(v) Exclusion Procedures; Protection of Sensitive Resources	Potential oil impact areas and priority protection sites are identified with oil slick trajectory modeling. Due to ice conditions in the nearshore areas, priority attention areas are not anticipated.	SH-1; W-6; Atlas Maps Nos. 80, 74, & 83 to 86.
(vi) Spill Containment and Control Actions	On-Water Recovery Two containment and recovery barge systems mobilize from "hot standby" at West Dock. (see Figures 1-5E and 1-5F). The barges carry workboats, boom, skimmers, mini barges, as well as fire boom and igniters. The barges deploy 615 meters downwind of the island at Hour 12. Two barge skimmer systems deploy as parts of TF1 and TF2 in parallel, facing into the oncoming oil (Figure 1-5E). Each system deploys a pair of 400-foot J booms towed by work boats that generally maintain 132-foot gap widths to the barge. The swath between tow boats is 354 feet, comprising two 132-foot boom openings and the barge beam. The boom is attached to the aft sides of the barge. The barges deploy LORI oleophilic side brush skimmers into boom apices. Collected free water is decanted under a plan approved by the Unified Command.	R-19A (2)

TABLE 1-10 (CONTINUED)
RESPONSE STRATEGY FOR LIBERTY
PRODUCTION WELL BLOWOUT TO BROKEN ICE (FREEZE-UP)

<table>
<tr><th>ADEC REQUIREMENT</th><th>RESPONSE STRATEGY</th><th>ACS TECHNICAL MANUAL TACTIC</th></tr>
<tr><td>(vi) Spill Containment and Control Actions (Continued)</td><td>Four J-boom configurations detached from the barges complete Task Forces 1 and 2. Each configuration operates a LORI side brush oleophilic skimmer. Oil and water are stored immediately in mini barges that decant and then lighter into the larger barges. When ice concentrations decline to 30 percent coverage and less, the J-boom configurations take positions on opposite sides of the barge skimmer systems, in a parallel arrangement. When ice concentrations increase beyond 30 percent, the J-boom configurations fall back to recover oil behind the barge skimmer systems, in a tandem arrangement (see Figure 1-5F).

Maneuvers to avoid broken ice in the collection booms decrease efficiency. (See Tables 1-11 and 1-12 for overall capacity. See Table 1-13 for simulated rates of oil recovery as affected by the ice conditions.) Recovery stops and the boats return to the barges at 60 percent ice coverage when slush loads the boom and consolidation of the ice becomes imminent (i.e., conditions have reached the realistic maximum operating limitations [RMOL]).

<table>
<tr><th><u>Vessel Task</u></th><th><u>TF1 (R-19A)</u></th><th><u>TF2 (R-19A)</u></th></tr>
<tr><td>Tow Boom</td><td>'Bay Class'</td><td>'Bay Class'</td></tr>
<tr><td>Tow Boom</td><td>'Bay Class'</td><td>'Bay Class'</td></tr>
<tr><td>Run Skimmer</td><td>'Bay Class'</td><td>Big Dipper</td></tr>
<tr><td>Run Skimmer</td><td>Arctic Rose</td><td>Agviq</td></tr>
<tr><td>Tow J-Boom</td><td>Kiwi</td><td>Deployer</td></tr>
<tr><td>Tow J-Boom</td><td>Irene</td><td>Retriever</td></tr>
<tr><td>Shuttle Mini-Barges</td><td>'Bay Class'</td><td>Northstar</td></tr>
</table></td><td>ACS Tech Manual Assumption 15B,

L-7</td></tr>
<tr><td>(vii) Spill Recovery Procedures</td><td>A staging area is established at West Dock.

Following a wind shift, Task Forces 1 and 2 re-deploy 615 meters southwest of Liberty Island to recover the new oil that continues to discharge from the blowout. In the following days, recovery continues within the operating limits of broken ice and slush.

On Day 14, broken ice concentrations and slush ice increase beyond the operating limit of the oil recovery systems. On Day 15, the broken and slush ice begins to consolidate. The on-water recovery resources are sent back to West Dock on Day 16. The Arctic Endeavor barge breaks a path through 14-inch thick fast ice.

Open water with thick oil at a safe distance from the production island is not found, and thus in situ burning is not conducted.</td><td>L-2

L-7

(See Technical Note: Predicted operating windows for tugs and barges at freeze-up and break-up, Attachment 3 in D. Dickins. 1998. "Realistic Broken Ice Scenarios for Break-Up and Freeze-Up at Northstar," for NSSRPT).</td></tr>
</table>

TABLE 1-10 (CONTINUED)
RESPONSE STRATEGY FOR LIBERTY
PRODUCTION WELL BLOWOUT TO BROKEN ICE (FREEZE-UP)

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures (continued)	In early January, a task force is deployed on ice roads to excavate oiled gravel from the pad. Vacuum trucks and super sucker trucks remove pools of oil from the pad. In addition, a loader mixes snow with remaining free oil and places the mixture into end dump trucks. After the free oil is recovered, a trimmer and a backhoe remove gravel contaminated with oil. Loaders place the gravel into end dumps and haul the gravel to the Eastern Operating Area Pad 3. There, the gravel undergoes long-term treatment under a plan approved by ADEC for soil stockpiles.	R-6 R-3 R-26 D-4
	<u>Recovery of Oiled Ice</u> During the months of November and December, the ice continues to grow in thickness around Liberty Production Island. During this period, BPXA initiates planning to cleanup oil trapped in the ice. The extent of oiling is delineated and the areas of highest contamination are identified. The plan involves mining rubble pile ice and transferring the recovered ice to temporary, lined storage pits at the West Dock Staging Pad (see ACS Map Atlas Sheet 65). Ice roads are built out to the sites by late December. It is estimated that BPXA has the capability to mine up to 1,100 tons of ice per hour with a conventional face mining system available on the North Slope. BPXA arranges for the delivery of two systems for early January, once the ice road is completed. The ice mining equipment has the capability to mine 9 million cubic yards in 120 days. As the ice becomes unstable for work activities, ice mining ceases and equipment is removed from the ice. Remaining oil in the ice rises to the surface as melt pools, where the oil is concentrated and available for in situ burning.	R-29 (2)
	<u>Spring Breakup</u> Oil in the ice surfaces in melt pools. Over approximately 3 weeks, the oil is burned in situ with 3 helicopters conducting multiple burn operations.	B-1, B-3, B-5
	As broken ice and open water conditions begin to dominate, on-water mechanical containment and recovery systems are mobilized to recover oil released from the ice. Scenario #1 describes these strategies.	R-17 & R-19
(viii) Lightering Procedures	The barge Beaufort 21 lighters in-place the *Arctic Endeavor* and *Beaufort 20* barges. Recovered fluids are transferred to the temporary tank farm on West Dock on Day 16, when all recovery equipment returns to West Dock due to ice conditions.	R-28
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	A Liquid Transfer Task Force assembles a temporary tank farm on West Dock. The objective is to transfer oil and water to the production pipeline to Lisburne Production Center. The Liquid Transfer Task Force Leader supervises teams to set up and operate six 400-bbl upright tanks. PZ pumps move the liquid from the tanks through a 3-inch hard-line and a flange connector into the production pipeline to Lisburne Production Center.	R-22
	The two recovery barges, *Arctic Endeavor* and *Beaufort 20*, resume lightering upon their return to West Dock on Day 16.	R-28

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TABLE 1-10 (CONTINUED)
RESPONSE STRATEGY FOR LIBERTY
PRODUCTION WELL BLOWOUT TO BROKEN ICE (FREEZE-UP)

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to (1) sign manifests, (2) measure liquid and other waste, and (3) submit a plan to ADEC for waste management. The Waste Management Team tallies the quantities and types of waste at the interim storage site at west dock staging area. Decontamination is at West Dock 2 for land decontamination of personnel and equipment and on-water decontamination of vessels. Temporary Storage For Ice Mining Twenty-four Euclid B-70's with a capacity of 47 cubic yards each and 17 maxihauls with a capacity of 30 cubic yards each are utilized to haul oiled ice back to shore. The trucks' combined capacity is 1,638 cubic yards. The trucks make 12 trips each per day, hauling 19,656 cubic yards per day. Over a 120 day period (January 1 - April 30), they move 2.3 million cubic yards of oiled ice and snow. Temporary storage is constructed at West Dock Staging Pad. Ten storage pits average 400-ft. x 400-ft. x 10-ft. deep, with pit liners to protect the surface from contamination. Each stores 230,000 cubic yards. Oiled ice is stockpiled into the pits to a height of about 35 feet. The oiled snow is allowed to melt and liquids are pumped off with vac trucks as they are available. All temporary storage areas are continuously monitored until all liquids are removed. Recovered liquids are processed through oil/water separators. Oil is returned to the production stream and water is injected for enhanced oil recovery.	D-1 to D-5 S-6 D-2, D-5 D-1
(xi) Wildlife Protection Plan	Wildlife monitoring and deterrents to protect the animals and workers are put in place at the spill scene during recovery operations. Liberty Production Island quarters and Building U-8 at Deadhorse are made available to agency biologists and veterinarians standing by to respond to potential reports of oiled wildlife.	W-1 W-5
(xii) Shoreline Cleanup Plan	Shoreline clean-up operations are initiated once break-up is complete. Shoreline assessment is conducted and the beaches to be cleaned and techniques to be used are determined. The Environment Unit submits a Shoreline Cleanup Plan that the Unified Command approves. *NOTE: The following discussion is based on a purely speculative prediction of shoreline impact, and is presented for illustrative purposes only. Prior to commencement of any shoreline cleanup operation, the affected areas must be surveyed to determine the appropriate response. Specific cleanup techniques to be used will be based on field data obtained at the time of the spill on the shoreline habitats, type and degree of shoreline contamination, and spill-specific physical processes. It is not possible to presuppose the outcome of the Shoreline Cleanup Assessment Team process and/or the decisions of the Unified Command.* Oiled surfaces on Tern, McClure and Stockton islands, and the shorelines along western Foggy Island Bay are cleaned up to the satisfaction of ADEC, as a non-emergency project between July 15th and September 30th. Low pressure, cold water deluge removes oil from shorelines on barrier where oiled ice rubble piles had been. Hot water, high-pressure washing removes oil from concrete and metal surfaces on Tern Island and along the Endicott Causeway. At both sites, absorbent boom and belt and brush skimmers recover oil from the seawater. The boom and skimmers work at the shoreline within primary and secondary containment boom that is anchored at the shoreline. Absorbent, containment, and shore seal boom prevent re-oiling of adjacent seawater during mechanical removal of oil from the shoreline. Trenches collect surface and subsurface oil. Trash pumps transfer the recovered oil to 2,400-gallon open top temporary tanks, and then to barges. Barges deliver recovered liquids to West Dock's temporary tank farm.	SH-1(1) SH-2 through SH-11 SH-5 (2) SH-3 (1) SH-4 (1) R-7

TABLE 1-11
OIL RECOVERY CAPACITY[1]
LIBERTY BLOWOUT DURING FREEZE-UP BROKEN ICE SCENARIO

A SPILL RECOVERY TACTIC	B NUMBER OF SYSTEMS[2]	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE (boph)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)	F OPERATING TIME (hours in a 24-hour shift)	G DAILY DERATED OIL RECOVERY CAPACITY (bopd) B X D X F
Day 1 (Up to Hour 12) No Recovery, RMOL conditions of >60% ice coverage during freeze-up exist.						
Day 1 (After Hour 12)						
Team 1, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	10	8,680
Team 2, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	10	8,680
Day 1 (After Hour 12) Total						**17,360**
Day 2-3						
Team 1, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	20	17,360
Team 2, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	20	17,360
Day 2-3 Total						**69,440**
Day 4						
Team 1, R-19A	1	4 LORI LSC-3	4 x 217 x 0.4[3] = 347	0	20	6,940
Team 2, R-19A	1	4 LORI LSC-3	4 x 217 x 0.4[3] = 347	0	20	6,940
Day 4 Total						**13,880**
Day 5-7 No Recovery, RMOL conditions of >60% ice coverage during freeze-up exist						
Day 8-9 (conditions averaged for time period specified)						
Team 1, R-19A	1	4 LORI LSC-3	4 x 217 x 0.7[3] = 608	0	20	12,160
Team 2, R-19A	1	4 LORI LSC-3	4 x 217 x 0.7[3] = 608	0	20	12,160
Day 8-9 Total						**43,500**
Day 10-12.5 No Recovery, RMOL conditions of >60% ice coverage during freeze-up exist.						

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TABLE 1-11 (CONTINUED)
OIL RECOVERY CAPACITY
LIBERTY BLOWOUT DURING FREEZE-UP BROKEN ICE SCENARIO

A SPILL RECOVERY TACTIC	B NUMBER OF SYSTEMS[2]	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE (boph)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)	F OPERATING TIME (hours in a 24-hour shift)	G DAILY DERATED OIL RECOVERY CAPACITY (bopd) B X D X F
Day 12 (After Hour 12)						
Team 1, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	10	8,680
Team 2, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	10	8,680
Day 12 (After Hour 12) Total						**17,360**
Day 13 Total						
Team 1, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	20	17,360
Team 2, R-19A	1	4 LORI LSC-3	4 x 217 = 868	0	20	17,360
Day 13 Total						**34,720**
Day 14 (Before Hour 12) Total						
Team 1, R-19A	1	4 LORI LSC-3	4 x 217 x 0.7[3] = 608	0	10	6,080
Team 2, R-19A	1	4 LORI LSC-3	4 x 217 x 0.7[3] = 608	0	10	6,080
Day 14 (Before Hour 12) Total						**12,160**
Day 14 (After Hour 12)-Day 15 No Recovery, RMOL conditions of >60% ice coverage during freeze-up exist.						
Total Capability Day 1-15						**208,420**

[1] Recovery capacities for broken ice are subject to additonal operating constraints. See Table 1-13. See ACS Tech Manual Tactic L-7, Table 1A.

[2] To determine the amount of equipment and personnel required, multiply the number of recovery systems (Col B) by the values in the equipment and personnel tables in the ACS *Technical Manual* Tactic.

[3] In 3/10ths, 5/10ths, and 7/10ths ice concentrations, containment efficiency is decreased by 30%, 60%, and 80% respectively. Decreased efficiency is attributed to the time required to remove ice from around the skimmer head and maneuvers to avoid ice and dump ice. See ACS *Technical Manual*, vol. 1, Assumption 15B.

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TABLE 1-12
LIQUID HANDLING CAPABILITY[1]
LIBERTY BLOWOUT DURING FREEZE-UP BROKEN ICE SCENARIO

A SPILL RECOVERY TACTIC	B NUMBER OF STORAGE SYSTEMS[2]	H STORAGE CAPACITY DESCRIPTION	I DERATED STORAGE CAPACITY VOLUME PER UNIT (bbl)	J OIL & EMULSION AVAILABLE[3] (bph)	K TIME ON LOCATION BEFORE OFFLOAD NEEDED (hrs) I/J	L OFF-LOADING MECHANISM	M OFF-LOADING RATE (boph)	N TRANSIT TIME - BOTH WAYS (hrs)	O OFFLOADING TIME (hrs) I/M	P OFFLOAD AND TRANSIT TIME (hrs) N+O
Team 1, R-19A	1	*Arctic Endeavor*	21,000	223[5]	94	R-28	4,000	N/A[4]	5.3	5.3
Team 2, R-19A	1	*Beaufort 20*	12,200	223[5]	55	R-28	4,000	N/A[4]	3.1	3.1

1 Recovery and liquid handling capacities for broken ice scenarios are subject to additional operating constraints as determined by the North Slope Spill Response Project Team. See Table 1-13.

2 To determine the amount of equipment and personnel required, multiply the number of recovery systems by the values in the equipment and personnel tables in the ACS *Technical Manual* .

3 The total volume of oil/emulsion available for recovery is the volume of oil on water x 1.67 (emulsion factor).

4 Barges are lightered in place with the Beaufort 21 (see ACS *Technical Manual* L-4).

5 Liquids handled/transferred in open water equals [39,971 bbl (from Table 1-13) x 1.67]/150 hours = 445 bph; divided between the two recovery teams = 223 bph.

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TABLE 1-13
NORTH SLOPE SPILL RESPONSE PROJECT TEAM ASSUMPTIONS FOR BROKEN ICE CONDITIONS
LIBERTY BLOWOUT DURING FREEZE-UP

A OPERATIONAL PERIOD (HOUR)	B BROKEN ICE CONCENTRATION (10THS)	C CONFIGURATION OF SKIMMING SYSTEMS	D VOLUME OF OIL ENCOUNTERED (bbl per hour)[2]	E NUMBER OF RECOVERY HOURS	F ICE EFFECT ON OIL CONTAINMENT	G PERCENTAGE OF AREA OCCUPIED BY OIL (1-ICE CONCENTRATION)	H OIL RECOVERED IN THIS OPERATIONAL PERIOD[4] (BBL)
0-6	7	In Transit	N/A	0[1]	0.2	0.3	0
6-12	7	>RMOL	0	0[1]	0.2	0.3	0
12-48	1	Parallel	433	30	0.9	0.9	10,522
48-72	2	Parallel	433	20	0.8	0.8	5,542
72-96	5	Tandem	240	20	0.4	0.5	(960+768+614) = 2,342
96-168	7	>RMOL	0	0[1]	0.2	0.3	0
168-180	5	Tandem	240	10	0.4	0.5	(480+384+307) = 1,171
180-192	1	Parallel	433	10	0.9	0.9	3,507
192-216	3	Parallel	433	20	0.7	0.7	4,243
216-264	7	>RMOL	0	0[1]	0.2	0.3	0
264-276	7	>RMOL	0	0[1]	0.2	0.3	0
276-312	1	Parallel	433	30	0.9	0.9	10,522
312-324	3	Parallel	433	10	0.7	0.7	2,122
324-360	7	>RMOL	0	0[1]	0.2	0.3	0
TOTAL OIL RECOVERED BY MECHANICAL RECOVERY, DAYS 1-15							39,971 bbl
TOTAL OIL BURNED IN SPRING MELT POOLS[3] = 85,337 bbl							
TOTAL OIL RECOVERED FROM ICE MINING = 21,505[5] bbl							
TOTAL OIL RECOVERED MECHANICALLY IN SPRING = 33,187 bbl							

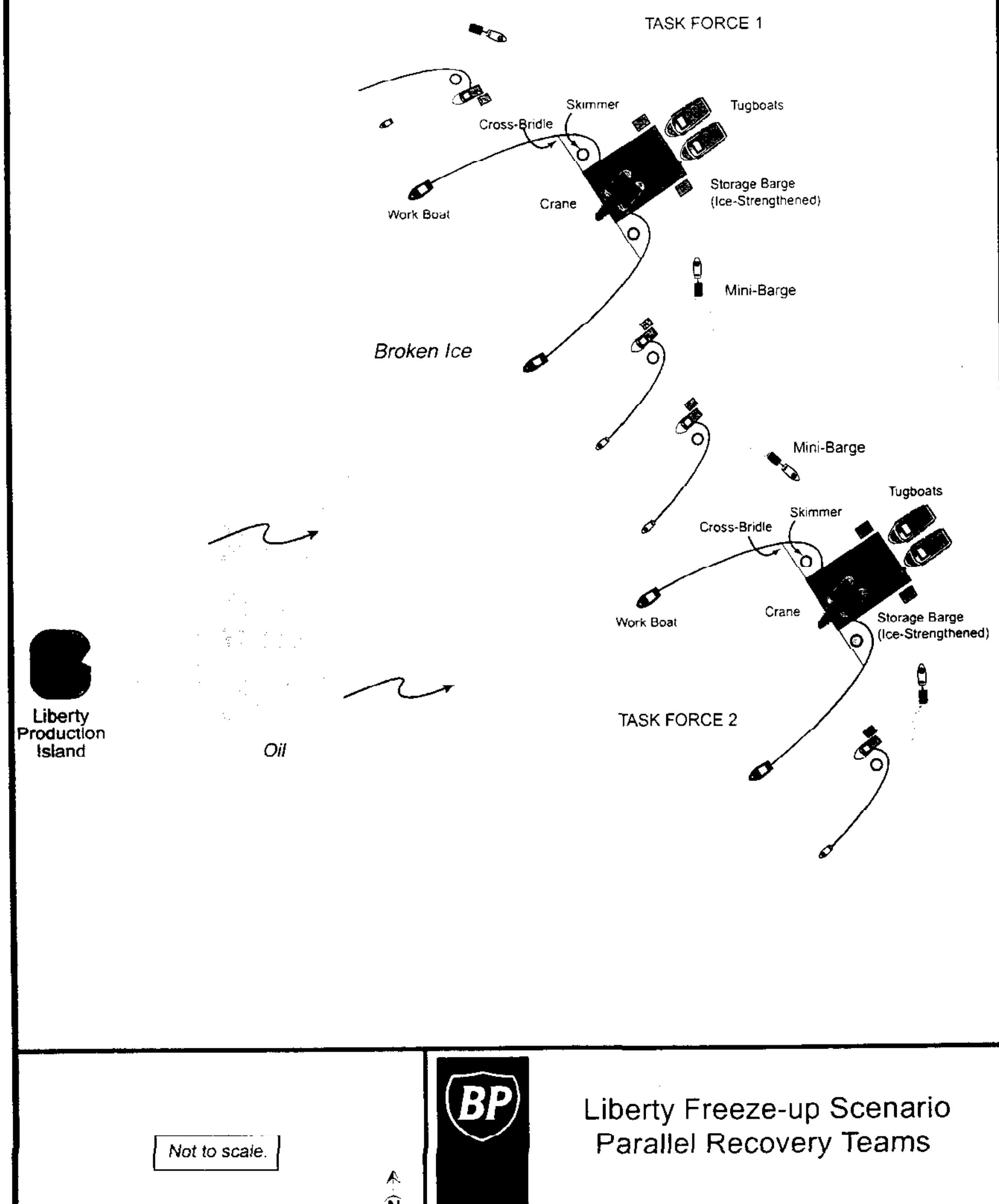
1 *Ice conditions exceed Realistic Maximum Operation Limitation of 6/10ths (see ACS Tactic L-7).*

2 Volume of oil encountered is expressed as the thick portion of the slick present at the prevailing surface current (240 ft. wide by 0.7 mm thick for tandem skimmer configuration; 1,000 feet wide by 0.3 mm thick for parallel configuration). (1998. S.L. Ross Environmental Research Ltd., D.F. Dickins and Associates Ltd., Vaudrey and Associates, Inc. Evaluation of Cleanup Capabilities for Large Blowout Spills in the Alaskan Beaufort Sea During Periods of Broken Ice)

3 Volume of oil available to melt pools = 180,000 bbl - 39,971 bbl (vol. recovered mechanically in fall) - 21,505 bbls (vol. recovered by ice mining ops during winter) = 140,029 bbl 118,524 bbl x 0.80 (avg. burn efficiency) x 0.90 (percentage of melt pools greater than 50 ft^2) = 85,337. Values and assumptions obtained from: 1998. S.L. Ross Environmental Research Ltd., D.F. Dickins and Associates Ltd., Vaudrey and Associates, Inc. *Evaluation of Cleanup Capabilities for Large Blowout Spills in the Alaskan Beaufort Sea During Periods of Broken Ice*, p. 116.

4 For parallel configuration, multiply the number of hours X volume of oil encountered X ice effect X area occupied by oil (e.g., parallel = single tier recovery configuration). For tandem configuration, the total amount of oil recovered is equal to the amount recovered by each of three tiers = [(number of hours X volume of oil encountered X ice effect X area occupied by oil) + (total encountered oil less oil recovered by Tier 1 X ice effect X area occupied by oil) + (remaining oil encountered by Tier 3 X ice effect X area occupied by oil)]

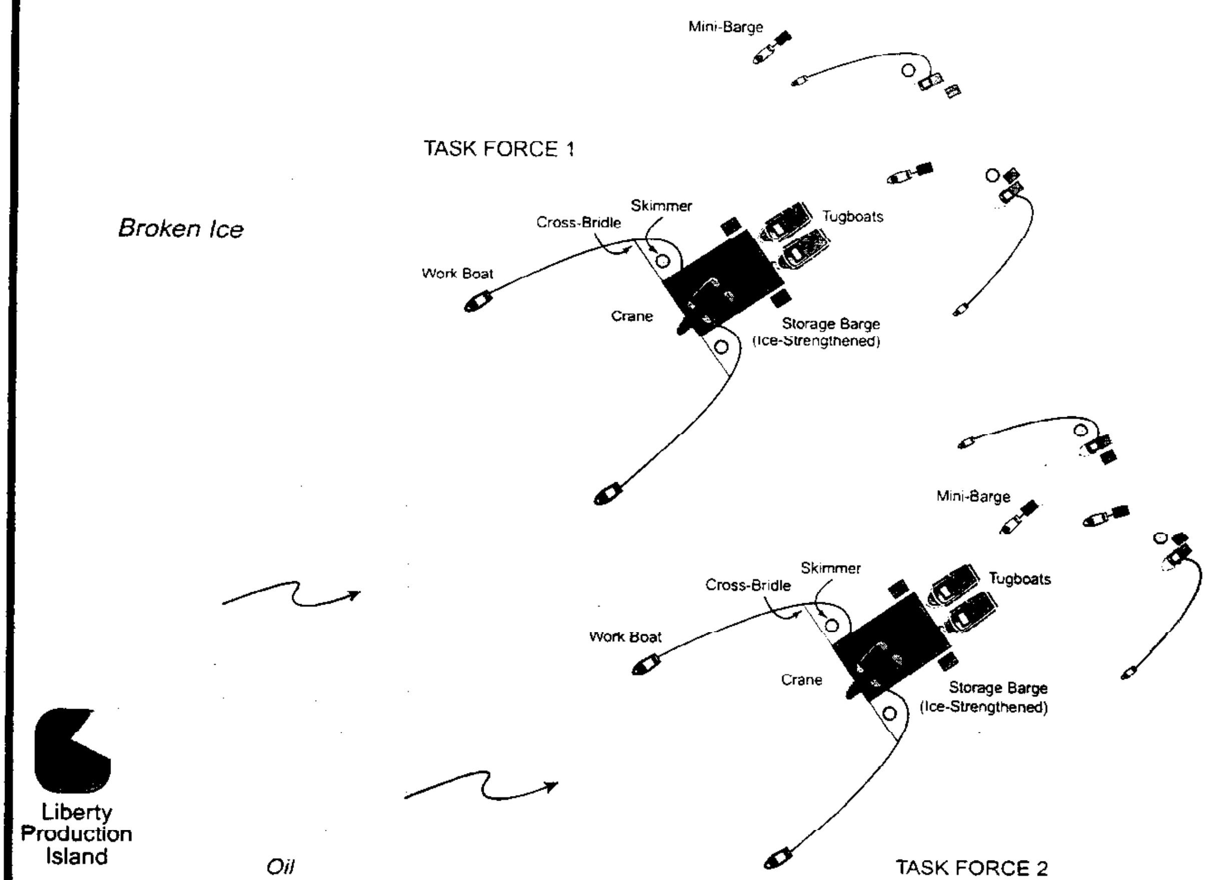
5 The total amount of oiled rubble is equal to the area of oiled ice that collides with the barrier islands/landfast ice edge during the storm event on Day 8. The volume of oil contained within the oiled rubble is equal to the amount of oil that fell to the ice surface prior to movement + the amount of oil remaining on the water between ice floes at the time of movement. Total Oiled Rubble = 8.2 million cubic yards, containing 68,487 bbl oil (0.00835 bbl/cu yd). The amount of oil removed by ice mining = volume of rubble removed X average oil content = (2.3 million cu yd) X (0.00835 bbl/cu yd) = 21,505 bbl



Liberty Freeze-up Scenario
Parallel Recovery Teams

Figure 1-5E

Contents



Not to scale.

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Liberty Freeze-up Scenario
Tandem Recovery Teams

Figure 1-5F

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SCENARIO 3

LIBERTY PIPELINE CHRONIC LEAK UNDER SOLID ICE

Contents

TABLE 1-14
SCENARIO CONDITIONS FOR LIBERTY SUB-SEA PIPELINE LEAK; SOLID ICE CONDITIONS

PARAMETER	PARAMETER CONDITIONS	PROJECT TEAM ASSUMPTION?
Spill Location:	Liberty production pipeline north of the Kadleroshilik River (see Figure 1-5G)	N/A
Spill Time:	January 15	N/A
Source of Spill:	Sub-sea pipeline	N/A
Cause of Spill:	Guillotine cut	N/A
Quantity of Spill:	1,764 bbl	No
Type of Spilled Oil:	Liberty crude	No
Wind Speed:	10 knots	Yes
Wind Direction:	SW Day 1; NE Days 2-15	Yes
Current:	NA	N/A
Air Temperature:	-35° F	N/A
Visibility:	Unrestricted	N/A
Surface:	Five feet of floating, landfast ice	N/A
Spill Trajectory:	Leaking oil rises to the under-ice surface almost directly above. Oil lies in stationary pools on the underside of the ice, and becomes trapped within the ice with limited spreading.	N/A

TABLE 1-15
RESPONSE STRATEGY FOR LIBERTY SUB-SEA PIPELINE LEAK TO SOLID ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Field Manager directs the shutdown of production, closing in wells at the surface and subsurface. The appropriate notifications are made and the IMT is activated. The control room operator shuts in the pipeline's offshore, undersea segment.	A-1 A-2 Vol. 3 IMS
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information, ice thickness measurements and determines PPE requirements. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection.	S-1 Through S-6
(iii) Well Control Plan	N/A	N/A
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up, the oiled area is delineated. A pattern of 2-inch diameter drill holes in the ice around the discovery hole maps oil on the undersurface of the ice. Leaked oil with an average 2-inch thickness is reported trapped on the rough undersurface of the continuous ice over the leak point.	S-6 T-3
(v) Exclusion Procedures; Protection of Sensitive Resources	The resource agencies specify no priority protection sites; none receive priority protection.	Vol. 2 Map Atlas W-6
(vi) Spill Containment and Control Actions	Oil becomes trapped in the rough undersurface of the ice and by ice growth at the periphery of the oiled area. The oil is contained within a 200-foot diameter area.	N/A
(vii) Spill Recovery Procedures	Recovery of spilled oil is made the first priority. Once containment and recovery of the oil is achieved, work will commence on a pipeline repair. The leak is adjacent to the existing ice road to the Liberty Production Facility. Additional ice pad construction prepares the site for temporary staging of vehicles and storage tanks. Five recovery teams are mobilized to the site. Each team constructs a series of recovery sumps throughout the contaminated area; each sump is approximately 10 feet on a side and 1.5 feet deep. Three to five holes within each sump allow effective recovery of almost all of the trapped oil in the vicinity of the sump (Dickins, D.F., "Late Winter Spill Response & Pipeline Repair," 1997). At an under-ice containment capacity of 0.026 bbl/sq ft (Vaudrey, K.D., "Design Basis Ice Criteria for Northstar Development," 1996), the area under each recovery sump contains 2.6 bbl of oil. Each recovery team completes 4 sumps per shift. Approximately 678 sumps are cut in 17 days at the rate of 40 per day. Based on tests in Prudhoe Bay, the estimated recovery efficiency is 95% (Nelson, W.G. and A.A. Allen. The Physical Interaction and Cleanup of Crude Oil with Slush and Solid First Year Ice. *Proceedings of the Fifth Arctic Marine Oil Spill Program Technical Seminar*, pp. 37-59. 1982.)	L-1, L-2 R-14 (5)

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TABLE 1-15 (CONTINUED)
RESPONSE STRATEGY FOR LIBERTY
SUB-SEA PIPELINE LEAK TO SOLID ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures (Continued)	Oil and water are temporarily stored in Fastanks on the temporary staging ice pads. Vacuum trucks remove the stored liquids to a temporary tank farm at the Endicott SDI. Once the recovery sumps have been completed and as much oil as possible has been removed from below the ice, the pipeline repair operation commences. Contaminated soil excavated from the pipeline trench is taken to Pad 3 for waste classification and storage until final disposal. During the pipeline repair crew's operations, sorbents are used to collect oil that appears on the surface water. Excavated ice that is oiled is loaded into dump trucks and taken to a lined storage pit at the Endicott SDI temporary tank farm. Pipeline repair is completed by mid-April. In early June, an in situ burning task force targets oil (1) collecting in pools on the melting upper surface of the ice via brine channels and top-down melting, and (2) blown to edges of Sag River overflow. Oil remaining in the under-ice surface is estimated to be 5% of the original volume released.	R-22 D-4 R-9 R-26 B-1,-3,-5,-6
(viii) Lightering Procedures	N/A	N/A
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	A Liquid Transfer Task Force assembles a temporary tank farm at the Endicott SDI. The objective is to transfer oil and water from recovery operations to the Lisburne Production Center. A lined temporary storage area is constructed to store contaminated ice excavated from the pipeline repair operation.	R-22 S-6 R-3
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to (1) sign manifests; (2) measure liquid and other waste; and, (3) submit a plan to ADEC for waste management. The Waste Management Team tallies the quantities and types of waste at the interim storage site at the Endicott SDI. A snowmelter is used to separate the oil from solid ice removed during pipeline repair operations. The amount of oil estimated remaining under the 10 feet wide X 200 feet long pipeline repair trench is estimated to be 2.6 bbl. The melted oil/water mixture is transferred into the temporary storage tanks and processed in the same manner as recovered liquids.	D-1 D-2 D-3 D-4 D-5 R-22
(xi) Wildlife Protection Plan	Polar bear monitoring and deterrents to protect the animals and workers are put in place at the spill scene during recovery operations. Liberty production facility quarters and Building U-8 at Deadhorse are made available to agency biologists and veterinarians standing by to respond to potential reports of oiled polar bears. No wildlife becomes oiled.	W-1
(xii) Shoreline Cleanup Plan	N/A	N/A

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TABLE 1-16
LIBERTY SUB-SEA PIPELINE LEAK
OIL RECOVERY CAPABILITY

A SPILL RECOVERY TACTIC, ACS TECH MANUAL TACTIC DESCRIPTION	B NUMBER OF RECOVERY SYSTEMS[1]	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE PER UNIT (bbl per hour)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)	F OPERATING TIME (hours per day)	G DAILY DERATED OIL RECOVERY CAPACITY (bbl per day) B X D X F
R-14	5	3" Diaphragm Pump	22.8[2]	6	20[2]	99[2]
B-5	1	In situ Burn	see [3] below	6	10	see [3] below

1 To determine the amount of equipment and personnel, multiply the number of recovery systems by the equipment and personnel table values in the ACS *Technical Manual* Tactic.

2 Rate of recovery is limited by the number of recovery sumps each team completes per shift.
Recovery rate = (5 recovery teams) X (4 sumps per shift) X (2.6 bbl per sump) X (2 shifts per day) X (95% efficiency; Dickins, 1997) = 98.8 bbl per day

3 No recovery numbers are calculated for in situ burn. In situ burning targets the estimated 5% of the total volume of oil that remains under the ice and appears in melt pools from mid-June to July.

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TABLE 1-17
LIQUID HANDLING CAPABILITY
LIBERTY SUB-SEA PIPELINE LEAK

A SPILL RECOVERY TACTIC, ACS TECH MANUAL TACTICS DESCRIPTION	H NUMBER OF STORAGE SYSTEMS[1]	I STORAGE CAPACITY DESCRIPTION	J DERATED STORAGE CAPACITY VOLUME (bbl)	K OIL & EMULSION AVAILABLE[2] (bph)	L TIME ON LOCATION PRIOR TO NEEDING TO OFFLOAD (hrs) J/K	M OFF-LOADING MECHANISM	N OFF-LOADING RATE (bbl/hr)	O TRANSIT TIME - BOTH WAYS (hrs)	P OFFLOADING TIME (hrs)	Q OFFLOAD AND TRANSIT TIME (hrs)
R-24	5	2,400-gallon Fastank (2 ea.)	114	8.3[3]	13.7	3-inch diaphragm pump	22.8	0	0	0
R-6	5	Fastanks to Vac Truck	300	8.3[3]	36.1	Vac Truck	150	0.7	1.5	2.2

1 To determine the amount of equipment and personnel, multiply the number of recovery systems by the equipment and personnel table values in the ACS *Technical Manual* Tactic.

2 The total volume of oil/emulsion available for recovery is the volume of oil that discharges to water X 1.67. For the purpose of this scenario, oil is assumed to emulsify as it rises through the water to the under-surface of the ice. The volume of oil/emulsion available for recovery is calculated as the amount of oil under each sump (2.6 bbl) times the number of sumps per day (40) times 1.67 (emulsification factor).

3 Limiting factor for transfer/offloading of the Fastanks is the recovery rate of the sumps.

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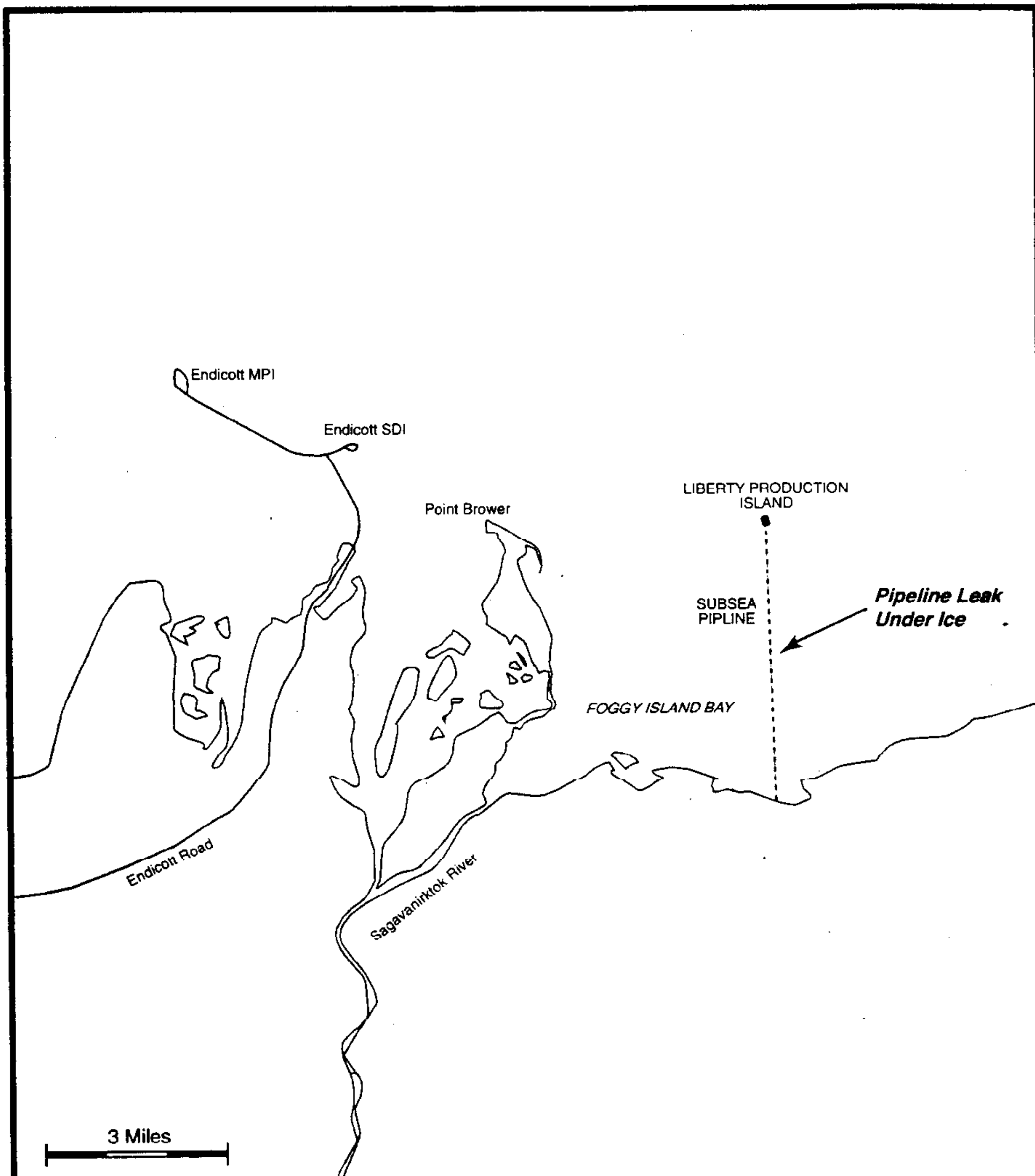


3 Miles

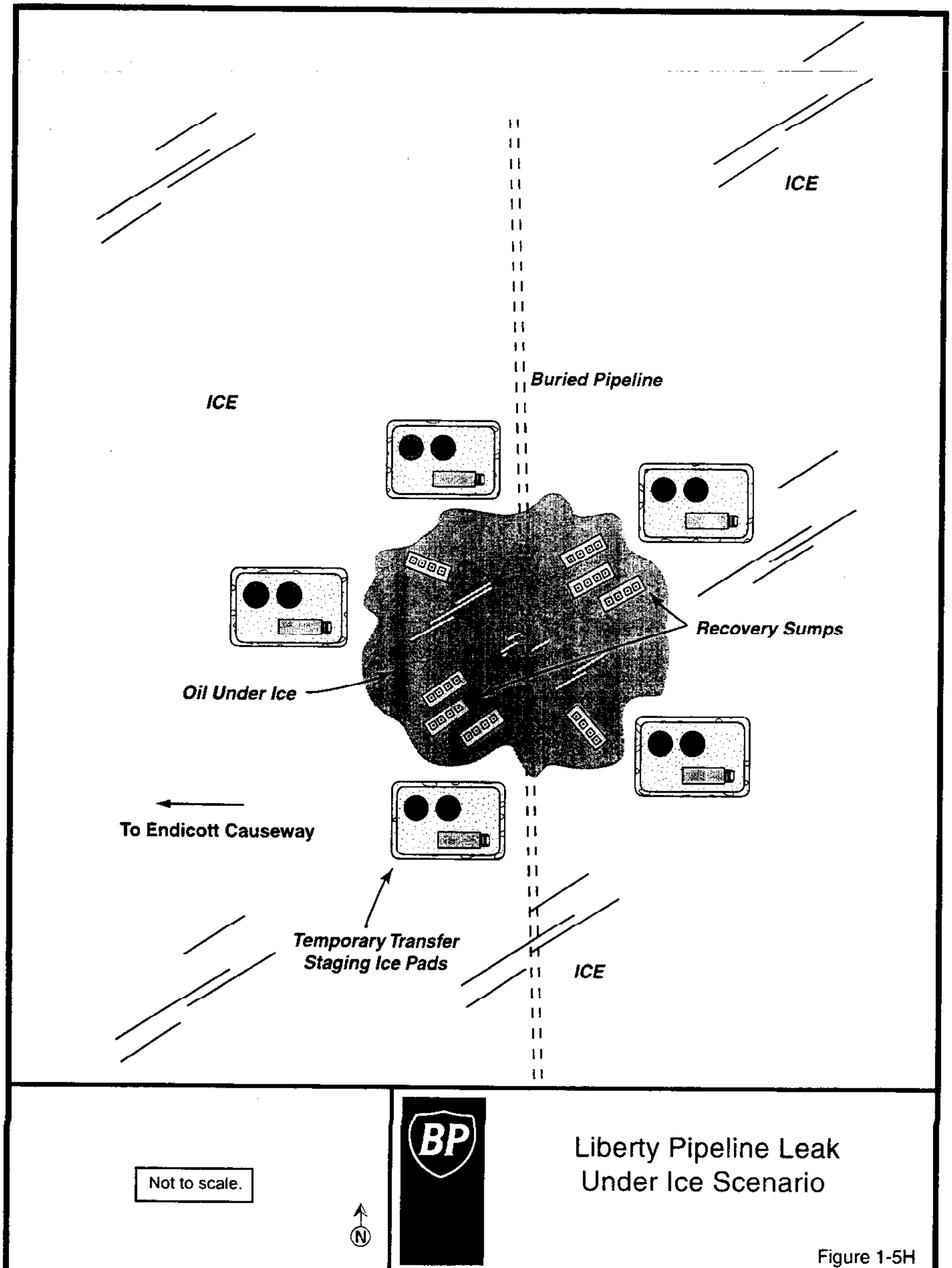
Approximate scale

N

Liberty Production Island
Scenario of a Leak Under Ice,
Vicinity Map

Figure 1-5G

Contents



Liberty Pipeline Leak
Under Ice Scenario

Figure 1-5H

Contents

SCENARIO 4

LIBERTY PIPELINE LEAK DURING BROKEN ICE CONDITIONS - BREAKUP

Contents

TABLE 1-18
SCENARIO CONDITIONS FOR LIBERTY SUB-SEA PIPELINE LEAK; BROKEN ICE CONDITIONS AT BREAKUP

PARAMETER	PARAMETER CONDITIONS				PROJECT TEAM ASSUMPTION?
Spill Location:	Liberty production sub-sea pipeline north of the Kadleroshilik River (see Figure 1-5G)				N/A
Spill Time:	June 22				N/A
Source of Spill:	Sub-sea pipeline				N/A
Cause of Spill:	Guillotine cut				N/A
Quantity of Spill:	1,764 bbl				No
Type of Spilled Oil:	Liberty crude				No
Wind:	10 knots				Yes
	DAY	**WIND FROM**			**NSSRPT, Aug. 10, 1998**
	1	SW			
	2 and 3	E			
	4 to 6	SE			
Surface Current:	0.3 knots (3% of wind speed)				Yes
Air Temperature:	35° F to 45°F				N/A
Visibility:	22% < 1/2 nautical mile				N/A
Surface:	Wave height < 1/2 foot. Broken ice coverage within 2 miles of the spill varies as shown below.				
	DAY	**ICE NOTES**			**Average Percent Coverage of Broken Ice within 1 Mile**
	1	Rotted fast ice. 4 ft thick, movements of 100s of feet. Floes to 1000 feet diameter.			90%
	2	Movements of 1000s of feet. Ice opens.			80% to 90%
	3	Steady flow past island.			60% to 80%
	4 to 6	Floes reduced to 50 to 500 ft. diameter			50%
Spill Trajectory:	Leaking oil rises to the rotting ice almost directly above. Within hours, the oil trapped underneath the ice migrates through the rotting ice and appears on the ice surface. The ice cover loosens and more oil escapes into larger openings as the floes move apart. Eventually, as the ice coverage decreases to less than 3/10ths, the oil on the water surface behaves as an open water spill, with localized oil patches temporarily trapped by wind against individual floes.				

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TABLE 1-19
RESPONSE STRATEGY FOR LIBERTY SUB-SEA PIPELINE LEAK TO BROKEN ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Field Manager directs the shutdown of production, closing in wells at the surface and subsurface. The appropriate notifications are made and the IMT is activated. The control room operator shuts in the pipeline's offshore, undersea segment.	A-1 A-2 Vol. 3 IMS
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the Site Safety Officer verifies that there are no sources of ignition in the area. The Site Safety Officer determines PPE requirements. The Site Safety Officer establishes monitoring protocol on all work vessels to ensure proper personnel protection.	S-1 Through S-6
(iii) Well Control Plan	N/A	N/A
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Oil movement is tracked by visual observation and remote sensing. Tracking buoys are deployed, and the Kuparuk Twin Otter with forward looking infrared tracks the oil within the ice leads. Aerial reconnaissance surveyors report oil surfacing in melt pools. The surveyors radio to the Liberty Production Island radio operator. The radio operator in turn notifies the Operations Supervisor and the Field Manager. Vector addition and trajectory modeling are used to forecast oil and ice movement.	T-4 T-5
(v) Exclusion Procedures; Protection of Sensitive Resources	Potential areas of impact by unrecovered oil and priority protection sites are identified with trajectory modeling. Priority Site / Map Atlas / Boom Length (ft) / Tactic / Task Force 12 Duck Is. / 74 / 1,500 / C-13 / SPTF#1 12 Duck Is. / 74 / 1,500 / C-13 / SPTF#1 12 Duck Is. / 74 / 500 / C-13 / SPTF#2 12 Pt. Brower / 74 / 750 / C-13 / SPTF#3 4 Kad River / 86 / 1,000 / C-14 / SPTF#4 A Shoreline Protection Task Force (SPTF) member helps direct response workers away from the cultural sites, based on a shoreline cleanup plan approved by the Unified Command and the State Historic Preservation Officer.	Map Atlas Sheets 74; 80; 83 to 86. W-6 C-13 (3) C-14 (1)
(vi) Spill Containment and Control Actions	A containment and recovery barge system mobilizes from "hot standby" at West Dock. The barge carries workboats, boom, skimmers, mini barges, as well as fire boom and igniters. The barge breaks its way out of West Dock. Ice concentrations have decreased below 70 percent and allow containment and recovery operations to commence at the spill scene by Hour 60. A primary staging area complete with decontamination facilities is established at West Dock. As a contingency, in situ burn operations are mobilized and stand by.	L-2, S6 B-1,-3,-4,-5

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TABLE 1-19 (CONTINUED)
RESPONSE STRATEGY FOR LIBERTY
SUB-SEA PIPELINE LEAK TO BROKEN ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures	Task Force 1, a barge skimmer system, deploys boom and a pair of LORI oleophilic side brush skimmers into its boom apices. Two J-boom configurations detached from the barge form Task Force 2. Each J configuration operates a LORI side brush oleophilic skimmer. Oil and water are stored immediately in mini barges that lighter into the larger barge. In ice concentrations greater than 30%, Task Force 2 falls back to recover oil behind Task Force 1 in a tandem arrangement. When ice concentrations decline to 30% coverage and less, Task Force 2 takes a position on opposite sides of Task Force 1 in a parallel arrangement. By Day 5.5, the oil is recovered from the water surface. <u>Vessel Task</u> / <u>Team 1 (R-19A)</u> / <u>Task Force</u> Tow Boom / 'Bay Class' / TF1 Tow Boom / 'Bay Class' / TF1 Run Skimmer / 'Bay Class' / TF2 Run Skimmer / *Arctic Rose* / TF2 Tow J-Boom / *Kiwi* / TF2 Tow J-Boom / *Irene* / TF2 Shuttle Mini-Barges / 'Bay Class' / TF2	R-19A
(viii) Lightering Procedures	Oil and water are stored immediately in mini barges that lighter into the larger barge.	R-28
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	A Liquid Transfer Task Force assembles at the Liberty Facility. The recovered fluids are offloaded from the storage barge and processed on the production island.	R-22 S-6
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to (1) sign manifests; (2) measure liquid and other waste; and, (3) submit a plan to ADEC for waste management. Liquid wastes are processed through the Liberty Facility, including its disposal well. Non-liquid oily wastes are transported to Western Operating Area for handling and disposal.	D-1 D-2
(xi) Wildlife Protection Plan	Wildlife monitoring and deterrents to protect animals and workers are put in place at the spill scene during recovery operations. International Bird Rescue and Research is put on stand-by in the event the wildlife treatment facility should be required. Building U-8 at Deadhorse is made available to agency biologists and veterinarians standing by to respond to potential reports of oiled wildlife.	W-1
(xii) Shoreline Cleanup Plan	Although no shoreline becomes oiled, a Shoreline Cleanup Plan is written. In the open water season, shoreline assessment team members search for beach impact. No impacted shoreline is found.	SH-1

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TABLE 1-20
LIBERTY SUB-SEA PIPELINE LEAK TO BROKEN ICE SCENARIO
OIL RECOVERY CAPABILITY

A SPILL RECOVERY TACTIC	B NUMBER OF SYSTEMS[1]	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE (boph)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)	F OPERATING TIME (hours in a 24-hour shift)	G DAILY DERATED OIL RECOVERY CAPACITY (bopd) B X D X F
Days 1 and 2: No recovery, based on >70% broken ice coverage RMOL (see ACS Tactic L-7 and Table 1.6.5-1).						
Day 3						
Open Water TF, R-19A	1	4 LORI LSC-3	$4 \times 217 \times 0.2^2 = 175$	0	10	1,750
Day 4-6						
Open Water TF, R-19A	1	4 LORI LSC-3	$4 \times 217 \times 0.4^2 = 350$	0	20	6,944

[1] To determine the amount of equipment and personnel, multiply the number of recovery systems by the values in the equipment and personnel tables in the ACS *Technical Manual* Tactic.

[2] In 3/10ths, 5/10ths, and 7/10ths ice concentrations, containment efficiency is decreased by 30%, 60%, and 80% respectively. This decreased efficiency is attributed to the time to remove ice from the skimmer head and maneuvers to avoid ice and dump ice. (1998. S.L. Ross Environmental Research Ltd., D.F. Dickins and Associates Ltd., Vaudrey and Associates, Inc. Evaluation of Cleanup Capabilities for Large Blowout Spills in the Alaskan Beaufort Sea during Periods of Broken Ice, p. 46.) See ACS *Technical Manual* vol. 1, Assumption 15.

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TABLE 1-21
LIBERTY SUB-SEA PIPELINE LEAK TO BROKEN ICE SCENARIO
LIQUID HANDLING CAPABILITY

A SPILL RECOVERY TACTIC	H NUMBER OF STORAGE SYSTEMS[1]	I STORAGE CAPACITY DESCRIPTION	J DERATED STORAGE CAPACITY VOLUME PER UNIT (bbl)	K OIL & EMULSION AVAILABLE[2] (bph)	L TIME ON LOCATION BEFORE OFFLOAD NEEDED (hrs) J/K	M OFF-LOADING MECHANISM	N OFF-LOADING RATE (boph)	O TRANSIT TIME - BOTH WAYS (hrs)	P OFFLOADING TIME (hrs) J/N	Q OFFLOAD AND TRANSIT TIME (hrs) O+P
Day 3										
Open Water TF, R-19A	4	Mini Barge	237	25[3, 4]	9.4	4-inch trash pump	1,074	0.5	0.2	0.7
Open Water TF, R-19A	1	*Arctic Endeavor*	21,000	50[3]	420[5]	R-28	628	2	33	35

[1] To determine the amount of equipment and personnel, multiply the number of recovery systems by the equipment and personnel tables values in the ACS *Technical Manual* Tactic.

[2] For oil that discharges to water, the total volume of oil/emulsion available for storage is the volume of oil x 1.67.

[3] Liquids handled/transferred in open water equals (1,764 bbl x 1.67)/60 hours = 50 bph. Half is recovered through the min barges, two at a time, and transferred to the interim storage barge.

[4] Liquids handled/transferred by the mini barges is divided between two J-boom components.

[5] Total liquids handled/transferred in the interim storage barge equals 1,794 bbl of oil x 1.67 = 2,996 bbl emulsion.

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1.7 NONMECHANICAL RESPONSE OPTIONS [18 AAC 75.425(e)(1)(G)]

BPXA will mechanically contain and clean up oil spills to the maximum extent possible. BPXA will request approval for in situ burning from the Federal On-Scene Coordinator and State On-Scene Coordinator when mechanical response methods prove ineffective or when non-mechanical response options will be used as a tool to minimize environmental damage.

1.7.1 Obtaining Permits and Approvals

Burning will not occur without approval of state and federal agencies. The BPXA Incident Commander will discuss the option of in situ burning with the federal and state on-scene coordinators. BPXA and ACS will complete an "Application for ISB." BPXA's application for an open burn permit under 18 AAC 50.030 is provided in Exhibit 1-1.

ACS Tactic B-3; Exhibit 1-1

1.7.2 Decision Criteria for Use

In situ burning of spilled oil will be considered under conditions such as the following:

ACS Tactic B-3

- Mechanical recovery is impractical or ineffective.
- Shorelines are threatened.
- Burning would augment the oil elimination capacity of mechanical recovery.
- Present and forecast wind conditions will carry the smoke plume away from populated areas.
- A successful test burn has been conducted.

Dispersants may be considered under conditions such as the following:

- Mechanical recovery is impractical or ineffective.
- Shorelines are threatened.
- Dispersant use would augment the oil elimination capacity of mechanical recovery.
- Adequate supplies of dispersant can be obtained.
- The oil is in a zone pre-approved for dispersant use.
- A successful test of the dispersant has been conducted.

1.7.3 Implementation Procedures

If the BPXA Incident Commander decides to use in situ burning and obtains the necessary authorization, ACS will carry out the response.

ACS Tactics B-1 through B-7; L-6

1.7.4 Required Equipment and Personnel

ACS maintains the equipment and personnel for in situ burning. A dispersant operation would involve use of dispersants and application equipment maintained within Alaska for response to a spill in Prince William Sound.

ACS Tactic L-6

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EXHIBIT 1-1
LIBERTY OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN
BP EXPLORATION (ALASKA) INC.
IN SITU BURNING OF OIL SPILLS ON NORTH SLOPE AND IN BEAUFORT SEA
OPEN BURN PERMIT APPLICATION

(Alaska Air Quality Plan, Section III.F, Open Burning)

BP Exploration (Alaska) Inc. hereby requests an ADEC open burn permit to conduct in situ burning of potential spills of crude oil from BPXA's North Slope operations as described in the BPXA Liberty Development Area *Oil Discharge Prevention and Contingency Plan* ("plan").

It should be noted that BPXA cannot burn an oil spill without the approval of the Alaska Regional Response Team at the time of the spill—in addition to the ADEC open burn permit. If in situ burning were being considered for use on a spill from BPXA facilities, BPXA would request approval from the RRT.

1. Location and inclusive dates for fires to the extent possible

It is not possible to state exactly when in situ burning of oil spills would be used. This application is for a general permit to burn oil spills, which could occur at any time. Section 1.6.13 of the plan summarizes the RPS volumes to open water from Liberty. Because multiple burns would be used on different oil concentrations, these burns could be spread over several days.

2. Location of all sensitive population centers, ground travel routes, airports or other activities that should not be impacted by smoke

The exact location of an in situ burn operation at Liberty cannot be specified until a spill actually occurs. However, the likely locations are in Foggy Island Bay, where no population centers, airports, or highways would be affected. The nearest village is Nuiqsut, located approximately 80 miles to the southwest. Endicott's Satellite Drilling Island is approximately 7 miles to the west.

3. Where the weather forecasts will be obtained and how they will be used to prevent smoke problems

The National Weather Service in Anchorage will be contacted to provide weather forecasts for the time period in which in situ burning is proposed. The following parameters will be obtained: ventilation factor, visibility, wind speed and direction. The burn will be conducted only after a small test burn confirms that good dispersion conditions exist.

4. How weather changes will be monitored and what will be done to reduce or mitigate smoke impacts if unfavorable weather should occur after ignition

On-site observations will be used to monitor the burn. If the wind shifts or dispersion changes during burning, oil held within fire-containment boom will be allowed to spread so that it becomes too thin to support continued burning.

5. Considerations for visibility impacts

Authorities having control over the sensitive features listed in Item 2 will be notified if visibility is expected to be reduced, due to smoke or fog, to less than 3 miles for a period of time in excess of 30 consecutive minutes and/or 180 minutes during a 24-hour period. It is not anticipated that smoke from an in situ burn will impact visibility at any of the locations listed in Item 2.

Contents

6. How coordination with air quality authorities having jurisdiction will be accomplished

The ADEC representative at the Liberty command center will be notified verbally before ignition. If an ADEC representative is not present, the Fairbanks office of ADEC will be notified by telephone.

7. The procedures that will be used to coordinate with other concerned agencies such as the Federal Aviation Administration, state troopers, military, adjacent land managers, etc.

Coordination with other concerned agencies will be simplified because of their representation on the Alaska RRT. BPXA will ensure that, at a minimum, the following agencies are notified before ignition:

- Federal Aviation Administration
- U.S. Coast Guard
- Alaska State Troopers
- North Slope Borough
- Village of Kaktovik
- Village of Nuiqsut

8. How the public will be informed prior to, during, and after the burning

The news media will be used to inform the public prior to, during, and after the burning.

9. What will be done within reason to reduce the duration of the active fire phase and smoldering phase

In situ burning for an oil spill in the Beaufort Sea would likely involve the burning of oil that is concentrated using fire-resistant containment boom. In addition, patches of oil thickened against ice floes or other barriers could be ignited. In either case, the active fire phase for each burn would be brief (on the order of several hours), with no smoldering phase.

10. What will be done to validate predicted smoke dispersal conditions such as a test fire, smoke bomb, etc.

If the RRT approves the use of burning, the approval would likely be for a test burn. In any case, BPXA would have ACS conduct a small test burn to ensure that smoke was dispersing as expected. Visual observation would then be used to verify predicted smoke dispersal.

11. For fires other than fire fighter training, an evaluation of alternatives to open burning, demonstrating that open burning is the only feasible alternative.

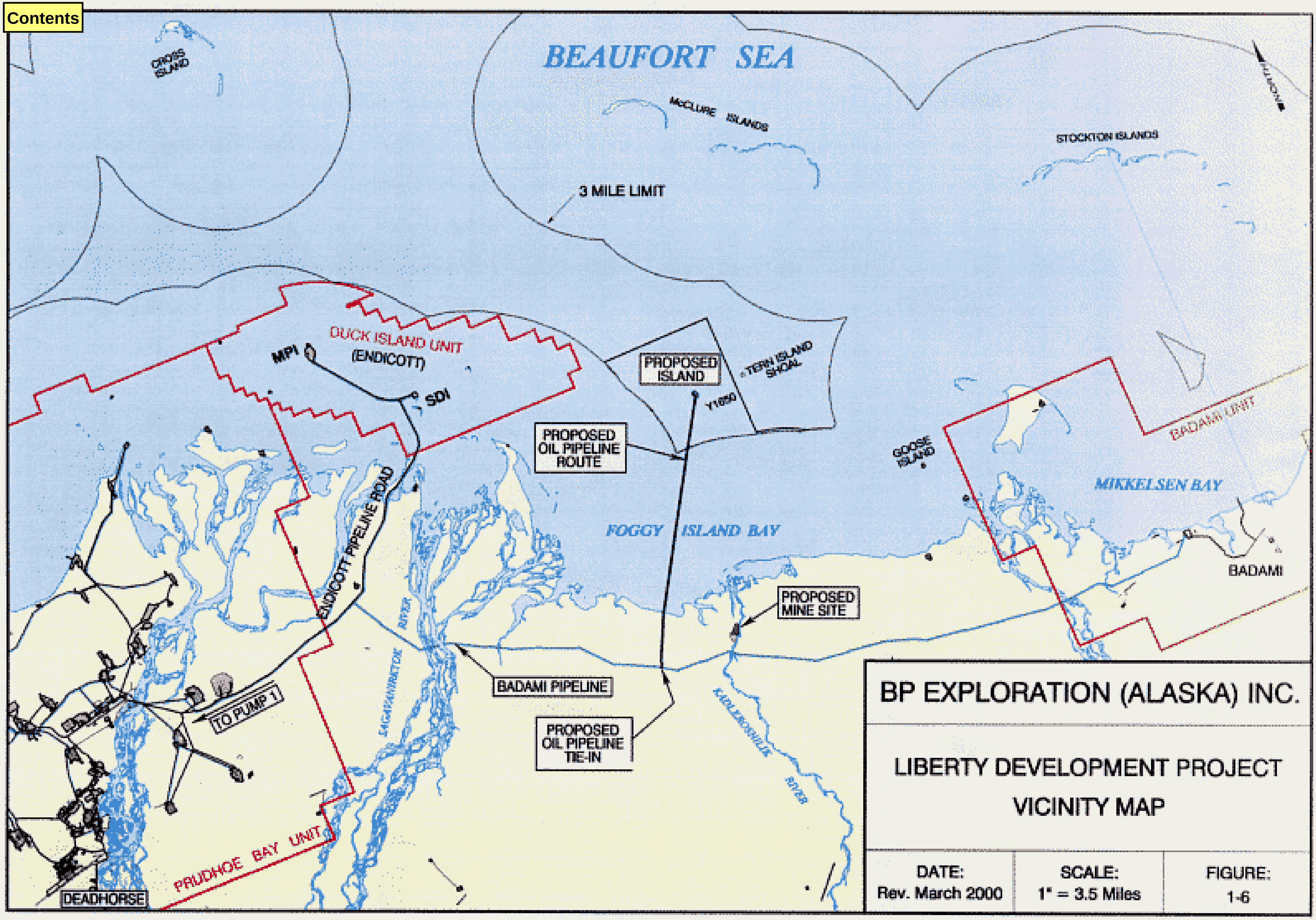
Such an evaluation cannot be made until the actual time of a spill.

Contents

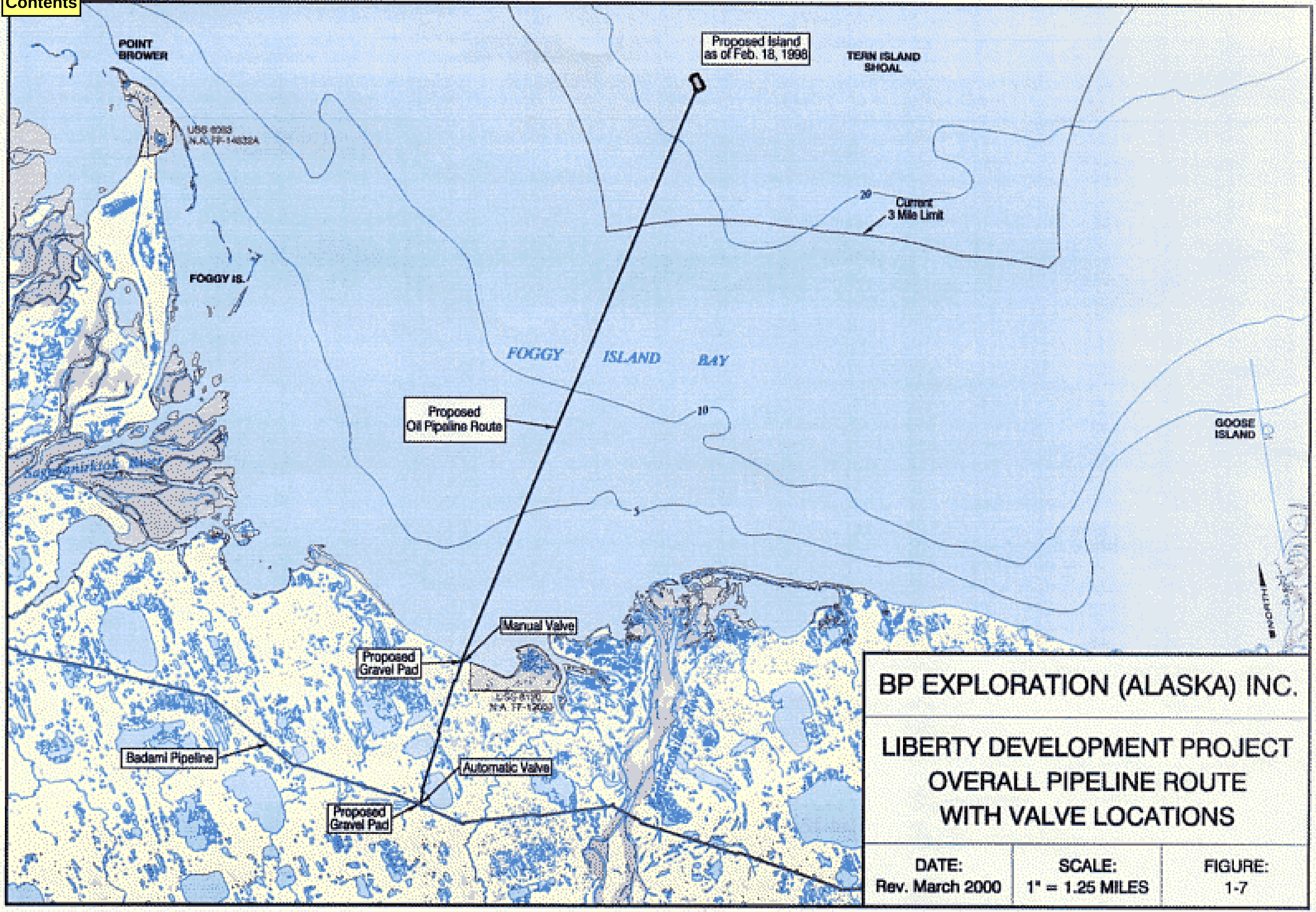
1.8 FACILITY DIAGRAMS [18 AAC 75.425(e)(1)(H)]

Facility diagrams of Liberty facilities follow.

- Vicinity Map (Figure 1-6)
- Liberty Overall Pipeline Route with Valve Locations (Figure 1-7)
- Liberty Development Island Layout (Figure 1-8)
- Liberty Development Island Grading and Drainage Plan (Figure 1-9)
- Liberty Development Badami Tie-In Pad Plan View (Figure 1-10)


BEAUFORT SEA
CROSS ISLAND
McCLURE ISLANDS
STOCKTON ISLANDS
3 MILE LIMIT
DUCK ISLAND UNIT
(ENDICOTT)
MPI
SDI
PROPOSED ISLAND
TERN ISLAND SHOAL
Y1650
PROPOSED OIL PIPELINE ROUTE
GOOSE ISLAND
BADAMI UNIT
MIKKELSEN BAY
FOGGY ISLAND BAY
BADAMI
ENDICOTT PIPELINE ROAD
RIVER
SAGAVANIRKTOK
PROPOSED MINE SITE
BADAMI PIPELINE
TO PUMP 1
PROPOSED OIL PIPELINE TIE-IN
KADLEROSHILIK RIVER
PRUDHOE BAY UNIT
DEADHORSE
BP EXPLORATION (ALASKA) INC.
LIBERTY DEVELOPMENT PROJECT
VICINITY MAP
DATE:
Rev. March 2000
SCALE:
1" = 3.5 Miles
FIGURE:
1-6

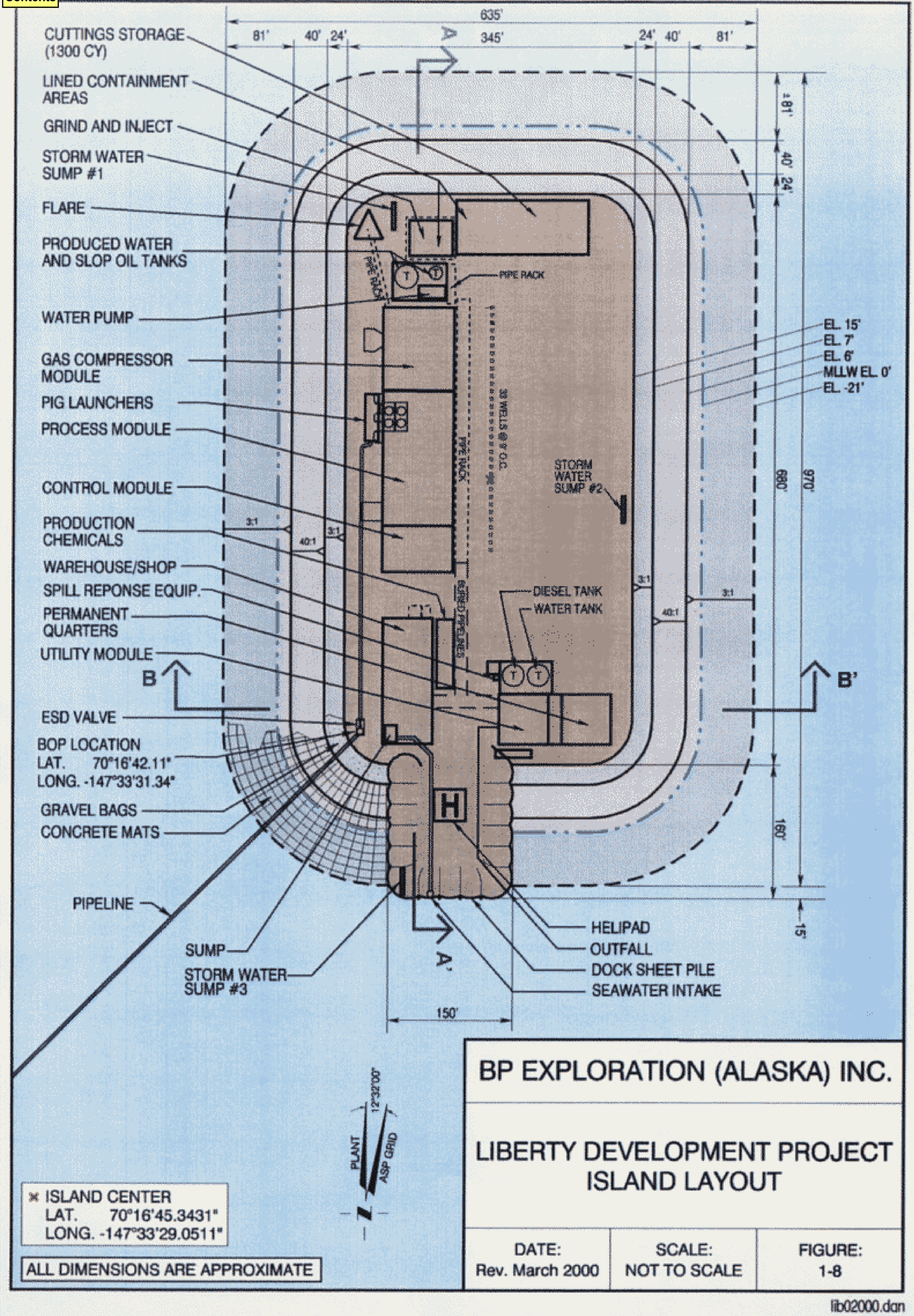
Contents

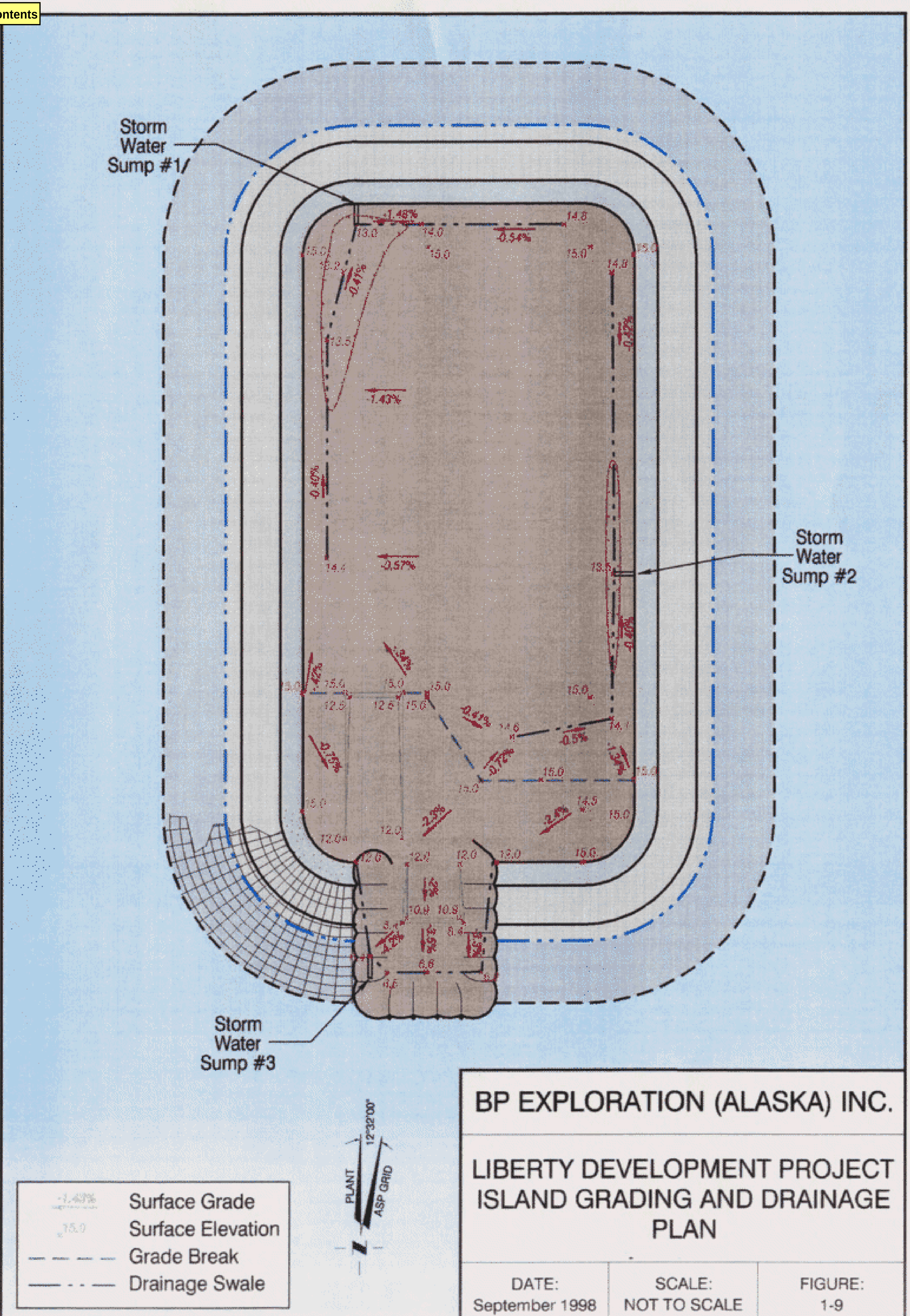


BP EXPLORATION (ALASKA) INC.

LIBERTY DEVELOPMENT PROJECT
OVERALL PIPELINE ROUTE
WITH VALVE LOCATIONS

DATE:	SCALE:	FIGURE:
Rev. March 2000	1" = 1.25 MILES	1-7


635'
81'
40'
24'
345'
24'
40'
81'
A
CUTTINGS STORAGE (1300 CY)
LINED CONTAINMENT AREAS
GRIND AND INJECT
STORM WATER SUMP #1
FLARE
PRODUCED WATER AND SLOP OIL TANKS
PIPE RACK
WATER PUMP
GAS COMPRESSOR MODULE
PIG LAUNCHERS
PROCESS MODULE
CONTROL MODULE
PRODUCTION CHEMICALS
WAREHOUSE/SHOP
SPILL REPONSE EQUIP.
PERMANENT QUARTERS
UTILITY MODULE
ESD VALVE
BOP LOCATION
LAT. 70°16'42.11"
LONG. -147°33'31.34"
GRAVEL BAGS
CONCRETE MATS
PIPELINE
SUMP
STORM WATER SUMP #3
38 WELLS @ 8' O.C.
BURIED PIPELINES
STORM WATER SUMP #2
DIESEL TANK
WATER TANK
EL. 15'
EL. 7'
EL. 6'
MLLW EL. 0'
EL. -21'
3:1
40:1
±81'
40'
24'
680'
970'
160'
15'
B
B'
H
HELIPAD
OUTFALL
DOCK SHEET PILE
SEAWATER INTAKE
A'
150'
12°32'00"
PLANT
ASP GRID
ISLAND CENTER
LAT. 70°16'45.3431"
LONG. -147°33'29.0511"
ALL DIMENSIONS ARE APPROXIMATE
BP EXPLORATION (ALASKA) INC.
LIBERTY DEVELOPMENT PROJECT
ISLAND LAYOUT
DATE: Rev. March 2000
SCALE: NOT TO SCALE
FIGURE: 1-8
lib02000.dgn



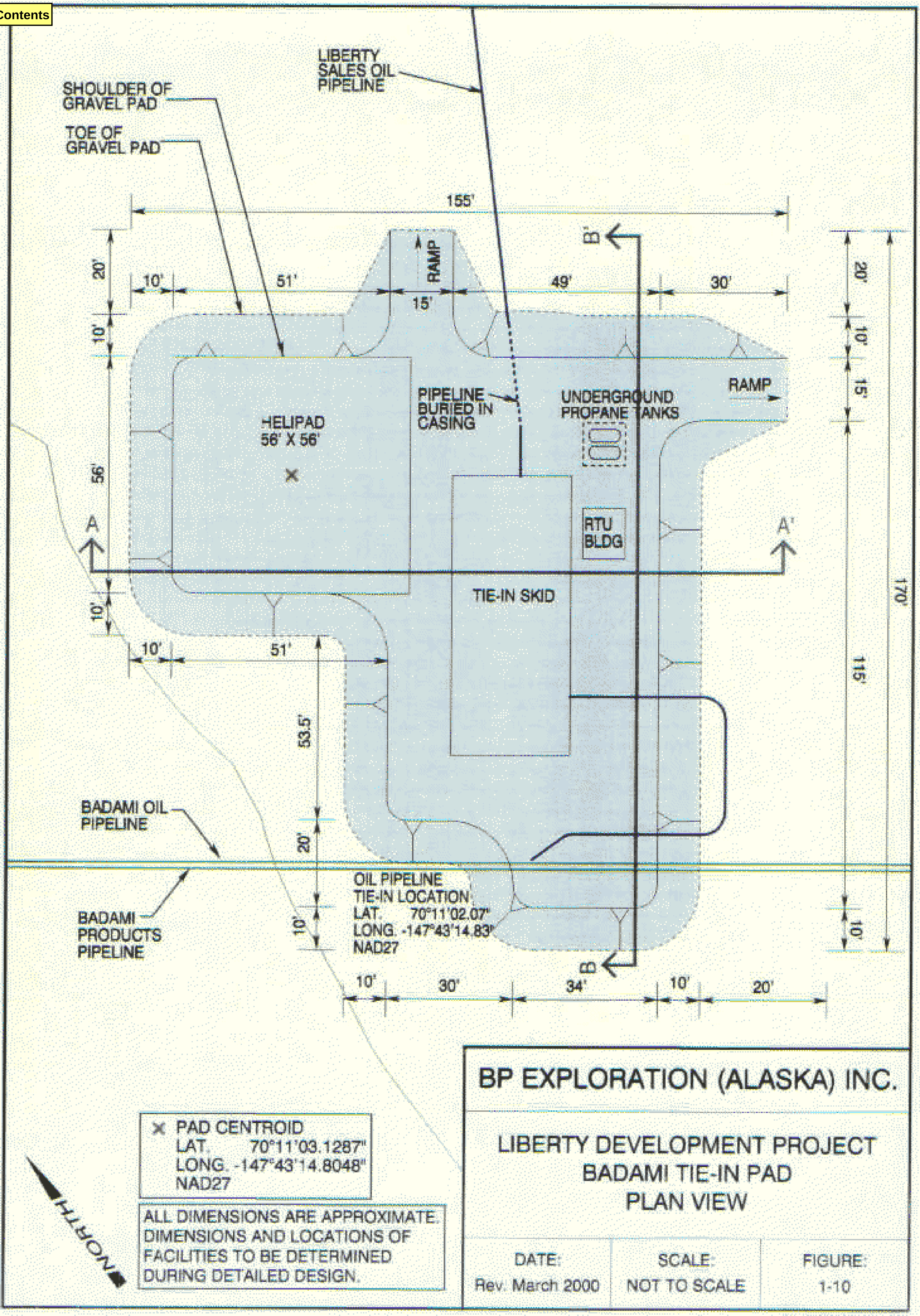
BP EXPLORATION (ALASKA) INC.

LIBERTY DEVELOPMENT PROJECT ISLAND GRADING AND DRAINAGE PLAN

DATE:	SCALE:	FIGURE:
September 1998	NOT TO SCALE	1-9

lib998.dgn

Contents



liberty/2000/pads.dgn

Contents

2. PREVENTION PLAN
[18 AAC 75.425(e)(2)]

2.1 PREVENTION, INSPECTION AND MAINTENANCE PROGRAMS [18 AAC 75.425(e)(2)(A)]

2.1.1 Prevention Training Programs [18 AAC 75.007(d)]

BPXA is developing a comprehensive training program for the Liberty development. This training program will address environmental awareness, environmental compliance, comprehensive safety issues, and operations.

On site Liberty personnel will receive spill prevention training. Special training will be required for all active members of the operations team. A complete investigation is conducted of any spill, remedial action items are assigned, and the findings and solutions will be communicated to all Liberty personnel.

For all BPXA operating areas, service company employees (i.e., CATCO, Peak, etc.) receive instruction to ensure safe conduct on the job, including a briefing prior to project commencement by responsible supervisors. Upon arrival, all personnel are instructed in safety and health responsibilities while on the project including rules, procedures, injury reporting and personal protective equipment. All employees will receive copies of, and be briefed on the ARCO/BPXA *Alaska Safety Handbook.*

Rig contractor employees receive the following additional training:

- Confined Space Entry
- Lockout/Tagout of Hazardous Energy Sources
- Hazard Communication Standard
- Hydrogen Sulfide Gas
- Safety and Accident Prevention
- First Aid/CPR Training (supervisors only)
- Well Control Training (certain employees)

All construction, drilling, and operations personnel will receive the appropriate level of training for their activities. Training will be in compliance with 30 CFR 250, Subpart O and with the stipulations of Lease sale 144. The training programs for well completion, workovers, and control must be reviewed and approved by MMS [250.1503(f)]. The well control training is certified by MMS.

All personnel involved with the operation and maintenance of Production Safety Systems are required to have training, as described in MMS regulations 30 CFR 250.1520, Table B. This training is intended to help eliminate the release of hydrocarbons into the atmosphere. MMS review and approval of these courses are required under MMS regulations, 250.1504(d). The training is also certified by MMS.

The BPXA Training Department maintains a database recording the courses taken by each BPXA employee, a brief description of the course, and the date completed. Access to this database is universal through the BPXA computer system. Current training for an individual is

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available through the immediate supervisor or by contacting the Training Department. Contractors maintain their own training records.

2.1.2 Substance Abuse Programs [18 AAC 75.007(e)]

BPXA policy provides guidance for an environment free of emergencies, substance abuse and related accidents. This environment is maintained through adherence to strict alcohol and drug abuse policies and professionally recognized rehabilitation programs. The company has jurisdiction to intervene and impose disciplinary measures when problems are identified.

The BPXA drug policy was established to ensure the safety of all employees, contractors, and non-employees and provide a safe working environment at all operations. The company prohibits the following in the work place or on the job:

- Possession of illicit drugs
- Possession of controlled substances without Physician Assistant's knowledge
- Use of drug or alcoholic substances
- Distribution or sale of drugs or alcohol

BPXA complies with DOT regulations mandating biological testing and supervisory training programs. BPXA employees who fall under these regulations (i.e., employees involved in safety-sensitive positions within natural gas, liquefied natural gas, and hazardous liquid pipeline operations) are required to undergo biological testing for pre-employment drug testing, reasonable suspicion (drug and/or alcohol testing), following reportable accidents (drug and/or alcohol), following alcohol or drug rehabilitation (return to duty and follow-up testing), and random drug testing. If the Company's Alcohol and Drug Abuse Policy or Program conflicts in any way with DOT regulations for such employees, the regulations will prevail.

Upon entering the company premises, BPXA employees and contractor personnel must be free from the influence of drugs and/or alcohol. BPXA employees are subject to the same testing categories as in the DOT program mentioned above, but only safety-sensitive personnel are in the company's non-DOT random drug testing program:

- Alaska Leadership Team
- All North Slope-based employees (currently not in a DOT program)
- Frequent travelers to the North Slope (receive the North Slope premium)
- Security
- Crisis Management Team
- Incident Management Team(s)
- HSE Professionals
- Emergency Response Coordinators

BPXA Liberty operations will conduct random drug testing as required to assure that the above requirements are being met. Contractor companies will be required to have a like program, which should include:

- Random drug testing at a minimum annual rate of 25%
- Testing situations such as pre-employment, post-accident, reasonable suspicion, random, return to duty, and follow-up

Contents

- Testing at the same screening and confirmation testing levels as the DOT requirement
- Submission of quarterly statistical information to the Anchorage HSE Department

Contractors required to meet these requirements are those with personnel who work on the North Slope seven of any 30 days in a calendar month, and who have personnel in any of the above-mentioned eight safety-sensitive categories.

BPXA supervisors, managers, and step-up supervisors are required to attend the supervisor awareness training on drug and alcohol misuse for either the DOT or company programs. The classes are open to all employees and contractor personnel. Information is provided on the available rehabilitation programs.

For BPXA employees and their families, the BPXA ANSWERS program is an elemental part of rehabilitation. ANSWERS is a confidential counseling and referral service provided free-of-charge to employees and their families. BPXA supports medical rehabilitation programs outside of ANSWERS which are covered by the BPXA medical plan.

2.1.3 Medical Monitoring

Upon beginning work with BPXA, new hires receive an entrance physical to establish baseline health conditions. Under federal Occupational Safety and Health Administration (OSHA) and State of Alaska Department of Occupational Safety and Health requirements, medical monitoring is conducted as required by the type of work performed.

2.1.4 Security Program [18 AAC 75.007(f)]

Access to North Slope Operations is controlled through BPXA Security checkpoints, where Security records personnel present in the operating areas. The security badge system provides a method for monitoring personnel. Each BPXA employee or contractor wears an identification badge indicating the employee's company and badge number. With this system, Security has the capability to recognize authorization levels and access personal history information in emergency situations. This program provides for security and safety of personnel while moving to and from the site and while at the site.

For safety reasons, access to the island will be restricted to authorized persons and regulatory personnel. Authorized regulatory personnel carrying photo identification may access the island at any time. They must contact the on-site supervisor to access facilities and comply with applicable safety regulations. All other personnel must obtain authorization from the Liberty Operations Team Lead at BPXA's Anchorage office or at the site.

Security personnel enforce BPXA policies. They are responsible for issuing traffic citations, monitoring of speed limits, promoting safety on the roads, and preventing vehicle-related accidents. Security uses a daily log to document activities, occurrences, and any inspections they are responsible for.

2.1.5 Fuel Transfer Procedures [18 AAC 75.025]

Appendix A

Best Management Practices for spill prevention were established through the adoption of guidelines and operating procedures. BPXA established *North Slope Fluid Transfer*

Contents

Guidelines to be used by employees and contractors during transfer operations. The primary prevention mechanism against discharge during the transfer of liquids is the proper coupling of lines and hoses. The use of surface liners at all inlet and outlet points provides a source of secondary containment for all fuel transfers. The use of surface liners became mandatory for transfer operations on April 2, 1993. The North Slope Unified Operating Procedure (UOP) for Surface Liner/Drip Pan Use was signed and issued by all North Slope Field Managers. Portable surface liners, also known as drip liners, protect the ground surface from contamination during fuel and chemical transfer procedures. The Environmental Technician identifies areas requiring a liner during transfer procedures with facility tags. The UOP mandates the use of liners for:

- Vacuum Trucks
- Fuel Trucks
- Sewage Trucks
- Chemical Delivery Units
- Chemical Transfer Units
- Fluid Transfers within Facilities

BPXA supplies contractors with liners and training in their proper use. Off-pad and remote site operations are conducted in accordance with the BPXA *Best Management Practices*, approved by ADEC in 1993.

Appendix A

Transfer from Barge to Tank

The permanent diesel tank at Liberty will be filled each summer by barge. Temporary diesel tanks will also be filled by transfers from a barge. The barge will be berthed at the dock and connected to the tanks through a fuel hose. The barge will be surrounded by oil spill containment boom during the entire transfer operation. Each fuel hose connection will have a drip pan. Barge personnel and Liberty personnel, in accordance with the required USCG-approved marine fuel transfer operations manual, will closely monitor the entire transfer. Personnel will monitor the hose and the tank level throughout the transfer and will be in communication by radio or hand signals to ensure that the transfer can be quickly stopped if necessary

After operators stationed at the barge and at the tank have connected the fill hose from the barge to the tanks and inspected the connections, valve positions will be manually changed. Once the emergency shut-down valve on the tank is opened, the barge supply pump will then be started. In most cases, when tank filling is complete, the operator at the tank will manually close the valve and the barge operator will stop the barge-mounted pump. After fueling is completed, any remaining fuel will be blown from the line.

Fuel oil will be brought to Liberty during the summer months, and transfers will take place during daylight hours only. Liberty facility personnel and barge personnel shall complete a Declaration of Inspection prior to each operation. The Declaration of Inspection describes communications procedures, start-up and topping off procedures, and assures that persons involved in the transfer have a common understanding of the transfer process.

Contents

In addition, the Liberty Operations Team Lead will ensure the following:

- Verify that the vessel has an approved State of Alaska contingency plan, as verified by viewing the certificate of approval. The response action plan section of the contingency plan must be on board the vessel.
- Complete and sign the contingency plan verification log.
- Submit a copy of log to ADEC and the BPXA contingency plan coordinator within the first five days of the month following the transfer.

Appendix A

Transfer for truck to tank

The permanent diesel tank and temporary diesel storage tanks at Liberty will be filled every 2 to 4 months during winter months by transfer from a tanker truck. The truck will travel to the island by ice roads and connect to the tank via fuel hose. Each fuel hose connection will have a drip pan. Truck and Liberty personnel will closely monitor the entire transfer, in accordance with the North Slope Fluid Transfer Guidelines. Personnel will visually monitor the hose and tank level throughout the transfer and stay in communication by radio and hand signals to assure that the transfer can be quickly stopped if necessary.

Appendix A

The maximum system pressure of the fuel transfer system on the truck is 125 pounds per square inch (psi), and the system has a pressure safety valve set at 125 psi. The safety valve releases fuel back into the truck. The truck's transfer hose has a working pressure of 300 psi and a design burst pressure of 1,200 psi.

Transfer from Fueling Truck to Equipment

During drilling activities, a tanker truck will be used for fueling operating equipment. These transfer operations will be conducted with the fueling truck driver in constant attendance. All fueling hose transfer connections will have a drip pan. The fueling truck will also carry absorbents, waste containers, and tools to contain and clean up minor drips and spills.

2.1.6 Operating Requirements for Exploration and Production Facilities [18 AAC 75.045]

General Facility Requirements

Liberty's facility will be constructed in accordance with MMS regulations, 30 CFR 250, Subpart C.

Flow Tests

Oil produced during a formation flow test or other drilling operations must be collected and stored in a manner that prevents the oil from entering federal or state land or waters. Oil produced from flow tests at Liberty will be stored in mobile tanks.

Platform Integrity Inspections

These requirements do not apply to Liberty, which is an island, rather than a platform. However, MMS review of the island's structural integrity will be performed by a certified verification agent.

Contents

Isolation Valves for Pipelines Leaving Platforms

Liberty will be an island, not a platform. An automated isolation valve will be installed on the pipeline leaving the Liberty facility, in accordance with MMS and DOT regulations.

Drip Pans and Curbing

Drip pans and curbing will be provided at transfer locations.

Catch Tanks

Liberty will have a sump designed to collect stormwater, which will be pumped and discharged to a permitted injection well.

Other Requirements for Tanks

Offshore oil storage tanks will meet the requirements of MMS regulations 30 CFR 250, Subpart C.

Sections 2.1.9 and 2.1.10

Other Requirements for Piping

Offshore and onshore piping will meet the requirements of MMS regulations 30 CFR 250, Subpart J, DOT regulations 49 CFR 195 and State of Alaska regulations 18 AAC 75.080.

Section 2.1.8

Well Cellars

A well cellar encircles each wellhead and is fabricated from 7-foot 2-inch diameter corrugated pipe, extending to a depth of 4 feet 3 inches. To prevent contamination of underlying gravel, the floor of the cellar is poured concrete, which is joined to a 20-inch pile casing. The 20-inch pile casing provides floor penetration for the wellhead. The cellar is designed to provide secondary containment. Fluids such as thaw water will be removed from well cellars on an as-needed basis.

Well Control and Emergency Shutdown

Drilling Assurance

This section outlines preventative and recovery measures to minimize hydrocarbon spill potential which are applied to development drilling operations and are applicable to onshore as well as offshore island facilities. All well control discussions presented in this section are aimed at preventing spills from occurring during drilling operations. Recovery measures that can be utilized to regain well control in the event of loss control are summarized in Section 1.6.3. The potential for spill incidents is noted in Section 2.3.

Sections 1.6.3 and 2.3

The following definitions apply to this section:

Barrier -- During drilling and well activities the following barriers will normally exist:

a) A barrier consisting of a homogenous mud column in hydrostatic overbalance in relation to the reservoir pore pressure.

Contents

b) A barrier consisting of a cemented casing, wellhead, pipe ram/annular preventer and drill string with Kelly valve/check valve.

Blowout -- Any uncontrolled flow of formation fluids to the surface due to formation pressure exceeding the hydrostatic pressure of the mud or fluid column and failure of the second barrier.

Shallow Gas Blowout -- Any uncontrolled flow of gas from gas pockets located above the intended reservoir prior to the blowout preventer being fitted.

Completion -- Covers any installation of production tubing, packers and other equipment, as well as perforation and stimulation in production and injection wells.

Development Drilling -- Covers all operations related to production, injection and observation wells between spudding and cementing the production casing.

Exploration Drilling -- Covers all operations related to wildcat and appraisal wells between spudding the well and plugging and abandonment.

Kick -- Unplanned introduction of hydrocarbons or fluids (brines, water) into the wellbore from formations.

Production -- Covers all wells which produce oil and/or gas but excludes well intervention, start-up and close-in operations.

Workover -- Covers all intervention operations other than operations carried out with wireline.

Remedial -- Covers only those intervention operations where wireline or coil tubing is used.

Well Control During Planning

The process of well control commences before actual drilling operations with the planning and design of any well or workover. This is more onerous for exploration and appraisal wells than for development wells due to the lesser amount of offset data available to make design decisions.

Offset data from exploration and appraisal wells in the form of lithology, geological horizon depths, pore pressure/fracture gradients, hydrocarbon zones, potential loss zones etc. allows for a more robust development well design. With good offset data:

- Appropriate precautions for shallow gas accumulations can be implemented in the well program.
- Correct mud weights (primary well control barrier) for drilling fluids can be selected for each hole section to prevent kicks while ensuring losses do not occur to potential thief zones.
- Hole sizes and hence casing sizes are selected to optimize production from the well while allowing well control incidents to be handled safely (i.e. kick tolerance). Kick tolerance is a safety factor which is utilized to allow for control of additional downhole formation pressure should it be encountered.
- Casing points are selected which allow weaker geological zones to be cased off prior to drilling deeper, higher pressure sections which require higher mud weights to prevent the breakdown of formations at the shoe. If known loss zones exist, casing programs are designed to minimize effects of lost circulation.
- Casing weights, grades, and cementing programs are designed utilizing data and engineering calculations to withstand drilling, completion, production and well control conditions.
- Directional drilling processes and procedures are in place to plan and drill wellbores so as to avoid collision with existing wells.

All the above planning parameters are in accordance with both AOGCC and MMS regulations and Operator policies and recommended practices, which are, at a minimum, equivalent to AOGCC and MMS regulations.

Blowout Prevention During Well Drilling

There are two areas where the potential for loss of well control exists during drilling. The first is during the drilling of the surface hole where the potential for a shallow gas blowout exists. It should be noted that shallow gas blowouts do not contain oil and no spill of oil occurs at the surface. However, the incident is critical from a safety standpoint. The second is while drilling the below surface hole where a blowout can occur while drilling into the reservoir or other hydrocarbon bearing zones or during completion of the well. In both cases, kick identification and management are the primary tools utilized to prevent a blowout.

Well Control During Surface Hole Drilling

During surface hole drilling, a shallow gas blowout can occur when a small, high-pressure volume of trapped gas is encountered. This causes a rapid unloading of the wellbore fluids (mud) and gas at surface in a very short time span.

Shallow seismic surveys are carried out over the proposed drilling location to establish the presence of gas accumulations. Offset data is also valuable, but accumulations tend to be localized so caution is vital at all times in case an incident occurs. Detection during drilling or tripping (i.e., running the drillstring into or out of the hole) will be visible by monitoring the returns to the surface from the drilling fluid system, monitoring the volume of drilling fluid required to fill the wellbore, and monitoring the drilling fluid weight in and out of the well to detect any influx of gas into the wellbore.

No attempt is made to shut in the well to contain the gas, as surface formations typically have insufficient strength to prevent gas broaching to the surface from these shallow depths. Instead, the flow of gas is directed away from the rig floor using a diverter valve and diverter line which vents the gas at a safe distance from the drill rig to atmosphere. Procedures are developed to keep pumping fluid to the drillstring wherever possible to try and establish primary well control, though most shallow blowouts deplete rapidly and/or bridge off.

Well Control While Drilling Below the Surface Hole

While drilling below the surface hole, causes of kicks include drilling into abnormally pressured formations with under-weight drilling fluid, tripping (pulling or putting drill pipe in the hole) too fast, not filling the hole, mud losses due to lost circulation zones, etc. The majority of kicks occur not because of well design shortcomings or drilling, but because of human error, especially during tripping operations. To assist the drilling operations team in detecting and preventing kicks during this drilling period, certain rig equipment is employed:

- A mud return line flow meter giving a reading of increased mud returns when drilling at constant pump rate could be an indication of a kick being taken downhole.
- A pit volume totaliser records the volume of mud in the mud system tanks and any changes in volume (gains or losses) set off alarms at the driller's console.

Contents

- Gas detection equipment is used around the drilling mud circulating system to sense the presence of gas breaking out of the mud which can be an indication of insufficient drilling fluid weight.
- A trip tank is utilized during tripping operations to accurately monitor mud volumes displaced from or pumped to the well as the drillstring is pulled out of, or run into, the well. This is a small tank with reduced cross-sectional area such that slight volume changes mean relatively large depth variances resulting in alarms being set off at the driller's console.
- All the above mechanical indicators are continually monitored at the driller's console during drilling and tripping operations.
- For areas where high pressures and/or small hole sizes are being drilled, an early kick detection system is utilized to detect much smaller volume changes in the fluid system.
- Mud logging services with formation sample catching, gas chromatography can indicate kicks and also confirm depths/formations being drilled. This greatly assists actual casing seat selection decisions consistent with well designs.
- Logging while drilling tools assist in formation identification and actual casing seat selection decisions as well as identifying potential hydrocarbon-bearing zones.

Equipment alone will not prevent kicks from occurring. Personnel training is required to monitor drilling conditions, react correctly to anomalies and follow procedures to establish whether or not a kick has been taken. As discussed in Section 2.1.1, personnel involved with well control and the operation and maintenance of Production Safety Systems will have training in accordance with MMS regulations.

Section 2.1.1

If it has been established that a kick has been taken below surface hole and a well control incident is underway, then blowout prevention (BOP) equipment and procedures are used to remove the kick safely from the wellbore and prevent further kicks and possible escalation into a more serious incident such as a blowout. BOP and casing installations conform to AOGCC regulations (20 AAC 25.035 and 25.285) and MMS regulations (30 CFR 250 Subpart D). To assist the drilling operations team in managing kicks, certain rig BOP equipment is employed. In the event primary well control is lost, this surface equipment will be utilized for secondary containment of the fluid influx into the wellbore. The BOP equipment will contain fluids and pressures in the annulus and drill pipe while the mud weight is raised to overbalance the bottom hole formation pressure. In addition, there are well kill procedures to circulate heavier mud into the well and remove the kick fluids safely. Blowout prevention equipment and procedures are described below:

- A BOP stack is located above the wellhead and is used on all hole sections below surface hole. It has a series of hydraulic (or manually operated) rams (pipe, variable and blind/shear) and annular preventers for closing in the well around the drillstring or open hole plus actuated and manual valves and kill/choke lines. The shear ram can close on the drillstring and sever it to give a complete seal across the wellbore. The BOP essentially acts like a valve at surface which contains all wellbore fluids and pressures while downhole operations are planned and executed safely. Redundancy exists in the BOP stack with additional ram preventers and valves.
- The casing program is designed to allow safe well control procedures to be carried out during drilling, workover, and production operations; the cementing

program isolates hydrocarbon zones and abnormally pressured formations, lost circulation zones, and freshwater aquifers.

- A choke manifold is a system of piping and valves for handling fluids circulated from the wellbore in a controlled and safe manner. All valves in the system have a backup.
- Degassers are used to remove gas from drill fluids circulated to the surface from the well.
- The BOP stack and choke manifold have redundancy built in such that a ram, choke or valve failure will not mean a leak and potential blowout of hydrocarbons.
- All BOP equipment is rated for the pressure regimes to be encountered in the development wells and is configured and regularly tested (witnessed by appropriate regulatory agencies) according to operator policies and agency regulations.

Drilling operations may resume when normal conditions prevail.

As with kick detection, equipment alone will not totally manage kicks. Training of personnel to react correctly to well control incidents and follow procedures to safely bring the well back under control is vital.

- Supervisory drilling staff are certified in well control which includes theory and procedures for both prevention and handling of well control incidents. This includes both rig site personnel (toolpusher, driller, relief driller, company man, drilling engineer) and office personnel (drilling superintendent, senior drilling engineer, operations drilling engineer)
- Drills are carried out with all crews to close in wells and simulate well control incidents. Well kill sheets are compiled and posted on the rig floor and updated once a tour for the drilling conditions prevalent at the time (i.e., hole sizes, drillstring, bottom hole assembly, mud weights, and slow pump rate). The well kill sheets are updated as hole conditions dictate.
- Operator policies and industry-recommended practices have procedures for different kill techniques suitable for specific well control situations.

Operator well control contingency plans provides guidelines on how to safely and effectively respond to and manage a well control incident.

Well Control During Completion

Completion operations (i.e., running the production tubing/associated equipment, perforating the well and installing the Christmas tree valve configuration [Christmas tree]) occur in a cased hole after the final casing string/liner has been set, cemented and pressure tested. During completion operations, well control is maintained through a minimum of two barriers. Completion fluid weight remains as the primary control barrier. A secondary barrier utilizes mechanical equipment at the surface. Kick detection equipment and kick management (i.e., equipment, people, training, procedures) are as described in the sections above.

Well Control During Rig Workovers

Much of the information provided for well control during drilling is also relevant for rig workover operations. Actual production pressure data is used to establish workover fluid

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weights much like offset data is used to establish drilling fluid weights. A minimum of two mechanical and/or fluid barriers are used prior to removing Christmas trees and installing BOP stacks and vice versa.

Well Control During Wireline/Coil Tubing Interventions

During intervention operations, a minimum of two mechanical barriers are maintained at surface. Coil tubing servicing (as opposed to drilling) and wireline operations are carried out through the Christmas tree. Coil tubing utilizes high-pressure hydraulic pack-off as the primary well control mechanism plus a BOP stack consisting of both pipe rams and blind/shear rams. Wireline also utilizes a hydraulic pack-off and lubricator as primary well control mechanism plus a manual wireline valve stack with wireline rams.

Well Control During Production

All production wells at Liberty will be equipped with automatic SSSVs and with SSVs in accordance with AOGCC regulations (20 AAC 25.265) and MMS regulations (30 CFR 250 Subpart H). SSSVs are required for all wells that flow to the surface unassisted. At Liberty, the safety valves will close automatically if pressure is lost in the system. In addition, all wellheads are equipped with the gauges and valves required by 20 AAC 25.200 and MMS regulations (30 CFR 250 Subpart H).

Workovers Operations

BOP and well control systems are installed before drilling below a casing string and as required during workover operations. The BOP is capable of controlling the maximum expected wellhead pressure. Casing and BOP installations conform to AOGCC regulations (20 AAC 25.035 and 25.285) and MMS regulations (30 CFR 250 Subpart F).

Written instructions discussing duties and obligations to prevent pollution are prepared for contractors servicing a well or systems appurtenant to a well or pressure vessels. A BPXA-authorized representative is present at all times to intervene when necessary to prevent a spill.

2.1.7 Oil Storage Tanks [18 AAC 75.065]

Section 3.1.3

Section 3.1.3 contains detailed information on tanks at Liberty facilities, which include a 3,000 bbl diesel tank, a 2,000 bbl slop oil tank, a 5,000 bbl produced water tank, and 17 temporary diesel storage tanks with 550-bbl capacity each.

New Tanks

All tanks at Liberty will be constructed in accordance with API Standard 650. As such, they may not be riveted or bolted, must have a cathodic protection system or other approved corrosion protection where soil conditions warrant, and must be equipped with a leak detection system that an observer can use from outside the tank to detect leaks in the bottom of the tank.

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All hydrocarbon storage tanks at Liberty will be double walled, which would contain any leaks and spills from the inner tank. The leak detection system to be installed under the oil containing storage tanks will be in accordance with API 653, Appendix I.

Cathodic protection is not required for the elevated tanks (the 3,000-bbl diesel tank and the temporary diesel storage tanks). The slop oil tank and the produced water tank will both be at grade level, and will be installed with impressed current cathodic protection. The cathodic protection system will include a metal oxide grid installed in the gravel under the tanks. A monitoring system will allow periodic checks of the system status. The liner will be installed at a slope to direct any liquid contents to a sump where liquids can be detected, pumped, and recovered for appropriate disposal.

The cathodic protection systems will comply with the applicable provisions of the following recommended practices and standards:

- API Recommended Practice 651, Cathodic Protection of Abovegrade Petroleum Storage Tanks
- NACE International Standard RP0193-93, External Cathodic Protection of On-Grade Metallic Storage Tank Bottoms
- NACE International Standard RP019-96, Control of External Corrosion on Underground or Submerged Metallic Piping Systems

Existing Installations

Not applicable.

Overfill Prevention

See Section 2.5.4.

Section 2.5.4

Inspections of Non-Elevated Tanks

The following tanks will be inspected in accordance with API 653 (NOTE: These tanks may be used for diesel storage during construction of Liberty):

- 5,000-bbl produced water tank. This tank will be located on gravel with an impermeable liner under the gravel.
- 2,000-bbl slop oil storage tank. This tank will be located on gravel with an impermeable liner under the gravel.

Routine Operational Examinations (External)

The external condition of each tank will be monitored by visual inspection from the ground. The frequency of inspections and records maintenance is summarized in Section 2.5.6.

Table 2-3

External Inspections by a Qualified Inspector

External inspections will be conducted by a qualified inspector per API 653 at intervals to be determined by results of previous inspections (the inspection intervals will not exceed 5 years). These inspections will use non-destructive testing methods (ultrasonic testing).

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Internal Inspections by a Qualified Inspector

Performance of scheduled internal condition examinations by an API 653 qualified inspector will be determined on the basis of external corrosion rates, but will not exceed 10 years between inspections.

Inspections of Elevated and Portable Tanks

The following elevated tanks at Liberty will undergo external inspections per API Standard 653 and to API RP 12R1:

- 3,000-bbl diesel storage tank located on an elevated steel platform.
- 17 temporary 550-bbl diesel storage tanks

Repair or Alteration

BPXA will immediately perform necessary maintenance or repairs, as required by 30 CFR 250.301.

Internal Heating Systems

Not applicable.

Internal Liners

Not applicable

2.1.8 Secondary Containment Areas for Oil Storage Tanks [18 AAC 75.075]

Offshore Tanks

All tanks at Liberty will have secondary containment as required in MMS [30 CFR 250.300(b)(5)], EPA, and ADEC regulations. EPA SPCC regulations 40 CFR 112.7(e)(2) and ADEC regulations [18 AAC 75.075] state that secondary containment for oil storage tanks must be able to hold the volume of the largest tank plus local precipitation. BPXA's established practice for secondary containment volume is 110% of tank capacity.

Secondary containment for all the tanks at Liberty will be provided through double-wall construction, which provides an outer tank, which will contain any leaks and spills from the inner tank. The interstitial space has leak detection instrumentation, which alarms if a leak is detected. The volume of this containment space is 10% of the maximum capacity of the storage tank.

Additional secondary containment for the permanent diesel tank will be provided by a seal-welded floor with a 6-inch-high seal-welded toe, which provides an additional 100 bbl of containment capacity. The temporary diesel storage tanks at Liberty will be located in a diked lined area with containment for the volume of one tank since the tanks will not be manifolded

Contents

together. The produced water and slop oil tanks will be located together on a timber mat foundation underlain by a geotech liner at the fueling area.

Inspections of secondary containment areas will follow the schedule outlined in Table 2-3.

Debris Removal

Table 2-3

The secondary containment system will be maintained free of debris and other material that might interfere with the effectiveness of the system, including excessive accumulated rainwater.

Drainage

Table 2-3

The secondary containment areas for the oil storage tanks will have a sump to accumulate precipitation that may fall in the diked area. The accumulated fluid will be inspected for contamination before pumping and discharge, and a written record of each pumping and discharge operation will be maintained.

Monitoring Wells

This section is not applicable.

Loading Racks

Tank truck loading areas and permanent unloading areas will:

- Have a secondary containment system designed to contain the maximum capacity of any single compartment of the tank truck, including containment curbing and a trenching system or drains with drainage to a collection tank or device. The tank truck loading area adjacent to the diesel tank containment area includes secondary containment with a capacity of 5,000 gallons. The largest tank truck to be used has a single largest tank compartment of 4,200 gallons.
- Be paved, surfaced or lined with sufficiently impermeable materials. The liner that is installed under the diesel tank secondary containment area will extend under the tank truck loading area.
- Be maintained free of debris or other materials or conditions that might interfere with the effectiveness of the system. The tank truck loading area will be maintained in conjunction with the diesel tank containment area.
- Have warning lights, warning signs, or a physical barrier system to prevent premature vehicular movement. The Liberty tank truck loading area will have warning signs to prevent premature vehicular movement.

2.1.9 Facility Piping Requirements & Corrosion Control [18 AAC 75.080]

Corrosion Control Program

Sales Oil Pipeline

Liberty will have a sales oil pipeline that will be both offshore and onshore. The pipeline will be constructed of steel pipe, be covered with a protective pipe wrap, and will have cathodic protection. Internal corrosion is not expected to be a problem.

Cathodic protection system surveys will consist of taking and recording electrical measurements at aboveground test stations to verify the condition of the magnesium ribbon. Annual cathodic protection surveys for the sales oil pipeline will be conducted in accordance with DOT regulations 49 CFR 195 and MMS regulations 30 CFR 250.1005(b).

The offshore pipeline segment will be "of all welded construction" as required by 18 AAC 75.080 (b)(1)(B). An external corrosion protective coating and cathodic protection system will be used in combination to protect the pipeline from external corrosion as required by 18 AAC 75.080 (b)(1)(A). No bare pipe will be installed in the buried offshore pipeline segment. Electrical isolation flanges will be installed at Liberty Island and the shore crossing. These locations will be the termination points of the cathodically protected offshore pipeline segment.

To ensure that the external cathodic protection system and the electrical isolation flanges are adequate for proper maintenance of the pipeline, periodic cathodic protection tests will be performed. As required by the DOT Pipeline Safety Regulations, 49 CFR, Ch. I, (October 1, 1996 Edition), Paragraphs 192.465 and 195.416, these tests will be performed annually at intervals not exceeding 15 months. The tests will be performed by measuring the electrical potential at three locations: a reference anode placed in the water near Liberty Island, from a reference anode placed in the water near the shore crossing, and across the isolation flanges located at Liberty Island and the shore crossing.

Buried Piping on Island

Underground diesel piping will be constructed of externally coated steel and be cathodically protected by a sacrificial anode system consisting of a magnesium ribbon buried near and parallel to the pipe. The system will include a method of measuring the potential difference and the condition of the sacrificial anodes. The system will be designed in accordance with NACE RP - 0169. Testing will be completed and documented on a regular schedule (to be determined).

The underground oil pipeline will be externally coated steel and cathodically protected with an impressed current system. The cathodic protection will be provided by distributed impressed current system installed parallel to the buried piping. The system will include test stations and a method of measuring the potential difference and the condition of the sacrificial anodes.

Buried Piping to Docks or Vessels

There is no such piping at Liberty. Transfers from a tank barge to the diesel storage tank and temporary diesel tanks will be accomplished using a temporary fuel transfer hose.

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Production Piping

The well production flowlines will be constructed of duplex corrosion resistant alloy piping.

Aboveground Piping to Docks or Vessels

There is no such piping at Liberty. Transfers from a tank barge to the diesel storage tank will be accomplished using a temporary fuel transfer hose.

Out of Service Piping

Piping removed from service for more than 1 year will be drained, identified as to origin, marked with the words "Out of Service," and capped or blank flanged.

Piping Supports

As required by 18 AAC 75.080 (g), the overland pipeline supports have been designed to resist seismic loads. The overland pipeline supports will contain all steel structural components. This is the common design practice used for other overland pipeline supports located on Alaska's North Slope, where experience shows that corrosion of the steel components does not readily occur.

Protection from Vehicles

Any aboveground diesel transfer lines on the island will be protected from damage by vehicles by timber curbing marked with reflectors.

Leak Detection

Section 2.5

Continuous monitoring of the oil pipeline's integrity will be performed using the combined procedures of regular pig inspections, multiple leak detection monitoring, and pipeline route surveys. The leak detection systems will monitor for pressure variances that leaks would induce and variances in the measured volumes of oil at the inlet and outlet of the Liberty sales oil pipeline

In addition to the monitoring system, the Liberty sales oil pipeline will have the following features, which will reduce the risk of small leaks in the subsea portion of the line:

- The subsea pipe will have more than 2.5 times the minimum wall thickness required for internal pressure containment.
- The line is designed with no flanges, valves or fittings in the subsea section.
- Pipeline operations will include routine "smart" pig inspections to assess the condition of the line.
- A supplemental leak detection system, LEOS, will be installed, which has a leak sensitivity of 0.05% of throughput (32.5 bbl/day)

Contents

Pipeline Pig Inspections

Pipeline pig inspections will be performed as part of a preventive maintenance program. Based on pig data, the pipeline's integrity can be assessed before a leak occurs. Three types of data collection pigs will be used (excluding cleaning pigs):

Table 2-1

Mechanical Damage Pigs

Mechanical caliper pigs may be used to assess mechanical damage to the oil pipeline (i.e., dents). A mechanical caliper pig run will be made prior to each wall thickness and geometry pig run.

Wall Thickness Measurement Pigs

Wall thickness in the 12-inch sales oil pipeline will be monitored for both internal and external corrosion using either magnetic flux leakage or ultrasonic wall measurement pigs.

3D Geometry Pigs (Axial, Vertical, and Lateral)

The geometry of the pipeline will be monitored using a 3D geometry pig, which gives an indication of pipeline bending strains and pipeline displacements. Offshore, the pipeline may undergo permanent displacements caused by thaw settlement, ice gouging or strudel scouring. Onshore, the pipeline will not undergo permanent displacement while supported on vertical support members.

TABLE 2-1
PROPOSED INSPECTION PIGGING SCHEDULE

PIG INSPECTION	INSPECTION SCHEDULE
Wall Thickness Measurement: Pigs will be run during summer operations or early winter so that any repairs required can be performed during the same winter season.	• Startup • Every 2 years thereafter
Pipeline Geometry: The purpose of the geometry pigging is to monitor the pipeline's configurations offshore.	• Startup • Once every calendar year for the first 5 years; duration between consecutive pig runs will not exceed 18 months during this period. • Every subsequent 2 years thereafter • Additional geometry runs will be carried out if severe ice gouges or strudel scours are suspected or observed to have occurred.
Mechanical Damage: Mechanical caliper pigs will be run to assess internal deformations that may hinder operation and the passage of other pigs.	• Startup: prior to initial wall thickness or geometry pig survey • Prior to every wall thickness or geometry pig survey

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2.2 DISCHARGE HISTORY (>55 GAL) [18 AAC 75.425(e)(2)(B)]

Liberty is a new facility. No discharge history exists

2.3 ANALYSIS OF POTENTIAL DISCHARGES [18 AAC 75.425(e)(2)(C)]

Tables 2-2

A number of types of spills could occur during drilling, production, and oil transportation operations in the Liberty area. Analyses have been conducted of potential discharges for Liberty and are summarized below.

TABLE 2-2
ANALYSIS OF POTENTIAL DISCHARGES

TYPE	TYPE OF LEAK	PRODUCT	SIZE	DURATION	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
Diesel transfer to tank truck	Tank overfill	Diesel	30 gal	30 sec	Transfer procedures are in place.
Diesel transfer from barge to diesel tank	Hose rupture	Diesel	440 to 880 gal	1 to 2 min	Transfer procedures are in place; boom will be deployed around the barge and the transfer operation will be monitored by personnel.
Produced water	Tank rupture	Produced water	5,000 bbl	Instant	The tank has secondary containment and a tank inspection program is in place.
Offshore pipeline leak	Pinhole	Crude oil	97.5 bbl	24 hours	The pipeline will have three leak detection systems.
Offshore pipeline leak	Guillotine	Crude oil	1,764 bbl	14 minutes for detection, confirmation, and complete shutdown	The pipeline has automatic shutdown valves and three leak detection systems. The pipeline design includes 2.5 times necessary wall thickness and was engineered to accommodate severe bends without leaking
Onshore pipeline leak	Guillotine	Crude oil	1,142 bbl	14 minutes for detection, confirmation, and complete shutdown	The pipeline has automatic shutdown valves and two leak detection systems for the aboveground portion. The onshore pipeline is elevated on VSMs and has expansion loops to accomodate movement.
Blowout	Uncontrolled flow from wellbore	Crude oil	180,000 bbl	15 days	Drilling operations have blowout prevention equipment and SSSVs. Personnel have operator training in well control and production safety systems.

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2.4 OPERATIONAL CONDITIONS INCREASING RISK OF A SPILL [18 AAC 75.425(e)(2)(D)]

Conditions specific to BPXA's North Slope operations that potentially increase the risk of discharge, and actions taken to eliminate or minimize identified risks are summarized below:

- **Temperature:** Heat from the operating facilities may cause gases to expand and increase the likelihood of discharge. North Slope facilities are engineered to accommodate temperature fluctuations.
- **Weather Conditions:** Icy roads, white-out conditions, and cold snaps present obvious threats to field operations. BPXA Security's strict enforcement of vehicle safety, speed limits, and the posting of warning signs on the island minimize the potential for vehicular accidents that may result in a spill. In addition, North Slope facilities are engineered to withstand arctic conditions.
- **Unplanned Shutdown in Valdez:** If Alyeska unexpectedly shuts down the pipeline, the risk to BPXA systems increases. BPXA's advanced communication system enables immediate communication between Alyeska and the North Slope operators, which allows for the coordination of impacts and minimizes the risks due to a shutdown of the pipeline.

Conditions specific to BPXA's Liberty operations that potentially increase the risk of discharge and actions taken to eliminate or minimize identified risks are summarized below:

- **Offshore pipeline:** Any leak in an offshore pipeline will immediately impact marine waters. To minimize the risk of subsea leaks, the sales oil pipeline has more than 2.5 times the minimum wall thickness required for internal pressure containment. The line is also designed with no flanges, valves or fittings in the subsea section. Leak detection systems are described in Section 2.5.3. Section 2.5.3
- **Ice pounding and ice strudel scour:** Ice pounding and ice strudel scour could threaten the offshore pipeline by causing soil displacements below the lowest point of ice contact with the seabed. Strudel scours typically occur near river deltas where river overflooding of nearshore ice sheets may occur during spring. The river overflood typically flows through vertical cracks or flow holes within the ice sheets and causes scouring of the seabed directly below. To protect against these forces, the offshore pipeline will be buried in a 7- to 8-foot trench and covered. The Liberty pipeline will be located at a sufficient depth so that ASME/ANSI elastic pipeline stress limits are not exceeded by the formation of pipeline spans caused by 100 year annual return period strudel scour dimensions. The pipeline will also be located at sufficient depth to avoid ice contact, and soil displacements that may cause pipeline strains in excess of project specific limit-strain criteria.
- **Upheaval Buckling:** Buried arctic pipelines are installed at temperatures that are below their operating temperatures. Since buried pipelines are restrained during thermal expansion, significant compressive force develops in pipelines that increase from their installed temperature to their operating temperature. This compressive force may cause upheaval buckling (vertical buckling displacement of a pipeline due to low lateral stability provided by the pipeline's overlying soil). The pipeline will be located at sufficient depth to avoid upheaval buckling.

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- **Permafrost Thaw Subsidence:** The weight and heat from a buried operating pipeline causes some differential thaw subsidence at locations where permafrost soils exist. Permafrost soils can be found in the nearshore area of the Liberty pipeline route.

2.5 DISCHARGE DETECTION [18 AAC 75.425(E)(2)(E)]

Discharge detection at Liberty will rely on a combination of mechanical and electronic systems as well as visual surveillance. The Liberty control system will monitor and operate the oil production wells, process facilities, and pipeline. The system will be monitored continuously with a microprocessor-based distributed control system. Incoming alarms from the facilities, wells or pipeline are documented by date and time by an alarm typewriter in the control room. This system allows for the quick tracking of cause-and-effect relationships during upset conditions. In addition, a manually operated shutdown system will be available if the computerized system is down and the facilities experience excess pressure or malfunction during production.

2.5.1 Wells

Lines connecting oil-producing wells will be equipped with low-pressure switches (p-pilots) used to isolate producing wells in the event of a line rupture. If the pressure in the line drops below 150 psi, the line will shut in. Small leaks that would not activate the low-pressure switch would be identified by operations personnel performing routine checks. Given that production fluids are mostly gas and water, with smaller amounts of oil, leaks would involve relatively large amounts of visible steam and gas, which are easily identified by both sight and sound. If small leaks occur, manual steps will be taken immediately by operational personnel to isolate the leak.

2.5.2 Sales Oil Pipeline

The Liberty sales oil pipeline will be equipped with three leak detection systems: MBLPC, PPA, and LEOS. The three systems will offer redundancy while increasing leak detection sensitivity.

The MBLPC system uses line-pack compensated volume balance of flow in and out of a pipeline segment, to evaluate if a leak is occurring. The system records the mass flow balance and the change in the fluid packed within the line every minute. Four processors use the data to perform flow calculations for different time periods. The system will warn or alarm if calculations indicate fluid loss above system settings.

The PPA system is based on rarefaction wave monitoring and uses algorithms to evaluate how current data differs from operation over the previous 5 minutes. The algorithms evaluate pressure and flow reading changes from measurement points and determine if a leak is present. The system is designed to filter out background hydraulic noise.

MBLPC and PPA systems continuously monitor the pipeline for leaks and have a minimum leak detection threshold of 1% of daily throughput. Leak detection of 0.15% has been experienced in existing BPXA North Slope pipelines utilizing best management operating procedures, provided that the following parameters are in place:

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- Crude oil meters are proved;
- Meters are accurate to custody transfer standards with expected throughput variability
- Flow conditions are steady-state.

Operating procedures require periodic calibration and proving of meters. In addition, procedures require that crude oil meters will be reproved if the daily over/short is greater than 100 bbl per day for two days. Meters are proven to a maximum deviation of 0.05% to assure their accuracy.

For the Liberty sales oil pipeline system, the volumetric throughput will be measured at both the island and the Badami tie-in. The accuracy of the meters will be such that the threshold for the leak detection system will be 0.15% of flow. A similar operational procedure will also be followed if there are volumetric discrepancies.

The third leak detection system that will be installed on the Liberty pipeline is LEOS. LEOS detects leaks through diffusion of hydrocarbon vapors into a permeable polyethylene sensor tube that is installed on the outside of a pipeline. Every 24 hours, the volume inside the tube is evacuated. As the tube is evacuated, the flow is directed past resistors that react to the presence of hydrocarbons. If a leak is present, the system can determine where the leak is located.

Section 4.11

2.5.3 Storage Tanks

All Liberty storage tanks will have double-walled construction with leak detection. In the event of a leak in the inner tank wall, the tank contents will flow through a one-inch ball valve and sight flow glass, and into a 6-inch pipe. This pipe will act as a sump to collect any fluids caused by a leak. A Magnetrol level float switch will be installed inside the pipe, which will trigger an alarm in the control room when the level in the sump reaches approximately 4 inches of fuel, or a sensitivity of 2.53 gallons. There will be a manual hose connection to the sump for cleanout.

Overfill Protection

Diesel Tank, Slop Oil, and Produced Water Tanks

Overfill protection is provided by an ESD valve, which is normally open but closes when the tank level reaches 90 percent. A horn sounds to alert the operator, and a pre-alarm is provided at 80 percent. In addition, a digital level readout is available on the programmable logic controller (PLC) panel to indicate the level in the tank.

The level transmitter sends a signal to the PLC, which provides local level indication and alarms as well as shutdown of equipment and unit isolation. Isolation valves are electrically opened and spring-closed to ensure positive action and isolation on failure of hardware or electrical power, even under extreme low-temperature conditions.

In the event that tank filling is not stopped manually, a high level switch will be activated once the diesel fuel level in the inner tank reaches a set height. Once activated, the high level switch will close the intake diesel valve and an alarm will sound. A control signal will close the ESD valve automatically, over a period of 10 to 15 seconds (to minimize pressure spikes). In

Contents

addition, to minimize risk of over-pressuring the hose, the barge mounted pump and filling connection includes a pressure relief to prevent hose rupture. If the relief valve is actuated, then diesel fuel will return directly to the barge's tank.

Temporary Diesel Tanks

The temporary diesel tanks will have visual dial gauges on the tanks to determine the liquid level inside the tanks. Separate fill and dispenser connections will be provided with a check valve in the fill connection, to prevent back flow in the fill line. Each connection will have a positive shut off ball valve (which meets the requirements of API 650) located on the front of the tank to allow quick positive shut off of any fill or dispenser line. Each discharge port will be fitted with a liquid tight end cap of proper design to take the full head of the liquid if the valve should fail.

Day Tanks

Day tanks for the diesel firewater pump (550 gallons) and the stand-by power generators (400 gallons) include pumps controlled by a level transmitter in the day tanks and an emergency shut-down valve for the fuel supply from the diesel storage tank. The tanks will be elevated and installed inside of buildings. The tanks are designed for operation with the associated diesel engine and are commonly used in similar applications.

Testing of Overfill Prevention Devices

The overfill protection devices for the diesel, produced water, and slop oil tanks will be tested before each transfer of diesel into the tank. Testing will involve the physical activation of the trip mechanism and verification of closure of the device.

2.5.4 Visual Inspections

Pipeline

The Liberty sales oil pipeline is subject to MMS, DOT, and ADEC regulations. Visual inspection of the pipeline is a requirement of both DOT and ADEC regulations. The required inspection schedule is summarized in Table 2-3. Table 2-3

The onshore portion of the pipeline will be visually monitored by overflights on a weekly basis (weather permitting) throughout the year.

The offshore pipeline route will also be visually monitored on a weekly schedule (weather permitting) during periods of open water or light sea ice. Inspections of the offshore pipeline route will consist of visual inspection for evidence of oil slicks or sheens. The goal of these surveys will be to visually detect oil slicks that may develop as a result of an oil leak that is below the leak detection system's monitoring threshold, assumed as 0.15% of the oil line's daily throughput.

The overflights will be supplemented by observations conducted during crew changes and supply runs.

Contents

TABLE 2-3
LIBERTY VISUAL MONITORING/INSPECTION REQUIREMENTS

Facilities	Regulating Agency	Responsible Position	Inspection Requirements	Frequency	Record keeping
Storage tanks	MMS	TBD	Visual inspection	External inspection monthly per API 653.	Life of tank
Secondary containment areas	ADEC	TBD	Visual inspection	Daily inspection [ADEC regulation, 18 AAC 75.075(a)(3)(A)	Field inspection form
Facility	MMS	TBD	Visual inspection	Daily or at intervals approved or prescribed by MMS [30 CFR 250.301]	Field inspection form, records to be maintained for 2 years.
Aboveground piping and valves	MMS, however will follow ADEC regulations EPA SPCC	TBD	Visual inspection for leaks or damage	Monthly inspection [ADEC regulation, 18 AAC 75.080(f)] Inspection on a regular basis [EPA, 40 CFR 112.7(e)(2)	Field inspection form
Offshore Pipeline	DOT, MMS, ADEC	TBD	Aerial observation of pipeline	Weekly during open water season, unless precluded by weather.	Surveillance form filled out with each inspection
Onshore Pipeline	DOT, MMS, ADEC	TBD	Aerial observation of pipeline	Weekly, unless precluded by weather [ADEC regulation, 18 AAC 75.055(a0(3)] 52 times a year, not to exceed a 2 week period between inspections [DOT regulation]	Surveillance form filled out with each inspection

Contents

Liberty Island Production Facility

The Liberty Production facility, its associated storage tanks, and piping and valves will be visually inspected, as outlined in Table 2-3. Although the facility is in federal waters and subject to MMS regulations only, BPXA has chosen to conduct inspections according to ADEC regulations as well.

2.6 RATIONALE FOR CLAIMED PREVENTION CREDITS [18 AAC 75.425(e)(2)(F)]

BPXA is not claiming any prevention credits for Liberty's response planning standards, as allowed under ADEC regulations 18 AAC 75.430.

2.7 COMPLIANCE SCHEDULE [18 AAC 75.425(e)(2)(G)]

Not Applicable

Contents

3. SUPPLEMENTAL INFORMATION [18 AAC 75.425(E)(3)]

3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]

3.1.1 Facility Ownership and Location

Following is the ownership breakdown in Liberty:

BP Exploration (Alaska) Inc.	100% of island
BP Transportation (Alaska) Inc.	100% of pipeline

The Liberty development will be a self-contained offshore drilling/production facility located on a gravel island in the Alaskan Beaufort Sea with a crude oil pipeline to shore. Water depth at the planned island location is approximately 21 feet. Liberty island will be located offshore in Foggy Island Bay approximately 6.5 miles east of the Endicott Satellite Drilling Island, about 5 miles north of the mouth of the Kadleroshilik River. Island coordinates (North American Datum 27) are:

Latitude: 70° 16' 45.3356"N
Longitude: 147° 33' 29.0891"W

3.1.2 General Site Description

In September 1996, BPXA acquired several leases on the outer continental shelf from MMS Lease Sale 144 BPXA drilled the Liberty #1 discovery confirmation well in February 1997, followed by testing in March 1997.

Facility Diagrams, Section 1.8

The Liberty drilling/production island will be a man-made gravel island. The Liberty development will include the wells and facilities to process 65,000 bopd to shore. There will be 14 producing wells, six water injection wells, two gas injection wells, and one disposal well. Produced gas will be used for fuel gas and artificial lift, with the balance being reinjected into the reservoir Seawater will be treated and used to waterflood the Liberty reservoir, and produced water will be commingled with the treated seawater for waterflood.

The Liberty development will include a 12-inch crude oil pipeline to shore, tied into the Badami sales oil pipeline. The offshore portion of the pipeline will be 6.1 miles long, and the overland portion will be 1.5 miles to the tie-in point with the Badami pipeline.

3.1.3 Description and Operation of Production Facilities

Bulk Storage Containers

Table 3-1 provides a summary of the major features of the oil storage containers planned for the Liberty production island.

Contents

TABLE 3-1
OIL STORAGE CONTAINERS

QUANTITY	TYPE	DESIGN/ CONSTRUCTION	TYPE OF OIL	CAPACITY	LOCATION
1	Diesel storage	Double-wall, flame arrestor, level alarms, aboveground, low temp steel, vented, vacuum relief, 20-in. emergency vent	Diesel	3,000 bbl	SE corner of island (near utilities module)
17	Diesel storage (temporary)	Double-wall, abovegound, designed to be stacked three high, visual liquid level gauge, 2-in. vent	Diesel	9,350 bbl total for all 17 tanks	SE corner of island (north of the PLQ). Will be moved to west side during the second season
1	Slop oil, temporary diesel storage	Double-wall, aboveground, vented, high level alarms and shutdown sensors.	Oil, misc. organics, and water	2,000 bbl	North of gas compressor module
1	Produced water, temporary diesel storage	Double-wall, aboveground, vented, high level alarms and shutdown sensors.	Oil and water, TEG	5,000 bbl	North of gas compressor module

Diesel Storage Tank

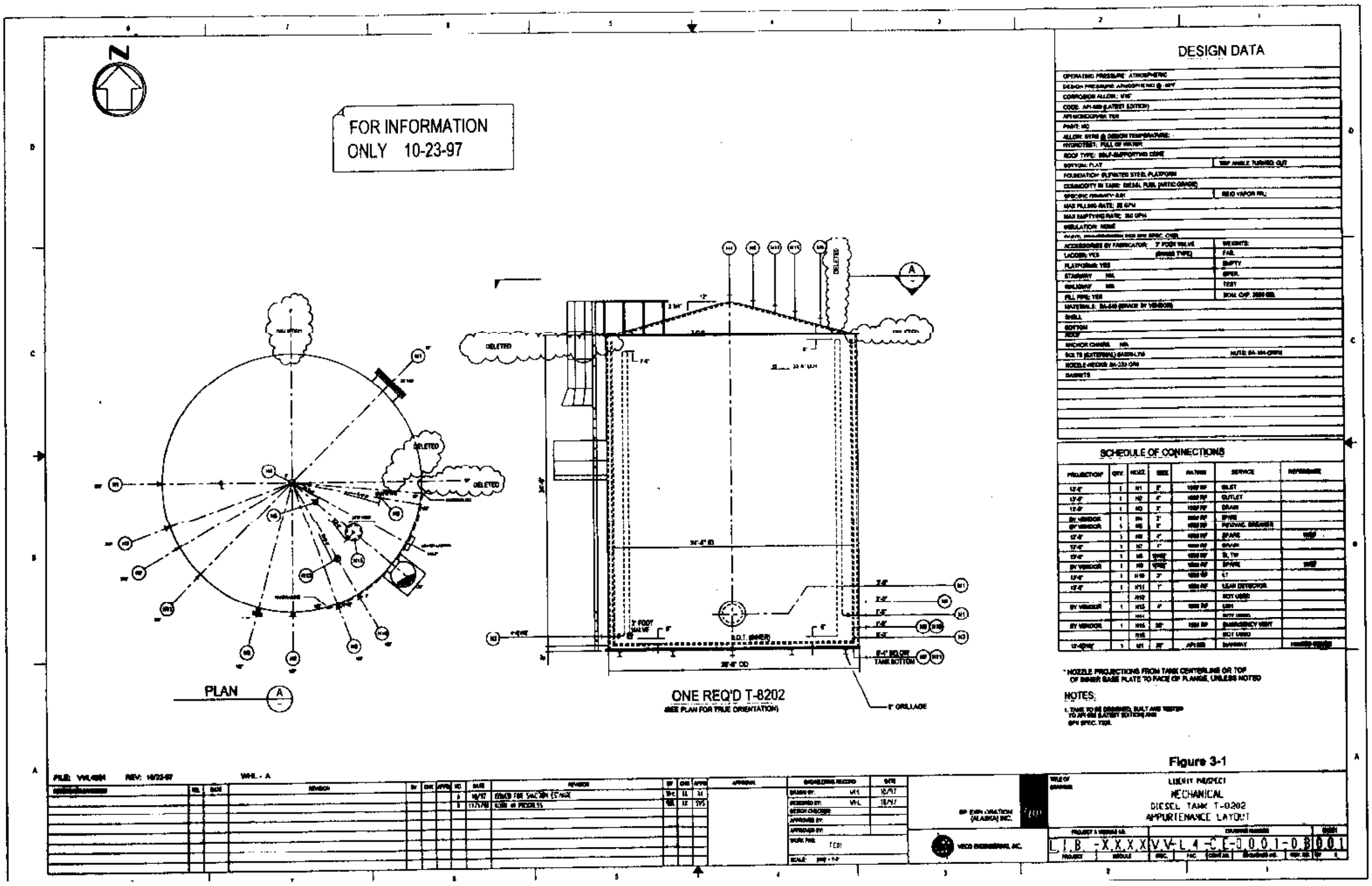
The diesel storage tank will be an aboveground, double-wall tank constructed of low temperature steel with a capacity of 3,000 bbl. The design includes a flame arrestor, vacuum relief, and a 20-inch emergency vent. The double-wall construction provides an outer tank, that will contain any leaks and spills from the inner tank. The interstitial space has leak detection instrumentation, which will alarm if fluids are present. The volume of this containment space is 10% of the maximum capacity of the storage tank.

Figures 3-1 and 3-2

The diesel storage tank will be equipped with level indication and high level alarms. During refueling, an inlet shutdown valve will automatically close when the tank reaches 90% of capacity. A horn will alert the operator when this high level occurs. In addition, a digital readout of the level in the tank will be available to the operator.

The controller for the diesel storage and dispensing control system is a PLC. The level transmitter for the diesel tank sends a signal to the PLC, which provides local level indication and alarms, and provides shutdown of equipment and isolates the unit to protect the environment. Isolation valves are electrically opened and spring closed to assure positive action and isolation upon failure of hardware or electrical power, even under extreme low-temperature conditions.

The tank will be located on a raised platform with a seal-welded floor and a seal-welded 6-inch-high toe board that will provide in excess of 100 bbl of containment. This will provide drip and spill containment for the tank and connected piping. Small fuel transfer pumps, which take suction from this tank, will be located in an attached environmentally controlled utility module with a spill containment floor.



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FOR INFORMATION ONLY 10-23-97
DESIGN DATA
SCHEDULE OF CONNECTIONS
DELETED
PLAN
A
ONE REQ'D T-8202
NOTES:
LIBERTY PROJECT
MECHANICAL
DIESEL TANK T-8202
APPURTENANCE LAYOUT
BP EXPLORATION (ALASKA) INC.
VECO ENGINEERING, INC.

Figure 3-1

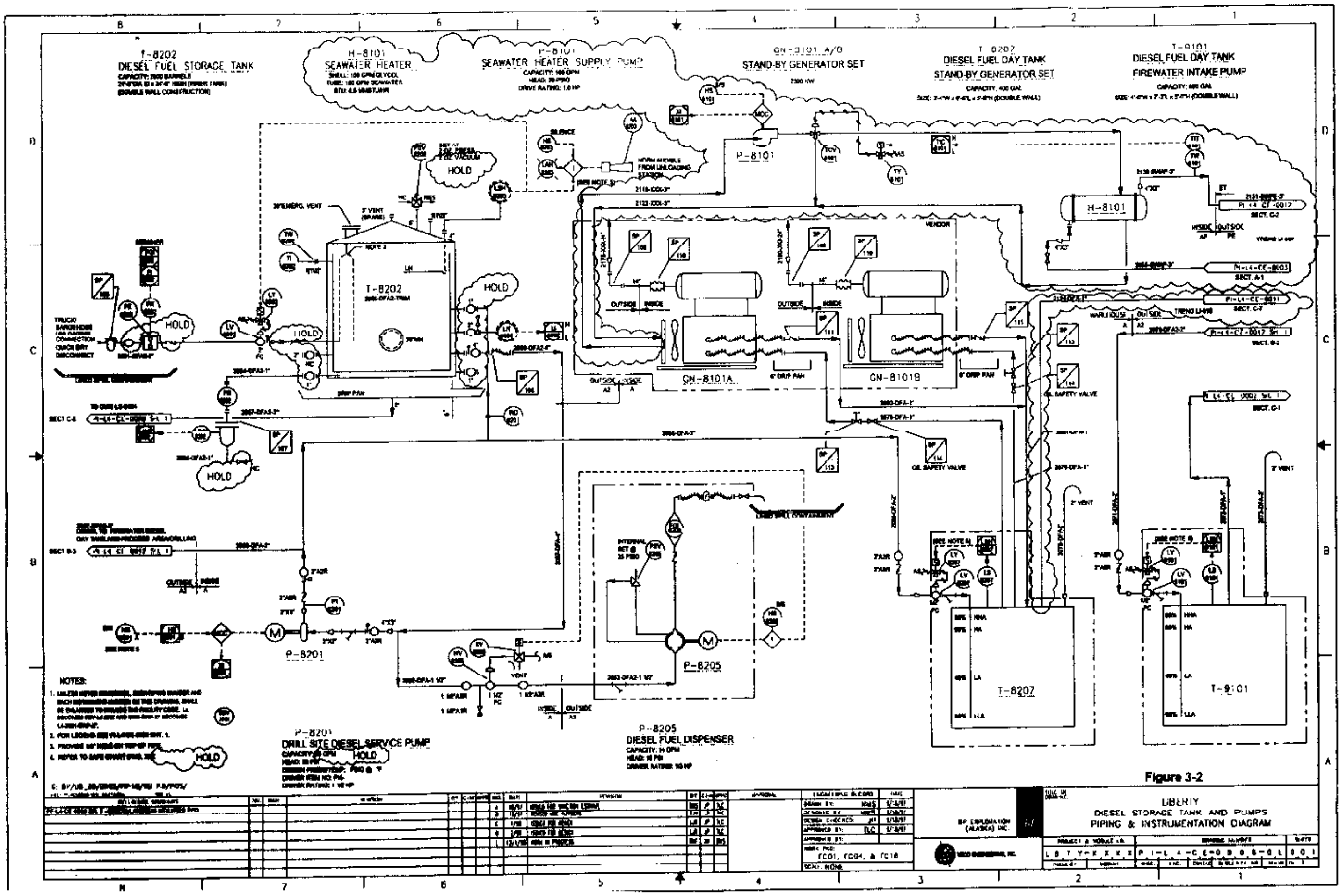

T-8202
DIESEL FUEL STORAGE TANK
H-8101
SEAWATER HEATER
P-8101
SEAWATER HEATER SUPPLY PUMP
GN-8101 A/B
STAND-BY GENERATOR SET
T-8207
DIESEL FUEL DAY TANK
STAND-BY GENERATOR SET
T-9101
DIESEL FUEL DAY TANK
FIREWATER INTAKE PUMP
HOLD
GN-8101A
GN-8101B
P-8201
P-8205
T-8207
T-9101
NOTES:
P-8201
DRILL SITE DIESEL SERVICE PUMP
P-8205
DIESEL FUEL DISPENSER
LIBERTY
DIESEL STORAGE TANK AND PUMPS
PIPING & INSTRUMENTATION DIAGRAM
BP EXPLORATION (ALASKA) INC.

Figure 3-2

Contents

The diesel storage tank will be located near the southeast corner of the island (near the utilities module). This location is also near the dock area where fueling barges will be tied up. The tank will be located in an area where facility operators can regularly observe it.

The function of the diesel storage tank is to provide fuel for:

- Miscellaneous construction and maintenance equipment and vehicles,
- Two standby generators,
- A diesel-driven firewater pump.

Diesel Storage Tanks (Temporary)

Temporary diesel storage capacity will be required on the island to support drilling and construction. Temporary tank storage will be mobilized to the site over the ice road after island construction and filled just before breakup. Once facilities modules are installed and operational, this temporary storage capacity will no longer be needed. There will be 17 tanks with a 550-bbl capacity each. The tanks will meet all industry and regulatory requirements for leak prevention and secondary containment.

Figure 3-3

The tanks will be double-walled, welded construction, capable of being stacked three high and individually manifolded. Tank outer dimensions are 9.8 ft. x 8.25 ft. x 54 ft. Construction standards will follow API 650 requirements for material, design, fabrication, erection, inspection, weld procedures, and welder qualifications, although the tanks will not have a API 650 nameplate because these tanks will not be cylindrical as per this standard.

The tanks will be installed in a diked, lined area with total containment capacity of 550 bbl (total capacity of a single tank). There will also be a containment area for the truck filling location, consisting of an impermeable liner located below grade and with the outside edges sloped upward. A sump will be installed so fluids can be detected and disposed of.

Each tank will have a visual dial gauge for liquid level determination. The fill port will be piped so as to prevent static charge during filling operations. The fill port will also have a check valve so liquid cannot be siphoned back into the lines once pumping has stopped.

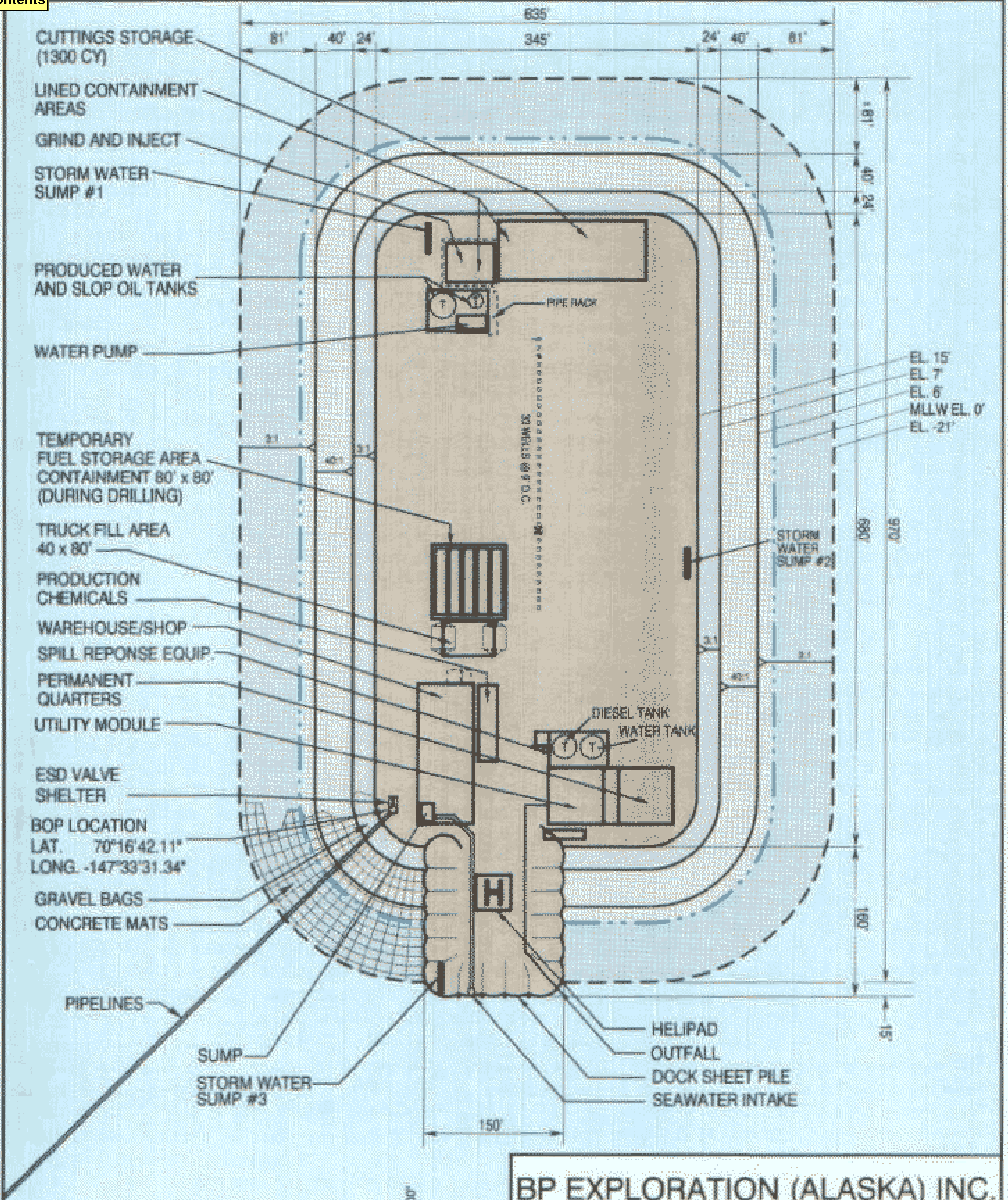
Slop Oil Tank

The slop oil tank will be an aboveground, double-wall tank constructed of low-temperature steel with a capacity of 2,000 bbl. The design includes flame arrestor, blanket gas, level indication and alarms, and vacuum relief. An inlet shut-down valve will automatically close upon detection of high level in the tank. The double-wall construction will provide an outer tank, which will contain any leaks and spills from the inner tank. The interstitial space has leak detection instrumentation that will alarm if fluids are present. The volume of this containment space is 10% of the maximum capacity of the storage tank. The slop oil tank will be located outside on a timber mat foundation, north of the gas compressor module. Additional containment will be provided by a geotechnical liner at the fueling area.

Figure 3-4

FIGURE 3-3
ISLAND LAYOUT DURING CONSTRUCTION
TEMPORARY FUEL STORAGE SITE

Contents



BP EXPLORATION (ALASKA) INC.

LIBERTY DEVELOPMENT PROJECT
ISLAND LAYOUT DURING DRILLING
TEMPORARY FUEL STORAGE SITE

DATE:	SCALE:	FIGURE:
January 1999	NOT TO SCALE	3-3

Contents

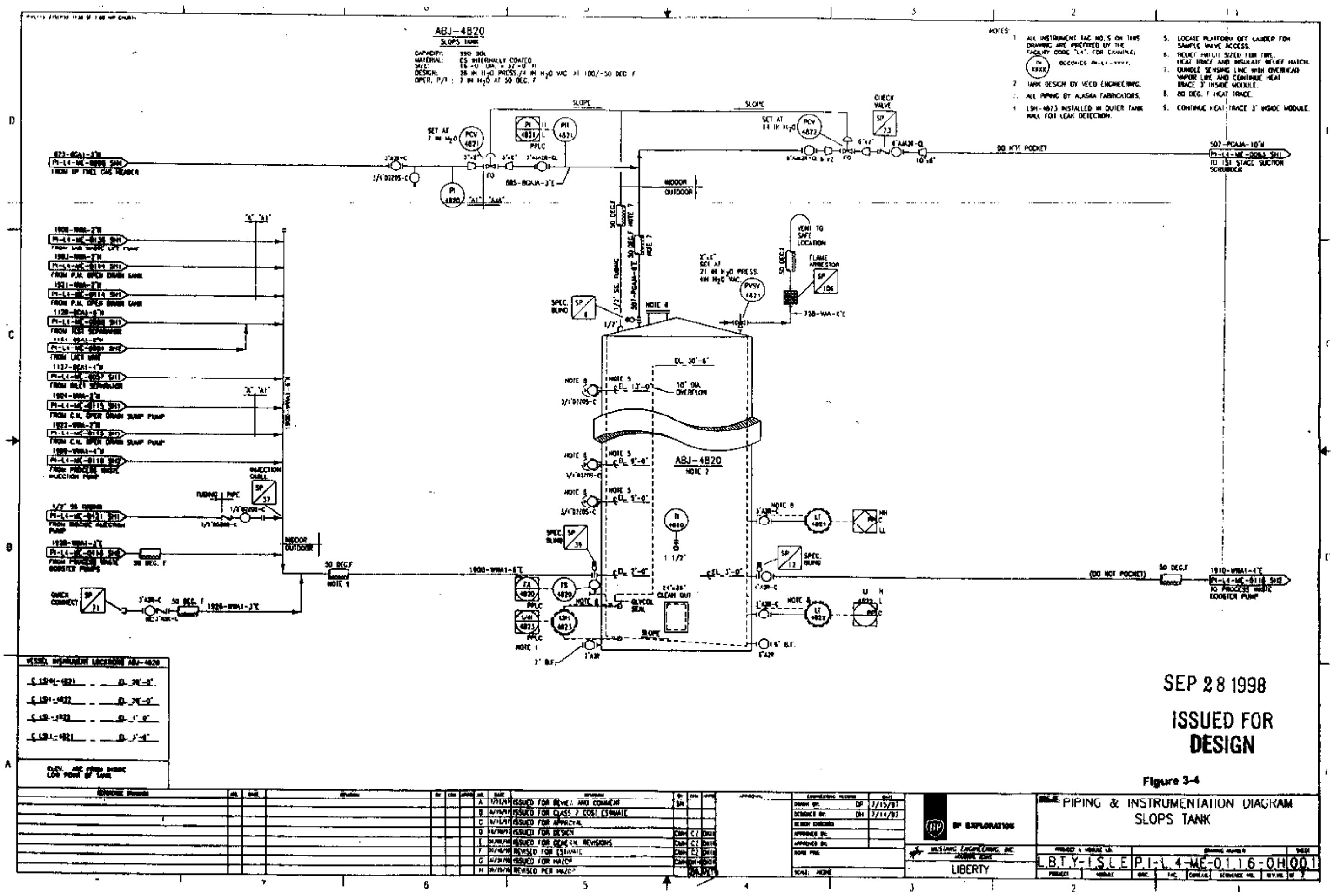


Figure 3-4

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Produced Water Tank

Figure 3-5

The produced water tank will be an aboveground, double-wall tank constructed of low-temperature steel with a 5,000 bbl capacity. The design includes flame arrestor, blanket gas, level indication and alarms, and vacuum relief. A piping and instrumentation diagram for the produced water tank in shown in Figure 3-5.

An inlet shut-down valve will automatically close upon detection of high level in the tank. The double-wall construction will provide an outer tank, which will contain any leaks and spills from the inner tank. The interstitial space has leak detection instrumentation that will alarm if fluids are present. The volume of this containment space is 10% of the maximum capacity of the storage tank. The produced water tank will be located outside on a timber mat foundation, north of the gas compressor module. Additional containment will be provided by a geotechnical liner at the fueling area.

Transfer Procedures and Major Fueling Areas

Fuel transfer procedures have been developed and implemented for North Slope operations. The *North Slope Fluid Transfer Guidelines*, dated February 15, 1993, prescribe practices for responsible transfers of diesel fuel and are used for Liberty operations. Appropriate use of surface liners and drip pans is described in the North Slope Unified Operating Procedure, Number 1-93, dated April 2, 1993.

Section 2.1.5, Appendix A

Major Fueling Area

Light vehicles, fueling trucks, and rolling equipment will be fueled at the vehicle fueling area near the diesel storage tank, outside the utilities module. The fueling dispenser will be a conventional dispenser with a low pressure transfer pump. The fuel transfer area for light vehicles (and barge unloading tank connections) will have a lined containment area of 5,000 gallons capacity During fueling, a polyethylene spill containment pan will be placed under the nozzle and fueling port of the vehicle. If a release to the containment occurs, absorbents will be applied Used absorbents will be containerized for appropriate handling and disposal.

Process and Flowline Description

All support infrastructure and facilities necessary to drill wells and process reservoir fluid will be installed on the island at Liberty. There will be 14 producing wells, six water injection wells, two gas injection wells, and one disposal well (23 total) at a wellhead spacing of nine feet. The process facilities will separate reservoir fluid into sales oil, gas, and produced water. Produced gas will be used for fuel gas and artificial lift, with the balance being re-injected into the reservoir. Seawater will be treated and used to waterflood the Liberty reservoir. Produced water will be commingled with treated seawater and injected as waterflood water.

A simplified flow process diagram is provided in Figure 3-6.

Figure 3-6

Contents

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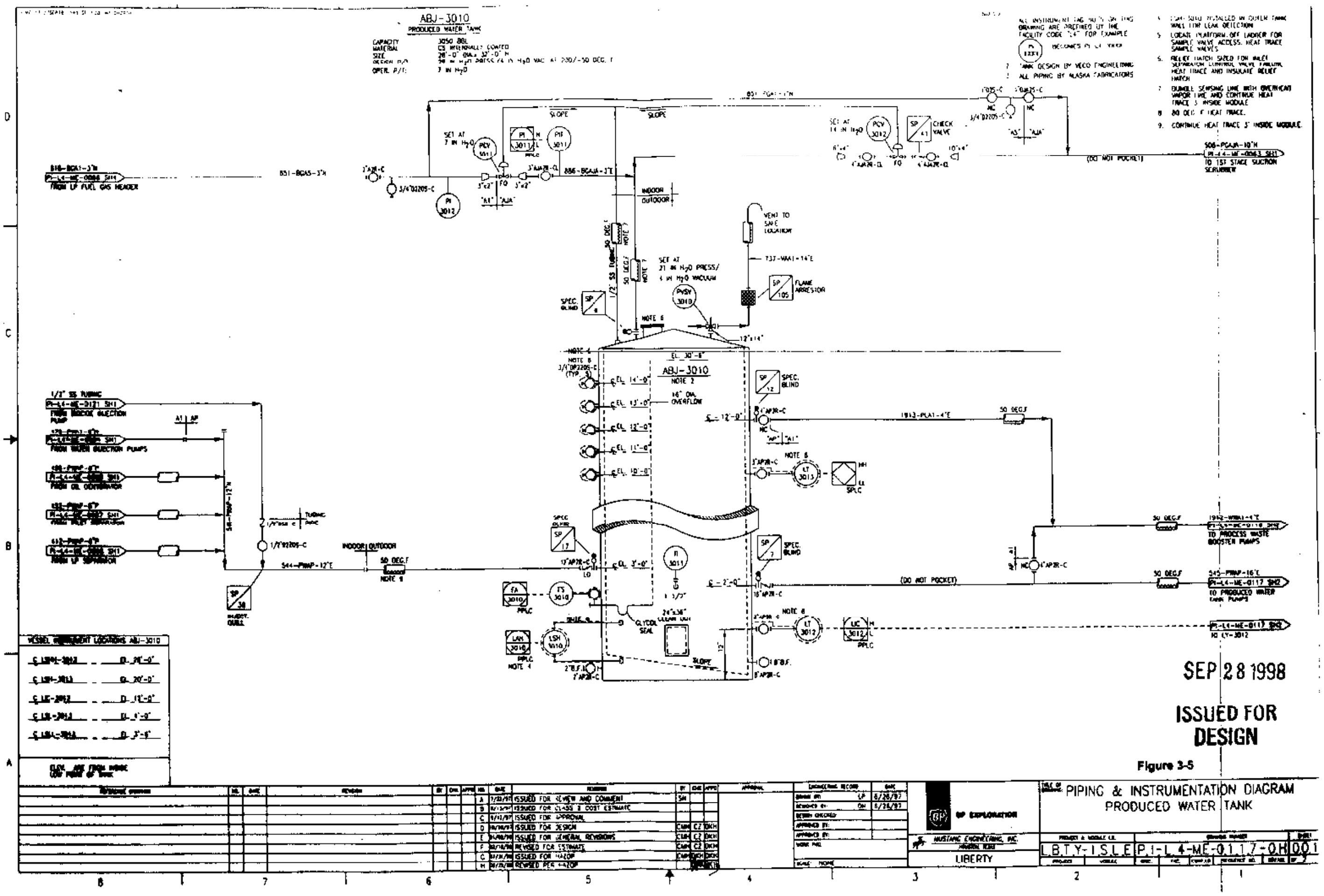
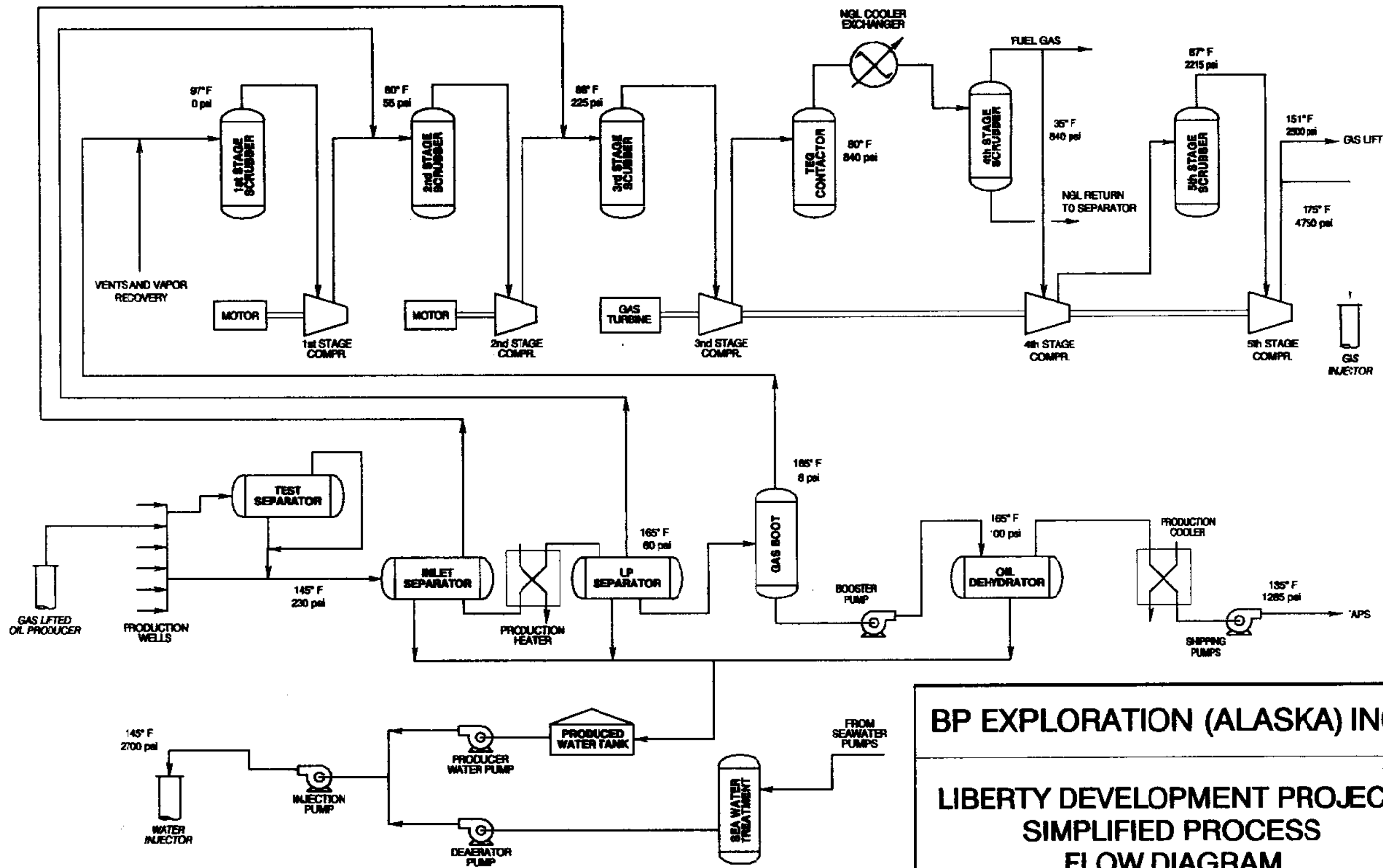


Figure 3-5

Contents



BP EXPLORATION (ALASKA) INC.		
LIBERTY DEVELOPMENT PROJECT SIMPLIFIED PROCESS FLOW DIAGRAM		
DATE: Rev. March 2000	SCALE: N/A	FIGURE: 3-6

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Pipeline Details

The 12-inch oil pipeline will be an ANSI Class 600 system. Based on a maximum operating temperature of 150°F, the maximum allowable operating pressure (MAOP) for the Liberty oil pipeline is 1,415 pounds per square inch gauge (psig) (based on fittings), and the offshore oil pipeline wall thickness is 0.688-inch.

The pressure containment criterion governs for the overland pipeline segment, and the recommended overland oil pipeline wall thickness is 0.281-inch. The overland pipeline material grade is API-5L X-65.

The Liberty sales oil pipeline will include facilities to allow passage of inspection and geometry pigs. A pig launcher will be required at the Liberty Island. The present design will have a pig receiver at the Badami tie-in.

A leak detection system, performing real-time monitoring for oil pipeline leakage, will be provided and interconnected to the process facility control system. Custody transfer metering will occur at Liberty as part of the process facilities, but an additional turbine flow meter is included at the onshore tie-in to enhance the leak detection system accuracy. This will require reliable power and communications at the remote tie-in location. The leak detection system will monitor the pressures at each end of the oil pipeline to warn of any potential leaks. Microwave communication links to interface with the Badami and Endicott pipelines leak detection systems and controls are included.

Offshore Route Segment

Facility Diagrams, Section 1.8

The offshore route segment is a straight route between the Liberty Production Island and a shore crossing location south-southwest of the island. The total offshore route segment is approximately 6.1 miles in length. The offshore segment is further divided into a nearshore zone and an intermediate zone. The nearshore zone extends approximately 1.5 miles from the shoreline out to the 6-foot water depth contour. The intermediate zone extends from the 6-foot water depth contour out to the production island, located in 21 feet of water. The length of the intermediate zone is approximately 4.6 miles.

The offshore buried portion of the oil pipeline will have an external corrosion protection coating (fusion-bonded epoxy [FBE]). Insulation of the offshore oil pipeline is not needed to maintain the pipeline above crude oil pour points since the sales oil will be 150°F.

Overland Route Segment

The overland route segment traverses the tundra in a southwest direction to the Badami Pipeline intersection located approximately 1.5 miles west of the Kadleroshilik River crossing.

The overland segment of the oil pipeline will have 2-inches of jacketed polyurethane foam insulation for maintaining an adequate pipeline operating temperature, and will be supported above ground.

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Valves

Automated isolation valves will be located on the Liberty Production Island and the Badami tie-in. At the landfall, the pipeline will have either a vertical loop or automated isolation valve. Each valve will be remotely controlled and mechanically or pneumatically operated.

The valves will be designed to close against full differential pressure during normal operating pressure and surge pressure conditions. The valves are currently designed to fail to their closed (fail-safe position). However, the shore crossing valve design may change during the detailed engineering stage.

Pipeline Skids

The present pipeline design includes the following associated skids with the following equipment.

- **Island**: Automated ESD valve, 12-inch pig traps, space for a drag reducing agent skid, and a single injection point
- **Shore Crossing**: Automated ESD valve, supervisory control and data acquisition (SCADA) and communications systems
- **Badami Tie-in**: A meter, pig trap, and automated ESD valve

3.1.4 Crude Oil and Reservoir Characteristics

The Liberty reservoir is an extension of the Endicott field and has similar crude oil properties. Liberty crude has the following characteristics:

API Gravity	22°
Specific Gravity @ 60°F:	0.922 g/m3
Viscosity @ 60°F:	143 cp
Viscosity @ 85°F:	33 cp
Pour Point:	37°F

Overall reservoir characteristics are as follows:

Average Depth:	10,700 ft true vertical depth (datum)
Reservoir Temperature:	225 °F
Reservoir Pressure:	5,200 pounds per square inch absolute @ 10,700 ft true vertical depth
Oil Flow:	72,000 bopd (maximum instantaneous rate) 65,000 bopd (maximum predicted annual average)
Gas Flow:	31.5 mmscfd (maximum instantaneous reservoir gas production with gas-to-oil ratio of standard cubic feet/standard barrel [scf/stb])
Gas/Oil Ratio:	Initially 900 scf/stb. There is no gas cap.
Produced Water:	Initially none, but eventually water will be produced because of waterflooding.

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3.2 RECEIVING ENVIRONMENT (FOR ONSHORE FACILITY) [18 AAC 75.425(e)(3)(B)]

ACS Maps 74, 80, 83 through 90, 94, and 95

The receiving environment for Liberty consists of a man-made gravel island situated in the Beaufort Sea. Large spills occurring at Liberty, particularly well blowouts and subsea pipeline ruptures, have the potential of reaching open water and/or ice.

3.2.1 Routes of Travel to Open Water

Movement of oil released into the open waters of Stefansson Sound and Foggy Island Bay is primarily in response to wind, currents, and spreading mechanisms. Since currents in the area are generally wind-driven, a qualitative estimate of the likely trajectory of spilled oil under open water conditions can be determined by inspecting the wind roses for Prudhoe Bay These data show that wind blows from the east to northeast for about 60 percent of the time. Easterly winds cause a westward movement of water, creating upwelling conditions across bays, a depressed shoreline water surface, and subsequent surface water movement to the north. For about 28 percent of the time, winds blow from the west and southwest. Winds from this direction cause the water to move eastward, creating downwelling conditions, elevated water levels (+1 m) nearshore, and subsequent surface water movement to the south (shoreward).

A spill on the island under prevailing easterly winds will be transported to the west-southwest. Assuming 10-knot winds from the northeast, oil spilled at Liberty could reach the shoreline of the Sag River Delta within the first 10 to 12 hours of the spill.

ACS Map Atlas, Current Maps

Under westerly wind conditions, oil released and not contained at the proposed island site will tend to move to the east. If westerly winds are sustained, the oil will migrate ENE within Foggy Island Bay. Oil could reach the Stockton Islands within 20 to 24 hours of the spill.

Estimated volumes of oil that reach open water are calculated in Section 1.6.13, and are based on ACS *Technical Manual* Tactics T-6 and T-7.

Section 1.6.13, ACS Tactics T-6 and T-7

Oil released into the water column under a floating solid ice cover will rise and gather in pools or lenses at the bottom of the ice sheet. Oil may become trapped or entrained as new ice grows beneath the oil (Industry Task Group 1983). Currents approaching 26 centimeters per seconds (cm/s), or 0.5 knots, would be needed to remove and transport exposed oil in subsurface depressions prior to entrainment (Cox and Schultz, 1981). Typical under-ice currents along the Liberty pipeline are unlikely to exceed an average of 2 cm/s; however, currents ≥ 10 cm/s do occur. These winter under-ice currents are unlikely to spread spilled oil beyond the initial point of contact with the ice under-surface. Research indicates that typical under-ice containment capacity for first-year landfast ice representative of the Liberty pipeline route ranges from 0.012 bbl per square foot (bbl/ft^2) for 25-inch-thick ice in December to 0.026 bbl/ft^2 for 60-inch-thick ice in April (equivalent to about one million bbl per square mile). As the natural containment capacity increases with ice thickness, the area needed to contain a given spill volume decreases steadily throughout the winter.

In broken ice conditions, oil would rise to the surface and either collect in the interstices or opening between individual floes, or be trapped underneath the floes themselves. During the early period of broken ice in the spring, that portion of the oil rising beneath the floes will

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naturally migrate through the rotting ice and appear on the ice surface within a matter of hours. In the case of oil trapped under newly forming pancakes or sheet ice in the fall, the likely fate will be rapid entrapment, with new ice quickly growing beneath the oil as already discussed. The fate of oil trapped between floes will depend largely on the ice concentration and time of year.

During freeze-up, the oil will most likely be entrained in the solidifying grease ice and slush present on the water surface prior to forming sheet ice. Storm winds at this time often break up and disperse the newly forming ice, leaving the oil to spread temporarily in an open water condition until it becomes incorporated in the next freezing cycle. At breakup, ice concentrations are highly variable from hour to hour and over short distances. In high ice concentrations, oil spreading is reduced and the oil is partially contained by the ice. As the ice cover loosens, more oil is able to escape into larger openings as the floes move apart. Eventually, as the ice concentration decreases, the oil on the water surface behaves essentially as an open water spill, with localized patches being temporarily trapped by wind against individual floes. Any oil present on the surface of individual floes will move with the ice as it responds to winds and nearshore currents.

3.2.2 RPS Volume to Open Water

RPS volumes to open water for a well blowout and a spill of the offshore segment of the pipeline are detailed in Section 1.6.13.

Section 1.6.13

3.3 COMMAND SYSTEM [18 AAC 75.425(e)(3)(C)]

All emergency response situations will use the Incident Command System (ICS), which provides clear definition of roles and lines of command, together with the flexibility for expansion or contraction of the organization as necessary. Under this system, the first person discovering or responding to an emergency situation becomes the Incident Commander (person in charge) until that individual relinquishes authority to another person better able to control the situation.

ACS Tactic L-8, ACS Vol. 3

Details of the management structure in a spill response are provided in the ACS *Technical Manual*, Volume 3. Appendix B of Volume 3 contains a description of ICS position responsibilities and checklists. Note that the SRT fulfills the function of the Tactical Response Team discussed in Volume 3. Appendix D of *Volume 3* contains many common ICS forms for documenting response decisions and activities. Costs associated with a spill response would be tracked through an Authorization for Expenditure (AFE) code.

In most Level I incidents, the TRT possesses the capabilities to effectively control the incident. The Operations Team Lead will fulfill the role of Incident Commander. ACS will be activated to stand by for all spills until an assessment is performed. Once the assessment is complete, ACS is either released or mobilized.

Level II/III responses are initiated by the Operations Team Lead. The IMT is activated and begins to provide support to the field responders (operations section) and to coordinate the collection and distribution of information. ACS provides manpower and equipment resources from Deadhorse to assist in spill containment and recovery. The North Slope operators coordinate with ACS to ensure that a reserve of trained manpower is available for an extended spill response.

Section 1.1, Table 3-2 ACS Tactics A-1, A-2, A-3

Contents

The QI would be notified during call out of the IMT (Level II or III response). During Level II events, the Mutual Aid agreements cover resource issues associated with personnel and equipment. During Level III events, the QI acts as the company representative for commitment of Off-Slope resources.

If the spill exceeds the response capabilities of the TRT, Mutual Aid will be activated. Through the Mutual Aid Agreement, dated November 4, 1999, response personnel are available to respond to a Level II or Level III incident. BPXA would arrange for equipment and manpower from contractors beyond the Mutual Aid agreement limits if necessary to complete a spill response. Contracts for additional trained response personnel are in place through ACS. Contracts with North Slope-based contractors for additional equipment are in place through ARCO.

ACS Tactic L-8

For significant oil spills, there may be On-Scene Coordinators from the Federal Government, the State, the Local Government and BPXA, as well as the responsible party, if it is not BPXA. These individuals will become part of the Unified Command, representing their organization. Each contributes to the process of:

- Determining and establishing overall incident objectives and priorities
- Selecting strategies
- Planning for tactical activities
- Conducting integrated tactical operations
- Using resources efficiently and effectively

The responsible party will be the Incident Commander in the unified structure unless the State or Federal On-Scene Commander determines the response is inadequate. At that time, either the State or Federal On-Scene Coordinator will assume the Incident Commander's duties.

Once the Liberty Development comes on stream, it will become signatory to the North Slope Mutual Aid Agreement.

3.4 REALISTIC MAXIMUM RESPONSE OPERATING LIMITATIONS [18 AAC 75.425(e)(3)(D)]

The realistic maximum response operating limitations are described in the ACS *Technical Manual*. Environmental conditions can sometimes limit response work. Some limitations are based on safety, and others concern equipment effectiveness. The ACS *Technical Manual* lists the percentage of time some variables reduce effectiveness of response for planning purposes.

ACS Tactic L-7

The single most limiting factor of mechanical containment and response effectiveness at Liberty is fall broken ice conditions during a blowout. An open-orifice blowout to broken ice presents a more difficult response because of the thin layer of oil deposited over the broken ice. Major factors affecting the response to a blowout in broken ice are:

- **Effects of Ice**: The major effects of the ice are that a certain percentage of the blowout lands on ice (not open water) and is thus unavailable for conventional containment and recovery-based countermeasures. In addition, as the ice

Contents

coverage increases, it becomes more and more difficult to operate containment boom to concentrate oil for recovery.

- **Initial Slick Conditions**: Each blowout produces a thick, relatively narrow bank of oil directly down drift of the blowout source, with a much wider relatively thin slick on each side of the thick slick. Containment and recovery response will be effective in the thick portion of the slick, but effectiveness will be reduced in the thin portion of the slick, particularly in a sheen.
- **Delays in Response During Broken Ice**: The ice conditions at West Dock, where the primary equipment and marine logistics are located, may require that ice-breaking barges are used to move equipment into open water further offshore. This ice-breaking equipment is maintained in an operational status during broken ice conditions of fall freeze-up and spring break-up. Marine equipment will typically be prepared for winter storage once ice conditions at West Dock preclude further movement.
- **Vessel Safety Restrictions During Freeze-up**: Depending on air temperature and wind conditions, icing conditions may occur on the decks of response vessels. This may limit their ability to safely operate.
- **Ice Management**: Resources will be expended on ice management to reduce the risk of boom failure and to limit safety concerns. Effectiveness could be reduced because of the reduced recovery resources.

Cleanup could be accelerated by the use of in situ burning with the ice providing natural containment. Selective burning of oil on melt pools followed by manual recovery of any residue will benefit oil recovery effectiveness.

3.5 LOGISTICAL SUPPORT [18 AAC 75.425(e)(3)(E)]

BPXA has an existing logistical support infrastructure for its operations on the North Slope. Transportation equipment, coordination procedures and maintenance procedures are in place under normal operations. BPXA has in place existing contracts for operational logistical support, which would also be utilized to support a spill response.

Section 3.8; ACS Tactic L-4

3.6 RESPONSE EQUIPMENT [18 AAC 75.425(e)(3)(F)]

3.6.1 Equipment Lists

A summary list of dedicated oil spill response equipment on the North Slope (ACS and North Slope Operators) is provided in the ACS *Technical Manual*, Volume 1.

ACS Tactic L-6

A list of dedicated oil spill response equipment to be positioned at Liberty is provided in Table 3-2.

Table 3-2

A forklift with snow bucket attachment and a 966 loader will be maintained at the island during drilling operations, both of which could be used for berm construction and other spill response operations if needed.

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3.6.2 Maintenance and Inspection of Response Equipment

Response equipment will be maintained in such a manner that it can be deployed rapidly and in a condition for immediate use. The on-site response equipment located at Liberty will be routinely inspected and tested by ACS personnel assigned to Liberty.

ACS Tactic L-6

ACS holds the following USCG Oil Spill Removal Organization (OSRO) classifications

- Class A through E for river environments
- Class A through D for inland environments
- Class D for ocean environments

ACS has fulfilled the equipment maintenance and testing criteria that these classifications require.

3.7 NONMECHANICAL RESPONSE INFORMATION [18 AAC 75.425(e)(3)(G)]

Section 1.6; ACS Tactics B-1 through B-7

Nonmechanical response information is provided in the ACS *Technical Manual*.

3.8 RESPONSE CONTRACTOR INFORMATION [18 AAC 75.425(e)(3)(H)]

ACS is the OSRO for BPXA's North Slope facilities including Liberty. Contact information for ACS is provided in Table 1-2.

Table 1-2

BPXA will activate ACS and the North Slope Operators to provide the initial manpower and resources required to respond to a large or lengthy spill response. If additional resources are required, they will be accessed through Master Services Agreements maintained by ACS. A copy of BPXA's Statement of Contractual Terms with ACS for Liberty will be provided in this plan prior to start-up of Liberty operations.

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TABLE 3-2
LIBERTY ON-SITE SPILL RESPONSE EQUIPMENT

QUANTITY	UNIT OF MEASURE	DESCRIPTION
2	EA.	Boat, spill response, 20-ft. aluminum hull, inflatable
350	FT.	Boom, fire, 12-in. x 18-in.
2	EA.	1000-ft. NOFI Boom bags
20	EA.	Anchors, 40# w/rigging
10	EA.	Anchors, 150# w/rigging
4	EA.	Mooring buoy w/anchor
2	EA.	Bird-scare cannons
1	EA.	Wildlife hazing kit
1	EA.	Wildlife capture and stabilization kit
2	EA.	Fastank, 2500 gal
1	EA.	ATV, 6 wheeler w/trailer
3	EA.	Connex, storage container, 20-ft. x 8-ft.
1	EA.	Connex, insulated and wired shop, 20-ft. x 8-ft.
1	EA.	Portable drum skimmer (dual surface interchangeable)
1	EA.	Komara Star heavy oil disc skimmer
1	EA.	Vertical rope mop, 2 mop
1	EA.	100 gallon fuel tank
2	EA.	Hand-held global position system
2	EA.	Light stand and cords
1	EA.	Generator, 2 KW diesel
1	EA.	Pump, diaphragm, 3-in. diesel
1	EA.	Pump, marine trash, 2-in. diesel
2	EA.	Pump, trash, 3-in. diesel
180	FT.	Hose, 2-in. discharge, arctic grade
90	FT.	Hose, 2-in. suction, arctic grade
700	FT.	Hose, 3-in. discharge
500	FT.	Hose, 3-in. suction
10	EA.	Misc. Kamlock adapters
1	EA.	Fold-a-Tank, 1500 gal
2	EA.	18-in. x 18-in. surface liner
2	EA.	36-in. x 42-in. surface liner
4	EA.	4-ft. x 5-ft. surface liners
2	ROLL	20-ft. x 100-ft. reinforced Visqueen
10	EA.	Roll, sorbent, 36-in. x 150-ft.

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TABLE 3-2 (CONTINUED)
LIBERTY ON-SITE SPILL RESPONSE EQUIPMENT

QUANTITY	UNIT OF MEASURE	DESCRIPTION
4	EA.	Bundle, glycol sorbent pads, 18-in. x 18-in.
18	EA.	Bundle, sorbent boom, 8-in. x 10-ft., 40 ft. per bundle
16	EA.	Bundle, sorbent pads, 18-in. x 18-in.
18	EA.	Bundle, sorbent pads, 36-in. x 36-in.
2	EA.	Fence post driver
20	EA.	Fence posts
3	EA.	Fuel can, 5 gal, diesel
2	ROLL.	Rope, 1/2-in. polypropylene, 600-ft. per roll
2	ROLL	Rope, 3/4-in. polypropylene, 600-ft. per roll
4	EA.	Rake, steel, garden
4	EA.	Shovels, aluminum scoop
4	EA.	Shovels, round point
4	EA.	Shovels, square nose
4	EA.	Survey lathe and flagging
1	EA.	Tool box
20	EA.	Hand-held igniters for in situ burning
1	EA.	Davit for launching rigid inflatable boat
1	EA.	Snowblower
1	EA.	Chain saw
1	EA.	Ice auger
1	EA.	Vikoma power vac unit
1	EA.	Multi-gas meter
4	EA.	GPS tracking buoys
1	EA.	Charts and file cabinet
1	EA.	Island outfall protection
1	EA.	Computer and printer
Communications Equipment		
1	EA.	Marine private coast station
2	LOTS	Transmission lines with connectors
2	EA.	VHF antenna
6	EA.	MT2000 hand-held radios
2	EA.	GP300 UHF hand-held radio
1	EA.	Mobile satellite phone system
1	EA.	Backboarded Spectra mobile radios

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3.9 TRAINING PROGRAM [18 AAC 75.425(E)(3)(I)]

3.9.1 SRT Training

The North Slope Spill Response Teams consist of workers who volunteer to be emergency spill response technicians. Each team member is required to have initial emergency response training and annual refresher training, which meets or exceeds the requirements in the Hazardous Waste Operations and Emergency Response (HAZWOPER) regulations, 29 CFR 1910.120(q). Annual requirements for HAZWOPER refreshers, medical physicals, and respiratory fit test are tracked by ACS through weekly reports from the database. See Section 3.9.5, Record Keeping.

ACS Tactic A-3, Section 3.9.5

The training program consists of weekly classes, which emphasizes hands-on experience, field exercises and team building drills. The courses are selected by the facility Lead ACS Technician in conjunction with field management and use BPXA, ACS and external training consultants. Table 3-3 lists typical SRT training courses. Because of operational time constraints, many of the courses are divided by subject area and taught in the 2- or 3-hour time frame of an SRT meeting. To ensure regular attendance at these meetings, team members are required to maintain an annual attendance rate of 75 percent or better. The training and attendance is documented and available for review. The yearly training schedule is also available at the facility and ACS.

Table 3-3

3.9.2 IMT Member Training

IMT members are trained on the North Slope Incident Management System (IMS). This training consists of IMS philosophy, drills and exercises, and practical experience. The IMS training program meets or exceeds the National Preparedness for Response Exercise Program (PREP) guidelines.

The IMS training program includes an introduction to new members of the IMT, position-specific training, and the IMS process flow. The program is designed to be provided in a progressive manner that leads personnel through the entire operational planning period for an incident. A majority of the IMS training modules consists of process flow information. Table 3-4 provides a summary of these modules.

Table 3-4

Tabletop exercises and drills are used to test personnel knowledge and competency of the system. When additional training or response procedures are identified, training programs or workshops are designed to address the identified issue. Current training schedules are available at the facility.

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TABLE 3-3
NORTH SLOPE SPILL RESPONSE TEAM
TRAINING PROGRAM COURSES

Category	Course Title
Communication	ICS Basic Radio Procedures
Decontamination	Decontamination Procedures
Environmental	Environmental Awareness Wildlife Hazing
Equipment	Basic Hydraulics For Spill Responders Boom Construction and Design Fastanks and Bladders Skimmer Types and Application Snow Machines and ATV Operations 90 Spill Response Equipment Proficiency Checks
Management	Incident Command System Management and Leadership During An Oil Spill Quarterly Drill and Exercises Staging Area Management
Miscellaneous	Global Positioning System
Response Tactics	In-Situ Burning Nearshore Operations Summer Response Tactics Winter Oil Spill Operations Winter Response Tactics
Safety/Survival	Arctic Cold Weather Survival Arctic Safety HAZWOPER Spill Site Safety Weather Port and Survival Equipment
Vessel-Related	Arctic Cold Water Survival Airboat Operations Boat Safety and Handling Boom Deployment On Rivers Captain/Crewman Vessel Training Charting and Navigation Deckhand/Knot Tying River Response School Swiftwater Survival

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TABLE 3-4
NORTH SLOPE IMS TRAINING MODULES

MODULE NUMBER	COURSE
0	IMS Overview
1	Development of Tactical Worksheet
2	Development of Initial Incident Briefing Form
3	Field Reports and Field Team Organization
4	Resource Ordering and Tracking
5	Initial Incident Briefing (201)
6	Mapping
7	Information Management: Situation Status
8	Information Management: Resource Status
9	Operational Planning Worksheet & Situation Reports
10	Operational Planning Worksheet for Next Operational Period
11	Assessment Meetings
12	Preparation of Tactical Objectives
13	Tactical Operations Planning
14	Preparation of Incident Action Plan Support Documents
15	Shift Change Briefing
16	Command
17	Environmental Unit Training
18	Documentation Unit Training
19	Safety Officer Training
20	Tabletop Talk-Around
21	Tabletop Exercise
22	Integrated Tabletop Exercise

3.9.3 Other Training

BPXA and contract personnel working at Liberty will be required to attend hydrogen sulfide and fire-fighting training. In addition, there may be specific departmental training requirements on Liberty facility operations. Environmental awareness training, provided at safety meetings, is based on SHARP, which consists of the following:

- Spill Reduction
- Hazardous Waste
- Animals / Wildlife
- Recycling
- Permitting

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3.9.4 Record Keeping

The Liberty ACS Technician will maintain a database as a record of the courses taken by each member of the SRT and Emergency Response Team (ERT). Records are kept for a minimum of 3 years or for the entire time that the employee or contractor is assigned responsibilities in this plan. The database provides a brief description of the course and the date completed. Current training status of employees and contractors will be available through the ACS Technician or by calling the facility manager. The qualifications of training instructors and training organizations hired to teach courses, including the instructor's training records, are maintained by BPXA and ACS. ACS maintains training records of all North Slope SRT personnel.

3.9.5 Spill Response Exercises

BPXA has fully adopted the National PREP guidelines as the structure for BPXA's training program and procedures. The PREP guidelines were developed to establish a workable exercise program that meets the intent of OPA 90 for spill response preparedness. Participation in the PREP and use of the PREP guidelines ensures all federal exercise requirements mandated by OPA 90 are met.

Internal Exercises

Internal exercises are those conducted wholly within BPXA and are designed to test the various components of this Plan to ensure it is adequate to meet the needs of BPXA for response to a spill. Internal exercises include:

- **Quarterly Qualified Individual Notification Drills:** To ensure the Qualified Individual is able to be reached on a 24-hour basis in a spill response emergency and carry out assigned duties.
- **Annual Spill Management Team Tabletop Exercises:** To ensure all personnel are familiar with the contents of this plan, including the DOT Information Summary, the Incident Command System, crisis response procedures, mitigating measures, notification numbers and procedures, and individual roles in the response structure.
- **Semi-Annual Equipment Deployment Exercises:** To ensure all internal and contractor-operated response equipment is fully functional and can be deployed in an efficient and productive manner.
- **Triennial Exercise of Entire Plan**
- **Government-Initiated Unannounced Exercises**

With the exception of government-initiated unannounced exercises, all internal exercises are self-evaluated and self-certified. Documentation, including a description of the exercise, objectives met and results of evaluations, is maintained for a minimum of three years. All exercise documentation is in written form, signed by the HSE Support Team Leader for each exercise, and available for review on request.

The Liberty facility manager, or his designee, will be responsible for the scheduling, development and evaluation of training programs and exercises and for ensuring that regulatory requirements are met.

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External Exercises

External exercises involve efforts outside of BPXA to test the interaction between BPXA and the response community. The external exercises also test the plan and the coordination between BPXA and the response community including: the OSRO (ACS); state, federal and local agencies; and local community representatives.

BPXA participates in an annual Mutual Aid Drill (MAD), which satisfies the requirement of one unannounced exercise per year. In addition to actively participating in the MAD, federal, state and local agencies are involved in the development and evaluation of the drill. Every year, equipment is deployed at the MAD per National PREP guidelines. The MAD exercise satisfies the National PREP requirements to exercise all aspects of the response plan at least every three years. The following are the components that are tested through the MAD exercise:

Organizational Design

- Notifications (includes training on 24-hour notifications and reporting to the National Response Center)
- Staff mobilization
- Ability to operate within the response management system described in the plan

Operational Response

- Discharge control
- Assessment of discharge
- Containment of discharge
- Recovery of spilled material
- Protection of economically and environmentally sensitive areas
- Disposal of recovered product

Response Support

- Communications
- Transportation
- Personnel support
- Equipment maintenance and support
- Procurement
- Documentation

3.10 PROTECTION OF ENVIRONMENTALLY SENSITIVE AREAS AND AREAS OF PUBLIC CONCERN [18 AAC 75.425(e)(3)(J)]

3.10.1 Prediction of Discharge Movement

Drainage for the Liberty gravel island will be directed toward the three sumps, located in the northwest corner, southwest corner, and in the middle of the east side.

Facility Diagrams, Section 1.8

A release from the onshore segment of the pipeline could affect several small tundra lakes, as shown in Figure 1-5. A release from the nearshore portion of the onshore pipeline could potentially flow into Foggy Island Bay.

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3.10.2 Information on Probable Points of Contact

ACS Map Sheets 74, 80, 83-90, 94, and 95; Tactics W-1 through W6

Priority protection sites, sensitivities, and wildlife protection strategies are described in the ACS *Technical Manual*, Volume 2. Protection strategies are described in the ACS *Technical Manual*.

3.11 ADDITIONAL INFORMATION [18 AAC 75.425(e)(3)(K)]

Not applicable.

3.12 BIBLIOGRAPHY [18 AAC 75.425(e)(3)(L)]

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4. BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(E)(4)]

This section discusses the BAT requirements contained in 18 AAC 75.425(e)(4)(A), (B), and (C) to address technologies not subject to RPS or performance standards in 18 AAC 75.445(k)(1) and (2). The discussion of each technology covers the requirement to analyze applicable technologies and to provide a justification that the technology is BAT. Not all aspects of the Liberty development are subject to ADEC BAT regulations. Those portions of the BAT review where ADEC regulations do not apply are identified.

4.1 COMMUNICATIONS [18 AAC 75.425(e)(1) (D)]

The communications system for use in a spill response at Liberty is described in the ACS *Technical Manual.*

ACS Tactic L-11A

4.2 SOURCE CONTROL [18 AAC 75.425(e)(1) (F)(i)]

BAT analysis of source control for a pipeline leak and tank overflow is provided in the following subsections. Loss of well control (i.e., a blowout) is discussed in the *BPXA Arctic Well Control Contingency Plan*, which addresses all possible methods of well control available, including surface control measures, relief well drilling, and blowout ignition. BPXA will use the services of a professional well control firm if well control was not regained by conventional mechanical means.

Section 1.6.3

No additional well control technologies are available for a blowout, other than those that will be employed by drilling engineers and well control personnel.

Pipeline

The pipeline source control procedures, required by 18 AAC 75.425(e)(1)(F)(i), involve the placement of automatic isolation valves at Liberty Island and the Badami pipeline tie-in location to stop the flow of oil into the Liberty pipeline. A check valve may also be provided at the Badami tie-in location to prevent backflow from the Badami pipeline.

Table 4-1

At the shore crossing, the pipeline will either have a vertical loop or an automated isolation valve. A vertical loop is feasible for the shore crossing for Liberty because of the small elevation change along the proposed overland route.

There are two technology options for the valves, automatic ball valves or automatic gate valves. Both valve options, when installed in new condition, are similar in terms of availability, transferability, cost, compatibility, and feasibility. In terms of effectiveness, ball valves typically have slightly faster closure times than gate valves. For this project, automatic ball valves will be used. As required by 18 AAC 75.055(b), the flow of oil can be completely stopped by these valves within one hour after a discharge has been detected. The valve closure time for these types of valves is usually on the order of 2 to 3 minutes. To avoid over-pressurizing the Liberty pipeline, the valves will have a closure time of 8.5 minutes.

A vertical loop is also an option for the landfall crossing due to the minimal pipeline profile changes. This alternative is considerably more effective in minimizing spill volumes during

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contingency spill events. Moreover, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance, is eliminated. However, valves are needed on each terminus of the pipeline to keep any oil from entering it, in the event that the pipeline needs to be isolated.

Tanks

The storage tanks associated with the Liberty Development will be located in the Outer Continental Shelf (OCS) and therefore, not subject to ADEC regulations. However, BPXA has performed the following BAT review as a proactive measure.

Source control procedures for purposes of this BAT analysis also relate to the emergency shutdown valves on the fill line for oil-containing tanks to prevent a catastrophic release of diesel. The valve type selected for this service is a soft-seated ball valve which meets API-598 (valve leakage class equivalent to Class VI), which is the BAT. The valves are equipped with air or electrically powered actuators which includes a spring return action resulting in a "fail closed" arrangement. This valve was selected for the following reasons:

Table 4-2

- Emergency shutdown valve (ESDV)-1210 is a soft-seated ball valve meeting API-598 valve leakage class (or equivalent to Class VI), which is the best available.
- The actuator chosen is one of the few (if not the only) electric actuator with a spring return action.
- The valve fails locked and is fire-safe.

4.3 TRAJECTORY ANALYSES [18 AAC 75.425(e)(1) (F)(iv)]

Trajectory analyses and forecasts are described in the ACS *Technical Manual.*

ACS Tactic L-11B

4.4 WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS [18 AAC 75.425(e)(1) (F)(ix)]

Wildlife capture, treatment, and release programs are described in the ACS *Technical Manual*

ACS Tactic L-11C

4.5 CATHODIC PROTECTION FOR TANKS [18 AAC 75.065(h)(3)]

The storage tanks associated with the Liberty Development will be located in the OCS and therefore, not subject to ADEC regulations. However, BPXA has performed the following BAT review as a proactive measure.

The diesel tank and temporary diesel tanks will be elevated and do not require cathodic protection. The cathodic protection systems to be installed under the 5,000-bbl produced water tank and the 2,000-bbl slop oil tank will be in accordance with API 651, *Cathodic Protection of Aboveground Petroleum Storage Tanks*. As such, no additional BAT analysis for the cathodic protection system has been conducted.

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TABLE 4-1
BEST AVAILABLE TECHNOLOGY ANALYSIS
SALES OIL LINE SOURCE CONTROL

BAT EVALUATION CRITERIA	CURRENT METHOD: AUTOMATIC ISOLATION VALVES AND/OR A VERTICAL LOOP	ALTERNATE METHOD: ADDITIONAL AUTOMATIC SHUTDOWN VALVES	ALTERNATIVE METHOD: MANUAL BLOCK VALVES	ALTERNATE METHOD: REPLACEMENT OF AUTOMATIC SHUTDOWN BALL VALVES WITH GATE VALVES
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	The sales oil pipeline will have two automatic isolation valves at each terminus and either an isolation valve or vertical loop at landfall.	Additional shutdown valves could be added to the system.	Proposed valves and/or the vertical loop could be replaced with manual block valves.	Gate valves could replace the ball valves and the vertical loops.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Will be installed.	Method is transferable.	Method is transferable.	Method is transferable.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	The proposed source control measure of automatic ball valves at each end with either a vertical loop or an additional isolation valve at landfall will be effective in minimizing spill volumes during spill events. Vertical loops form a terrace structure that would significantly limit the amount of oil spilled due to drain down effects. Moreover, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance, is eliminated.	Additional automated valves would afford little additional source control since the Liberty pipeline is relatively short. Also, little oil would leak from the line once it was depressurized, therefore; additional automation would not significantly improve source control.	Manual block valves would increase shutdown time and therefore, spill volume.	This technology would have a longer closing time than the ball valves, and is not as effective in a fire. Compared to vertical loops, the additional possibility of oil leakage at the mechanical connections of the valves, traditionally an area of concern and maintenance would be added to the project in a roadless area. Additionally, failure to close, while not adding to the risk of a spill, could allow more oil to spill.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant.	The system described is planned and is a base case for comparison.	Additional automation would be cost in excess of $300,000.	Additional cost in excess of $50,000.	Additional automation would be cost in excess of $100,000.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Method is current.	Method is current.	Alternative equipment would be new.	Alternative equipment would be new.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Will be installed.	Method is compatible.	Compatible with the proposed project.	Compatible with the proposed project.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible	Method is feasible.	Feasible to implement.	Feasible to implement.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	There are no offsetting environmental impacts.	There are no offsetting environmental impacts	Possibility of increase discharge to tundra and water from the pipe, in the event of a spill.	Possibility of increase discharge to tundra and water from the pipe, in the event of a spill.

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TABLE 4-2
BEST AVAILABLE TECHNOLOGY ANALYSIS
SOURCE CONTROL
OIL-CONTAINING TANKS EMERGENCY SHUTDOWN VALVE
Diesel Storage Tank, Slop Oil Tank, Produced Water Tank

BAT EVALUATION CRITERIA	PROPOSED METHOD AUTOMATIC BALL VALVE CLOSURE	ALTERNATIVE: MANUAL CLOSURE
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant.	Technology exists to do this, and it is commonly done in piping systems.	Does not apply.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations.	This technology is applicable to these tank systems.	Does not apply.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits.	This is an effective means of preventing releases where operator error may occur	There would be no backup if an operator made an error.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant.	This technology is proposed by the applicant.	Possible savings of $10,000 to $20,000 in not having to install ESD valve.
AGE AND CONDITION: The age and condition of the technology in use by the applicant.	This is a new installation with new equipment.	This would be a new installation with new equipment.
COMPATIBILITY: Whether each technology is compatible with existing operations and technology in use by the applicant.	Compatible with the new systems planned for this new installation.	Compatible; this is a new installation.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects.	This technology is feasible to implement.	This technology is feasible to implement.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution and energy requirements, offset any anticipated environmental benefits.	Inadvertent valve closure could cause an increase in pressure in the hose or piping connection to the tank inlet. Connections to the slop oil tank, produced water tank, and day tanks will be hard piped with appropriate pump and pressure controls. The diesel fueling hose from the barge or truck could be at risk. To mitigate this risk, the shut-off valve will close slowly to prevent inadvertent pressure surges. In addition, the barge connection includes a pressure relief to prevent hose rupture. Proper procedures and communications will also be in place to prevent occurrence.	No backup provision for operator error.
OTHER	Acceptable under the Uniform Fire Code.	Unacceptable under the Uniform Fire Code.

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4.6 LEAK DETECTION FOR TANKS [18 AAC 76.065(h)(4)]

The storage tanks associated with the Liberty Development will be located in the OCS and therefore, not subject to ADEC regulation. However, BPXA has performed the following BAT review as a proactive measure.

The leak detection system to be installed under the oil containing storage tanks will be in accordance with API 653, Appendix I. As such, no additional BAT analysis for the leak detection system has been conducted.

4.7 TANK LIQUID LEVEL DETERMINATION [18 AAC 76.065(j)(3)]

The storage tanks associated with the Liberty Development will be located in the OCS and therefore, not subject to ADEC regulation. However, BPXA has performed the following BAT review as a proactive measure.

The level transmitters for the slop oil, produced water and diesel tank will use state-of-the-art technology sending a signal to the PLC which provides level indication, alarms, shutdown of equipment and isolates the unit to protect the environment. Isolation valves will be electrically and pneumatically opened and spring-closed, thereby ensuring positive action and isolation on failure of either pneumatic or electrical power, even under extreme low-temperature conditions.

Table 4-3

Electronic level transmitters mounted on the tanks will sense hydrostatic liquid head. The slop oil and produced water tanks will have two level transmitters each. The diesel tank will have one electronic level transmitter. The transmitters send level signals to the PLC in the Control Room. Another option for determining level in the tanks would be to manually employ a dip stick into the tanks.

The controller for the diesel storage and dispensing control system is a PLC. They are almost universally used in similar applications. PLCs are selected for the following reasons:

- They are the state-of-the-art systems used in logic control and alarming.
- They have replaced relay systems because of the ease of programming in software versus hardware and interconnected wiring. Components are standardized and are easily replaced using off-the-shelf items.
- They have been proven to work reliably in severe climatic conditions.
- PLC controllers are intelligent devices. The hardware and software can be selected, configured, and programmed to be fail-safe by detecting hardware and software failures and taking the appropriate control or alarm action.
- They are programmed using languages that meet the latest requirements of the International Electro-mechanical Committee (IEC) and are IEC 1131-3 compliant. This means that PLC logic can be designed and modified by anyone familiar with these standard programming language features. Changes can be made locally or from a remote location using remote access software.
- The data resident in PLC controllers can be easily accessed by human machine interfaces or Information Technology Departments using standardized databases.
- The PLC database will be password protected. Only authorized personnel will have access to make logic or shutdown sequence changes.

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TABLE 4-3
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	PROPOSED SYSTEM OR METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATIVE 1: HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATIVE 2: PNEUMATIC CONTROL SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant.	Microprocessor-based PLCs are used in almost all electronic control systems in industry today. The reason for PLCs' popularity is that the controllers have proven to be BAT over the past 20+ years.	Hardware relay logic control systems are still in use today, but are becoming less popular.	Pneumatic control systems are used in very few applications today and never where pumps and motors are turned on or off.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations.	Allen Bradley PLC-5s and all instrumentation are completely transferable to applicant's operations. Many BP facilities on the North Slope of Alaska use AB PLCs: the central plant control system will utilize AB PLCs. The brands and models of instrumentation used in the control system design are also common to the central facility.	Technology is not easily compatible with planned instrumentation and control system.	Technology is not compatible with planned instrumentation and control system.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits.	Critical operation parameters such as tank levels are continuously monitored by the control system and are displayed for easy operator reference. Any abnormal condition (i.e., high tank level) activates automatic safeguards (i.e., close tank inlet valves) to prevent spills, etc. Pre-alarm operators of pending abnormal conditions. The entire control system is designed to be fail safe. All field sensing devices, PLC hardware and software, and field-actuating devices are designed to stop diesel/methanol flow in the event any device fails. Dispensing pump incorporates an ESV, which closes under impact or fire exposure.	Relay systems do not provide for logic status monitoring or alarming.	Pneumatic systems are prone to freezing if moisture build-up occurs in the tubing.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant.	All instruments and control system hardware will be purchased, are technically acceptable and reasonably priced based on budgetary pricing. All instrument and controls technology used in the system design should remain in service for at least the next 20 years. Design changes can be implemented at minimal costs.	The cost of design changes to a relay based logic system is high. Re-wiring is required for any revision.	The cost of design changes to a pneumatic logic system is high. Re-tubing is required for revision.
AGE AND CONDITION: The age and condition of the technology in use by the applicant.	All instrument and controls equipment is brand new, purchased specifically for this project.	Not applicable, system would be new.	Not applicable, system would be new.

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TABLE 4-3 (CONTINUED)
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	PROPOSED SYSTEM OR METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATIVE 1: HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATIVE 2: PNEUMATIC CONTROL SYSTEM
COMPATIBILITY: Whether each technology is compatible with existing operations and technology in use by the applicant.	Allen Bradley PLCs are used at various BP facilities on the North Slope of Alaska. The central control system will utilize AB PLCs.	Not applicable	Not applicable
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects.	AB PLCs are easily programmed, commissioned and maintained because of their software-based systems. All programming is IEC 1131-3 compliant. System status, input/output status and program status alarms are readily available to operating and maintenance personnel for troubleshooting. All PLC information is available for displaying on human/machine interfaces for quick and accurate operating responses to abnormal conditions.	Engineering revisions to relay logic systems are very time-consuming and costly. Maintenance is very low-tech and often causes more spurious trips than it prevents. Operator interface is available locally only.	Engineering revisions to pneumatic control systems are very time-consuming and costly. Operator interface is available locally only.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution and energy requirements, offset any anticipated environmental benefits.	Electrically and electro-pneumatic operated valves provide high reliability for shutting down the diesel or oil flows while consuming minimal amounts of energy.	None	None

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4.8 MAINTENANCE FOR BURIED STEEL PIPING [18 AAC 75.080(b)]

The Liberty facility will have a buried diesel line for transporting fuel to the rig. The sales oil pipeline will also be buried near the island's edge and at the shoreline crossing. All buried line segments will be cathodically protected, as described in Sections 2.1.9 and 4.12.

Sections 2.1.9 and 4.12

The line segments will be visually inspected anytime piping is exposed. Evidence of external corrosion will be fully investigated to determine the extent of corrosion. Pipeline repairs necessitating pipe replacement will be cause for an internal inspection of the affected sections of the pipe.

4.9 PROTECTIVE WRAPPING OR COATINGS [18 AAC 75.080(b)(1)(A)]

Sales Oil Pipeline

As required by 18 AAC 75.080 (b)(1)(A), the buried pipeline in the offshore segment will be protected from external corrosion by an external coating. The available technologies for this coating are:

Table 4-4

- Dual layer FBE for corrosion and mechanical protection
- Single layer of conventional FBE for corrosion protection
- Paint
- Ceramic
- Cold tar enamel
- Neoprene or foam

Of these six technologies, dual layer FBE is considered BAT, based on the physical properties of each technology in relation to the physical environment of the Liberty pipeline and FBEs relative cost to a neoprene or foam type coating system.

Paint and ceramic coatings are not effective for the pipeline, since these materials are brittle. The pipeline requires a coating material that is ductile, since the pipeline may be subjected to high bending strains potentially caused by ice gouging and permafrost thaw settlement. Also, since the pipeline will be dragged over ice surfaces during construction, a durable coating material will be required. Paint and cold tar enamel will wear quickly if dragged across ice. Neoprene or foam type coatings will be ductile and durable, however they are more costly than FBE type coatings. Also, neoprene and foam type coatings will reduce the weight of the pipelines, therefore more cost would be incurred to provide additional weight to the pipeline for stability during pipe laying operations.

Both dual layer and single layer FBE coatings are ductile, however dual layer FBE, composed of an inner layer of conventional FBE for corrosion protection and an outer layer of impact resistant FBE for mechanical protection, will be more durable (hence more transferable) than a single layer FBE coating. Dual layer FBE has been used on other pipelines and is readily available for the Liberty pipeline. The dual layer FBE coating's inner layer is the conventional FBE material that has been effective as a corrosion protection coating on marine pipelines. Both layers, which are feasible to apply, have a low coating breakdown factor which will cause less impact to the environment while making the dual layer FBE coating compatible with sacrificial anodes. High coating breakdown factors adversely affect sacrificial anode systems.

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The cost to apply the dual layer FBE coating (in a new condition) is considered reasonable by BPXA. Therefore, a dual layer FBE coating is considered the BAT suited for the Liberty pipeline. If it is determined that the durability of the impact resistant layer of FBE is not required, a single layer of corrosion protective FBE may be used.

4.10 CORROSION SURVEYS FOR AN EXISTING FACILITY [18 AAC 75.080(b)(2)(A)]

Liberty is a new facility, and as such, is not subject to this requirement.

4.11 CRUDE OIL TRANSMISSION PIPELINE LEAK DETECTION [18 AAC 75.055(a)]

As required by 18 AAC 75.425(e)(4)(A)(iv), a BAT review, summarized in Table 4-5, has been made for leak detection technologies applicable to the Liberty pipelines. These technologies are:

Tables 4-5

- MBLPC
- PPA
- MB
- Real Time Transient Model (RTTM)
- Negative Pressure Wave Monitoring (NPWM)
- LEOS

The Liberty sales oil pipeline will have MBLPC, PPA, and LEOS leak detection systems installed. These systems will achieve the minimum leak detection threshold limit of 1% of daily oil throughput in the sales oil pipeline, as specified by 18 AAC 75.055(a)(1). As required by 18 AAC 75.055(a)(2), verification of oil flow will be continuously performed by the MBLPC and PPA systems.

Both the MBLPC and PPA systems provide better leak detection capabilities than other systems in terms of cost and technology. The MBLPC and PPA systems provide more accurate leak detection capabilities than a mass balance (MB) system, have adequate opportunity to detect a leak on the order of 1% or smaller of daily throughput unlike the NPWM system, and provide leak detection monitoring at a relatively lower cost and better ease of implementation compared to the most accurate RTTM system. Since the flow in the pipeline will be predominately steady state as opposed to transient, the added cost and difficulty to implement an RTTM system, which would be the best system for transient flow conditions, will not be offset by the added accuracy benefit of RTTM. Typically, MBLPC systems provide lower leak detection threshold limits than PPA systems; however, PPA systems typically detect leaks faster than MBLPC systems.

The LEOS leak detection system will be installed on the offshore portion of the sales oil pipeline, to supplement the MBLPC and PPA systems. This system is being installed to provide small volume leak detection capability below the detection threshold of MBLPC and PPA during the winter ice period. The LEOS system has a detection sensitivity of 0.05% of throughput. An additional benefit of the LEOS system is that it can determine the location of a leak.

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TABLE 4-4
BEST AVAILABLE TECHNOLOGY ANALYSIS
EXTERNAL COATINGS FOR BURIED SECTIONS OF PIPELINES

BAT EVALUATION CRITERIA	PROPOSED SYSTEM: FUSION BONDED EPOXY	ALTERNATE METHOD COAL TAR OR EXTRUDED POLYETHYLENES	ALTERNATE METHOD PAINTS (ENAMEL OR ZINC OXIDE PRIMER)	ALTERNATE METHOD NO COATING
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Technology is available and is used.	Technology is available and is used. Not available in existing coating mills in Alaska.	Technology is available and is used for above ground piping.	Technology is available.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Can be used.	Can be used.	Can be used.	Can be used.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Effective means to provide coverage over the entire length of the buried section of pipeline. In addition, this product can be covered with concrete to provide additional physical protection at the rivers where the pipe might be pulled in during installation.	Would likely not be as effective as fusion bonded epoxy. Likely to be damaged in shipment to the site at low temperatures and is not reliable within the pipeline operating temperatures.	Does not provide the required protection that is required for buried pipe that comes in contact with soils.	Not effective means of providing protection of the buried sections of the pipeline. Also DOT regulations require that pipeline have external coating on new pipelines.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant.	Approximate cost is $100,000 to coat the buried sections of the pipeline.	Similar cost as proposed system.	Cost of approximately $75,000.	There would be no cost.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Method is current.	Method is current.	Method is current.	Method is current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Compatible with coating systems and installation method proposed. It is compatible with concrete coating that will be installed over the fusion bonded epoxy to provide mechanical protection when the pipe is pulled in.	Not compatible with cold temperature environment that the pipe will be installed in.	Not compatible with concrete coating that will be installed over the line to provide mechanical protection of the pipe.	Compatible.

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TABLE 4-4 (CONTINUED)
BEST AVAILABLE TECHNOLOGY ANALYSIS
EXTERNAL COATINGS FOR BURIED SECTIONS OF PIPELINES

BAT EVALUATION CRITERIA	PROPOSED SYSTEM: FUSION BONDED EPOXY	ALTERNATE METHOD COAL TAR OR EXTRUDED POLYETHYLENES	ALTERNATE METHOD PAINTS (ENAMEL OR ZINC OXIDE PRIMER)	ALTERNATE METHOD NO COATING
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible and is commonly used.	Not feasible to use because it will not provide the level of protection required based on the period of the year the line will be installed (cold temperature weather) and the operating temperature of the pipeline.	Not appropriate coating for a buried pipeline.	Not feasible to have uncoated buried pipe. DOT regulations require that new lines have external corrosion coating.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	No additional environmental impacts.	Coal tar coatings present possible environmental concerns when coating has to be removed for maintenance or field installation.	No additional environmental impacts. Buried in the same ditch as the pipeline.	No additional environmental impacts.

TABLE 4-5
BEST AVAILABLE TECHNOLOGY REVIEW
PIPELINE LEAK DETECTION SYSTEM

BEST AVAILABLE TECHNOLOGY EVALUATION CRITERIA	MBLPC - MASS BALANCE LINE PACK COMPENSATION (PROPOSED)	PPA PRESSURE POINT ANALYSIS (PROPOSED)	MB - MASS BALANCE	RTTM - REAL TIME TRANSIENT MODEL	NPWM - NEGATIVE PRESSURE WAVE MONITORING	LEOS – EXTERNAL SENSING VAPOR MONITORING (PROPOSED)
AVAILABILITY: Whether technology is used in other pipelines/applications or is available for use in the Liberty pipelines.	MBLPC has been used on other pipelines and can be obtained for the Liberty pipeline	PPA has been used on other pipelines and can be obtained for the Liberty pipeline.	MB has been used on other pipelines and can be obtained for the Liberty pipeline. However, most leak detection vendors will offer MBLPC over MB because MBLPC offers better performance than MB	RTTM has been used on other pipelines and can be obtained for the Liberty pipeline	NPWM can be obtained for the Liberty pipeline and has been used on other pipelines	LEOS can be obtained for the pipeline. It has been used on many land-based pipelines and has been successfully installed on the Northstar project. There is a minimum six month lead time to manufacture and deliver the system.
TRANSFERABILITY: Is technology transferable to the Liberty pipelines	MBLPC technology can be transferred to the Liberty pipeline if: · Transient flow conditions do not occur frequently. · There is no multi-phase flow. · There is no slack line flow.	PPA technology can be transferred to the Liberty pipeline if: Transient flow conditions do not occur frequently and if there are no high amplitude transient flow conditions. · There is no multi-phase flow. · There is no slack line flow. The SCADA system can scan oil pipeline data every 6 seconds or less and products pipeline data every 60 seconds. Leak locating will require the SCADA system to scan pipeline data in the pipeline every 0.25 seconds.	MB technology can be transferred to the Liberty pipeline if: · The pipeline operates in a steady state mode. There is no batching. There is no multi-phase flow · There is no slack line flow. Temperature remains constant. Pipeline is less than 20 miles long.	RTTM can be transferred to the Liberty pipeline if: There is no multi-phase flow There is no slack line flow However, RTTM can be operated effectively regardless if the pipeline operates under predominately steady state or transient flow conditions.	NPWM Technology can be transferred to the Liberty pipeline if: · The pipeline operate in a steady state mode · There is no batching · There is no multi-phase flow · There is no slack line flow. Pressure wave transducers are spaced at close intervals.	LEOS can be transferred to Liberty with the provision that it is installed inside a protective conduit. Care must be exercised during pipeline installation. There are no operational pipeline flow conditions that will affect the performance of the LEOS system.
EFFECTIVENESS: Is there reasonable expectation that each technology will provide increased spill prevention or other environmental benefits	As required for the Liberty pipeline, MBLPC can detect leaks that are as low as 1% of daily throughput. MBLPC system performance is dependent upon the accuracy of the pipeline's flow meters. With flow meter calibration, detection of leaks smaller than this 1% threshold can be accomplished.	As required for the Liberty pipeline, PPA can detect leaks that are as low as 1% of daily throughput. PPA system performance is dependent upon pump or compressor performance. With calibration and ideal pump or compressor operation, detection of leaks smaller than this 1% threshold may be accomplished.	Less effective than MBLPC	Can detect leaks that are 1% of the daily throughput even when the flow is transient.	Will not provide the required leak detection threshold of 1% daily throughput. Typically, NPWM can detect leaks on the order of 3 to 4% daily throughput for liquid lines and 10 to 15% daily throughput for gas lines.	Will detect oil or gas seepage. As little as 0.3 barrels or more of oil can be detected within a 24-hour period.
COST: Cost to the project for achieving the technology with consideration of this cost relative to the remaining years of the technology's service	Approximately $120,000 for the Leak Detection and Location software, computer, and monitor.	Approximately $120,000 for the Leak Detection and Location software, computer, and monitor.	Approximately $50,000 for the Leak Detection and Location software.	Approximately $350,000 for the Leak Detection and Location software.	Minimum of $130,000 for the Leak Detection and Location software.	Approximately $1.5 million for materials, hardware and installation.
AGE AND CONDITION: Age and condition of the technology to be used	The required software and hardware will be new when installed.	The required software and hardware will be new when installed.	The required software and hardware would be new when installed.	The required software and hardware would be new when installed.	The required software and hardware would be new when installed.	The required software and hardware would be new when installed.

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TABLE 4-5 (CONTINUED)
BEST AVAILABLE TECHNOLOGY REVIEW
PIPELINE LEAK DETECTION SYSTEM

BEST AVAILABLE TECHNOLOGY EVALUATION CRITERIA	MBLPC - MASS BALANCE LINE PACK COMPENSATION (PROPOSED)	PPA PRESSURE POINT ANALYSIS (PROPOSED)	MB - MASS BALANCE	RTTM - REAL TIME TRANSIENT MODEL	NPWM - NEGATIVE PRESSURE WAVE MONITORING	LEOS – EXTERNAL SENSING VAPOR MONITORING (PROPOSED)
COMPATIBILITY: Is technology compatible with existing operations and technologies in use or to be used on the Liberty pipelines	MBLPC is compatible with Supervisory Control and Data Acquisition (SCADA) systems. Pressure, temperature, and flow data can be transferred from Liberty's leak detection or SCADA computer via modem to the Badami - Endicott leak detection monitoring systems.	PPA is compatible with Supervisory Control and Data Acquisition (SCADA) systems. Pressure, temperature, and flow data can be transferred from Liberty's leak detection or SCADA computer via modem to the Badami - Endicott leak detection monitoring systems	MB is compatible with Supervisory Control and Data Acquisition (SCADA) systems. Pressure, temperature, and flow data can be transferred from Liberty's leak detection or SCADA computer via modem to the Badami - Endicott leak detection monitoring systems.	RTTM is compatible with Supervisory Control and Data Acquisition (SCADA) systems. Pressure, temperature, and flow data can be transferred from Liberty's leak detection or SCADA computer via modem to the Badami - Endicott leak detection monitoring systems	NPWM is compatible with Supervisory Control and Data Acquisition (SCADA) systems. Acoustic monitoring data can be transferred from Liberty's Leak detection or SCADA computer via modem to the Badami - Endicott leak detection monitoring systems.	LEOS is compatible with Supervisory Control and Data Acquistion systems. It is operated as a stand alone system with an alarm condition annunciation relay to the operations control desk.
FEASIBILITY: The feasibility of each technology in terms of engineering and other operational aspects	MBLPC is simple to implement on short pipelines (less than 20 miles long) such as the Liberty pipeline.	PPA is simple to implement on pipelines similar to the Liberty pipeline.	MB is simple to implement on short pipelines (less than 20 miles long) such as the Liberty pipeline. It is the least expensive system to install on the pipeline.	RTTM is the most difficult and costly system to implement on the Liberty pipeline.	NPWM is as expensive as the other software alternatives, but it offers the least effectiveness in detecting leaks that are 1% of pipeline flowrate.	LEOS is relatively simple to implement but requires care to protect the tube from mechanical damage during installation.
ENVIRONMENTAL IMPACTS: The environmental impacts and benefits of the technology relating to air, land, and water	<u>Impacts:</u> None: System is preventative in nature. Implementation will significantly reduce oil loss to the environment if leak were ever to occur. <u>Disadvantages Compared to Other Systems:</u> MBLPC may be slightly slower to detect leaks than PPA systems. <u>Benefits:</u> May provide comparable performance (accuracy) to an *RTTM* system *at a lower cost.* Much better performance compared to MB systems when there is significant packing and unpacking. Requires data collection in 30 or 60 second intervals for oil lines. This imposes less restriction on the SCADA system than a PPA system which requires data collection every 6 seconds or less for oil line monitoring. Can be combined with PPA monitoring.	<u>Impacts:</u> None: System is preventative in nature. Implementation will significantly reduce oil loss to the environment if leak were ever to occur. <u>Disadvantages Compared to Other Systems:</u> Oil line Monitoring will require a SCADA system that is capable of collecting data every 6 seconds or less. Leak locating will require pressure measurements every *0.25 seconds*. <u>Benefits:</u> Can compensate for monitoring the pipeline during steady packing or unpacking. Can monitor bi-directional pipelines. Can be combined with MBLPC monitoring. Fast leak detection to stop oil loss.	<u>Impacts:</u> None: System is preventative in nature. Implementation will significantly reduce oil loss to the environment if leak were ever to occur. <u>Disadvantages Compared to Other</u> Systems: MB does not perform as well as MBLPC systems. <u>Benefits:</u> Requires data collection in 30 or 60 second intervals for oil lines. This imposes less restriction on the SCADA system than a PPA system, which requires data collection every 6 seconds or less.	<u>Impacts:</u> None: System is preventative in nature. Implementation will significantly reduce oil loss to the environment if leak were ever to occur. <u>Disadvantages Compared to Other Systems:</u> N/A <u>Benefits:</u> Much better performance compared to other systems when there is predominately *transient flow*. Requires data collection in 30 or 60 second intervals for oil lines. This imposes less restriction on the SCADA system than a PPA system, which requires data collection every 6 seconds or less for oil line monitoring.	<u>Impacts</u> There is only one brief opportunity for the detection of a leak. This is when the pressure wave from a leak passes by the transducer locations. Once this pressure wave passes all of the transducer locations, the opportunity for detection is gone. Therefore this system may not perform well to stop oil loss. <u>Benefits.</u> Rapid detection time. Accurate leak location.	<u>Impacts:</u> None: The plastic LEOS tube is inert and will not affect the environment. Implementation will significantly reduce oil loss to the environment if a small leak were ever to occur. <u>Disadvantages Compared to Other Systems:</u> N/A <u>Benefits:</u> Very low detection threshold compared to other systems for a seepage leak. Provides unambiguous leak detection capability and will not be affected by false alarms. Does not require operations personnel to interpret data. System is self checking and uses a small calibration gas sample injected at the start of every measurement cycle.

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4.12 CATHODIC PROTECTION FOR PIPELINES [18 AAC 75.080(b)(1)(A)]

Table 4-6

As required by 18 AAC 75.080 (b)(1)(A), the crude oil pipeline and the buried diesel line that will be located on Liberty Island, will both be equipped with a cathodic protection system designed for the local soil conditions. The two available technologies are Passive Sacrificial Anodes and a Remote Anode Impressed Current system. Of the two, a Passive Sacrificial Anode cathodic protection system is considered to be the BAT for the Liberty pipeline. This system will provide reliable, low maintenance pipeline corrosion protection that will not damage the proposed anti-corrosion coating.

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TABLE 4-6
BEST AVAILABLE TECHNOLOGY REVIEW OF PIPELINE CATHODIC PROTECTION

BEST AVAILABLE TECHNOLOGY EVALUATION CRITERIA	PROPOSED SYSTEM: PASSIVE SACRIFICIAL ANODES	ALTERNATE METHOD: REMOTE ANODE IMPRESSED CURRENT SYSTEM
AVAILABILITY: Whether technology is used in other pipelines/applications or is available for use in the Liberty pipelines.	Frequently used on other pipelines and readily available for the Liberty pipeline.	Used on other pipelines, including the Cook Inlet pipeline. Is available for the Liberty pipeline.
TRANSFERABILITY: Is technology transferable to the Liberty pipelines	This technology was designed for buried and marine pipeline applications.	This technology was designed for buried and marine pipeline applications.
EFFECTIVENESS: Is there reasonable expectation that each technology will provide increased spill prevention or other environmental benefits	Technology is field-proven and reliable. It requires little or no maintenance and offers immediate protection of the pipeline. If required, additional anodes could be added to the pipeline to retrofit the system.	Does not offer immediate protection of the pipeline. Current generated by this system can travel only a limited distance through ice bonded permafrost.
COST: Cost to the project for achieving the technology with consideration of this cost relative to the remaining years of the technology's service	Initial cost is affordable. Requires little to no maintenance over the technology's lifetime.	Since ice bonded permafrost is a poor conductor, more cathodic protection sources will be required to protect the offshore pipeline in the nearshore, ice bonded permafrost zone. This will make the initial cost less affordable than a sacrificial anode system. Must maintain and monitor the system regularly over the technology's lifetime (i.e., groundbed, pipeline polarization, cathodic protection current). Electrical power supply and rectifier required.
AGE AND CONDITION: Age and condition of the technology to be used	All new materials.	All new materials.
COMPATIBILITY Is technology compatible with existing operations and technologies in use or to be used on the Liberty pipelines	Low cathodic protection voltage minimizes the risk of cathodic disbondment (damage) to the dual layer FBE anti-corrosion coating.	Must ensure that voltage is low enough to minimize the risk of cathodic disbondment (damage) to the dual layer FBE anti-corrosion coating.
FEASIBILITY The feasibility of each technology in terms of engineering and other operational aspects	Relatively easy to install.	Has been installed for other pipelines, however deep well anodes are typically required. These may potentially damage submerged steel used at Liberty Island.
ENVIRONMENTAL IMPACTS: The environmental impacts and benefits of the technology relating to air, land, and water	Impacts: No impacts for the buried pipeline. The Liberty pipeline will be buried in a relatively low current location, so the technology is ideal for this pipeline. Benefits: Little to no maintenance required.	Impacts: Requires continual maintenance and monitoring while in service. Benefits: Output current can be adjusted if ever required.

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APPENDIX A

BEST MANAGEMENT PRACTICES GUIDELINES

CONTINGENCY PLAN VERIFICATION LOG FOR FUEL TRANSFERS BY BARGES OR VESSELS

Contents

Provided in Appendix A are:

- Best Management Practices for Field Operations, Fuel and Hazardous Substance Storage and Transfer
- North Slope Fluid Transfer Guidelines
- North Slope Unified Operating Procedures for Surface Liner/Drip Pan Use
- Contingency Plan Verification Log for Fuel Transfers by Barges or Vessels

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BEST MANAGEMENT PRACTICES FOR FIELD OPERATIONS, FUEL AND HAZARDOUS SUBSTANCE STORAGE AND TRANSFER

Contents

BP EXPLORATION (ALASKA), INC.
BEST MANAGEMENT PRACTICES FOR FIELD OPERATIONS FUEL AND HAZARDOUS SUBSTANCE STORAGE AND TRANSFER

Comprehensive Oil Discharge Prevention and Contingency Plans have been developed and approved by the ADEC covering long-term, fixed-facility operations associated with BPXA's North Slope Operations. The four primary components to these Contingency Plans include emergency response actions, a prevention plan, supplemental information, and a Best Available Technology (BAT) analysis to aid in overall spill response. Best management practices (BMPs) for BPXA long-term activities are defined within the Prevention Plan section of the Contingency Plans for BPXA's operations. BPXA Prevention Plans include the following:

- Prevention Programs in Place
  - Prevention Training
  - Substance Abuse
  - Medical Monitoring
  - Security
  - Fuel Transfer Procedures
  - Description of Secondary Containment Areas
  - Corrosion Control
  - Inspection
  - Blowout Prevention
- Spill History
- Potential Discharge Analysis
- Conditions that Might Increase the Risk of Discharge

Existing and Proposed Discharge Detection

Exploration activities in and around BPXA's North Slope operating areas are covered under the respective Contingency Plans. For exploration activities outside of the PBU WOA, Milne Point Unit, Endicott and Badami areas, separate Contingency Plans are developed, reviewed, and approved by ADEC prior to commencement of activities.

The purpose of this plan is to describe BPXA's procedures for minimizing the potential for release of fuel or hazardous materials to the surrounding environment during short-term tundra travel projects or field operations outside of BPXA's routine North Slope operations. Fuel and chemical containers and tanks stored for seven days or longer will be stored in impermeable secondary containment, capable of containing 110 percent of the volume of the largest independent container or tank. Standard procedures for preventative maintenance and fuel or chemical transfer operations during short-term tundra travel projects and field operations are described below. These standard procedures parallel those outlined in the Prevention Plan section of BPXA's established ODPCPs. As field contingency plans are updated, the Best Management Practices for Field Operations will be updated as well. Project supervisors will ensure that employees review these procedures and have sufficient training or experience to conduct the operations. Checklists will be completed, signed, and dated by employees supervising the field operations and turned into the field HSE Supervisor, OI Environmental Compliance Advisor, or Anchorage HSE prior to commencing short-term field operations. A copy of the checklist will be maintained by both BPXA PBU North Slope Environment and Anchorage Environment.

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PREVENTIVE MAINTENANCE

Preventative maintenance for all BPXA vehicles and equipment used for BPXA's operations is an established practice. As part of this practice, maintenance for vehicles and equipment is conducted on a routine basis. Performance records, hours logged, inspections, and maintenance of vehicles and equipment are tracked as part of this program. Preventative maintenance is conducted at a shop with designated recycling and containment sumps and containers.

All contractor vehicles and equipment will be inspected according to routine operating procedures described below. Where it is necessary for repairs and maintenance to occur in the field, drip pans or liners containing other absorbent material will be used to prevent any leaks or spills that may occur from impacting the surrounding environment.

ROUTINE FIELD OPERATIONS

Whenever possible, spill prevention equipment, such as dry-disconnect fittings, positive closing valves, valve caps, and hose-end caps, will be used. All containers and tanks will be marked or labeled with their contents. In addition, all drums and tanks will be labeled with the permittee's name, user's name, the manufacturer's name, and maximum volumes or capacities. All stationary drums and tanks will be labeled with the date they were placed into storage. All valves, vents, drains and overflows will be marked with open and closed positions. At a minimum, sufficient amounts of absorbent and spill recovery materials will be kept on site to respond to 5-gallon spills. A sufficient quantity of spill response equipment to respond to the maximum spill possible will be available within the North Slope operating area.

Prior to operations, sites will be assessed to determine the best possible location to stage vehicles and equipment to allow for adequate protection of water bodies, wet tundra locations, and wildlife habitats. Wherever possible, vehicle and equipment staging as well as refueling will be conducted at least 100 feet away from water bodies. An initial inspection will be conducted of vehicles, vessels, vessel hatches, drums, containers, valves, hoses, connections, and associated piping to ensure they are properly connected and no leaks or drips are present. Equipment will be positioned so that valves, piping, tanks, etc., are not exposed to vehicular traffic where they might be damaged by vehicles or heavy equipment. Volume measuring methods and devices for storage tanks will be identified. Unattended operating equipment will either be operated on impermeable surfaces or liners will be placed under the equipment in areas where leakage may occur. If operations occur on a pad, whenever possible equipment will be placed sufficiently far away from the edge of the pad to prevent spills from running off the pad should a spill occur.

Daily visual inspections will be conducted of vehicles, equipment, absorbents, drip pans, and liners for signs of system malfunctions, leaks, or drips. If necessary to prevent a spill or potential malfunction, the operation will be shut down to investigate and stop a leak or drip. Off-pad over night vehicle parking will require confirmation as to the integrity of the vehicle's fluid systems. If the systems indicate a drip or leak potential, liners will be placed under the vehicle.

Prior to demobilization, all equipment, hoses, or other associated piping and connections will be properly purged. Absorbents, liners, tools, stakes, wastes, and other debris will be removed from the site after the project is complete. The intent will be to leave the site as it was found with no debris or impact.

Absorbent materials contaminated with fuel or other chemicals will be collected and stored in non-leaking containers or designated bags. Employees will contact the HSE Supervisor for guidance to properly manage materials or dispose of wastes resulting from operations.

If a spill occurs, it will be reported and cleaned up by the responsible party on site or by the Spill Response Team in accordance with all applicable federal, state, and local regulations and the supporting business unit's Oil Discharge Prevention and Contingency Plan. Employees will immediately report all spills by radio or phone to their supervisor, Security, or PBU (659-2222).

An inspection of field operating sites will be conducted by BPXA Anchorage HSE subsequent to demobilization, and in spring should demobilization occur in winter, to ensure that no environmental damage has been caused by the field operations.

TRANSFER PROCEDURES

The primary prevention mechanism against discharge during the transfer of liquids is the use of surface liners at all inlet and outlet points. Beginning August 21, 1991, the use of surface liners was made mandatory for all BPXA North Slope transfer operations. Surface liners, also known as drip liners, protect the ground surface from contamination in the even of a leak or spill during fuel and chemical transfer procedures. All hose connections and ends must have a liner under the connection points before transfer begins. The Environmental Office identifies areas that require use of a liner during transfer procedures with facility tags. The use of liners is mandated for all:

- Vac Trucks
- Fuel Trucks
- Sewage Trucks
- Chemical Delivery Units
- Chemical Transfer Units
- Fluid Transfers within Facilities areas

BPXA supplies contract companies with liners and provides training for proper use. In addition to the use of surface liners, fuel and chemical transfer operations will be monitored by on-site personnel throughout the transfer procedure. Prior to beginning transfer operations, all tank and container levels will be checked to prevent overfilling. Tank levels, containments, liners, and piping will be inspected both before and after each transfer for signs of fuel or chemical loss, leakage, or failure.

BEST MANAGEMENT PRACTICE REVIEW PROCEDURE

The above procedures will be reviewed annually by PBU Environment, Endicott Environment, Milne Point Unit Environment, Badami Environment, Anchorage Environment, and operations personnel to ensure they are the best methods and procedures for preventing the release of fuel or hazardous materials. Periodic analyses of database records of previous spills, analyses of spill prevention control procedures, and new technologies will be used to modify these procedures as needed during reviews.

Questions, modifications, or comments should be directed to Anchorage HSE at 564-5326 (Fax: 564-5020).

BEST MANAGEMENT PRACTICES FOR FIELD OPERATIONS EMPLOYEE CHECKLIST

This checklist is required for all off-gravel pad projects which will be staged for less than 7 days. Fuel or chemical containers or tanks stored for 7 days or longer must be stored within impermeable secondary containment capable of containing 110% of the volume of the largest independent container or tank. Immediately notify your supervisor of discrepancies or items that cannot be checked off or completed.

Initial Vehicle and Equipment Inspection

_____ Check the vehicle/equipment you are using to ensure that it has been properly maintained, that all parts appear to be in good condition, and that hoses and connections are properly connected and do not show signs of wear or stress.

_____ Read and closely follow all operating procedures for vehicles/equipment you will be using.

_____ When possible, use spill prevention equipment in the system such as, dry-disconnect fittings, positive closing valves, valve caps, and hose end caps.

_____ Check that containers and storage tanks are marked or labeled with their contents. In addition, check that all drums and tanks are labeled with the permittee's name, user's name, manufacturer's name, maximum volumes or capacities. All stationary drums and tanks will be labeled with the date they were placed into storage. Do not use unmarked containers or tanks.

_____ Identify volume measuring devices and methods for storage tanks and prepare strapping chart when necessary.

_____ Mark or label all valves, vents, drains, and overflows with open and closed positions.

On-Site Inspections and Operations

_____ Obtain proper permit, approval, or special precautions from the field environmental office prior to conducting off-gravel pad operations (i.e., placing or excavating gravel or tundra, drilling holes, traveling on tundra or snow, placing signs).

_____ Wherever practical, vehicles and equipment will be staged at least 100 feet away from water bodies.

_____ Prior to starting up the system, inspect vehicles, vessels, vessel hatches, drums, containers, valves, hoses, connections, and associated piping to ensure they are properly connected and in proper positions.

_____ Maintain adequate amounts of absorbent and spill recovery materials at the site.

_____ Conduct daily (walk-around) inspections of all vehicles/equipment, absorbents, drip pans, and liners that are being used for signs of system malfunctions or leaks or drips. If necessary to prevent a spill or potential malfunction in the system, shut down the entire operation to investigate and stop a leak or drip.

_____ Off-pad parking of vehicles will require inspection for leaks and drips. If such is noted, drip pans or portable liners, will be strategically placed under the potential leak source.

_____ On-site containers must be properly stored and secured. Whenever practical, liners will be placed beneath containers.

_____ Fluid containers must be properly stored and secured during transport.

Fuel or Chemical Transfer Operations

_____ Two persons are required to conduct large fluid transfers (bulk product transfers), an equipment operator and observer, who must maintain constant communication by established methods (i.e., voice, radios, or hand signals) throughout the operation.

_____ Ensure that all ignition sources have been moved a safe distance away from the transfer operations and that fire extinguishers are available.

_____ Use proper bonding and grounding procedures.

_____ Prior to transfers, check all tank and container levels, valves, vessel hatches, and vents to prevent overfilling.

_____ Conduct brief safety meeting with delivery personnel to brief them on their role in the transfer procedure.

_____ Use portable liners or drip pans under all connections, openings, and vents to contain potential splashes, leaks, or drips. Absorbent pads should be placed inside liners or drip pans to absorb any liquids.

_____ Maintain a constant line-of-site to all transfers throughout the transfer process. Transfer operations must not be left unattended.

_____ Check all tank and container levels, containment, and piping after each transfer for signs of fuel or chemical loss, leakage, or failure.

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De-Mobilizing Site Operations

_____ Prior to demobilizing the system, properly purge all equipment, hoses, connections, and associated piping.

_____ After the project is complete, remove all absorbents, liners, tools, stakes, wastes, or other debris resulting from operations. Leave the site as it was found with no debris or impact.

If a small spill occurs, immediately report it by radio or phone to your supervisor, Security, or PBU (659-2222). Follow the procedures in the supporting business unit's Oil Discharge Prevention and Contingency Plan. Provide written report to Endicott within 24 hours of the event.

Collect all absorbent materials contaminated with fuels or chemicals in non-leaking containers or designated bags. Contact the HSE Supervisor for guidance to properly manage materials or dispose of wastes resulting from operations.

Questions, comments, or modifications should be directed to the Badami HSE Manager at 659-1266.

Project: ______________________________

Checklist Completed By:

____
Print Name

____
Company Name

____
Signature

____
Date

Turn checklist into the Liberty HSE Manager or Anchorage HSE at MB 11-6 prior to initiating project. The checklist can be faxed to 564-5020 (Anchorage Environment).

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NORTH SLOPE FLUID TRANSFER GUIDELINES

NORTH SLOPE FLUID TRANSFER GUIDELINES

FEBRUARY 15, 1993

Note: SAFETY is the first and foremost goal in all operations, including the transfer of all fluids. It is EVERYONE'S responsibility to ensure all related safety and environmental guidelines are being followed at all times.

1) Check your vehicle and/or equipment. Ensure that it is has been properly maintained and that there are no leaking parts. **If your vehicle or equipment does not appear to be in proper order and leaks are apparent, stop the job and have adequate repairs done.** In accordance with field operating procedures, a surface liner may be used for a short period of time under critical use equipment.

2) Stage vehicles away from water bodies, tundra and wildlife habitats. Staging or parking of vehicles and equipment in off-pad locations or on-pad edges should be avoided whenever possible.

3) Position equipment so that valves, piping, tanks, etc., are protected from damage by other vehicles or heavy equipment.

4) Verify that you have adequate secondary containment and absorbent pads on hand. Utilize as per published field operating procedures.

5) Before starting any fluid transfer operation, inspect all hoses, connections, valves, etc. Ensure that these items have been properly maintained; gaskets are present and in good shape; all valves are checked to insure they're in the proper on/off position, and that each connection is tightened properly.

6) Prior to the actual fluid transfer, check all tank and container levels, valves, and vents to prevent overfilling or accidental releases.

7) Use secondary containment under all appropriate connections, vents or any other likely source of spillage. Use as many secondary containers as are practical, or as are required per the published field operating procedures.

8) Upon starting the transfer of liquids, keep line of sight with operator and/or all connections, hoses, vents or any other likely source of spillage. Be prepared to stop proceedings if any leak is noticed. **Do not attempt to repair a leaking situation while fluid is being transferred. Stop operations to fix leaks!**

9) Maintain a constant line-of-sight with critical components throughout the transfer. **Transfer operations must not be left unattended.**

10) After transfer is complete, take every precaution while breaking connections. Secondary containment and absorbent pads must continue to be used until the rigging down process is complete.

11) Check all tank and container levels after each transfer for signs of spills. Immediately report all spills to the Field Environmental group in your area.

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NORTH SLOPE UNIFIED OPERATING PROCEDURES
FOR
SURFACE LINER/DRIP PAN USE

Contents

NORTH SLOPE UNIFIED OPERATING PROCEDURE

UOP Number 1-93
ISSUE DATE: April 2, 1993

Subject: Surface Liner/Drip Pan Use
Scope: Field-wide

ISSUING AUTHORITY

☐	ARCO-EOA	Signature	Reference hard copy
☐	ARCO-KUP	Signature	Reference hard copy
☐	BP-END	Signature	Reference hard copy
☐	BP-WOA	Signature	Reference hard copy
☐	CONOCO	Signature	Reference hard copy

PURPOSE
To insure the proper use of surface liners and/or drip pans to provide secondary containment, maintain contaminant-free work sites and to instill proper spill prevention techniques during normal North Slope field operations.

APPLICABILITY

These procedures apply to all North Slope assigned (company and contract) personnel involved in field operations and maintenance. Also included are construction contractors, drilling rigs, and contractors servicing rigs. These procedures pertain to normal field operations, construction projects, drilling operations, temporary storage and/or transfer of fluids, and the staging of equipment (operating or parked).

DEFINITION

A surface liner is any safe non-permeable container (drip pan, bucket, fold-a-tank, built-in secondary containment system, etc.) designed to catch/hold fluids, for the purpose of preventing spills that may result in a negative environmental impact.
Reasonable or appropriately sized surface liners means operator discretion based on worst case spill risk and probability factors.

EXCEPTIONS

Liner use practices do not apply to connections and other tank discharge points when it involves the pickup or delivery of potable or raw water. This exception does not exempt the mechanical integrity of the equipment being used for such projects, nor does the exception apply to any other related product such as sewage or sea water. Drilling ice pads will fall into the category of, and comply with the procedures set forth in, Section II of this DOP. This applies to the pad only. Ice road activity will continue to be regulated under Section I.

RESPONSIBILITIES

Supervisors are responsible for ensuring all employees under their supervision adhere to this policy. Additionally, geographic assignments will be made for DOP compliance monitoring in specific areas when under the control of a single employee. It is the general responsibility of all employees, contractors, drilling contractors, service contractors, and construction contractors working within the North Slope operating areas to adhere to the rules as set forth in this policy

NORTH SLOPE UNIFIED OPERATING PROCEDURE

UOP Number 1-93 **Subject: Surface Liner/Drip Pan Use**
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PROCEDURES

The following procedures pertain to operational requirements for all equipment and fluid transfers. The objective is that maximum ground surface protection be provided. Surface liners will be utilized to meet this requirement.

Surface liners should be of adequate size and volume to catch and hold a potential spill of probable size as determined reasonable by the equipment operator.

I. Off-pad locations where high potential for tundra damage exists. Maximum protection of the tundra and surface waters is the primary objective and the highest priority. All equipment stationary on off-pad sites (operating or parked and running) will utilize surface liners under the radiator, engine, or other areas of potential spillage/leakage when said equipment remains stationary for one hour or more. All parked, non-operating equipment will utilize liners as needed for the prevention of small spills and/or spotting of work sites. Equipment known to leak will be immediately released from the job. Appropriately sized liners are specifically required:

A. Under all support equipment (heaters, compressor, generators, etc.).

B. Under heavy and light duty parked equipment (dozers, loaders, cranes, trucks, etc.).

C. During all fluid transfers utilizing vac trucks, fueling trucks, tank transfers, pumping operations, etc. This includes the transfer of all freeze protection fluids, hydro-testing fluids, and sea-water. Appropriately sized liners are required at all connection points from the beginning of hook-up through time of disconnection.

D. Under fluid containers (55 gal. drums, day fuel tanks, etc.) in support of any given operation.

NOTE: Over-night or term parking of vehicles and equipment off pad is to be avoided whenever possible.

II. All well pads, facilities, and other job sites located on gravel based pads. Protection of the pad must be provided by use of appropriately sized surface liners or drip pans during all active field operations (examples listed below). The primary objectives are good housekeeping practices, clean job sites, and spill prevention. All equipment leaking fluids will have liners placed under the appropriate areas whenever the unit is stationary. This is a temporary measure only and is not intended to be a practice in lieu of proper maintenance. Equipment known to leak (because of poor maintenance), or where a traditional high risk of spills exists during operation, will be released from the job site if liners or drip pans are not available and placed in use.

A. Operation of well service equipment (wireline, slickline, chemical trucks, coil tubing units, etc.).

B. Under all support equipment not equipped with built-in containment systems (heaters, compressors, bleed tanks, etc.).

C. Under all stationary heavy equipment (loaders, cranes, vac-trucks, supersuckers, etc.).

D. Liners are required at all connection points from the beginning of hook-up to the time of disconnect during all fluid transfers. This includes vac-trucks, fuel trucks, tank transfers, and other pumping operations such as the transfer of freeze protection fluids, hydro-testing fluids, and sea-water. Liners are required at all swivel, manifold, tank, truck, and vessel connections. Hammer union type connections between two straight joints will typically not require a protective liner but operator discretion should be exercised.

E. Under all drums actually being used as primary containment for excess or waste fluids (bleed backs, pressure relief, or temporary storage).

NORTH SLOPE UNIFIED OPERATING PROCEDURE

III. Parking along the bullrails at all camps and facilities. Appropriately sized surface liners or drip pans will be required, regardless of whether the units are running or not, for the following applications:

A. Any vehicle dripping engine oil or other fluids.

Note: This is a temporary measure, only acceptable until maintenance can be scheduled and the vehicle repaired.

B. All heavy equipment dripping engine oil or other fluids.

Note: This is a temporary measure, only acceptable until maintenance can be scheduled and the equipment repaired.

C. Support equipment (heaters, compressors, light plants) dripping engine oil or other fluids.

Note: This is a temporary measure, only acceptable until maintenance can be scheduled and the units repaired.

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NORTH SLOPE UNIFIED OPERATING PROCEDURE

SITE-SPECIFIC PROCEDURES

I. Fuel pump area. Liners are required during all fueling operations at the fuel pumps.

Note: A marked drum will be placed at the fuel pumps for sorbent disposal. The Environmental Department will monitor and dispose of the sorbents on a regular basis. If the drum is full, contact the Environmental representative for disposal.

II. Surface liner availability

A. 18-in. x 18-in. and 4-ft. x 5-ft. surface liners are available through the material operations warehouse. These liners will be charged directly to the individual department cost code.

B. A supply of surface liners will be available at the fuel pumps to be used during fill-up operations.

C. NS Environmental will maintain a supply of 18-in. x 18-in. surface liners, 4-ft. x 5-ft. surface liners, and 1,500 gallon fold-a-tanks. These containment units are for check-out on a short term basis (less than 72 hours). If not returned in 72 hours, the department authorizing issuance will be charged for replacement. Specifications for these items are as follows:

1. An 18-in. x 18-in. surface liner is approx. 1.5-in. deep and is designed to hold one 18-in. x 18-in. sorbent pad. Primary use is for small drips (under engine, transmission, hydraulic connections) where total volume is expected to be less than 1/2 pint. Liner capacity is approximately two gallons and cannot be picked up when full of fluid.

2. A 4-ft. x 5-ft. surface liner is approx. 4-in. deep, has cleats and sandbags to hold liner in place, and a corrugated mat inside for operator safety. Liner is designed to be used during fluid transfers (vac truck to unit or tank to vac truck). Liner capacity is approx. 49 gallons and cannot be picked up or moved when full of liquid.

3. 1,500 and 3,000 gallon fold-a-tank liners are designed for jobs where larger releases are possible (pipeline repairs, valve replacements, etc.). These jobs must be coordinated through the Environmental Department, as special monitoring procedures may be required.

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CONTINGENCY PLAN VERIFICATION LOG FOR FUEL TRANSFERS BY BARGES OR VESSELS

Contents

State of Alaska

Department of Environmental Conservation

Contingency Plan Verification Log

This log is to be completed by terminal facility owners/operators who are subject to the requirements of AS 46.04.030 and 18.AAC 75, Article 4, and who load or unload tank vessels or oil barges carrying petroleum products as cargo in Alaska waters. Completion of this form is required by 18 AAC 75.465, which is printed on Page 2.

PLEASE TYPE OR PRINT CLEARLY

Month/Year ______________________

Terminal Name: ______________________

Terminal Owner: ______________________

Terminal Address: ______________________

DATE	NAME OF VESSEL	VESSEL CONTINGENCY PLAN HOLDER (Company Name) (Please Print)	VESSEL OPERATOR SIGNATURE	TERMINAL OWNER OR OPERATOR SIGNATURE

VESSEL OPERATOR, by signature, hereby certifies that a current copy of the response action plan section of the current approved oil discharge prevention and contingency plan for that vessel or barge is onboard the vessel or barge.