



BP EXPLORATION (ALASKA) INC.

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

**MILNE POINT UNIT
NORTH SLOPE, ALASKA**

VOLUME 1 OF 2, RESPONSE ACTION PLAN

OCTOBER 2011



BP EXPLORATION (ALASKA), INC.

**MILNE POINT UNIT
OIL DISCHARGE PREVENTION
AND
CONTINGENCY PLAN**

Volume 1 of 2, Response Action Plan

OCTOBER 2011

BP EXPLORATION (ALASKA), INC.**MILNE POINT UNIT
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN****MANAGEMENT APPROVAL AND RESOURCE COMMITMENT STATEMENT**

This plan is consistent with the requirements of the National Contingency Plan and the Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges / Releases (Area Contingency Plan). It 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 oil spill response will be based on the following priorities:

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

Bruce Price
Area Operations Manager
Milne Point Unit



Date

10/25/11

BP EXPLORATION (ALASKA), INC.

P.O. Box 196612
Anchorage, Alaska 99519

900 East Benson Boulevard
Anchorage, Alaska 99508

(907) 564-5111 – telephone

THIS PAGE INTENTIONALLY LEFT BLANK

RECORD OF REVISIONS – VOLUME 1

REVISION NUMBER	REVISION DATE	SUMMARY OF REVISION CHANGE
1	July 2012	Introduction: - The plan amendment process was updated to clarify that holders of electronic copies will receive replacement CDs; - The ODPCP expiration date was corrected; Part 1: - Job titles, names and phone numbers were updated; - In Section 1.1 (Emergency Action Checklist), the term “tier” was corrected to “level” as it pertains to BPXA spill response operations; - A sentence was added to Figure 1-2 describing how the Incident Management Team is activated. - Section 1.6.3, clarified that waste management guidance is found in the “Alaska Waste Disposal and Reuse Guide;” - Table 1-18 was corrected to show accurate oil recovery rates; - Table 1-20 was corrected to show accurate number of dump truck operators per shift; - Table 1-22 was corrected to indicate disposal/recycle options for recovered fluids; - Table 1-23 was corrected to show accurate oil recovery rate; Part 3: - Language describing the Incident Management Team management structure was clarified; - Language in Section 3.3 (Command System) was clarified for Incident Management Team Member Training; - Table 3-8 (North Slope Incident Management System Training Modules) was added; and Part 4: - Language in Section 4.3 (Trajectory Analyses and Forecasts) was updated to better describe the process.
2	Sept. 2012	Introduction: - Figure I-1 was replaced with an updated Milne Point Area Map; Part 1: - Table 1-23 (Capability of Oil Recovery – Crude Oil Transmission Pipeline Spill During Summer) was updated to reflect the oil recovery rate per unit to 24 barrels of oil per hour (boph) from 236 boph for Crucial Disc C 13/24; and Part 4: - Part 4.4, Wildlife Capture and Release Program, was updated to reflect BAT references in Volume 2.
3	January 2013	Updates to Table 1-2 (BPXA Contact List).

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS – VOLUME 1

MANAGEMENT APPROVAL AND RESOURCE COMMITMENT STATEMENT	i
RECORD OF REVISIONS – VOLUME 1	ROR-1
LIST OF FIGURES – VOLUME 1	TOC-4
LIST OF TABLES – VOLUME 1	TOC-5
LIST OF ACRONYMS – VOLUME 1	TOC-7
INTRODUCTION.....	I-1
Plan Distribution	I-4
Updating Procedures.....	I-4
Plan Renewal	I-5
State of Alaska Approval Letter	I-7
Alaska Clean Seas Statement of Contractual Terms.....	I-9
PART 1. RESPONSE ACTION PLAN [18 AAC 75.425(e)(1)]	1-1
1.1 EMERGENCY ACTION CHECKLIST [18 AAC 75.425(e)(1)(A) AND 40 CFR 112.20(h)].....	1-1
1.2 REPORTING AND NOTIFICATION [18 AAC 75.425(e)(1)(B) AND 40 CFR 112.20(h)(1) AND (3)]	1-8
1.2.1 Internal Notification Procedures	1-8
1.2.2 External Notification Procedures	1-8
1.2.3 Qualified Individuals [40 CFR 112.20(h)].....	1-8
1.2.4 Reporting Requirements.....	1-14
1.3 SAFETY [18 AAC 75.425(e)(1)(C) AND 40 CFR 112.20(h)(3)]	1-15
1.4 COMMUNICATIONS [18 AAC 75.425(e)(1)(D)].....	1-16
1.5 DEPLOYMENT STRATEGIES [18 AAC 75.425(e)(1)(E)].....	1-17
1.6 RESPONSE SCENARIOS AND STRATEGIES [18 AAC 75.425(e)(1)(F) AND 40 CFR 112.20(h)(5)]	1-19
1.6.1 Qualifier Statement	1-19
1.6.2 Response Planning Standard [18 AAC 75.430]	1-19

Milne Point Unit ODPCP Volume 1 – Response Action Plan

1.6.3	Waste Disposal Approval [40 CFR 112.20(h)(7)(iii)]	1-19
1.6.4	Response Scenarios and Strategies	1-20
	Scenario 1 Oil Tank Rupture during Typical Summer Conditions	1-23
	Scenario 2 Production Well Blowout during Typical Summer Conditions	1-31
	Scenario 3 Production Well Blowout during Typical Winter Conditions	1-41
	Scenario 4 Crude Oil Transmission Pipeline Spill during Summer	1-51
	Response Strategy 1 Production Well Blowout during Open Water Conditions	1-67
	Response Strategy 2 Production Well Blowout to Broken Ice	1-67
	Response Strategy 3 Flowline Rupture Over Central Creek to Open Water	1-73
1.7	NON-MECHANICAL RESPONSE OPTIONS [18 AAC 75.425(e)(1)(G)]	1-78
1.8	FACILITY DIAGRAMS	1-79
1.9	RESPONSE SCENARIO FOR AN EXPLORATION OR PRODUCTION FACILITY [18 AAC 75.425(e)(1)(I)]	1-80
1.9.1	Response Strategy for Well Blowout Control	1-80
1.9.2	Response Scenarios for Well Blowouts	1-81
PART 3.	SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)]	3-1
3.1	FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]	3-1
3.2	RECEIVING ENVIRONMENT [18 AAC 75.425(e)(3)(B)]	3-2
3.2.1	Potential Routes of Discharges [18 AAC 75.425(e)(3)(B)(i)]	3-2
3.2.2	Estimate of Response Planning Standard Volume to Reach Open Water [18 AAC 75.425(e)(3)(B)(ii)]	3-2
3.3	COMMAND SYSTEM [18 AAC 75.425(e)(3)(C) AND 40 CFR 112.20(h)(7)]	3-3
3.4	REALISTIC MAXIMUM RESPONSE OPERATING LIMITATIONS [18 AAC 75.425(e)(3)(D)]	3-5
3.4.1	Introduction	3-5
3.4.2	Weather and Ice Conditions During the Shoulder Seasons	3-5
3.4.3	In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions	3-6
3.5	LOGISTICAL SUPPORT [18 AAC 75.425(e)(3)(E) AND 40 CFR 112.20(h)(7)]	3-12
3.6	RESPONSE EQUIPMENT [18 AAC 75.425(e)(3)(F) AND 40 CFR 112.20(h)(7) AND (h)(8)]	3-13
3.6.1	Equipment Lists	3-13
3.6.2	Maintenance and Inspection of Response Equipment	3-13
3.6.3	Pre-Deployed and Pre-Staged Equipment	3-13
3.7	NON-MECHANICAL RESPONSE INFORMATION [18 AAC 75.425(e)(3)(G) AND 40 CFR 112.20(h)(7)]	3-15
3.7.1	Environmental Consequences	3-15
3.7.2	Operational Capability	3-16

Milne Point Unit ODPCH Volume 1 – Response Action Plan

3.7.3	Effectiveness of In Situ Burning in Ice	3-16
3.8	RESPONSE CONTRACTOR INFORMATION [18 AAC 75.425(e)(3)(H) AND 40 CFR 112.20(h)(3)]	3-17
3.9	RESPONSE TRAINING AND DRILLS [18 AAC 75.425(e)(3)(I) AND 40 CFR 112.20(h)(8)]	3-18
3.9.1	North Slope Spill Response Team Training	3-18
3.9.2	Incident Management Team Member Training	3-21
3.9.3	Spill Response Exercises	3-23
3.10	PROTECTION OF ENVIRONMENTALLY SENSITIVE AREAS [18 AAC 75.425(e)(3)(J)].....	3-26
3.11	ADDITIONAL INFORMATION [18 AAC 75.425(e)(3)(K)].....	3-27
3.12	BIBLIOGRAPHY [18 AAC 75.425(e)(3)(L)]	3-28
PART 4.	BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]	4-1
4.1	COMMUNICATIONS [18 AAC 75.425(e)(4)(A)(i)].....	4-1
4.2	SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(i)]	4-1
4.2.1	Well Source Control.....	4-1
4.2.2	Crude Oil Transmission Pipeline Source Control	4-7
4.2.3	Tank Source Control.....	4-9
4.3	TRAJECTORY ANALYSES AND FORECASTS [18 AAC 75.425(e)(4)(A)(i)]	4-11
4.4	WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS [18 AAC 75.425(e)(4)(A)(i)]	4-12
PART 5.	RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)].....	5-1
5.1	OIL STORAGE TANK [18 AAC 75.432]	5-1
5.2	WELL BLOWOUT [18 AAC 75.434]	5-1
5.3	CRUDE OIL TRANSMISSION PIPELINE [18 AAC 75.436].....	5-1
FEDERAL FACILITY RESPONSE PLANS		

LIST OF FIGURES – VOLUME 1

I-1:	Milne Point Unit Area Map	I-3
1-1:	Immediate Spill Notifications and Reporting	1-5
1-2:	MPU Incident Management Team	1-6
1-3:	North Slope Spill Report Form	1-13
1-4:	Milne Point Unit Central Facilities Pad Oil Reserve Tank Rupture Scenario	1-30
1-5:	Wind Direction during Summer	1-39
1-6:	Milne Point Unit E Pad Production Well Blowout during Typical Summer Conditions	1-40
1-7:	Wind Direction during Winter	1-49
1-8:	Milne Point Unit E Pad Production Well Blowout during Typical Winter Conditions	1-50
1-9:	Crude Oil Transmission Pipeline Scenario	1-60
1-10:	Milne Point Unit Central Creek Flowline Leak Response Strategy	1-77
1-11:	Well Capping Decision Tree	1-83
5-1:	Cross Section of Milne Point Unit Crude Oil Transmission Pipeline	5-2

LIST OF TABLES – VOLUME 1

1-1:	Immediate Response Checklist	1-2
1-2:	BPXA Contact List.....	1-7
1-3:	Agency Reporting Requirements for Oil Spills.....	1-10
1-4:	Radio Equipment.....	1-16
1-5:	Seasonal Transportation Options	1-17
1-6:	Oil Tank Rupture During Typical Summer Conditions Scenario Conditions	1-25
1-7:	Response Strategy - Oil Tank Rupture During Typical Summer Conditions.....	1-26
1-8:	Capability of Oil Recovery – Oil Tank Rupture	1-28
1-9:	Major Equipment Equivalents to Meet the Response Planning Standard.....	1-29
1-10:	Staff to Operate Oil Recovery and Transfer Equipment	1-29
1-11:	Production Well Blowout During Typical Summer Conditions Scenario Conditions	1-33
1-12:	Response Strategy - Production Well Blowout During Typical Summer Conditions.....	1-34
1-13:	Capability of Oil Recovery – Production Well Blowout During Typical Summer Conditions	1-37
1-14:	Major Equipment Equivalents to Meet the Response Planning Standard.....	1-38
1-15:	Staff to Operate Oil Recovery and Transfer Equipment	1-38
1-16:	Production Well Blowout During Typical Winter Conditions Scenario Conditions.....	1-43
1-17:	Response Strategy – Production Well Blowout During Typical Winter Conditions	1-44
1-18:	Capability of Oil Recovery – Production Well Blowout During Typical Winter Conditions	1-47
1-19:	Major Equipment Equivalents to Meet the Response Planning Standard.....	1-48
1-20:	Staff to Operate Oil Recovery and Transfer Equipment	1-48
1-21:	Crude Oil Transmission Pipeline Spill During Summer Scenario Conditions.....	1-53
1-22:	Response Strategy – Crude Oil Transmission Pipeline Spill During Summer	1-54
1-23:	Capability of Oil Recovery – Crude Oil Transmission Pipeline Spill During Summer	1-57
1-24:	Major Equipment Equivalents to Meet the Response Planning Standard.....	1-58
1-25:	Staff To Operate Oil Recovery and Transfer Equipment.....	1-59
1-26:	Response Strategy – Production Well Blowout During Open Water Conditions.....	1-63
1-27:	Response Strategy - Production Well Blowout During Broken Ice Conditions.....	1-69
1-28:	Response Strategy - Flowline Rupture Over Central Creek to Open Water	1-75
1-29:	Well Firefighting and Capping Equipment List.....	1-82
3-2:	Minimum Ignitable Thickness on Water	3-8
3-3:	Burn/Removal Rates for Large Fires on Water.....	3-9

Milne Point Unit ODPCP Volume 1 – Response Action Plan

3-4:	Fire Extinguishing Slick Thickness	3-9
3-5:	Safe Distances between In Situ Burns and Downwind Human Populations on Flat Terrain: Location of Fire Zones	3-16
3-6:	North Slope Spill Response Team Minimum Staffing Levels	3-18
3-7:	North Slope Spill Response Team Training Program Courses	3-22
3-8:	Nable 3-8: North Slope Spill Response Team Training Program Courses	3-22
4-1:	Best Available Technology Analysis – Well Blowout Source Control.....	4-5
4-2:	Best Available Technology Analysis – Crude Oil Transmission Pipeline Source Control.....	4-8
4-3:	Best Available Technology Analysis – Tank Source Control.....	4-10

LIST OF ACRONYMS – VOLUME 1

AAC	Alaska Administrative Code
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
ADFG	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
ADW	Alaska Drilling and Wells
AOGCC	Alaska Oil and Gas Conservation Commission
AOM	Area Operations Manager
API	American Petroleum Institute
ARRT	Alaska Regional Response Team
ASTM	American Society for Testing and Materials
ATV	all-terrain vehicles
BAT	best available technology
bbl	barrels
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BOP	blowout preventer
bopd	barrels of oil per day
BOPE	blowout prevention equipment
boph	barrels of oil per hour
BPXA	BP Exploration (Alaska), Inc.
BST	Business Support Team
°C	degrees Celsius
CFP	Central Facilities Pad
CFR	Code of Federal Regulation
COTP	Crude Oil Transmission Pipeline
COTU	Crude Oil Topping Unit
CS	containment site
DOT	U.S. Department of Transportation
DS	drill site
EPA	U.S. Environmental Protection Agency
ERD	extended reach drilling
ESI	environmental sensitivity index
°F	degrees Fahrenheit
FCP	Forward Command Post
FLIR	forward-looking infrared
FOSC	federal on-scene coordinator
GC	gathering center
G & I	grind and inject
GOR	gas-to-oil ratio
GPB	Greater Prudhoe Bay Unit
gpm	gallons per minute
GPS	global positioning system
HAZWOPER	Hazardous Waste Operations and Emergency Response

Milne Point Unit ODPCP Volume 1 – Response Action Plan

HSSEE	Health, Safety, Security, Environment and Engineering Department
HSE	Health, Safety, and Environment
IBRRC	International Bird Rescue Research Center
IC	Incident Commander
ICP	Incident Command Post
ICS	Incident Command System
IMS	Incident Management System
IMT	Incident Management Team
LEL	lower explosive limit
LOSC	Local On-Scene Coordinator
MAD	Mutual Aid Drill
MESA	most environmentally sensitive area
mm/min	millimeters per minute
mPa/s	milli pascals per second
MMS	U.S. Minerals Management Service
MPU	Milne Point Unit
NPDES	National Pollutant Discharge Elimination System
NPREP	National Preparedness for Response Exercise Program
NRC	National Response Center
NSB	North Slope Borough
NSSRT	North Slope Spill Response Team
ODPCP	Oil Discharge Prevention and Contingency Plan
OIM	Offshore Installation Manager
OPA 90	Oil Pollution Act of 1990
ORR	oil recovery rate
ORT	oil reserve tank
OSHA	Occupational Safety and Health Administration
OSM	Onshore Site Manager
OSRO	Oil Spill Removal Organization
PLC	programmable logic controller
PPE	personal protective equipment
PS1	Pump Station 1
QI	Qualified Individual
RPIC	responsible party incident commander
RPS	response planning standard
SCAT	Shoreline Cleanup Assessment Technology
SOSC	state on-scene coordinator
SPCC	spill prevention, control, and countermeasure
SPCO	State Pipeline Coordinator's Office
SRT	Spill Response Team
USC	United States Code
USCG	U.S. Coast Guard
VHF	Very High Frequency
VSM	vertical support member
WAG	water-alternating-gas

INTRODUCTION

This Oil Discharge Prevention and Contingency Plan (ODPCP) covers the Milne Point Unit (MPU), which is located within the North Slope Borough on the Arctic coast of Alaska, 280 miles north of the Arctic Circle, 200 miles west of the Alaska-Canada border and 25 miles northwest of Prudhoe Bay (Figure I-1). MPU is comprised of a Central Facilities Pad (CFP) containing the operations center and central processing facility and 13 gravel well pads with approximately 120 wells. BP Exploration (Alaska), Inc. (BPXA) owns and operates 100 percent of MPU.

The ODPCP addresses oil spill prevention and response requirements promulgated by the State of Alaska in Title 18, Chapter 75 of the Alaska Administrative Code (AAC). It is comprised of five parts consistent with 18 AAC 75.425(d)(2). As allowed under 18 AAC 75.425(e)(2), the ODPCP is represented by two volumes: Volume 1, Response Action Plan, and Volume 2, Prevention Plan. The Response Action Plan (Volume 1) is contained herein.

The Response Action Plan also addresses federal oil spill planning regulations of the U.S. Environmental Protection Agency (EPA) under 40 Code of Federal Regulation (CFR) Part 112.20, and U.S. Department of Transportation (DOT) under 49 CFR Part 194, Subpart B, Sections 109 and 113.

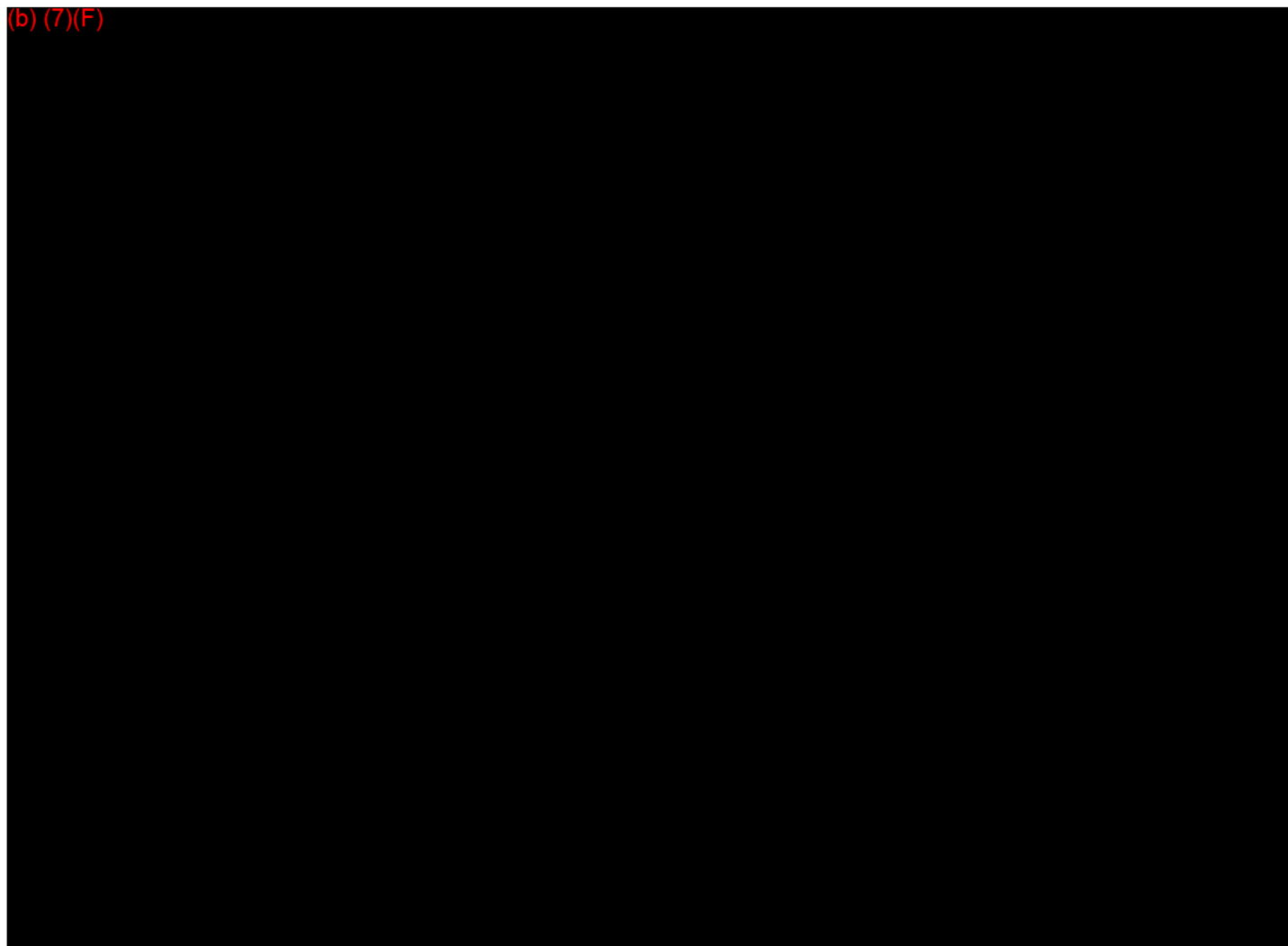
The Response Action Plan, with the resources and equipment listed herein, is a planning document that demonstrates the potential response capability available to respond to an oil spill from tanks, pipelines, wells and other equipment covered by this plan. It is not a guarantee of what will occur, or the resource deployment sequencing that will be used in an actual spill event. Nothing in this plan is intended to limit the discretion of persons in charge of an actual spill response to take the actions deemed necessary to maximize the effectiveness of the response; consistent with safety considerations. Response operations in a spill event will be tailored to meet actual circumstances.

This plan incorporates by reference information provided in the Alaska Clean Seas (ACS) *Technical Manual*.

THIS PAGE INTENTIONALLY LEFT BLANK

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

(b) (7)(F)



PLAN DISTRIBUTION

The Response Action Plan is maintained on the BP Exploration (Alaska), Inc. (BPXA) intranet website, accessible by BPXA employees and contractors. Hard copies of the plan or electronic copies on CD are distributed to regulatory agencies and emergency operations centers. Additional copies are in the Anchorage Crisis Center, the Safety & Operational Risk (S&OR) Department, and at ACS. A record of plan distribution is maintained by the S&OR Department.

UPDATING PROCEDURES

The Response Action Plan is reviewed annually and revised and updated when changes occur. Below is a list of key factors that may cause revisions to the plan:

- New developments;
- Change to worst case discharge volume(s);
- Change in commodities transported;
- Change in oil spill removal organizations;
- Change in Qualified Individual;
- Change in a National Contingency Plan or Area Contingency Plan that has a significant impact on the appropriateness of response equipment or strategies;
- Change in response procedures, and/or
- Change in ownership.

Routine updates are submitted for Alaska Department of Environmental Conservation (ADEC) review within five days after the date of proposed change. Routine updates are limited to revisions of personnel and training. Other modifications to the plan are considered amendments and must be reviewed and approved by ADEC. Plan amendments are submitted within 30 days of revising the plan.

Revisions to the plan are documented in the Record of Revisions table at the beginning of the plan and posted on the BPXA intranet site for BPXA employee and contractor reference. Hardcopies of the changed pages or new CDs (for electronic copy holders) are distributed to regulatory agencies and emergency operations centers. Upon receipt of revisions, the recipient replaces pages (hardcopy) or the previous CD, as instructed in the distribution letter. Those holding controlled copy CDs will be sent replacement CDs. It is the responsibility of each plan recipient to ensure that updates are promptly incorporated into the plan and that outdated CD revisions are discarded or archived.

PLAN RENEWAL

The plan renewal cycle involves the State and Federal agency approvals listed below.

REGULATING AGENCY	RENEWAL CYCLE	EXPIRATION DATE
ADEC	5 years	September 26, 2016
EPA Facility Response Plan	No more than every 5 years	October 4, 2015
DOT Facility Response Plan	5 years	December 17, 2013

THIS PAGE INTENTIONALLY LEFT BLANK

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION DIVISION OF SPILL PREVENTION AND RESPONSE INDUSTRY PREPAREDNESS PROGRAM

SEAN PARNELL, GOVERNOR
555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
<http://www.dec.state.ak.us>

September 26, 2011

File No: 305.30
(BPXA MPU)

Mr. Mike Bronson/ Ms. Eppie Hogan
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plan for the Milne Point Unit, North Slope, Alaska. Plan Number 10-CP-4132, Dated January 2011. Plan Approval**

Dear Mr. Bronson/ Ms. Hogan:

The Alaska Department of Environmental Conservation (department) has completed our review of your application for the above referenced Oil Discharge Prevention and Contingency Plan (plan) dated January 2011. The department coordinated the State of Alaska's public review for compliance with 18 AAC 75, using the review procedures outlined in 18 AAC 75.455. Based on our review, the department has determined that your plan is consistent with the applicable requirements of the referenced regulations and is hereby approved.

This approval applies to the following plan:

Plan Title: **BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plan**

Supporting Documents: **Alaska Clean Seas (ACS) Technical Manual, © June 2010, as revised and updated**

Plan Holder: **BPXA Exploration (Alaska) Inc.
900 East Benson Boulevard
P. O. Box 196612
Anchorage, AK 99519-6612**

Covered Facilities: **Production and drilling operations conducted within the Milne Point Unit and operation of the Milne Point crude oil transmission pipeline from the Central Facilities Pad to the Kuparuk Pipeline**

Mr. Mike Bronson/ Ms. Eppie Hogan
BPXA Exploration (Alaska), Inc.

2

September 26, 2011

PLAN APPROVAL: Approval of the referenced plan is hereby granted, effective **September 26, 2011**. A certificate of approval stating that the department has approved the contingency plan is enclosed. This approval is subject to the following terms and conditions.

TERMS AND CONDITIONS

The following items must be completed and/or received as specified to complete the plan in accordance with AS 46.04.030(e).

1. Notice of Changed Relationship with Response Action Contractor.

Because the plan relies on the use of response contractors for its implementation, BP Exploration (Alaska) Inc. (BPXA) must immediately notify us in writing of any change in the contractual relationship with the plan holder's response action contractors, and of any event including but not limited to any breach by either party to the response contract that may excuse a response contractor from performing, that indicates a response contractor may fail or refuse to perform, or that may otherwise affect the response, prevention, or preparedness capabilities described in the approved plan.

This condition is reasonable and necessary because there are certain risks associated with allowing a plan holder to rely in part or total upon a response contractor instead of obtaining its own response capability. The risks arise, in part, because the certainty of the contractor's response is dependent upon the continuation of the legal relationship between the contractor and the plan holder. Given this risk, the department must be promptly informed of any change of the contractual relationship between the plan holder and the response contractor, and of any other event that may arguably excuse the response contractor from performing or that would otherwise affect the response, prevention, or preparedness capabilities described in the approved plan. The department may seek appropriate modifications to the plan or take other steps to ensure that the plan holder has continuous access to sufficient resources to protect the environment and to contain, clean up, and mitigate potential oil spills. 18 AAC 75.425(e)(3)(H) and 18 AAC 75.445(i)

This condition is reasonable and necessary to ensure that a statement signed by a person with appropriate authority to commit the oil discharge prevention and response resources necessary to implement the plan is submitted as required by 18 AAC 75.425(e)(c)(3).

- 2. Blowout Contingency Plan.** A copy of the Blowout Contingency Plan (BCP) must be maintained at the Milne Point facility and made available to the department upon request.

Mr. Mike Bronson/ Ms. Eppie Hogan
BPXA Exploration (Alaska), Inc.

3

September 26, 2011

This condition is necessary to ensure that the plan holder is prepared to control a potential well blowout. The department will review the blowout contingency plan when performing site inspections and/or in Anchorage BPXA offices. 18 AAC 75.425(e)(1)(I), 18 AAC.445(d)(2), and 18 AAC 75.480

- 3. Final Copy of the Plan.** Within 30 days of this letter, the plan holder must submit to the department updated versions of the approved plan, including all revisions instituted during the recent plan review. BPXA must send three complete plan copies to the Exploration, Production & Refineries Section. In addition, you must send an updated version of the plan to each reviewer and controlled document holder of your plan.

EXPIRATION: This approval expires **September 26, 2016**. After the approval expires, Alaska law prohibits operation of the facility until an approved plan is once again in effect.

AMENDMENT: Except for routine updates under 18 AAC 75.415(b), before a change to this plan may take effect, the plan holder must submit an Application for Amendment to the plan with any additional information needed to evaluate the proposed amendment. This is to ensure that changes to the plan do not diminish the plan holder's ability to respond to a discharge and to evaluate any additional environmental considerations that may need to be taken into account (18 AAC 75.415).

RENEWAL: To renew this approval, the plan holder must submit a completed renewal application and plan to the department no later than 180 days prior to the expiration of this approval. This is to ensure that the submitted plan is approved before the current plan in effect expires (18 AAC 75.420).

REVOCATION, SUSPENSION OR MODIFICATION: This approval is effective only while the plan holder is in "compliance with the plan" and with all of the terms and conditions described above. The department may, after notice and opportunity for a hearing, revoke, suspend or require the modification of an approved plan if the plan holder is not in compliance with it, or for any other reason stated in AS 46.04.030(f). In addition, Alaska law provides that a vessel or facility that is not in "compliance with the plan" may not operate (AS 46.04.030). The department may terminate approval prior to the expiration date if deficiencies are identified that would adversely affect spill prevention, response or preparedness capabilities.

DUTY TO RESPOND: Notwithstanding any other provisions or requirements of this contingency plan, a person causing or permitting the discharge of oil is required by law to immediately contain and cleanup the discharge regardless of the adequacy or inadequacy of a contingency plan (AS 46.04.020).

Mr. Mike Bronson/ Ms. Eppie Hogan
BPXA Exploration (Alaska), Inc.

4

September 26, 2011

NOTIFICATION OF NON-READINESS: Within twenty-four (24) hours after any significant response equipment specified in the plan becomes non-operational or is removed from its designated storage location, the plan holder must notify the department in writing and provide a schedule for the equipment's substitution, repair, or return to service (18 AAC 75.475[b]).

CIVIL AND CRIMINAL SANCTIONS: Failure to comply with the plan may subject the plan holder to civil liability for damages and to civil and criminal penalties. Civil and criminal sanctions may also be imposed for any violation of AS 46.04, any regulation issued there under, or any violation of a lawful order of the department.

INSPECTIONS, DRILLS, RIGHTS TO ACCESS, AND VERIFICATION OF EQUIPMENT, SUPPLIES AND PERSONNEL: The department has the right to verify the ability of the plan holder to carry out the provisions of its contingency plan and access to inventories of equipment, supplies, and personnel through such means as inspections and discharge exercises, without prior notice to the plan holder. The department has the right to enter and inspect the covered vessel or facility in a safe manner at any reasonable time for these purposes and to otherwise ensure compliance with the plan and the terms and conditions (AS 46.04.030[e] and AS 46.04.060). The plan holder shall conduct exercises for the purpose of testing the adequacy of the contingency plan and its implementation (18 AAC 75.480 and 485).

FAILURE TO PERFORM: In granting approval of the plan, the department has determined that the plan, as represented to the department by the applicant in the plan and application for approval, satisfies the minimum planning standards and other requirements established by applicable statutes and regulations, taking as true all information provided by the applicant. The department does not warrant to the applicant, the plan holder, or any other person or entity: (1) the accuracy or validity of the information or assurances relied upon; (2) that the plan is or will be implemented; or (3) that even full compliance and implementation with the plan will result in complete containment, control, or cleanup of any given oil spill, including a spill specifically described in the planning standards.

The plan holder is encouraged to take any additional precautions and obtain any additional response capability it deems appropriate to further guard against the risk of oil spills and to enhance its ability to comply with its duty under AS 46.04.020(a) to immediately contain and clean up an oil discharge.

COMPLIANCE WITH APPLICABLE LAWS: If amendments to the approved plan are necessary to meet the requirements of any new laws or regulations, the plan holder must submit an application for amendment to the department at the above address. The plan holder must adhere to all applicable state

Mr. Mike Bronson/ Ms. Eppie Hogan
BPXA Exploration (Alaska), Inc.

5

September 26, 2011

statutes and regulations as they may be amended from time to time. This approval does not relieve the plan holder of the responsibility for securing other federal, state, or local approvals or permits, and the plan holder is still required to comply with all other applicable laws.

INFORMAL REVIEW OR ADJUDICATORY HEARING: Any person who disagrees with this decision may request an adjudicatory hearing in accordance with 18 AAC 15.195 - 18 AAC 15.340 or an informal review by the Division Director in accordance with 18 AAC 15.185.

Informal review requests must be delivered to the Division Director, 410 Willoughby Avenue, Suite 303, PO Box 111800, Juneau, Alaska 99811-1800 within 15 days of the permit decision.

Adjudicatory hearing requests must be delivered to the Commissioner of the Department of Environmental Conservation, 410 Willoughby Avenue, Suite 303, PO Box 111800, Juneau, Alaska 99811-1800, within 30 days of the permit decision. If a hearing is not requested within 30 days, the right to appeal is waived. Anyone who submits a request for an informal review or an adjudicatory hearing should also send a copy of the request to the undersigned.

If you have any questions, please contact Jeanne Swartz at (907) 269-7604.

Sincerely,



Betty Schorr
Program Manager

Attachment: Summary of Basis for Department Decision

Enclosure: Certificate of Approval, Number 11CER-022

Electronic cc: (w/o enclosure)

Scott Pexton, ADEC

Jeanne Swartz, ADEC

Laurie Silfven, ADEC

Tom DeRuyter, ADEC

Gordon Brower, NSB

James Sceeles, NSB

C-Plan Reviewer, ADNRR

Gordon Matumeak, NSB

Mr. Mike Bronson/ Ms. Eppie Hogan
BPXA Exploration (Alaska), Inc.

6

September 26, 2011

Mike Thompson, JPO
Jack Winters/Mac McLean, ADFG
Matt Carr, USEPA
MSTC Shawn Erwin, USCG
MST1 Brian Schughart, USCG
LCDR Bradley Clare, USCG
Melanie Barber, USDOT
Pam Miller, Northern Alaska Environmental Center
Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska
Tony Parkin, BPXA



ALASKA DEPARTMENT
of
Environmental Conservation
Certificate of Approval
for



Oil Discharge Prevention and Contingency Plan

Certificate Number: **11CER-022**

Plan Number: **10-CP-4132**

Name of Plan: **BP (Exploration) Alaska, Inc. North Slope Production Oil Discharge Prevention and Contingency Plan**

Covered Facilities: **Production and drilling operations conducted within the Milne Point Unit and operation of the Milne Point crude oil transmission pipeline from the Central Facilities Pad to the Kuparuk Pipeline**

Address: **BP (Exploration) Alaska, Inc., 900 East Benson Boulevard, Anchorage, AK 99508 or P. O. Box 196612, Anchorage, AK 99519**

Telephone: **(907) 564-5111** Fax: **(907) 564-5020**

Region of Operation (18 AAC 75.495): **North Slope**

Effective Date of Approval: **September 26, 2011**

Expiration Date: **September 26, 2016**

This approval is subject to the terms and conditions of the applicable Alaska Department of Environmental Conservation contingency plan approval letter and continuing compliance with the requirements of AS 46.04 and 18 AAC 75.

 9.26.2011
Betty Schorr, Approving Authority Date
Program Manager, Industry Preparedness Program

**ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM**

**BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT OIL DISCHARGE PREVENTION AND CONTINGENCY
PLAN
NORTH SLOPE, ALASKA**

**Summary of Basis for Department Decision
Renewal of Existing Plan
September 26, 2011**

Pursuant to 18 AAC 75.460(b)(1), the following is a summary of the basis for the Alaska Department of Environmental Conservation (department) decision to approve the BP Exploration (Alaska) Inc. (BPXA) Milne Point Unit (MPU) Oil Discharge Prevention and Contingency Plan (plan). Our approval includes referenced portions of the Alaska Clean Seas Company's Oil Spill Response Manual, latest revision dated June, 2010 consisting of three volumes. This document summarizes key points and discusses issues raised during the department's review of BPXA's application for a plan renewal.

The following summarizes documents and milestones in the review process:

- On October 7, 2010 the department received a notice of intent to file a plan renewal from BPXA, department Plan No.11-CP-4132.
- On December 15, 2010 the department received a copy of the plan from Eppie Hogan.
- On December 27, 2010 the department determined the BPXA MPU plan was sufficient for review.
- On January 11, 2011 the department issued the "Start of Plan Review" letter.
- On January 20, 2011 a public notice announcing the public review of BPXA's application for Milne Point Unit Operations was published in the Anchorage Daily News, the Fairbanks News-Miner and the Arctic Sounder. The notice was also published on the department website.
- The department declared January 21, 2011 as Day 1 of the 30-day public review period. Day 30 fell on February 22, 2011.
- On February 16, 2011 the department suspended review of the plan. The department determined based upon review of the plan that additional information and/or plan revisions were required to complete the plan.

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

Written comments were received from the North Slope Borough (NSB) on February 22, 2011. No other public comments were submitted in the 30-day public review period.

- On March 15, 2011 the department met with Lydia Miner of SLR (BPXA's consultant) and Eppie Hogan and Mike Bronson of BPXA and discussed comments submitted by NSB.
- The department issued a Request for Additional Information (RAI) letter on May 24, 2011 incorporating comments and questions expressed during the public review period as they related to the department regulations at 18 AAC 75.
- On June 10, 2011 the department received BPXA's response to the RAI letter dated May 24, 2011.
- On July 5, 2011 the plan was determined complete and the department issued a letter extending the plan review period an additional ten days until July 15, 2011.
- The department received no additional comments concerning this review.

Plan Summary

Milne Point Unit is an onshore production facility on the North Slope, Alaska. The facility has production wells on well pads, flow lines that carry three-phase oil to a central processing facility, and a crude oil transmission pipeline (COTP) that ties in to the Kuparuk COTP. Milne Point Unit has been in operation for many years.

Response Planning Standard and Scenarios

The largest Response Planning Standard (RPS) volume for the BPXA MPU plan is based upon 789 barrels (bbl) of oil per day (bopd) for 3 days to total 2,367 barrels of oil (bbl) at the wellhead in accordance with 18 AAC 75.434. The RPS has initially been set at 789 bopd based on the departments' RPS volume determination for a production facility as outlined in 18 AAC 75.434(e), with three times the average daily production of the highest-producing well. The highest-producing well, E-24A, uses assisted lift for production. The plan also includes a tank RPS volume of 998 bbls.

Pursuant to 18 AAC 75.425(e)(1)(F), the plan must contain a description of the discharge containment, control, and cleanup actions to be taken, which clearly demonstrates the strategies and procedures to conduct and maintain an effective response, presented in the form of a response scenario to a discharge of each RPS volume. The plan contains scenarios for a major spill from a winter blowout of a production well (2,367 bopd), a major spill from a summer blowout of a production well (2,367 bopd), a major spill from an oil reserve

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

tank failure at a drill site during summer (998 bbl), and a major spill from a crude oil transmission pipeline during summer (7,017 bbl). Additional strategies presented in this plan include a production well blowout from a well on a drilling pad adjacent to the coastline during open water conditions and a production well blowout from the same well pad during broken ice conditions.

Public Comments and Department Review

Overall, the plan was well-developed on submittal. Revisions were necessary to complete the plan, as described in the department's RFAI letter issued May 24, 2011. Written comments were received from NSB on February 22, 2011. The department addressed concerns raised in the public comments by NSB in our RFAI letter. The BPXA response to the RFAI letter was received by the department on June 10, 2011. The State understands it may be desirable for NSB to include all manner of preventative and response issues in the plan, however the State has no authority and will not require BPXA to include in the plan requirements that are outside the requirements of 18 AAC 75.

This Summary of Basis for Departmental Decision addresses concerns, comments, and questions from the department's RFAI letter dated May 24, 2011 and from the NSB comments received February 22, 2011. The department believes all comments have been fully addressed. NSB and the department requests are shown below in bold text and the department responses are listed below in standard text.

(1) 1. NSB requested that BPXA submit a revised, redlined version of the C-Plan with all of the proposed changes for this new five (5) year renewal, as compared to the existing C-Plan.

Department response: BPXA provided a chart with the new C-Plan, titled "Summary of Milne Point Unit Renewal Changes". This chart lists the current MPU contents, the Volume where the change was made in the renewal plan. This chart serves the same purpose as a revised, redlined version of the C Plan. Also, the existing MPU plan is contained in one volume while the plan under renewal review is divided into two volumes. This would make a revised, redlined version of the C-Plan difficult to produce.

(2) 1. NSB requested that BPXA distribute copies of the final oil spill prevention plan to the following NSB representatives:

- 1. Susana Montana, North Slope Planning Department, Barrow**
- 2. Gordon Matumeak, North Slope Planning Department, Nuiqsut**
- 3. Harvey Consulting, LLC. (NSB Consultant)**

Department response: The department addressed this request in our Request for Additional Information (RFAI) letter dated May 24, 2011. BPXA

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

added the requested NSB employees/contractors to the controlled copy plan holder list in their response to the department's RFAI letter, dated June 9, 2011.

PART 1 Response Action Plan

(3) 1. NSB requested that BPXA provide an executed version of the Alaska Clean Seas (ACS) Statement of Contractual Terms.

Department response: The department addressed this request in our RFAI letter dated May 24, 2011. BPXA stated that the ACS Statement of Contractual Terms in the current MPU C-Plan is still active and valid and provided a copy in the renewed C-Plan in their response to the department's RFAI letter, dated June 9, 2011.

(4) 1. NSB requested that BPXA provide a Statement of Contractual Terms for any contractors that BPXA will use for source control, containment or recovery operations, including, but not limited to, major marine vessel suppliers of oil spill support vessels and also Boots and Coots.

Department response: A Statement of Contractual Terms for contractors that are not Primary Response Action Contractors (PRAC)s is not required under 18 AAC 75 and is not required as part of a state-approved plan.

(5) 1.1 Emergency Action Checklist

18 AAC 75.425(e)(1)(A) describes a short checklist of the immediate response and notification steps to be taken if an oil discharge occurs. Information in this section of the plan includes a flow chart for immediate oil spill notification and reporting and also the Incident Management Team (IMT) structure. BPXA was requested to provide clarification on the points listed below.

1. NSB requested that the ICS organization chart should represent a Tier III spill (as described on page 1-1), and it should include all the positions that would be required to resource a worst-case discharge, including Finance Section positions and positions needed to support the Incident Commander.

Department response: The department addressed this request in our RFAI letter dated May 24, 2011. BPXA stated that their Incident Management Team (IMT) can expand as needed to respond to an incident. They added the Finance Section, based in Anchorage, to the ICS organization chart and removed the "Tier II" designation in the title of the chart (Figure 1-2) to avoid confusion in their response to the department's RFAI letter, dated June 9, 2011.

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

2. NSB requested BPXA provide a complete contact list for the ICS positions shown on Page 1-6.

Department response: A complete contact list for the ICS positions are not required as part of a state-approved plan.

3. NSB requested that BPXA remove Waska Williams from the first responder contact list and replace his name with:

Thomas Simmonds III	(907) 878-4843
Gordon Matumeak	(907) 878-2194
Charles Russell	(907)878-4849
Tony Cabinboy	(907) 878-2193
Susan Atos	(907) 878-2191*

Department response: The department was recently notified that Susan Atos no longer works for the North Slope Borough. The department addressed this request in our RFAI letter dated May 24, 2011. BPXA changed Table 1-3 to replace the name Waska Williams with the names provided by the NSB with the exception* of Susan Atos in their response to the department's RFAI letter, dated June 9, 2011.

(6) 1.5 Deployment Strategies

18 AAC 75.425(e)(1)(E) describes proposed initial response actions that may be taken, including procedures for the transport of equipment, personnel, and other resources to the spill site and plans for alternative methods in adverse weather conditions. We requested that BPXA update information as specified in the following items.

The item listed was a comment submitted by the department in our RFAI dated May 24, 2011:

- 1. The response action plan must include a description of the interim actions that the operator will perform until the responder identified in the plan initiates a full response to the discharge [18 AAC 75.425(e)(1)(E)(ii)]. Please provide a brief description of interim actions BPXA will perform prior to a full response initiated by Alaska Clean Seas.**

BPXA stated in their response to the department's RFAI letter, dated June 9, 2011, that in order to meet the full intent of 18 AAC 75.425(e)(1)(E)(ii), the plan references Section 1.1 (Emergency Action checklist), which describes initial response activities and Section 1.6 (Response Scenarios and Strategies). Interim actions are described on page 1-18. The plan is unchanged.

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

(7) 1.6 Response Scenarios

18 AAC 75.425(e)(1)(F) describes a written description of hypothetical spill scenarios and responses to the discharges in a manner that is to be used as a general guide for a discharge of any size. We requested that BPXA update information as specified in the following items.

The items listed below were comments submitted by NSB:

- 1. The existing plan uses a well blowout at an L-Pad well as the worst-case scenario. L-Pad is located on the perimeter of the MPU along the coastline and has the potential to impact the offshore coastal waters of the Beaufort Sea. BPXA is requested to revise the worst-case scenario to include a well blowout at F-Pad or L-Pad to demonstrate strategies for cleaning up a spill at a remote, logistically challenging well pad with the potential to impact offshore waters.**

Department response: The department notes that the response planning standard (RPS) for a worst-case well blowout in this plan is projected to be from the highest-producing well at the MPU; the E-24A well on E-Pad. There is no regulatory requirement for a separate response scenario based solely on logistical challenges.

- 2. The RPS for a well blowout is based on a 3-day spill, instead of a 15-day spill. BPXA was requested to revise the plan to reflect a 15-day spill or include an Alaska Oil and Gas Conservation Commission (AOGCC) certification explaining why a shorter blowout duration is appropriate.**

Department response: 18.AAC 75.434(e)(2) indicates that if the highest-producing well at a production facility is an assisted-lift well. No additional volume equal to the annual average daily oil production volume for the maximum producing well at the facility for each of 12 days beyond 72 hours is required. The department finds BPXA's RPS volume for a well blowout satisfies the regulatory requirement.

- 3. Response Strategy 2 – Production Well Blowout to Broken Ice is a description of how a response to a well blowout at L-Pad, adjacent to the Beaufort Sea coastline, would be conducted in a seasonal condition in which broken ice was present. It was requested that BPXA include an alternative cleanup strategy that meets the 72-hour RPS when the use of vessels and minibarges is precluded because of the presence of 100% offshore broken ice coverage.**

Department response: The department finds in Response Strategy 2 that the description of the event begins with a well blowout occurring when there is 100% broken ice coverage near F-Pad. Continuing through the subsequent 30 days, the broken ice coverage decreases. Vessels and

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

minibarges may be deployed when broken ice coverage has diminished during the 30 days following the blowout. As long as there is broken ice coverage in a manner that prevents deployment of vessels, the tactics that would be used to clean up the oil are in-situ burning (ISB) and/or mechanical recovery. The department finds that the strategy as described is adequate.

4. BPXA was requested to provide more information about a spill trajectory or potential oil thickness to determine whether ISB would be a viable response option for Response Strategy 2 – Production Well Blowout to Broken Ice.

Department response: Information about surveillance of the spill is described in Table 1-27, page 1-67. Wind roses are provided in Figures 1-5 and 1-7, for summer and winter conditions, respectively. Tactic B-3 in the Alaska Clean Seas (ACS) Technical Manual describes the thicknesses for oil deposition required to support ISB burning in broken ice conditions using heli-torches, as described in Table 1-27, page 1-68. This tactic was not listed in the ACS Technical Manual column accompanying the tactic description so the department addressed this request in our RFAI letter dated May 24, 2011. BPXA added a reference to ACS Tactic B-3 to Response Strategy 2 in their response to the department's RFAI letter, dated June 9, 2011.

5. BPXA was requested to provide a scenario during fall freeze-up conditions.

Department response: The plan contains scenarios for spill response during winter and summer conditions. Additionally, Response Strategy 2 addresses response activities when broken ice is present in the Beaufort Sea, during shoulder seasons, spring or fall. Per 18 AAC 75.425(e)(1)(F), the department is satisfied that the plan adequately describes strategies that account for variations in the receiving environment.

6. BPXA was requested to provide a flowline spill scenario to be included in the plan.

Department response: A flowline RPS is not required under 18 AAC 75 and a scenario for response to a flowline spill is not required as part of a state-approved plan.

7. BPXA was requested to include a Master Equipment List in the plan and to indicate whether BPXA owns the equipment items or whether the equipment is provided by contractors. Additionally, BPXA was requested to indicate where each piece of equipment is located.

Department response: The department is satisfied that the spill response master equipment list is incorporated by reference as Tactic L-6. This information is provided in Section 3.6.1 Equipment Lists.

8. BPXA was requested to show how personnel will be resourced to meet the RPS for different spill response scenarios and strategies in

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

the plan. BPXA was requested to describe whether these personnel would be employees or contractors, the location of the personnel and the depth of personnel resources.

Department response: The information requested about response personnel is not required under 18 AAC 75 and is not required as part of a state-approved plan.

10. BPXA was requested to increase the training/ qualification requirements for General Technicians, as described in Section 3.9 of the plan or else to incorporate a much higher percentage of Skilled Technicians and Team Leaders to spill response teams in order to have a sufficient number of trained and qualified personnel available during a response.

Department response: The department addressed this request in our Request for Additional Information (RAI) letter dated May 24, 2011. BPXA edited the staffing tables to all four spill scenarios to more clearly illustrate the ratio of Team Leads to other response positions in their response to the department's RAI letter, dated June 9, 2011.

11. BPXA was requested to provide Statements of Contractual Terms for all of the contracted equipment and personnel for equipment and resources described in Part 1 of the MPU plan. Additionally, BPXA was requested to provide copies of any agreements (e. g. Memorandums of Understanding or Facility Sharing Agreements) made by BPXA to access facilities on the North Slope outside of the MPU Facility for spill response activities.

Department response: A Statement of Contractual Terms for contractors that are not Primary Response Action Contractors (PRAC)s is not required under 18 AAC 75 and is not required as part of a state-approved plan.

12. BPXA was requested to provide a list of pre-staged equipment for protection of environmentally sensitive areas., including a map showing all the locations of pre-staged equipment, and a list of the equipment in each location.

Department response: See response to Item #8, this section.

PART 2 Prevention Plan

(8) 2.1 Discharge Prevention Program

18 AAC 75.425(e)(2)(1) provides for a description and schedule of regular oil discharge prevention, inspection, and maintenance programs in place at the facility.

The items listed below were comments submitted by NSB:

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

- 1. BPXA was requested to include the listing of each position with job duties, the training and level of knowledge appropriate to that position, the listing of any licenses, certifications, or other prerequisites needed to hold each position, and a listing of training objectives and the means of achieving them in the plan. BPXA's Prevention Training Program should include a matrix listing each position, the required training and qualifications, and the training and certification frequency. Additionally, BPXA was requested to provide information on how contractors are trained on oil spill prevention.**

Department response: The department addressed this request in our Request for Additional Information (RAI) letter dated May 24, 2011. BPXA, in their response to the department's RAI letter, dated June 9, 2011, stated that a list of the scores of individual positions involved in spill prevention training, with qualifications and training requirements, is not required by the regulations and is subject to frequent changes in details. Additionally, BPXA stated that the department may request training records for inspection. The plan was not modified to include a matrix, however language was added to the plan's Section 2.1.1 to clarify how the facility's oil spill prevention programs meet state and federal regulations for training. Additional statements have been added at the beginnings of Parts 2 and 3 regarding the sources of information used for the updates in Section 2.1.1.

- 2. BPXA was requested to provide information about what actual prevention measures are employed to support their statement that produced oil from flow tests and other drilling operations are handled in a manner to prevent spills.**

Department response: Information about the specific measures taken to prevent oil spills from flow tests, drilling operations, and other activities is provided in Sections 3 and 4.

- 3. BPXA was requested to insert the following statement into the new plan: "Facilities are staffed 24 hours a day. At shift changes, personnel inspect oil tank levels and tankage, sumps and drains, piping, valves, glands, wellheads, pumps, and other machinery for indications of oil leaks" or explain why this statement was changed from the 2007 plan.**

Department response: The information requested is not required under 18 AAC 75 and is not required as part of a state-approved plan.

- 4. BPXA was requested to insert the following statement from the existing MPU plan into the new plan: "BPXA conducts in-line inspections of the crude oil transmission pipelines that are subject to 49 CFR 195.452 at intervals not to exceed five years", or else explain why the pipeline inspection frequency was changed and include the revised pipeline inspection schedule.**

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

Department response: The information requested is not required under 18 AAC 75 and is not required as part of a state-approved plan.

5. BPXA was requested to provide information on MPU leak detection testing to verify its system is capable of detecting a leak rate of 1% of daily throughput, and is capable of stopping oil within 1 hour from spill detection.

Department response: The department addressed this request in our Request for Additional Information (RAFI) letter dated May 24, 2011. BPXA, in their response to the department's RAFI letter, dated June 9, 2011, added language to the plan's Section 2.1.7 containing details about the facility's automated leak detection capability.

6. BPXA was requested to add a column to the Appendix A portable oil storage tank table to specify the tank inspection standards and the inspection frequencies that apply to each tank.

Department response: The information requested is not required as part of a state-approved plan.

7. BPXA was requested to update due dates for tank inspections in Appendix A and also verify that all required tank inspections have been completed and any required repairs made.

Department response: BPXA submits updates to Appendix A of the the plan when the inspections are completed. The department maintains information relating to tank inspections, including repairs, in department files.

8. BPXA was requested to provide the secondary containment area (SCA) volume for each tank.

Department response: The information requested is not required as part of a state-approved plan.

9. BPXA was requested to include tank tables in the Oil Pollution Act of 1990 (OPA 90) section of the MPU plan, including SCA volumes for all tanks of 660 gallon size and larger, as is required by NSB reviews.

Department response: The information requested is not required under 18 AAC 75 and is not required as part of a state-approved plan.

10. BPXA was requested to provide information in Appendix A that is limited only to tanks located at MPU.

Department response: Portable tanks frequently move between facilities on the North Slope, so providing information in Appendix A about all of the portable tanks insures that if any portable tank is sited temporarily at MPU, it will be covered by prevention provisions in the plan.

11. BPXA was requested to list each tank's construction date and the number and type of inspections it has received over its life.

Department response: The information requested is not required as part of a state-approved plan.

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

12. BPXA was requested to include information about BPXA's Secondary Containment Standard (CRT-AK-04-90) and how it is met for the tanks listed in Appendix A.

Department response: The information requested is not required as part of a state-approved plan.

13. BPXA was requested for an explanation about why none of the MPU tanks listed in Appendix A have a liquid level mechanism, overflow alarm system, or leak detection system.

Department response: Part 4 of the plan gives information about the Best Available Technology (BAT) consistent with criteria for 18 AAC 75.445(k), including BAT for overflow protection of tanks. The BAT for overflow protection of tanks is a 2-person procedure. The BAT analysis given in Table 4-5 demonstrates the effectiveness of this system.

14. BPXA was requested to provide information to show how it inspects, maintains, repairs, and verifies SCA liner integrity.

Department response: The information requested is not required as part of a state-approved plan.

15. BPXA was requested to provide a section in the plan with information describing SCA installation requirements for the portable tanks used at MPU. This section would explain how BPXA and its contractors verify 110% containment prior to operating the tank, and how BPXA and its contractors verify the containment tanks listed in Appendix C prior to operating the tank.

Department response: The information requested is not required as part of a state-approved plan.

16. BPXA was requested to revise Appendix C to show the minimum dimensions of an adequate SCA structure for MPU portable tanks to be used as a field guide.

Department response: The information requested is not required as part of a state-approved plan.

17. BPXA was requested to expand Table 2-3 or create an additional table to show all facility piping sections, not just buried pipeline sections, including information on: inspection frequency, pipeline length, source control method, cathodic protection system, leak detection system, and volume that may be discharged if the leak is not detected until the monthly flowline inspection occurs.

Department response: Well pad maps in Appendix B show the plotted locations of facility piping at MPU. Information about inspection frequency, pipeline length, source control method, cathodic protection system, leak detection system, and volume that may be discharged if the leak is not detected until the monthly flowline inspection occurs is not required as part of a state-approved plan.

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

18. BPXA was requested to explain why it eliminated pipeline inspection frequency information from the draft January 2010 version of the MPU plan.

Department response: The existing plan includes a footnote in Table 2-3 regarding the inspection frequency of MPU Below-Grade Pipe Inventory: *All in-service below grade piping is being incorporated into a 5 year rolling plan from 2007 forward.* This same information is incorporated into text in the draft January 2010 plan on Page 2-12. The department finds this information sufficiently addresses the inspection frequency for piping in culverts or utiliways.

19. BPXA was requested to retain information about all MPU piping located in culverts or utiliways, including abandoned and out-of-service piping in Table 2-3.

Department response: Text given in the draft January 2010 plan on Page 2-12 indicates the out-of-service piping located in culverts and utiliways is cleaned, isolated from the piping system, and is no longer maintained under a department-required corrosion monitoring and preventative maintenance program. The department finds this information sufficiently addresses the reason not to include abandoned and out-of-service piping in Table 2-3.

20. BPXA was requested to provide a description of its abandonment plan of out-of-service piping. This description should describe the condition of this piping, and note whether the piping has future utility. If the abandoned or out-of-service piping has no future utility, BPXA was requested to provide an abandonment plan should be submitted to NSB.

Department response: The information requested is not required as part of a state-approved plan.

The items listed below were comments submitted by the department:

2.1.10 Flow Lines and Facility Oil Piping, Corrosion Control and Preventative Maintenance
Department Request No. 9

1. Text states that *BPXA maintains and inspects aboveground ADEC-regulated flow lines consistent with the requirements of API 570.* Please provide information in this section to clarify whether BPXA has a program for aboveground flow lines consistent with the requirements of the codified edition of American Petroleum Institute's (API) Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003 (API 570), excluding Section 8. 18 AAC 75.047 (d).

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

2. Text states that *BPXA maintains and inspects aboveground ADEC-regulated facility oil piping in accordance with the requirements of API 570*. Please provide information in this section to clarify whether BPXA has a program for facility oil piping in accordance with the requirements of the codified edition of API Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003 (API 570). 18 AAC 75.080 (j)(1).
3. Text states that *flow lines and facility oil piping are in a corrosion control program as required by 18 AAC 75.047 (c) and 18 AAC 75.080(b)*. Please provide information in this section to clarify whether BPXA has a corrosion monitoring and control program for flow lines consistent with Chapter VIII of the codified edition of Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids (ASME B31.4-2002). 18 AAC 75.047 (c)(1).
4. Text states that *the safe operation of facility oil piping between inspections required by 18 AAC 75.080(I) is demonstrated by way of the API 570 program*. Please provide information in this section to clarify whether BPXA maintains all facility oil piping under a program developed in accordance with the requirements of the codified edition of API Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003 (API 570). 18 AAC 75.080 (j)(1).
5. Text states that *flow lines are in a preventative maintenance program as required by 18 AAC 75.047(d)(2)*.
 - a. Please provide information in this section to clarify whether BPXA has in place” a preventative maintenance program for buried flow lines, if applicable, that is consistent with Chapters VII and VIII of the codified edition of Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids (ASME B31.4-2002). 18 AAC 75.047(d)(2)(B).

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

- b. Please provide information in this section to clarify whether BPXA has in place a preventative maintenance program for aboveground flow lines that is consistent with the requirements the codified edition of API Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003 (API 570). 18 AAC 75.047(d)(2)(C).
 - c. Please provide information in this section to clarify whether BPXA has in place a preventative maintenance program for aboveground flow lines that is consistent with Chapters VII and VIII of the codified edition of Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids (ASME B31.4-2002). 18 AAC 75.047(d)(2)(C).
 - d. Please provide information in this section to clarify whether BPXA maintains [does “has in place” sound better?] a preventative maintenance program for all flow lines with procedures to review proposed changes in operations to evaluate potential impacts on pipe integrity. 18 AAC 75.047(d)(2)(D).
6. Please provide information in this section to clarify whether aboveground flow lines are supported consistent with the requirements of Paragraph 421 of the codified edition of Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids (ASME B31.4-2002). 18 AAC 75.047(g).
7. Please provide information in this section to clarify whether aboveground facility oil piping is supported consistent with the requirements of Paragraph 321 of the codified edition of the Process Piping (ASME B31.3-2004). 18 AAC 75.080(i).

**2.1.10 Flow Lines and Facility Oil Piping, Out-of-Service Requirements
Department Request No. 10**

- 1. Please briefly describe the method of providing written notification to the Department, specifying the person(s) to be notified, and describing the information to be provided when flow lines are removed from service and when the specific actions required at 18 AAC 75.047(f) are completed.

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

2. Please briefly describe the method of providing written notification to the Department, specifying the person(s) to be notified, and describing the information to be provided when facility oil piping is removed from service and when the specific actions required at 18 AAC 75.080(o) are completed.

Department response: The department addressed these requests in our Request for Additional Information (RFAI) letter dated May 24, 2011. BPXA added language to Section 2.1.10 of the plan that stated that the facility's oil spill prevention programs consist of the equipment and activities required by applicable parts of the department's oil spill prevention regulations (18 AAC 75 Article 1 and EPA's Spill Prevention, Control and Countermeasure regulations (40 CFR 112) in their response to the department's RFAI letter, dated June 9, 2011. Additionally, two tables were added to the plan to explain how BPXA will meet the applicable engineering standards for the regulated flow lines, facility oil piping, corrosion control and preventative maintenance in order for BPXA to comply with the provisions of 18 AAC 75 Article 1.

(9) 2.3 Discharge History

18 AAC 75.425(e)(2)(B) provides a history of all known oil discharges greater than 55 gallons that have occurred at the facility within the state.

The item listed below was a comment submitted by the department:

- 1. Milne Point has had oil storage since 1985. Appendix C does not list any spills earlier than 1994. Please clarify if there were no spills greater than 55 gallons prior to February, 1994. If there were spills before that time, please amend Appendix C to include information about the earlier spills.**

Department response: The department addressed this request in our Request for Additional Information (RFAI) letter dated May 24, 2011. BPXA stated in their response to the department's RFAI letter, dated June 9, 2011 that Appendix C does not list spills before 1994 because BPXA's operation started that year.

(10) 2.3 Potential Discharge Analysis

This section provides an analysis of potential oil discharges, including size, frequency, cause, duration, and location, and a description of actions taken to prevent a potential discharge. 18 AAC 75.425(e)(2)(C).

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

The items listed below were comments submitted by NSB:

- 1. BPXA should include in the Potential Discharge Analysis section data contained in the 2010 State of Alaska commissioned North Slope Spill Analysis Report (Nuka Report) and should recommend additional oil spill prevention measures to reduce spill frequency, including improved training programs.**

Department response: Information requested is not required as part of a state-approved plan.

- 2. BPXA was requested to revise Table 2-5 to include the potential size of pipeline oil spills from each MPU pipeline.**

Department response: The information requested is not required as part of a state-approved plan.

- 3. BPXA was requested to include leak detection systems, installation of new pipelines to replace old pipelines, and/ or source control methods that limit spill size as additional prevention measures that should be included in the proposed plan as additional prevention measures that can be used to mitigate pipeline leaks.**

Department response: The information requested is not required as part of a state-approved plan.

- 4. BPXA was requested to provide additional information in the Prevention Section of the proposed plan to show how BPXA plans to mitigate valve leaks.**

Department response: The department addressed this request in our Request for Additional Information (RAFI) letter dated May 24, 2011. BPXA stated in their response to the department's RAFI letter, dated June 9, 2011 that the plan was revised to describe that six valve-related releases make up the 78 percent of the total estimated volume of releases attributed to equipment failure. BPXA further stated that regular preventative maintenance involves inspection of valves, which are repaired or replaced if required and that the effectiveness of the preventative program is demonstrated by the absence of reported valve-related releases since 2005.

(11) 2.6 Waivers

This section provides information for operations subject to a waiver, alternate compliance schedule, or existing condition of the plan approval under 18 AAC 75.005 - 18 AAC 75.085 or 18 AAC 75.400 - 18 AAC 75.496. 18 AAC 75.425(e)(2)(F).

The item listed below was a comment submitted by NSB:

- 1. BPXA was requested to provide NSB with a final set of field maps for use during emergency response events because NSB will be serving as the Local On Scene Coordinator (LOSC) to address the**

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

department's waiver of the requirement to mark flowlines at one-mile intervals.

Department response: The LOSC has access to more detailed maps in the IMT command center then are provided in the plan. The information requested is not required as part of a state-approved plan

(12) Drilling Operations

The item listed below was a comment submitted by NSB:

- 1. BPXA was requested to provide information about preventative measures specific to production drilling operations as part of the proposed plan.**

Department response: The department is satisfied that the individual components regulated by 18 AAC 75 have been included as part of the plan.

(13) Surface and Subsurface Safety Valves

The item listed below was a comment submitted by NSB:

- 1. BPXA was requested to provide information on the type of surface safety valves and subsurface safety valves installed in the MPU wells and how they are used to prevent spills.**

Department response: The information requested is not required as part of a state-approved plan.

(14) Remotely Operated Valves on the MPU Pipelines

The item listed below was a comment submitted by NSB:

- 1. BPXA was requested to provide information on how often remotely operated valves are tested and a map showing the location of these valves. Also, BPXA was requested to describe the maintenance and inspection programs for these valves.**

Department response: Information about automated wellhead valves and subsurface safety valves (SSVs) is provided in section 2.5.2. Maps of the locations of the SSVs and their maintenance and inspection is not required as part of a state-approved plan.

PART III Supplemental Information

(15) 3.6 Response Equipment

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

This section describes a complete list of contracted or other oil discharge containment, control, cleanup, storage, transfer, lightering, and related response equipment to meet the applicable response planning standard, and to protect environmentally sensitive areas and areas of public concern. 18 AAC 75.425(e)(3)(F).

The item listed below was a comment submitted by NSB:

- 1. BPXA was requested to include a detailed description in the proposed plan of specifically how in-situ burning (ISB) will be used at MPU.**

Department response: See response to Item #4, (7) 1.6 Response Scenarios.

(16) 3.7 Non-Mechanical Response Information

18 AAC 75.425(e)(3)(G)(iv) requires identification of all permits, approvals, or authorizations for the use of nonmechanical response option and the timeline for obtaining them.

The item listed below was a comment submitted by the department:

- 1. Please identify all necessary permits, approvals, or authorizations for the use of ISB and the timeline for obtaining them.**

Department response: The department addressed this request in our Request for Additional Information (RFAI) letter dated May 24, 2011. BPXA stated in their response to the department's RFAI letter, dated June 9, 2011 that ACS Tactic B-1 describes the permits, approvals and authorizations required to implement the ISB response option. ACS Tactic B-1 is listed in the scenarios and strategies in Section 1.6 where non-mechanical response options would be considered.

(14) 3.9 Training

This section describes the training programs for discharge response personnel. 18 AAC 75.425 (e)(3)(I).

The items listed below were comments submitted by NSB:

- 1. BPXA was requested to revise the proposed plan to assign General Technicians' duties "*associated with mobilization, deployment and support functions for the response, such as deployment of boom sections; assembly of anchor systems; assembly of temporary***

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

storage devices; loading and unloading of equipment and decontamination of equipment.” To Skilled Technicians or Skilled Technicians working in combination with General Technicians. Alternatively, BPXA was requested to increase the qualification requirements for General Technicians.

Department response: See response to Item #10, (7) 1.6 Response Scenarios.

- 2. In the ICS training program, BPXA was requested to list required courses for the ICS training program, a description of each course, or required minimum frequency each course should be taken. Additionally, this information should be listed by position, including a matrix summarizing this information.**

Department response: The information requested regarding ICS training and the description of ICS courses is not required as part of a state-approved plan.

- 3. BPXA was requested to provide additional information about spill response training courses. Specifically, BPXA was asked to provide information about which General Technicians are required to take which course listed in Table 3-7 and with what frequency.**

Department response: ACS tracks all spill response team training and these records may be reviewed upon request by the department. The department believes that attempting to track all spill prevention training through updates in the plan would not be a practical method of reviewing training records. A list of personnel and their specific training records kept in the plan is not required as part of a state-approved plan.

PART 4 Best Available Technology (BAT) Review

(15) 4.2 Source Control

This section describes use of the best available well source control technology. 18 AAC 75.425 (e)(4)(A)(i).

The item listed below was a comment submitted by NSB:

- 1. BPXA was requested to provide verification about whether all equipment required for well capping is located on the North Slope. Additionally, BPXA was requested to provide verification that the well-capping equipment owned by BPXA is in “response-ready” condition and Boots and Coots (BPXA’s well control contractor) certifies that the BPXA well-capping equipment is ready for immediate deployment.**

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

Department response: The information requested regarding verification of the readiness of well capping equipment is not required as part of a state-approved plan.

- 2. BPXA was requested to provide a detailed list of all the equipment to be used for well capping, and include information on the location and condition of each piece of equipment. Additionally, BPXA was requested to provide a list of any well capping equipment it plans to use that is located outside of Alaska and describe the method it plans to use for transporting this equipment to MPU in a timely manner.**

Department response: The information requested regarding well capping equipment is not required as part of a state-approved plan.

- 3. BPXA was requested to provide copies of five studies; Danberger 1993, Izon, Danberger, Mayes 2007, and Sanpower (2001 and 2010).**

Department response: The information requested is not required as part of a state-approved plan. However, BPXA stated that it will make the Danberger 1993 and Izon, Danberger, Mayes 2007 studies available if they cannot be obtained elsewhere. The Sanpower studies are proprietary.

- 4. BPXA was requested to provide justification to show why additional automated shutdown valves in BPXA's crude oil transmission pipeline (COTP) as described in the COTP source control BAT would afford little additional source control since the MPU pipeline is relatively short.**

Department response: The information requested regarding the number of automated shutdown valves in the COTP source control BAT is not required as part of a state-approved plan. BPXA stated that there is a discharge risk with every valve installed in a COTP and they will add language to Table 4-2 to explain the offsetting impact of not increasing the number of automated shutdown valves.

PART 5 Response Planning Standard

(16) 5.0 Response Planning Standard

This section provides a calculation of the applicable response planning standards set out in 18 AAC 75.430 – 18 AAC 75.440 and 18 AAC 75.442.

The item listed below was a comment submitted by NSB:

- 1. BPXA was requested to revise the RPS to include a 15 day spill, or include an AOGCC certification explaining why a shorter blowout duration is appropriate.**

Department response: See response to Item #2, section (7).

BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
PLAN APPROVAL BASIS FOR DECISION, SEPTEMBER 26, 2011

END

AS REQUIRED UNDER AS 46.04.30, AS 46.04.035 and 18 AAC 75.445(l) (1) in fulfillment of a requirement for registration of primary response action contractors and for approval of an Oil Discharge Prevention and Contingency Plan.

PLAN TITLE: Oil Discharge Prevention and Contingency Plan, Milne Point Unit

PLAN HOLDER: BP Exploration (Alaska), Inc.

This statement is a certification to the Alaska Department of Environmental Conservation summarizing the contract between BP Exploration (Alaska), Inc., the oil discharge prevention and contingency plan holder (hereinafter "PLAN HOLDER") and Alaska Clean Seas, the oil spill primary response action contractor or a holder of an approved oil discharge prevention and contingency plan under contract (hereinafter "CONTRACTOR"), executed July 1, 2005, and the original of which is located at Alaska Clean Seas, 4220 B Street, Anchorage, Alaska, as evidence of the PLAN HOLDER's access to the containment, control and/or cleanup resources required under standards at AS 46.04.030 and 18 AAC 75.400 - 18 AAC 75.495. The PLAN HOLDER and the CONTRACTOR attest to the Department that the provisions of this written contract clearly obligate the CONTRACTOR to:

- (A) provide the response services and equipment listed for the CONTRACTOR in the contingency plan;
- (B) respond if a discharge occurs;
- (C) notify the PLAN HOLDER immediately if the CONTRACTOR cannot carry out the response actions specified in this contract or the contingency plan;
- (D) give written notice at least 30 days before terminating this contract with the PLAN HOLDER;
- (E) respond to a Department-conducted discharge exercise required of the PLAN HOLDER; and
- (F) continuously maintain in a state of readiness, in accordance with industry standards, the equipment and other spill response resources to be provided by the CONTRACTOR under the contingency plan.

I hereby certify that as a representative of the PLAN HOLDER, I have the authority to legally bind the PLAN HOLDER in this matter. I am aware that false statements, representations, or certifications may be punishable as civil or criminal violations of law.

Janice L. Vosika 7/14/2005
Signature Date

Name: Janice L. Vosika

Title: Delivery Manager, Milne Point

For: BP Exploration (Alaska), Inc.
PLAN HOLDER

I hereby certify that as a representative of the CONTRACTOR, I have the authority to legally bind the CONTRACTOR in this matter. I am aware that false statements, representations, or certifications may be punishable as civil or criminal violations of law.

Brad Hahn 7/14/05
Signature Date

Name: Brad Hahn

Title: President

For: Alaska Clean Seas, CONTRACTOR

PART 1. RESPONSE ACTION PLAN

[18 AAC 75.425(e)(1)]

1.1 EMERGENCY ACTION CHECKLIST

[18 AAC 75.425(e)(1)(A) AND 40 CFR 112.20(h)]

Table 1-1 lists immediate response actions for an oil spill. Figure 1-1 provides a flow chart for immediate oil spill notification and reporting. Figure 1-2 illustrates the Incident Management Team (IMT) structure.

A spill response operation on the North Slope falls into one of three categories listed below.

A Level I spill has limited duration and impacts, and can be handled by a BP Exploration (Alaska), Inc. (BPXA) response organization with immediately available local resources. Typical characteristics of a Level I spill are as follows:

- Less than one shift of the IMT in duration,
- Does not require mutual aid from other operators, and
- No written Incident Action Plan.

A Level II spill is more complex, longer in duration, and characterized by more widespread effects. The activation of a BPXA response organization is composed of response resources available in Alaska. Typical characteristics of a Level II spill are as follows:

- More than one shift of the IMT in duration,
- Team members drawn from off-duty North Slope-based personnel and Anchorage-based personnel,
- Agency involvement and formation of a Unified Command, and
- Written Incident Action Plan.

A Level III spill is major, complex or compound in nature, has pronounced impacts on people, the environment, and/or property, and involves response operations for an extended period of time. A Level III spill involves the activation of all elements of the Incident Command System (ICS), supplemented by response resources from inside and outside of Alaska.

The response organization structure described in this plan is based on the ICS and accommodates each level of response. All three levels involve activation of the Spill Response Team (SRT), an IMT, and/or the Business Support Team (BST). As necessary, BPXA uses the resources of other North Slope operators through Alaska Clean Seas (ACS), Mutual Aid, spill response cooperatives, and contractors. Formation of a Unified Command with state, federal and local (North Slope Borough) government can occur at all levels.

*Milne Point Unit ODPCP, Volume 1 – Response Action Plan***TABLE 1-1: IMMEDIATE RESPONSE CHECKLIST**

LEVEL I, II, & III SPILLS	
FIRST RESPONDER	☐ Assess safety of situation, determine whether source can be stopped, and stop the source of spill if possible. The first responder only takes action to the level they are trained to take. ☐ Immediately report the spill by calling Security at 670-3300 or Milne Point Radio Harmony Channel 88. Immediately notify supervisory personnel after reporting the spill. ☐ Provide information on: • Personnel safety • Source of the spill • Type of product spilled • Amount spilled • Status of control operations
RADIO DISPATCHER/ OPERATOR	☐ Immediately notify ACS Environmental Technician. Call x3473 or Call Sign ENVIRO ONE or Pager 670-3471, #532.
DEPUTY OPERATIONS SECTION CHIEF (ON-SCENE COMMANDER)	☐ Report to scene, if required. ☐ Make an initial assessment of the spill and associated safety and environmental issues. ☐ Stop the source of spill if possible. ☐ Upon arrival on scene, begin response operations. If necessary, mobilize SRT and on-site equipment required to control and clean up spill. ☐ Work with the Environment Team to report spill to agencies. ☐ Assess response activities. If response is adequate, remain at Level I. If additional capabilities are needed, go to Level II/III response. ☐ Supervise control and recovery operations. Upon completion, ensure appropriate storage and disposal of oily wastes/materials. ☐ Confirm success of cleanup and plan remediation if required. ☐ Assess response activities. If response is adequate, remain at Level I. If additional capabilities are needed, go to Level II or Level III response below.
LEVEL II & III SPILLS	
RADIO DISPATCHER/ OPERATOR	☐ Immediately notify: • SRT • Environmental Advisor • Milne Point Onshore Site Manager • Area Operations Manager North



*Milne Point Unit ODPCP, Volume 1 – Response Action Plan***TABLE 1-1 (CONTINUED): IMMEDIATE RESPONSE CHECKLIST**

LEVEL I, II, & III SPILLS	
SAFETY OFFICER	☐ Account for the safety of personnel. ☐ Ensure establishment of site-entry and exit procedures, including lower explosive limit (LEL) and air monitoring, and personnel and equipment decontamination. ☐ Determine if a threat of fire or explosion exists. If a threat exists, suspend control and/or response operations and notify Fire/Safety Department. ☐ Determine appropriate personal protective equipment (PPE) and brief site workers.
ENVIRONMENTAL ADVISOR TEAM 670-3382 (Milne Point)	☐ Make immediate phone notification to the agencies. ☐ Initiate necessary permits for agency approval. ☐ Prepare cleanup and waste management plan for agency approval. ☐ Ensure agency notifications are complete and maintain follow-up notifications on a periodic basis and whenever there is a significant change in the course of a reported incident.
INCIDENT COMMANDER	☐ Activate all or part of the IMT and establish the Command Post. ☐ Notify the BP Notification Center at 1-800-321-8642. The BP Notification Center will contact BPXA's BST Duty Officer and share information provided by the Incident Commander (IC). Provide the BP Notification Center with a contact name and phone number. ☐ Notify Qualified Individual (QI) ☐ Continue internal and external notifications. ☐ Maintain communications with Anchorage Crisis Center. ☐ Coordinate staff activity. ☐ Manage incident operations and approve release of major resources and supplies.
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, staff, material, and supply needs. ☐ Supervise control and recovery operations. ☐ Ensure appropriate storage and disposal of oily wastes/materials.
PLANNING SECTION CHIEF	☐ Ramp up Planning Section. ☐ Ensure Agency Notifications have been made and updates are provided. ☐ Compile and display status information in Command Post. ☐ Assist in development of planning process. ☐ Document aspects of the response. ☐ Provide environmental support as needed.
LOGISTICS SECTION CHIEF	☐ Order equipment, personnel, material, and supplies as requested. ☐ Provide transportation support. ☐ Provide support for all field operations and Command Post operations.



Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-1 (CONTINUED): IMMEDIATE RESPONSE CHECKLIST

LEVEL II & III SPILLS	
FINANCE SECTION CHIEF	☐ Issue cost code for tracking of expenses. ☐ Notify insurance representatives as warranted. ☐ Track expenditures and provide audit function as needed.
BST DUTY OFFICER	☐ Activate BST as needed to support operation. ☐ Coordinate with the IC to mobilize backup resources. ☐ Activate the Anchorage Crisis Center to provide information distribution support. ☐ Coordinate Government and Public Affairs notification and information effort.



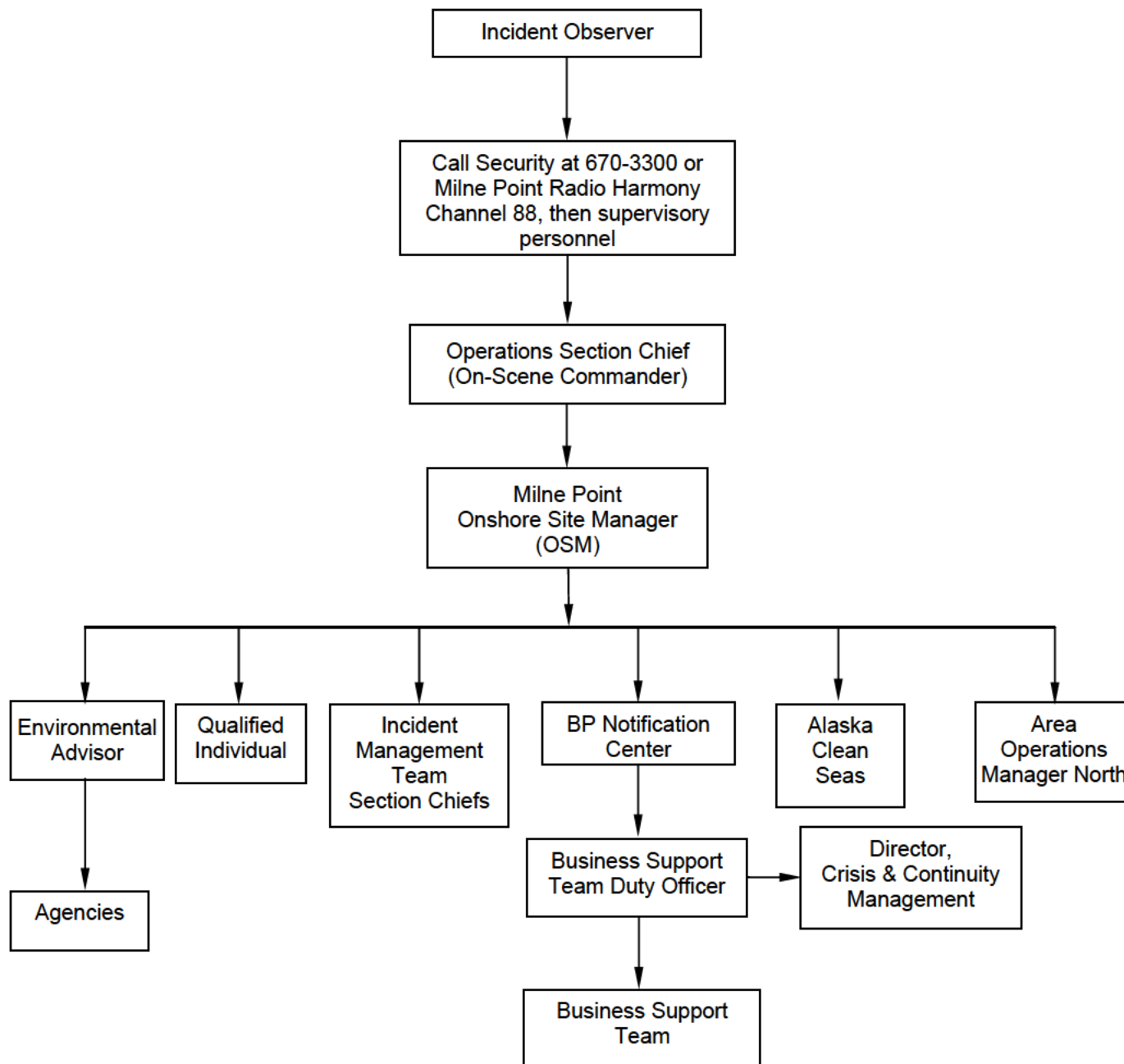
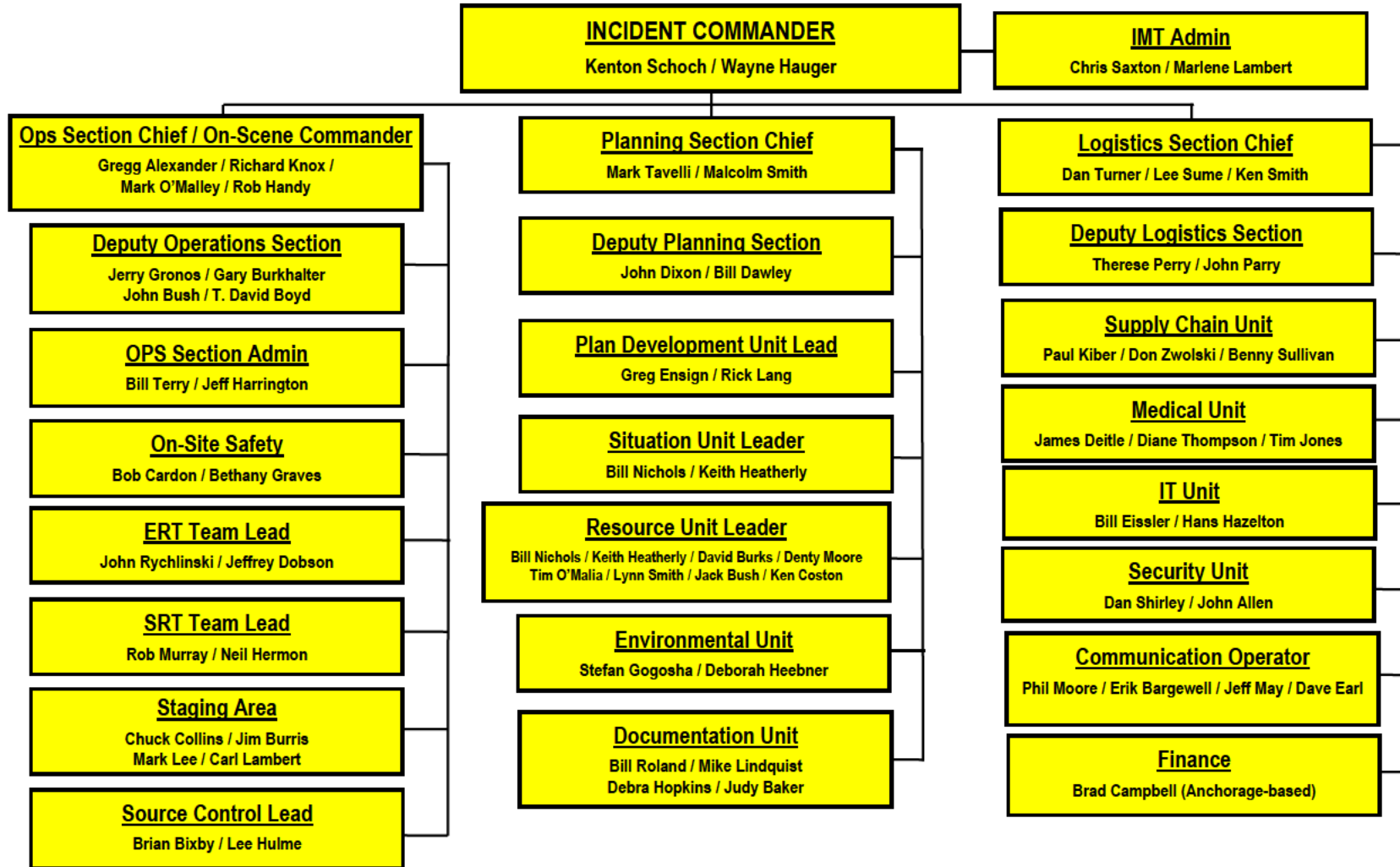
FIGURE 1-1: IMMEDIATE SPILL NOTIFICATIONS AND REPORTING

FIGURE 1-2: MPU INCIDENT MANAGEMENT TEAM



The IMT is activated by dispatch via Harmony radio system at the direction of the Incident Commander.

Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

TABLE 1-2: BPXA CONTACT LIST

POSITION	NAME	TELEPHONE
VP Operations	Bruce Williams	(907) 564-4632
Environmental Team Lead (North Slope)	Tom Barrett / Chuck Wheat	(907) 659-5196
ENDICOTT/BADAMI		
Endicott OIM / Qualified Individual	Rick Rodriguez / Gary Herring	(907) 659-6555
Endicott OTL / Alternate Qualified Individual	Paul Boots / Konrad Schruff	(907) 659-6527
Environmental Advisor North	Geoff Kany / Chrissy May	(907) 659-6810
ACS Environmental Tech. – Endicott	Vince Volpe / Lance Douglas	(907) 659-6541
MILNE POINT UNIT (MPU)		
MPU OSM / Qualified Individual	Kenton Schoch / Wayne Hauger	(907) 670-3323
MPU Field OTL / Alt. Qualified Individual	Mark O'Malley / Rob Handy	(907) 670-3330
MPU Facility O&M TL / Alt. Qualified Individual	Gregg Alexander / Richard Knox	(907) 670-3331
Environmental Advisor MPU	Stephan Gogosha / Deb Heebner	(907) 670-3382
ACS Environmental Tech – MPU	Rob Murray / Neil Hermon	(907) 670-3473
NORTHSTAR		
Northstar OIM / Qualified Individual	JoDee Johnson / Jerry Sharp	(907) 670-3576
Alt. Qualified Individual (GPB QI)	Adrian McCaa / Shawn Croghan	(907) 659-4490
Environmental Advisor North	Geoff Kany / Chrissy May	(907) 659-6810
ACS Environmental Tech – Northstar	Philip Hubbard / Greg Guild	(907) 670-3508
GREATER PRUDHOE BAY (GPB)		
Campaign Maint. OSM / Qualified Individual	Adrian McCaa / Shawn Croghan	(907) 659-4490
Inspection Exec. TL / Alt. Qualified Individual	Randy Selman / Randy Sulte	(907) 659-8185
Environmental Advisor West	Bill Fletcher / Steve McKendrick	(907) 659-4789
Environmental Advisor East	Mike Villanova / Eric Boyette	(907) 659-5999
Environmental Advisor Central	Patrick Conway / Alex Reyes	(907) 659-5893
Environmental Advisor – Functions	Beth Sharp / TBD	(907) 659-4145
ACS Environmental Spill Technician – West	Fred Chace / Vic Richart	(907) 659-4159
ACS Environmental Spill Technician – East	Cory Settle / Tommy Cumming	(907) 659-5800
WELL CONTROL SPECIALISTS	(800) BLOWOUT / (800) 256-9688	
Boots and Coots Services	(281) 931-8884	
ALASKA CLEAN SEAS, OSRO		
Prudhoe Bay Office, Pouch 340022	Ron Hocking / Fred McAdams,	(907) 659-2405
Prudhoe Bay, Alaska 99734	Operations Mgr.	
BP Notification Center (Naperville)		(800) 321-8642
The numbers below are 24-hour spill reporting numbers. Qualified Individuals can be reached via these and/or the numbers above.		
Endicott/Badami	(907) 659-2222	
Milne Point Unit	(907) 670-3300	
Northstar	(907) 670-3515	
Greater Prudhoe Bay	(907) 659-5700	
O&M – Operations and Maintenance	OSRO – Oil Spill Removal Organization	TL – Team Lead
OIM – Offshore Installation Manager	OTL – Operations Team Lead	
OSM – Onshore Site Manager	TBD – To be determined	

1.2 REPORTING AND NOTIFICATION [18 AAC 75.425(e)(1)(B) AND 40 CFR 112.20(h)(1) AND (3)]

1.2.1 INTERNAL NOTIFICATION PROCEDURES

It is BPXA policy for employees and contractors to report spills of oil or hazardous substances on BPXA leases to a BPXA representative regardless of size. See Table 1-1, Immediate Response Checklist. The On-Scene Commander or designee ensures that safety is considered and that internal notifications are made.

1.2.2 EXTERNAL NOTIFICATION PROCEDURES

The Environmental Advisor notifies regulatory agencies per the “BPXA North Slope Event Reporting, Clean-up, and Disposal Procedure.” Agency notification requirements for oil spills are listed in Table 1-3. See Figure 1-3, North Slope Spill Report Form.

1.2.3 QUALIFIED INDIVIDUALS [40 CFR 112.20(H)]

In the event of a spill requiring notification of the National Response Center, the Environmental Advisor or designee ensures the designated Qualified Individual (QI) is notified and is able to respond. In the event the primary QI is unavailable, the alternate QI will be contacted to respond. QIs are listed in Table 1-2 BPXA Contact List and Appendix A, Oil Pollution Act of 1990 Addendum.

The prerequisites for designation of a QI, as defined in 33 United States Code (U.S.C.) 1321(c)(4), are:

- Available on a 24-hour basis;
- Speak English fluently;
- Located in the United States;
- Trained as a Qualified and Alternate Qualified Individual under the response plan; and
- Familiar with the response action plan and how to carry it out.

The QI must be trained and authorized to carry out the following responsibilities:

- Activate and engage in contracting oil spill removal organization(s) and other response-related resources,
- Act as a liaison with the Federal On-Scene Coordinator, and
- Acquire funds to carry out response activities.

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

The QI and alternate QI are not responsible for:

- The adequacy of the response plan prepared by the owner/operator, and
- Acquiring funds for response resources beyond the full authority as designated by the owner/operator.

The QI or the QI's designee communicates to appropriate federal officials and response personnel if there is an oil spill requiring those communications (30 Code of Federal Regulation (CFR) 254.53(a)(2)). Many spill response duties are delegated to members of an IMT (40 CFR 112.20(h)(3)(ix)). The immediate duties are listed in Table 1-1.

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-3: AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
National Response Center (NRC) Notifies federal agencies as applicable. See specific federal agency below for guidance on reportable spill size.	Off pad to water or tundra	Any	Immediately	(800) 424-8802 (24 hr)	--	Not required – form is completed during phone notification process.
	To ice pad, ice road, or snow-covered tundra from an improperly functioning vessel/vehicle engine ¹	Any	Immediately			
EPA	Navigable waters of the U.S. (includes tundra) or to land that may threaten navigable waters	Any	Immediately	Anchorage (907) 257-1342 (907) 271-5083 (907) 271-3424 (FAX) (M-F, 8 to 5) Seattle (206) 553-1263 (24 hr)	Matt Carr	For facility requiring Spill Prevention, Control, and Countermeasures (SPCC) Plan, if spill is 1,000 gallons or more or if it is second spill >42 gallons in 12 months to water or tundra.
U.S. Department of Transportation (DOT)	From a DOT-regulated pipeline and spill is not in or threatening navigable waters	≥5 gallons, resulting from an accident	Immediately ²	(800) 424-8802	NRC and State Office of Pipeline Safety (Note: NRC notifies federal agencies)	Required within 30 days on DOT Form 7000-I (see form for details).
		≥210 gallons, resulting from pipeline maintenance activity ³	Monthly written report			
	From a DOT-regulated pipeline and spill is in or threatening navigable waters	Any	Immediately	(800) 424-8802		Not required – form is completed during phone notification process
State Pipeline Coordinator's Office (Joint Pipeline Office) Anchorage, Alaska	Pipelines administered by the State Pipeline Coordinator's Office (SPCO) authorized under AS 38.35	Any	Immediately	(907) 257-1330 (direct) (907) 257-1300 (office) (907) 272-0690 (FAX)	Mike Thompson (State Pipeline Coordinator)	Not required.



Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

TABLE 1-3 (CONTINUED): AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
Alaska Department of Environmental Conservation (ADEC)/Alaska Department of Natural Resources (ADNR) ⁴ ADNR has the same spill reporting requirements as ADEC ⁴	Off pad to water or tundra	Any	Immediately (within 30 minutes)	<u>ADEC</u> (907) 451-2121 (907) 451-2362 (FAX) or <u>Alaska State Troopers</u> (800) 478-9300 (M-F after 5, Sat, Sun)	<u>ADEC</u> Tom DeRuyter ADEC fax number or <u>Alaska State Troopers</u> After-hours spills with immediate notification requirements	Required within 15 days after spill containment and cleanup are completed, or if no cleanup occurs, within 15 days after discharge or release.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra (Note: spills to snow, ice roads, and ice pads that do not penetrate to surface water or tundra are treated as spills to gravel pads)	<1 gallon	None			
		1 to 10 gallons	Monthly written report			
		>10 to 55 gallons	Within 48 hours			
		>55 gallons	Immediately			
	Impermeable secondary containment areas or structures	>55 gallons	Within 48 hours	ADNR (907) 451-2678 (907) 451-2751 (FAX)	ADNR Spill Report Number ADNR fax number	

¹ Oil spills from "properly functioning vessel" engines are not reportable to the NRC (exempt by 40 CFR 110.5). "Vessel" is defined as any artificial contrivance used or capable of being used as a means of transportation on water [33 U.S.C. §1311(a)(3)]. This includes trucks, rolling stock, and exploratory vehicles traveling on frozen tundra, but not equipment like light plants. Equipment used for traveling on ice roads, including vehicles, construction machinery, water trucks, and rolligons, will be considered a "vessel" by EPA. "Improperly functioning" refers to mechanical problems such as a broken line or hose.

² The operator shall give verbal notice if the release:

- Caused a death or personal injury requiring hospitalization;
- Resulted in either a fire or explosion not intentionally set by the operator;
- Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator and/or others exceeding \$50,000;
- Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; and
- If, in the operator's judgment, it was significant even though it did not meet the criteria.

³ No report is required for a release less than 5 barrels resulting from a pipeline maintenance activity if the release is:

- Not otherwise reportable;
- Did not result in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; and
- Confined to company property or pipeline right-of-way and cleaned up promptly.

⁴ The low concentrations and volumes of scale inhibitors, corrosion inhibitors, or biocides that are contained in and being used for their intended purpose in brines, seawater, produced water, drilling fluids, or crude oil do not trigger a spill reporting requirement. Rather, the requirement to notify ADEC of the release shall consider the parent material without the inclusion of these substances. As with all spill reports, all materials released must be included in the report whether or not they would, on an individual basis, trigger a reporting requirement to the State.



*Milne Point Unit ODPCP, Volume 1 – Response Action Plan***TABLE 1-3 (CONTINUED): AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS**

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
Alaska Oil and Gas Conservation Commission (AOGCC)	From wells or involving any crude loss Uncontrolled releases	Any >10 barrels or resulting in the shutdown of operations at production facilities	Immediately	(907) 279-1433 (24 hr) (907) 276-7542 (FAX) (907) 659-3607 (pager) (907) 659-2717 (FAX)	Dan Seamount John Norman Cathy Foerster	Required within 5 days of loss and Final report within 30 days
North Slope Borough	Off pad to water or tundra	Any	Immediately	(907) 852-0440	Planning Department	Copy of reports submitted as requested.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra	>55 gallons	Immediately		<u>After Hours*</u>	
	Impermeable secondary containment areas or structures	>55 gallons	Within 48 hours		Thomas Simmonds III, (907) 717-5668 Gordon Matumeak, (907) 878-2194 Charles Russell, (907) 878-4849 Tony Cabinboy, (907) 878-2193	

* North Slope Borough after hours reporting is a courtesy.



*Milne Point Unit ODPCP, Volume 1 – Response Action Plan***FIGURE 1-3: NORTH SLOPE SPILL REPORT FORM**

Company:	Cause:					
Contact:						
Phone Number:						
Spill Date:						
Spill Time:	Cleanup:					
Location:						
Material Spilled:						
Amount:						
Area Affected:	Disposal:					
Contained?						
Tundra or water affected?						
Weather Conditions? (temp, wind speed, skies)						
Comments:						
Time BPXA Person-in-Charge of Facility (Environmental Advisor) first obtained Knowledge of the Spill:						
Agency	Phone	Date	Time	Reported By	Reported To	Report Number
NRC (notifies EPA/ USCG/ USDOT/ BSEE) (+ GPB see note below) For DOT PL events, notify the BP DOT PL TL For BSEE events, notify Regional Supervisor.	(800) 424-8802					
ADEC After Hours (STATE TROOPERS)	(800) 478-9300					
ADEC During Business Hours	(907) 451-2121					
ADEC (sewage)	(877) 569-4114					
ADFG	(907) 459-7200					
ADNR	(907) 451-2678					
AOGCC (Anchorage)	(907) 279-1433					
AOGCC (Slope)	(907) 659-3607					
NSB During Business Hours	(907) 852-0440					
NSB After Hours	(907) 878-2193					
SPCO	(907) 257-1300					
BSEE (Notify for oil spills ≥ 1 bbl)	(907) 334-5300					
NPDES Hotline	(206) 553-1846					

Note FOR GPB ONLY: For spills reported to NRC and >10 gallons to water or tundra, or >55 gallons to gravel pad (includes snow, ice roads and ice pads), Send an email or fax to Robbie Hedeem at EPA within 5 days (hedeem.roberta@epa.gov, fax 206-553-8509).

Done on Date:

Time:



1.2.4 REPORTING REQUIREMENTS

Immediate reports are made to the NRC and other agencies verbally, and contain the information sought on the NRC online reporting report (to the extent known at the time of initial notification) or on the form found in Figure 1-3.

Depending upon the type and amount of the release, individual government agencies have written reporting requirements. See Table 1-3.

Written reports include the following:

- Date and time of discharge;
- Location of discharge;
- Name of facility, vessel or pipeline;
- Weather conditions on scene;
- 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, vessel or pipeline;
- Type and amount of each hazardous substance discharged;
- Cause of the discharge;
- Description of environmental damage caused by the discharge;
- 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; and
- Other information the agency requires to fully assess the cause and impact of the discharge.

Immediate reports are made to the NRC and other agencies verbally, and contain the information sought on the NRC online reporting fixed report (to the extent known at the time of initial notification) or on the form found in Figure 1-3.

1.3 SAFETY [18 AAC 75.425(e)(1)(C) AND 40 CFR 112.20(h)(3)]

The BP Control of Work Requirement was developed to reduce the number and frequency of injuries and serious incidents that occur in the workplace. The requirements ensure that there is a formal approach to managing work risks. The requirements are a procedural form of control, consisting of 12 elements supported by mandatory requirements. They cover the means of safely controlling construction, maintenance, demolition, remediation, operating tasks and similar work activities and apply to BP employees and every employee of any other company engaged to perform work on BPXA premises. The requirements are detailed in the *2010 BP Team Alaska Safety Handbook*.

The steps to develop an incident-specific safety plan are outlined in the *ACS Technical Manual*, Tactics S-1 through S-6. The *ACS Technical Manual*, Tactics S-1 through S-6, incorporated here by reference, discuss site entry procedures, site safety plan (ICS Form 201-5) development, and personnel protection procedures.

The *2010 BP Team Alaska Safety Handbook* covers the key standards and procedures used at BPXA that are essential to safely perform work. The handbook is distributed to BPXA employees and contractors.

The BPXA well plan prepared for each drilling operation conducted on the North Slope is 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; uses the best technical information available concerning subsurface formation characteristics and pressures; and provides information critical to the success and safety of the drilling program.

Emergency procedures are in place for evacuation in and around the facility in the event of a discharge or release of stored materials. The location of stored materials is presented in Volume 2 (Table 3-1 and Appendix A). Hazards posed by discharged materials and a discussion of discharge flow direction, prevailing wind direction and speed, receiving environment, and emergency response actions are presented in the response scenarios in Part 1 and in tables and text in Parts 2 and 3.

Emergency procedures are on the BPXA intranet and are available to employees and contractors. The procedures cover alarm and notification systems, primary and alternate evacuation routes, designated safe areas, roll-call procedures, and initial identification and treatment of injured personnel, including transportation to medical facilities. Evacuation routes identifying designated safe areas are posted on diagrams throughout the facility. Safe areas for well pads are the pad entrances or upwind of the incident. In the event of an incident, the Incident Command Post (ICP) is set up in the Milne Point Unit (MPU) gymnasium.

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

The communications plan is compatible with the communications equipment available through BPXA's Anchorage office, BPXA's North Slope facilities, and ACS. Radio equipment on site is listed in Table 1-4.

TABLE 1-4: RADIO EQUIPMENT

Equipment	• 10 MT1000 hand-held radios • VHF oil spill repeater and antenna (located at Kuparuk CPF3) • Harmony Radios
VHF Frequencies	VHF Oil Spill (OS-35, located at Kuparuk CPF3): • Repeater transmit: 154.585 MHz • Repeater receive: 150.980 MHz

VHF and Harmony radios allow the Forward Command Post (FCP) to communicate with the ICP and Section Chiefs. Telephone, cell phone, fax and e-mail communication allows for connection between the ICP, Anchorage Crisis Center, government agencies, and support contractors. It also provides for hardcopy transmissions for documentation.

During a Level II or III response, on-site communication may be established by transporting the FCP to the location. The module can be transported by truck or rolligon. The module allows work space for response personnel and a communication center.

The VHF repeater provides a direct tie-in to the ACS communications system. With such repeaters installed across the North Slope, coverage is provided from Alpine 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 provides the repeater, coast station, antennas, hand-held radios, and backboarded mobiles when necessary in an emergency.

A detailed explanation of oil spill communications on the North Slope is provided in the ACS *Technical Manual*, Tactic L-5, incorporated here by reference.

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

In this plan, mobilization means readying for travel. Deployment means readying for use at the site. Travel time is the period between mobilization and deployment.

BPXA daily operations provide an infrastructure for a spill response. The road system is an extensive network that allows land access to major facilities. The extensive transportation infrastructure of personnel and equipment can support a small response and can be enhanced for a major spill. Transportation options depend on location, season, and weather, and are summarized in Table 1-5.

TABLE 1-5: SEASONAL TRANSPORTATION OPTIONS

MODE	SEASON		
	SUMMER	WINTER	BREAKUP/FREEZE-UP
Vessels	X	NA	X
Airboats	X	X	X
Helicopters	X	X	X
Fixed-Wing Aircraft	X	X	X
Vehicles	X	X	X
Heavy All-Terrain Vehicles (ATVs)/Rolligon	X	X	X

The ACS *Technical Manual*, Tactics L-3, L-4, and L-6 provide detailed information on transportation procedures and are incorporated here by reference. Transportation times would be unaffected by freeze up and breakup conditions for modes of transport other than vessels. ACS bay boats can be used to transit in ice up to 4 inches thick during freeze-up, with some limitations. Other vessels would not be used during this time. During breakup, vessel response is limited to airboats.

If the Kuparuk River bridge washes out, typically a few days between mid-May and mid-June, it may impact spill response time at Milne Point. This potential impact is mitigated in several ways. Equipment and supplies are stockpiled on the west side of the bridge prior to the anticipated annual washout. It is estimated additional personnel from Greater Prudhoe Bay Unit (GPB) and ACS can arrive by helicopter to assist with the deployment of pre-staged connex and trailer equipment within 1 hour of notification. It would take an estimated 3 to 4 hours for additional equipment to arrive. When the river precludes bridge traffic, Milne Point may rely more upon mutual aid resources from Kuparuk.

Marine vessel access is available from July through September. BPXA and ACS have contracts in place with the major North Slope marine contractors.

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

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

Section 1.1 describes immediate response and notification actions, which include notification of ACS. While ACS is mobilizing personnel and equipment to the spill site, on-site BPXA and ACS personnel determine safety procedures, notify government agencies and BPXA personnel, and proceed with source-control measures. Off-site BPXA personnel may be consulted as necessary. See Table 1-1.

1.6 RESPONSE SCENARIOS AND STRATEGIES [18 AAC 75.425(e)(1)(F) AND 40 CFR 112.20(h)(5)]

1.6.1 QUALIFIER STATEMENT

Scenarios are developed in accordance with 18 Alaska Administrative Code (AAC) 75.425(e)(1)(F) and (I), 18 AAC 75.445(d) and 40 CFR 112.20(h)(5). They describe equipment, personnel and strategies that could be used to respond to an oil spill. The scenarios describe oil spill recovery by 100% mechanical means, as required by 18 AAC 75.425(e)(1)(F)(vii).

The scenarios are for illustration only and are not performance standards or guarantees of performance. 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 an incident, 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 required permits.

Although equipment is specified in the scenarios, 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 people in charge of the spill response to select a specific sequence or take the time they deem necessary for an effective response without jeopardizing safety.

Some scenarios simulate heavy equipment operators, e.g., truck drivers and front-end loader operators. Personnel in the equipment operator category typically operate their equipment on a regular schedule on the North Slope unrelated to spill responses and are not members of the North Slope Spill Response Team (NSSRT).

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.

The response strategies illustrate specific response measures that can reduce the risk, magnitude or environmental consequences of an oil spill during periods of sea ice when mechanical spill response is limited, as described in 18 AAC 75.445(f) and 18 AAC 75.425(e)(3)(D). Section 3.4, Realistic Maximum Operating Limitations, and Section 3.7, Non-Mechanical Response Information, describe the capability of BPXA and ACS to effectively remove spilled oil by means of in situ burning in a range of ice conditions during spring breakup and fall freeze-up.

1.6.2 RESPONSE PLANNING STANDARD [18 AAC 75.430]

The Response Planning Standard (RPS) scenarios presented in this section show that the plan meets the RPS volumes described in Part 5.

1.6.3 WASTE DISPOSAL APPROVAL [40 CFR 112.20(H)(7)(III)]

The method of disposal for oil and contaminated materials from oil spill recovery operations must be approved by state and federal agencies before implementation. At the time of the spill, the Operations Section Chief, in consultation with the Environmental Unit Leader, will determine a reuse, recycle, or

disposal method best suited to the condition of the oil, the degree of contamination of recovered debris, and the logistics involved. See Tactics D-1 through D-5 in the *ACS Technical Manual*.

When an IMT is not involved, spills of crude oil and exempt hazardous substances (refined fuels, lube and hydraulic oils, produced waters, seawater, source water, glycol, and drilling muds) of 200 gallons or less to gravel pads, roads, ice roads, or ice pads can automatically use pre-approved permitted storage and disposal facilities. For spills above the threshold level, or to other receiving environments, approval for storage and disposal will be obtained from the State On-Scene Coordinator (SOSC) before material is removed to those facilities. The approval can be in the form of a verbal communication during initial spill notification.

An initial determination of exempt, hazardous, or non-hazardous must be made for classification of the waste. This classification must 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. For example:

- Spills from common carrier transportation pipelines are non-exempt, and it must be determined whether the material to be disposed of is hazardous.
- 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 it must be determined whether the material to be disposed of is hazardous.
- Spills of non-exempt fluids that occur during filling a tank (e.g., vehicle, storage, etc.) are non-exempt, even though they may occur on a well pad, and it must be determined whether the material to be disposed of is hazardous.

The preferred management option for recovered oil and diesel is to recycle it back into the production stream. If the material is not suitable for recycling, a waste classification will be determined. If hazardous, it will be placed in drums and stored on site until it is shipped to an approved hazardous waste treatment, storage, or disposal facility. The Environmental Advisor will determine the appropriate management method. Guidelines for handling and managing oil and contaminated materials from oil spill recovery operations or for oily waste from normal operations are found in the “Alaska Waste Disposal and Reuse Guide.”

1.6.4 RESPONSE SCENARIOS AND STRATEGIES

The Response Planning Standard (RPS) scenarios presented in this section and listed below show how the plan meets the RFP volumes presented in Part 5.

- Scenario 1: Oil Tank Rupture During Typical Summer Conditions
- Scenario 2: Production Well Blowout During Typical Summer Conditions
- Scenario 3: Production Well Blowout During Typical Winter Conditions
- Scenario 4: Crude Oil Transmission Spill During Summer
- Strategy #1: Production Well Blowout to Open Water

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

- Strategy #2: Production Well Blowout to Broken Ice
- Strategy #3: Flowline Rupture Over Central Creek to Open Water

THIS PAGE INTENTIONALLY LEFT BLANK

SCENARIO 1

**OIL TANK RUPTURE DURING
TYPICAL SUMMER CONDITIONS**

THIS PAGE INTENTIONALLY LEFT BLANK

**TABLE 1-6: OIL TANK RUPTURE DURING TYPICAL SUMMER CONDITIONS
SCENARIO CONDITIONS**

PARAMETER	CONDITIONS
Spill Location	MPU CFP, Oil Reserve Tank (ORT) T-6001
Date and Time	August 1, 6:00 am
Cause of Spill	Tank Failure
Quantity of Spilled Oil	Adjusted RPS volume = 998 barrels (bbl) that escapes secondary containment. No oil reaches open water. Refer to Part 5 for detailed explanation of adjusted RPS.
Oil Type	Alaska North Slope crude oil
Weather	Sunny, 45 degrees Fahrenheit (°F)
Spill Trajectory	Oil flows across the pad and onto the tundra. The spill affects approximately 8,500 square feet (ft²) on the pad; infiltrating to a depth of approximately 3 feet. Assuming an absorption rate of 0.125 bbl per cubic yard (ACS <i>Technical Manual</i> Tactic R-5), the pad retains approximately 122 bbl. The affected pad area measures 75 feet long from the edge of secondary containment and 160 feet wide at the toe of the pad. Oil not retained on the pad flows onto the tundra and affects an area of 36,000 ft² of tundra. The oiled tundra extends approximately 150 feet north of the pad and is approximately 320 feet wide at that point. Approximately 75 bbl of oil is projected to reach small ponds adjacent to the pad (Figure 1-4). The ponds do not drain directly to the Beaufort Sea.

**TABLE 1-7: RESPONSE STRATEGY - OIL TANK RUPTURE
DURING TYPICAL SUMMER CONDITIONS**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	A plant operator requests lines flowing into the ORT be closed. The tank shut-in procedure is evaluated to ensure possible sources have been secured. Notification procedures begin, along with SRT mobilization. A staging area and field command post are established at the CFP. Within the first two hours of the spill the production supervisors prepare a team to perform repairs to the tank and initiate fluid transfer from the damaged ORT to the other ORT.	A-1, A-2, L-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the On-Scene Commander, with the assistance of the Site Safety Officer, verifies that all sources of ignition are shut down or removed from the area. The Site Safety Officer and On-Scene Commander perform a visual inspection of the tank and a site safety assessment. After declaring the area clear, the Site Safety Officer begins to prepare a site safety plan (ICS Form 201-5) including PPE requirements. The first draft of site safety plan focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. 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
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up by Hour 4, the oiled area is delineated. The extent of oil on the pad and tundra is delineated on land with lathe and/or hand-held global positioning systems (GPS) units. By Hour 4 an aircraft is dispatched to monitor for oil in surrounding bodies of water. If the oil reaches water, the slick is tracked by the aircraft, which records with forward-looking infrared (FLIR) system. The infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. Field data are used to periodically update the map.	T-1, T-2 T-4 T-7
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit Leader identifies priority protection sites, relying on the ACS <i>Technical Manual</i> descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major concern. No priority protection sites are within the plume. The area is monitored for birds and mammals that may be at risk from the spill.	ACS Map Atlas Sheet 37, W-6
(vi) Spill Containment and Control Actions	Application for burn permits are undertaken. After the decontamination area is set up by Hour 4, the SRT places shoreseal boom, sandbags, and sorbent boom on the soiled perimeter of the pad and shoreseal boom on the tundra by Hour 6 to deflect and contain oil.	B-1 C-4

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

**TABLE 1-7 (CONTINUED): RESPONSE STRATEGY - OIL TANK RUPTURE
DURING TYPICAL SUMMER CONDITIONS**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures	By Hour 5, vacuum trucks are set up to collect pooled oil from trenches and other depressions from their position on the pad. A vacuum truck can effectively reach out 200 feet to recover oil. If oil is encountered in ponds it is recovered with a Manta Ray skimmer head. Air monitoring is conducted by the Site Safety Officer (or designee). On Day 2, a backhoe excavates trenches on the pad, enhancing direct recovery. By Day 3, after the easily accessible oil has been recovered, ADEC approves crews to begin flushing low-pressure water over the tundra, moving oil down to collection areas where it is recovered with vacuum trucks and sorbent within the boom. Contaminated vegetation is burned to reduce re-oiling of adjacent habitat or left in place. Once the liquid oil is recovered, contaminated gravel is recovered on a non-emergency basis with a front-end loader and hauled to stockpiles with dump trucks.	R-6 R-7 R-4 B-2 R-26
(viii) Lightering Procedures	A vacuum truck recovers remaining oil from secondary containment.	R-27
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	By Hour 5, vacuum trucks on the CFP begin collecting the recovered oil directly from the collection areas. If oil is encountered in ponds it is recovered with a Manta Ray skimmer head. Recovered fluids in vacuum trucks are manifested accordingly. Gravel volume estimates and measurements of the fraction of oil in gravel yield oil volume estimates.	R-6 T-7
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Oiled pad gravel is hauled to D Pad Gravel Storage temporarily. Oiled gravel is ultimately transported to GPB Drill Site (DS) 4 grind and inject (G & I) on a non-emergency basis for disposal. Recovered liquids are injected for recycling at the other ORT, T-6101B, if production operations allow. Transportation to Gathering Center 2 (GC-2) is another viable option. If recycling is not possible, recovered fluids are injected at Well B-50 at MPU. Solid oily wastes and non-oily waste are classified and disposed of according to classification.	D-1 D-2 D-3
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. A wildlife task force is on scene by Hour 6 to exclude birds and mammals from entering oiled areas, monitor the oil trajectory area, and prepare to capture oiled animals. The task force operates on foot on Days 1 through 10. A wildlife stabilization and treatment center is made operational and is staffed by International Bird Rescue Research Center (IBRRC) staff by Hour 24. No oiled wildlife are encountered.	W-1 through W-6
(xii) Shoreline Cleanup Plan	Tundra, shorelines, and gravel areas are cleaned over 30 days to the satisfaction of ADEC. Monitoring programs are established for these areas.	R-9 and R-26 SH-1, 2, 3, 4, 5, 7, 10, 11 and 12

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-8: CAPABILITY OF OIL RECOVERY – OIL TANK RUPTURE

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL	NUMBER OF RECOVERY SYSTEMS	RECOVERY SYSTEM	OIL RECOVERY RATE PER UNIT (barrels of oil per hour [boph])	MOBILIZATION, DEPLOYMENT, AND TRANSIT TIME TO SITE ¹ (hours)	OPERATING TIME (hours per 24-hour shift)	OIL RECOVERY CAPACITY (barrels of oil per day [bopd]) B X D X F
LIQUID RECOVERY						
R-6, R-7 (Option 1: Disposal at T-1601B)	2	Vacuum Truck	100 ²	5	20	4,000
R-6, R-7 (Option 2: Disposal GC-2)	2	Vacuum Truck	86 ³	5	20	3,440
TUNDRA						
R-4 and R-7	2	Flushing with Recovery by Vacuum Truck with Manta Ray Skimmer	34	72	20	1,360
OILED GRAVEL RECOVERY						
R-26	2	Front-end Loader with Dump Truck	25 cubic yards/hour ⁴	Non-emergency response.	10	500 cubic yards/day

¹ The sum of the mobilization, deployment, and transit time is not the fastest time possible; rather, it is the time that each specific tactic is first employed in this specific scenario.

² Vacuum truck recovery calculation: $\text{Time} = (\text{miles to disposal} * 2) / 10 \text{ mph} + 2(T_c / S_r)$,
 $\text{Time} = (0.13 \text{ miles from spill site to CFP} * 2) / 10 \text{ mph} + 2(300 \text{ bbl}/200 \text{ boph}) = 3 \text{ hours}$, where,
 T_c = Vacuum Truck Capacity = 300 bbl
 S_r = Suction Rate = 200 boph

Oil recovery rate (ORR) = (vacuum truck capacity/time),

ORR = (300 bbl/3 hours) = 100 boph

³ Vacuum truck recovery calculation: $\text{Time} = (\text{miles to disposal} * 2) / 10 \text{ mph} + 2(T_c / S_r)$,
 $\text{Time} = (8 \text{ miles from spill site to GC-2} * 2) / 35 \text{ mph} + 2(300 \text{ bbl}/200 \text{ boph}) = 3.5 \text{ hours}$, where,
 T_c = Vacuum Truck Capacity = 300 bbl
 S_r = Suction Rate = 200 boph

Oil recovery rate (ORR) = (vacuum truck capacity/time),

ORR = (300 bbl/3.5 hours) = 86 boph,

⁴ Dump recovery calculation: $T_c / (L_t + T_t + U_t) = 20 \text{ cubic yards} / [0.5 \text{ hour} + (4 \text{ miles from E Pad to D Pad} * 2 \text{ trips}/35 \text{ mph}) + 0.08 \text{ hour}] = 25 \text{ cubic yards/hour}$, where,

T_c = Truck Capacity = 20 cubic yards

L_t = Load Time = 0.5 hours

U_t = Unload Time = 0.08 hours



Milne Point Unit ODPCP, Volume 1 – Response Action Plan

**TABLE 1-9: MAJOR EQUIPMENT EQUIVALENTS
TO MEET THE RESPONSE PLANNING STANDARD**

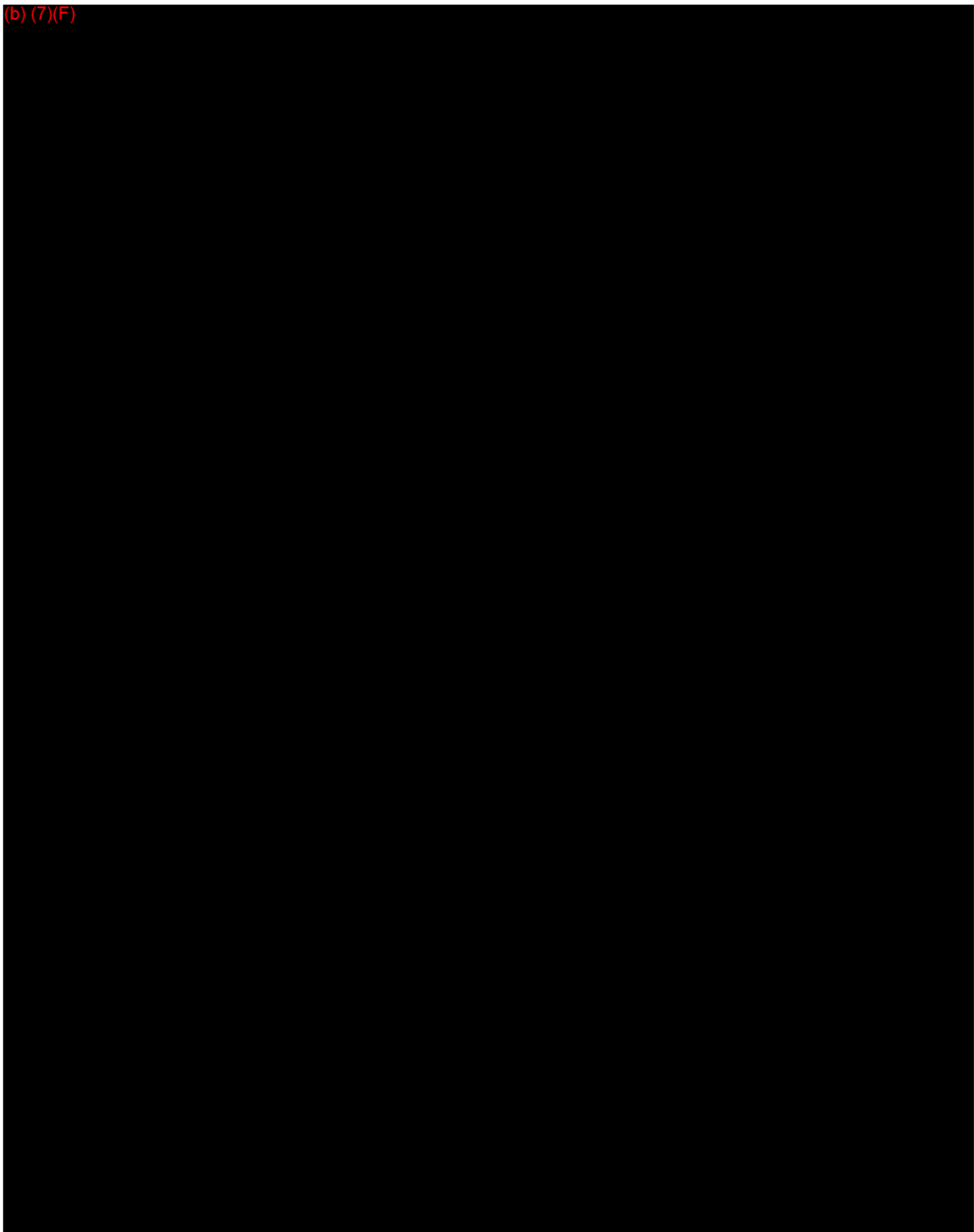
RECOVERY TACTIC	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
Containment		
C-4	Backhoe, Front-end loader (or Bobcat)	2 2
Liquid Recovery		
R-6, R-7	Vacuum Truck	2
Tundra		
R-4	Water Truck	2
R-7	Vacuum Truck with Manta Ray skimmer	2
Oiled Gravel Recovery		
R-26	Backhoe, Front-end loader, Bobcat, 2 Dump Trucks	2 2 2 4

**TABLE 1-10: STAFF TO OPERATE
OIL RECOVERY AND TRANSFER EQUIPMENT**

LABOR CATEGORY	TACTIC	NO. UNITS	NO. STAFF PER UNIT	TOTAL DAYS 1-3	TOTAL DAYS 3-6	TOTAL AFTER DAY 6
Team Lead	Containment	-	-	1	0	0
	Recovery	-	-	1	1	1
Equipment Operator	C-4	4	1	4	0	0
Equipment Operator	R-6, R-7	2	1	2	0	0
General Technician	R-6, R-7	2	1	2	0	0
Equipment Operator	R-4	2	2	0	4	0
Equipment Operator	R-7	2	2	0	4	0
Equipment Operator	R-26	2	5	0	0	10
Total				10	9	11

Note: Equipment operators are not members of the North Slope SRT.

(b) (7)(F)



SCENARIO 2

**PRODUCTION WELL BLOWOUT
DURING TYPICAL SUMMER CONDITIONS**

THIS PAGE INTENTIONALLY LEFT BLANK

**TABLE 1-11: PRODUCTION WELL BLOWOUT DURING TYPICAL SUMMER CONDITIONS
SCENARIO CONDITIONS**

PARAMETER	CONDITIONS
Spill Location	MPU E Pad, Well E-24A
Date and Time	August 1, 6:00 am
Cause of Spill	Uncontrolled well blowout (with assisted lift)
Quantity of Oil Spilled	RPS volume = 789 bopd x 3 days = 2,367 bbl Refer to Part 5 for detailed explanation of RPS.
Oil Type	Alaska North Slope Crude
Weather	Sunny, 40°F
Wind Speed	During summer, the average wind speed is 11 knots. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007). The weather data presented are the summer average from 2001 through 2006.
Wind Direction	During summer, the predominant wind directions are from the east and east-northeast. The predominant wind directions were determined as the 16 cardinal compass directions that blow over 10 percent of the time. See Figure 1-5.
Spill Trajectory	Pad lies on the tundra approximately 2.5 miles from the Beaufort Sea coast. Well E-24A is on a gravel pad. A pond lies 130 feet southwest of Well E-24A. The SL Ross model (1997) predicts that the discharged oil takes the form of an aerial plume extending from the well in the direction of prominent winds (<i>ACS Technical Manual Tactic T-6</i>). The S.L. Ross model indicates that 10 percent of the discharged oil is in the form of drops so small (50 µm or less) that they do not fall to the ground but are held aloft by atmospheric turbulence. For response planning purposes, the 10 percent oil discharge predicted by the S.L. Ross model to remain airborne is proportionally distributed between the recovery zones. Simulated oil flows from the 6.3-inch open orifice well with assisted lift at the rate of 789 bopd with 92 gas-to-oil ratio (GOR), according to AOGCC's production reports from January 2009 through December 2009. These parameters are below the minimum threshold assumptions of the SL Ross model; consequently, the parameters were increased to fit the model assumptions. The oil falls within 275 feet of the well. Approximately 94 percent (2,233 bbl) of the oil falls to the pad. Six percent (145 bbl) falls over the tundra. See Figure 1-6.

TABLE 1-12: RESPONSE STRATEGY - PRODUCTION WELL BLOWOUT DURING TYPICAL SUMMER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the roll of Initial On-Scene IC, calls the emergency phone number, notifies the Drilling Superintendent, NS Well Operations Team lead, and the affected ADW Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the E Pad wells at the surface and subsurface. The electrical submersible pump providing assisted lift is shut down upon pad shutdown. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1, A-2, L-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The On-Scene Commander sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the On-Scene Commander, with the assistance of the Site Safety Officer and Fire Chief, verify no ignition sources in the area. The Site Safety Officer determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations, oil field operations, and traffic are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up by Hour 6, the oiled area is delineated. The extent of oil on the pad and tundra is delineated on land with lathe and/or hand-held GPS units. By Hour 4 an aircraft is dispatched to monitor for oil in surrounding bodies of water. If the oil reaches water, the slick is tracked by the aircraft, which records with FLIR system. The infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. Field data are used to periodically update the map.	T-1, T-2, T-4, T-7
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit Leader identifies priority protection sites, relying on the ACS <i>Technical Manual</i> descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major concern. No priority sites lie within the projected plume. The area is monitored for birds and mammals that may be at risk from the spill.	ACS Map Atlas Sheet 37, W-6

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-12 (CONTINUED): RESPONSE STRATEGY - PRODUCTION WELL BLOWOUT DURING TYPICAL SUMMER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions	After the decontamination area is set up by Hour 6, the SRT places shoreseal boom and sandbags on the perimeter of the pad. Gravel berms are constructed to contain the oil. The SRT also places shoreseal boom around the perimeter of the spill on the tundra by Hour 8. Containment and recovery operations are not conducted directly under the fallout plume, but as closely to the plume as safety protocols allow.	C-4
(vii) Spill Recovery Procedures	Liquid Recovery: By Hour 8 vacuum trucks are set up to collect pooled oil on the tundra, the pad, and from trenches by direct suction. A vacuum truck can effectively reach out 200 feet to recover oil. If oil is encountered in ponds it is recovered with a Manta Ray skimmer head. On Hour 36, the wind shifts. The plume shifts from a SW to a WSW orientation allowing crews better access to oiled areas. On Day 2, trenches are excavated to intercept the flow of oil and channel it to collection areas for recovery. On Day 3, well control is achieved and recovery crews have full access to the site. Liquid recovery continues. Tundra Recovery: Once liquid recovery by direct suction is no longer viable, crews begin flushing low-pressure water over the tundra, moving oil down to collection areas where it is recovered with vacuum trucks and sorbent within the boom. Teams also deploy three rope mops to recover oil in tundra polygons and low-lying areas. Hoses and pumps in series transfer fluids from the containment areas to a Fastank with secondary containment. A vacuum truck then recovers fluids from Fastank and transfers to recycling or disposal as appropriate. Oiled vegetation is burned, if feasible, and as site conditions allow. Oiled Gravel Recovery: Once the flushing crews have completed their task, contaminated gravel is recovered on a non-emergency basis with front-end loaders and hauled to stockpiles on D Pad with dump trucks. Tundra areas are treated over 30 days to the satisfaction of ADEC, based on a plan approved by Unified Command. The oil removal capacity illustrated in the scenario exceeds the response planning standard volume.	R-6 R-7 R-4 R-8 R-24 B-2 R-26
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Vacuum trucks begin collecting the oil by direct suction and from trenches. Recovered fluids in vacuum trucks are manifested accordingly. Front-end loaders and dump trucks transport oiled gravel to D Pad Gravel Storage. Gravel volume estimates and measurements of the fraction of oil in gravel yield oil volume estimates.	R-6, R-7 R-26, T-7

*Milne Point Unit ODPCP, Volume 1 – Response Action Plan***TABLE 1-12 (CONTINUED): RESPONSE STRATEGY - PRODUCTION WELL BLOWOUT DURING TYPICAL SUMMER CONDITIONS**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Recovered oil is injected for recycling at Milne Point's ORTs, as production operation allows. Transportation to Gathering Center 2 (GC-2) is another viable option. If recycling is not possible, recovered fluids are injected at Well B-50 at MPU. Oily gravel is stockpiled at D Pad Gravel Storage temporarily. Oily gravel is ultimately transported to GPB DS4 G & I on a non-emergency basis for disposal. Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly.	D-1 D-4 D-2 D-3
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. A wildlife task force is on scene by Hour 6 to exclude bird and mammals from entering oiled areas, monitor the oil trajectory area, and prepare to capture oiled wildlife. The task force operates on foot on Days 1 through 30. A wildlife stabilization and treatment center is made operational and is staffed by IBRRC staff by Hour 24. No oiled animals are encountered.	W-1 through W-6
(xii) Shoreline Cleanup Plan	Not applicable	Not applicable

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-13: CAPABILITY OF OIL RECOVERY – PRODUCTION WELL BLOWOUT DURING TYPICAL SUMMER CONDITIONS

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL	NUMBER OF RECOVERY SYSTEMS	RECOVERY SYSTEM	OIL RECOVERY RATE PER UNIT (BOPH OR CUBIC YARDS PER HOUR)	MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE ¹ (HOURS)	OPERATING TIME (HOURS PER DAY)	DAILY OIL RECOVERY CAPACITY (BOPD OR CUBIC YARDS PER DAY) B X D X F
Liquid Recovery						
R-6, R-7	2	Vacuum Truck	97 boph ²	8	20	3,880
Tundra Recovery						
R-4 and R-7	2	Vacuum Truck with Manta Ray Skimmer	34	72	20	1,360
R-8	4	Rope Mops	3	72	20	240
Oiled Gravel Recovery						
R-26	2	Front-end Loader with Dump Truck	25 yd ³ /hour ³	Non-emergency response.	10	500 yd ³ /day

¹ The sum of the mobilization, deployment, and transit time is not the fastest time possible; rather, it is the time that each specific tactic is first employed in this specific scenario.

² Vacuum truck recovery calculation: Time = (miles to disposal * 2) / 10 mph + 2(T_c / S_r),
 Time = (0.5 miles from E Pad to CFP * 2) / 10 mph + 2 (300 bbl / 200 boph) = 3.1 hours, where,
 T_c = Vacuum Truck Capacity = 300 bbl
 S_r = Suction Rate = 200 boph
 Oil recovery rate (ORR) = (vacuum truck capacity/time),
 ORR = (300 bbl/3.1 hours) = 97 boph

³ Dump recovery calculation: T_c/(L_t+T_t+U_t) = 20 yd³ / [0.5 hour + (4 miles from E Pad to D Pad* 2 trips/35 mph) + 0.08 hour] = 25 yd³/hour, where,
 T_c = Truck Capacity = 20 yd³
 L_t = Load Time = 0.5 hours
 U_t = Unload Time = 0.08 hours



Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-14: MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD

RECOVERY TACTIC	EQUIPMENT	TOTAL QUANTITY
C-4	Backhoe	2
	Front-end Loader with Bucket	2
R-6, R-7	Vacuum Truck	2
R-4	Water Truck	2
R-7	Vacuum Trucks with Manta Ray skimmers	2
R-8	Rope Mops	4
R-24	Fastank Trash Pump with suction hose and discharge hose	4 Fastanks 1 each suction hose and discharge hose
R-24	Vacuum Truck (Transfer)	1
R-26	Front-end Loader,	1
	Bobcat,	1
	Dump Trucks	2

TABLE 1-15: STAFF TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TACTIC	TACTICAL UNITS	STAFF PER UNIT	DAYS 1 - 3, STAFF PER SHIFT	AFTER DAY 3, STAFF PER SHIFT	NONEMERGENCY OPERATIONS, STAFF PER SHIFT
Team Lead	Containment	2	1	1	0	0
Team Lead	Recovery	2	1	1	2	1
Equipment Operator	C-4	2	2	4	0	0
Equipment Operator	R-6, R-7	2	2	4	4	0
Equipment Operator	R-4, R-7	2	4	0	8	0
General Technician	R-8	4	2	0	8	0
General Technician	R-24	4	2	0	12 set up 6 maintain	0
Equipment Operator	R-26 – Front-end Loader	1	1	0	0	1
	R-26 – Bobcat	1	1	0	0	1
	R-26 – Dump Trucks	2	2	0	0	2
Total	-	-	-	10	34 set up 28 maintain	5

Note: Equipment operators are not members of the North Slope SRT.

FIGURE 1-5: WIND DIRECTION DURING SUMMER

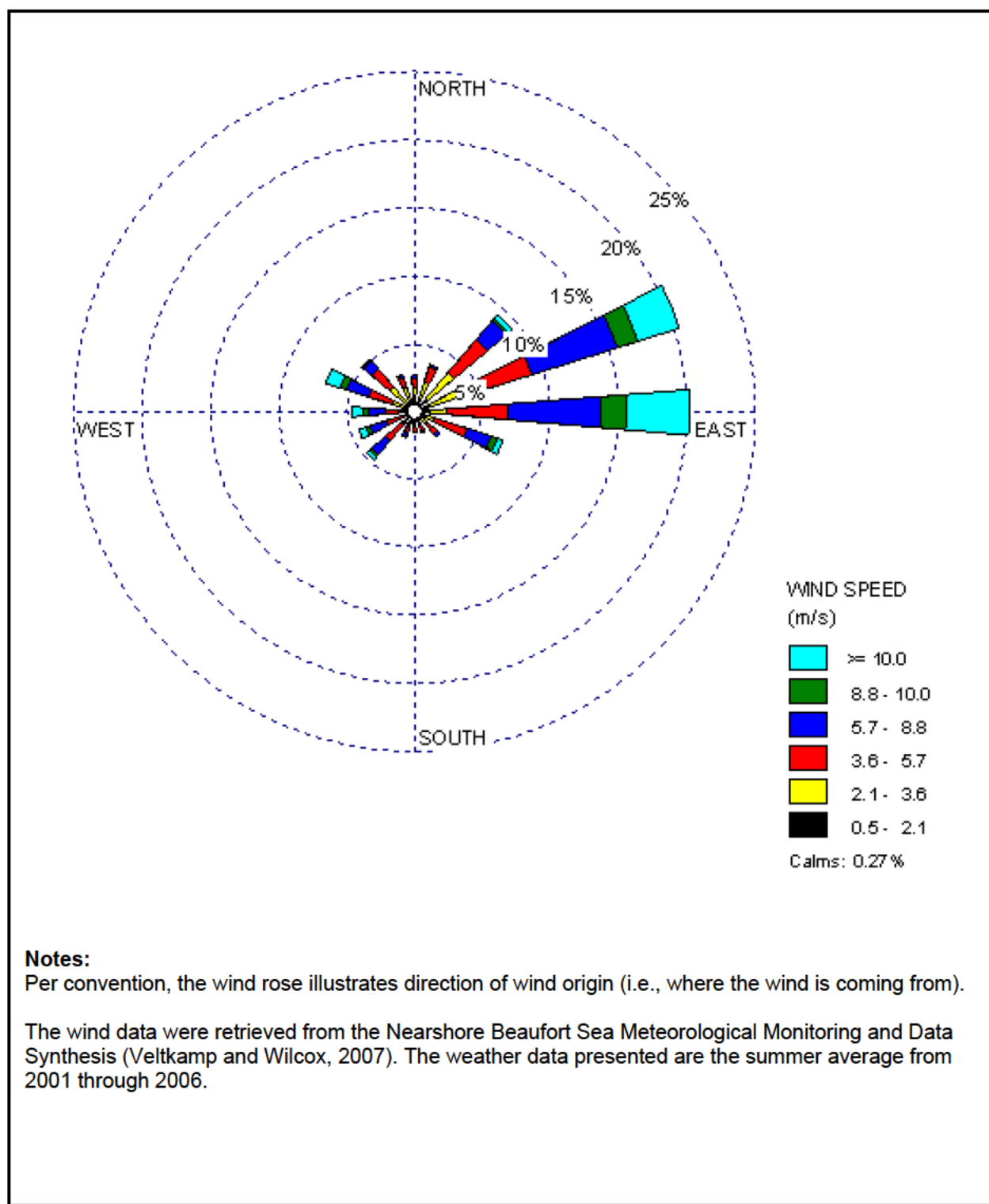
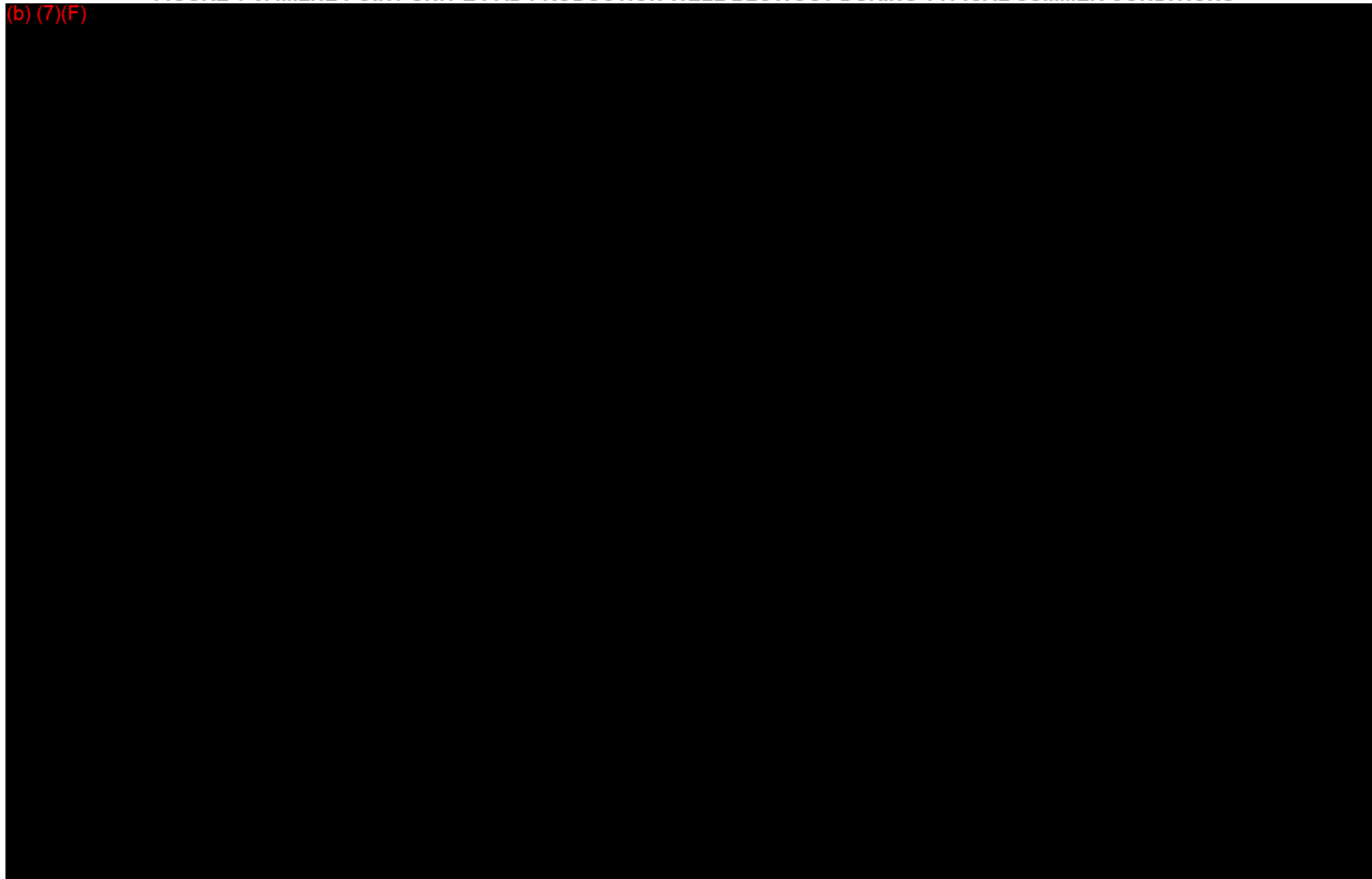


FIGURE 1-6: MILNE POINT UNIT E PAD PRODUCTION WELL BLOWOUT DURING TYPICAL SUMMER CONDITIONS

(b) (7)(F)



SCENARIO 3

**PRODUCTION WELL BLOWOUT
DURING TYPICAL WINTER CONDITIONS**

THIS PAGE INTENTIONALLY LEFT BLANK

**TABLE 1-16: PRODUCTION WELL BLOWOUT DURING
TYPICAL WINTER CONDITIONS SCENARIO CONDITIONS**

PARAMETER	PARAMETER CONDITIONS
Spill Location	MPU E Pad, Well E-24A
Date and Time	February 1, 6:00 am
Cause of Spill	Uncontrolled well blowout (with assisted lift)
Quantity of Oil Spilled	RPS volume = 789 bopd x 3 days = 2,367 bbl Refer to Part 5 for detailed explanation of the RPS.
Oil Type	Alaska North Slope Crude
Weather	Overcast, -20°F
Wind Speed	During winter, the average wind speed is 10 knots. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007). The weather data presented are the winter average from December 2000 through 2006.
Wind Direction	During winter, there are four predominant wind directions. The predominant wind directions were determined as the 16 cardinal compass directions that blow over 10 percent of the time. See Error! Not a valid result for table..
Spill Trajectory	Pad lies on the tundra approximately 2.5 miles from the Beaufort Sea coast. Well E-24A is on a gravel pad. A pond lies 130 feet southwest of Well E-24A. The SL Ross model (1997) predicts that the discharged oil takes the form of an aerial plume extending from the well in the direction of prominent winds (ACS <i>Technical Manual</i> Tactic T-6). The S.L. Ross model indicates that 10 percent of the discharged oil is in the form of drops so small (50 µm or less) that they do not fall to the ground but are held aloft by atmospheric turbulence. For response planning purposes, the 10-percent oil discharge predicted by the S.L. Ross model to remain airborne is proportionally distributed between the recovery zones. Simulated oil flows from the 6.3-inch open orifice well with assisted lift at the rate of 789 bopd with 92 gas-to-oil ratio (GOR), according to AOGCC's production reports from January 2009 through December 2009. These parameters are below the minimum threshold assumptions of the SL Ross model; consequently, the parameters were increased to fit the model assumptions. The discharged oil falls within 275 feet of the well. The directions are dictated by the predominant winds: - From Hour 0 to 13, 439 bbl fall SW of the well. - From Hour 13 to 39, 832 bbl fall WSW of the well. - From Hour 39 to 54, 497 bbl fall W of the well. - From Hour 54 to 72, 600 bbl fall ENE of the well. Overall, approximately 96 percent of the discharged oil falls to the pad, and 4 percent falls to the frozen, snow covered tundra. The fallout plume area is roughly equivalent: approximately 13,800 square feet of pad and 13,800 square feet frozen, snow covered tundra are impacted (before spreading).

**TABLE 1-17: RESPONSE STRATEGY – PRODUCTION WELL BLOWOUT
DURING TYPICAL WINTER CONDITIONS**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the roll of Initial On-Scene IC, calls the emergency phone number, notifies the Drilling Superintendent, NS Well Operations Team lead, and the affected ADW Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the E Pad wells at the surface and subsurface. The electrical submersible pump providing assisted lift is shut down upon pad shutdown. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1, A-2, L-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The On-Scene Commander sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the On-Scene Commander with the assistance of the Site Safety Officer and Fire Chief, verify no ignition sources in the area. The Site Safety Officer determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable OSHA and fire hazard standards. Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations, oil field operations, and traffic are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up by Hour 6, the oiled area is delineated. The extent of oil on the pad and tundra is delineated on land with lathe and/or hand-held GPS units. By Hour 4, a FLIR-capable aircraft is mobilized. Field data are used to periodically update the trajectory map.	T-1, T-2, T-7
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit Leader identifies priority protection sites, relying on the ACS <i>Technical Manual</i> descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major concern. No priority sites lie within the projected plume. The area is monitored for birds and mammals that may be at risk from the spill.	ACS Map Atlas Sheet 37, W-6

Milne Point Unit ODCPCP, Volume 1 – Response Action Plan

TABLE 1-17 (CONTINUED): RESPONSE STRATEGY – PRODUCTION WELL BLOWOUT DURING TYPICAL WINTER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions	After the decontamination area is set up by Hour 6, the SRT builds snow berms around the heaviest oiling at the perimeter of the pad. SRT also selectively places shoreseal boom where snow berms aren't as viable. Trenches are excavated to intercept the flow of oil and channel it to collection areas for recovery. The SRT begins placing snow fencing on the downwind side of the oiled snow on the tundra by Hour 12. Snow fencing prevents the wind from spreading the lightly oiled snow before being recovered. Containment and recovery operations are not conducted directly under the fallout plume, but as closely to the plume as safety protocols allow.	C-1, C-4 C-19
(vii) Spill Recovery Procedures	Liquid Recovery: By Hour 8 vacuum trucks are set up to collect pooled oil on the snow-covered tundra, the pad, and from trenches by direct suction. A vacuum truck can effectively reach out 200 feet to recover oil. On Hour 13, the first wind shift occurs allowing crews better access to oiled areas. On Day 3, well control is achieved and recovery crews have full access to the site. Liquid recovery continues. Oiled Snow Recovery: Contaminated snow is recovered with front-end loaders and hauled to stockpiles on D Pad with dump trucks. Lightly oiled snow on tundra is cleaned up manually with shovels and brooms. Oiled Gravel Recovery: Once the liquid recovery has ceased and the pad structures are cleaned and removed, contaminated gravel is excavated on a non-emergency basis. The gravel is excavated with trimmers and front-end loaders and hauled to stockpiles on D Pad with dump trucks. Oil is removed over 30 days to ADEC's satisfaction. The oil removal capacity illustrated in the scenario exceeds the response planning standard volume.	R-6, R-7 R-3, R-2 R-26
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Vacuum trucks recover oil by direct suction. Recovered fluids in vacuum trucks are manifested accordingly. Oiled snow is stored in interim storage pits at D Pad. The storage pits are monitored until the contents have been processed. Dump trucks transport oiled gravel to D Pad Gravel Storage. Gravel volume estimates and measurements of the fraction of oil in gravel yield oil volume estimates.	R-6, R-7 R-3, R-26, T-7
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Recovered oil is injected for recycling at Milne Point's ORTs, as production operation allows. Transportation to GC-2 is another viable option. If recycling is not possible, recovered fluids are injected at Well B-50 at MPU. Oiled snow and gravel is stockpiled at D Pad Gravel Storage temporarily. Oiled snow and gravel is ultimately transported to GPB DS4 G & I on a non-emergency basis for disposal. Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly.	D-1 D-4 D-2 D-3

**TABLE 1-17 (CONTINUED): RESPONSE STRATEGY – PRODUCTION WELL BLOWOUT
DURING TYPICAL WINTER CONDITIONS**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. A wildlife task force is in place by Hour 6 to exclude bird and mammals from entering oiled areas, monitor the oil trajectory area, and prepare to capture oiled wildlife. The task force operates on foot on Days 1 through 30. A wildlife stabilization and treatment center is made operational and is staffed by IBRRC staff by Hour 24. No oiled animals are encountered.	W-1 through W-6
(xii) Shoreline Cleanup Plan	Not applicable	Not applicable

Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

TABLE 1-18: CAPABILITY OF OIL RECOVERY – PRODUCTION WELL BLOWOUT DURING TYPICAL WINTER CONDITIONS

A SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL	B NUMBER OF RECOVERY SYSTEMS	C RECOVERY SYSTEM	D OIL RECOVERY RATE PER UNIT (boph or yd ³ /hour)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE ¹ (hours)	F OPERATING TIME (hours per day)	G DAILY OIL RECOVERY CAPACITY (bopd or yd ³ /day) B X D X F
Liquid Recovery						
R-6, R-7	2	Vacuum Truck	73 boph ²	8	20	2,920 bopd
Oiled Snow Recovery						
R-3	2	Front-end Loader with Dump Truck	42 yd ³ /hour ³	72	20	1,680 yd ³ /day
R-2	2	Shovels/Brooms/Snow Machine with Trailer	3 yd ³ /hour	72	20	120 yd ³ /day
Oiled Gravel Recovery						
R-26	2	Front-end Loader, Bobcat, Dump Truck	25 yd ³ /hour ⁴	Non-emergency response.	20	1,000 yd ³ /day

¹ The sum of the mobilization, deployment, and transit time is not the fastest time possible; rather, it is the time that each specific tactic is first employed in this specific scenario.

² Vacuum truck recovery calculation: Time = (miles to disposal * 2) / 10 mph + 2(T_c / S_r),
 Time = (0.5 miles from E Pad to CFP * 2) / 10mph + 2 (300 bbl / 150 boph) = 4.1 hours, where,
 T_c = Vacuum Truck Capacity = 300 bbl
 S_r = Suction Rate = 150 boph
 Oil recovery rate (ORR) = (vacuum truck capacity/time),
 ORR = (300 bbl/4.1 hours) = 73 boph

³ Dump recovery calculation for snow: T_c/(L_t+T_t+U_t) = 20 yd³/[0.17 hour + (4 miles from E Pad to D Pad* 2 trips/35 mph) + 0.08 hour] = 42 yd³/hour, where,
 T_c = Truck Capacity = 20 yd³
 L_t = Load Time = 0.17 hours
 T_t = Travel Time = 4 miles from E Pad to D Pad* 2 trips at 35 mph
 U_t = Unload Time = 0.08 hours

⁴ Dump recovery calculation for gravel: T_c/(L_t+T_t+U_t) = 20 yd³ / [0.5 hour + (4 miles from E Pad to D Pad* 2 trips/35 mph) + 0.08 hour] = 25 yd³/hour, where,
 T_c = Truck Capacity = 20 yd³
 L_t = Load Time = 0.5 hours
 T_t = Travel Time = 4 miles from E Pad to D Pad* 2 trips at 35 mph
 U_t = Unload Time = 0.08 hours



**TABLE 1-19: MAJOR EQUIPMENT EQUIVALENTS TO MEET
THE RESPONSE PLANNING STANDARD**

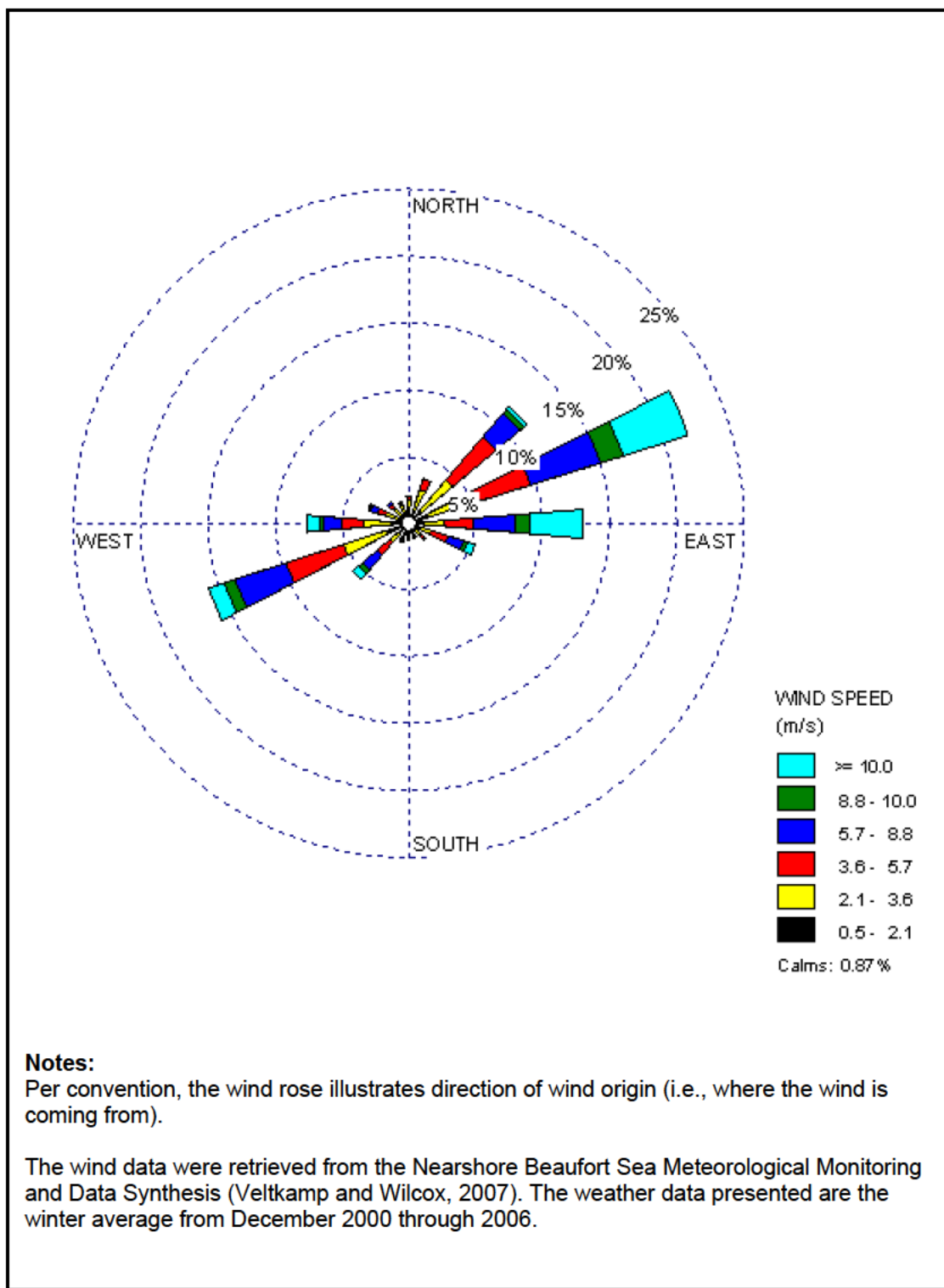
CONTAINMENT/RECOVERY TACTIC	EQUIPMENT	TOTAL QUANTITY
C-1 (on pad)	Front-end Loader	2
C-19	Snow Fencing T-Post Driver T-Posts Wire Ties	150 feet Variable Variable Variable
R-2	Shovels Snow Machine with Trailer Front-end Loader Dump Truck	12 6 2 2
R-3	Front-end Loader Dump Truck	2 2
R-6, R-7	Vacuum Truck	2
R-26	Front-end Loader Bobcat Dump Trucks	2 2 4

TABLE 1-20: STAFF TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	DAYS 1-3, STAFF PER SHIFT	AFTER DAY 3, STAFF PER SHIFT	NONEMERGENCY OPERATIONS STAFF PER SHIFT
Team Lead	Containment	-	-	1	0	0
Team Lead	Recovery	-	-	1	4	1
Equipment Operator	C-1	2	1	2	0	0
General Technician	C-19	2	2	4	0	0
General Technician	R-2	2	9	0	18	0
Equipment Operator	R-2 – Front-end Loader	2	1	0	2	0
	R-2 – Dump Truck	2	1	0	2	0
Equipment Operator	R-3 – Front-end Loader	2	1	0	2	0
	R-3 – Dump Truck	2	2	0	4	0
Equipment Operator	R-6, R-7	2	4	8	8	0
Equipment Operator	R-26 – Front-end Loader	1	1	0	0	1
	R-26 – Bobcat	2	1	0	0	2
	R-26 – Dump Trucks	2	2	0	0	4
Total	-	-	-	16	40	8

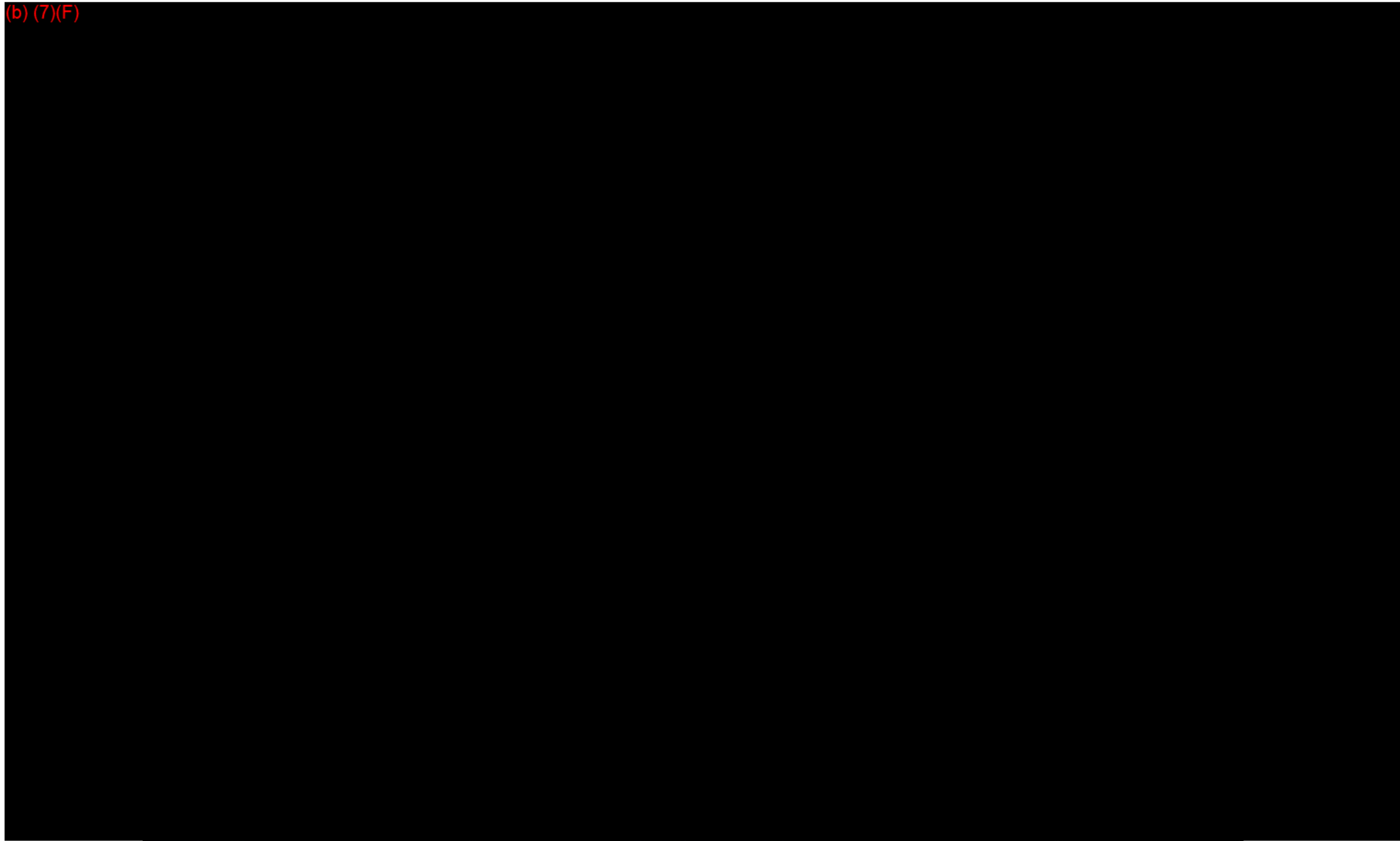
Note: Equipment operators are not members of the North Slope SRT.

FIGURE 1-7: WIND DIRECTION DURING WINTER



Milne Point Unit ODPCP, Volume 1 – Response Action Plan

(b) (7)(F)



SCENARIO 4

**CRUDE OIL TRANSMISSION PIPELINE SPILL
DURING SUMMER**

THIS PAGE INTENTIONALLY LEFT BLANK

**TABLE 1-21: CRUDE OIL TRANSMISSION PIPELINE SPILL DURING SUMMER
SCENARIO CONDITIONS**

PARAMETER	CONDITIONS
Spill Location	MPU 14-inch sales pipeline Near the intersection of the CPF access road and the Milne Point Road (Figure 1-9)
Date and Time	July 1, 6:00 am
Cause of Spill	Pipeline Rupture
Quantity of Spilled Oil	7,017 bbl Refer to Part 5 for detailed explanation of adjusted RPS.
Oil Type	Alaska North Slope crude
Weather	Sunny, 40 F
Wind Speed	During summer, the average wind speed is 11 knots. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007). The weather data presented are the summer average from 2001 through 2006.
Wind Direction	During summer, the predominant wind directions are from the east and east-northeast.
Spill Trajectory	The discharged oil falls to tundra beneath the pipeline on the north side of the CPF access road (Figure 1-9). There are several small lakes or ponds nearby.

Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

TABLE 1-22: RESPONSE STRATEGY – CRUDE OIL TRANSMISSION PIPELINE SPILL DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Control Room Operator reports the alarm to the MPU Communications Operator and closes the (b) (7)(F) . The source is controlled by shut-in of operations and temporary repairs to the line. Notification procedures begin, along with SRT mobilization.	A-1, A-2, L-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the On-Scene Commander, with the assistance of the Site Safety Officer, verifies that sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the Site Safety Officer for work areas to ensure personnel protection. The scene is secured by Security. Within the first few hours of the spill, Security blocks traffic to and from Milne Point at Greater Prudhoe Bay's L and V Pads' access road, Kuparuk's flowline access road, and at the West Sak 24 Pad along the Milne Point Road. Response personnel and equipment are allowed through Security's road blocks.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	By Hour 4 an aircraft is dispatched to monitor for oil in surrounding bodies of water. The slick is tracked by the aircraft, which records with FLIR system. The infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. Once safety zones and a decontamination unit have been set up by Hour 6, the oiled area is delineated. The extent of oil on tundra is delineated on land with lathe and/or hand-held GPS units. Field data are used to periodically update the trajectory map.	T-1, T-2, T-7
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit Leader identifies priority protection sites, relying on the ACS <i>Technical Manual</i> descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major concern. No priority sites lie within the projected plume. The area is monitored for birds and mammals that may be at risk from the spill.	ACS Map Atlas Sheet 37, W-6
(vi) Spill Containment and Control Actions	By Hour 2, staging areas are established on either side of the "hot zone" at D Pad and Texaco Prudhoe 1, and a field command post is established at CFP. By Hour 3, culvert containment is determined and put in place at culverts under Milne Point Road and to contain and prevent oil from reaching the other side. The containment is placed before oil encroaches the culvert. By Hour 6, shoreseal boom is placed at the edges of the spill on the tundra. By Hour 8, containment boom is deployed to nearby lakes to isolate the oiled shoreline.	L-2 C-3 C-4 C-5

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

**TABLE 1-22 (CONTINUED): RESPONSE STRATEGY – CRUDE OIL TRANSMISSION PIPELINE
SPILL DURING SUMMER**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures	Lake Recovery: By Hour 6, several parallel rows of containment boom are placed in the surrounding lakes. A Crucial C Disc 13/24 is placed in the biggest lake, nearest the source. Two MI-30 skimmers are placed in the two smaller, adjacent lakes. Hoses and pumps in series transfer fluids from the containment areas to Fastanks. A vacuum truck transfers fluids from Fastanks to recycling or disposal as appropriate. Source Area Recovery: By Hour 6, vacuum trucks transfer oil from under the pipeline, concentrating on tundra depressions. The recovery crews work with the source area containment crew (who are placing the shoreseal boom). By the beginning of Day 2, teams deploy three rope mops to recover oil in tundra polygons and low-lying areas. Hoses and pumps in series transfer fluids from the containment areas to a Fastank with secondary containment. A vacuum truck then recovers fluids from Fastank and transfers to recycling or disposal as appropriate. On Day 4, after a majority of the free product is removed by direct suction, crews flush low-pressure water over the tundra into collection pits or shoreseal boom areas. The oil is recovered by a vacuum truck equipped with a Manta Ray skimmer.	R-9 R-8, R-24, R-6 R-6 R-8 R-4, R-7
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Vacuum trucks transfer recovered oil from the rupture site to the ORT. Recovered fluids in vacuum trucks are manifested accordingly. A pump-and-hose series transfers liquids from the lake to a Fastank to a vacuum truck. Gravel pile measurements and tests of oil in gravel yield volume estimates of oil in gravel.	R-6 R-24, R-6 D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Recovered liquids are hauled to the ORT for recycling upon approval of the waste management plan. Recovered fluids could also be transported to Gathering Center 2 (GC-2) or ConocoPhillips CPF-1 for hydrocarbon recycle. Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly.	D-1 D-2 D-3
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. By Hour 6, a wildlife task force is on site to exclude birds and mammals from entering oiled areas onshore and on water, monitor wildlife in the trajectory, and capture oiled wildlife. The task force operates continuously on ATVs and from a skiff from Day 1 through Day 30. A wildlife stabilization and treatment center is made operational and is staffed by IBRRC staff by Hour 24. No oiled animals are encountered.	W-1 through W-6

**TABLE 1-22 (CONTINUED): RESPONSE STRATEGY – CRUDE OIL TRANSMISSION PIPELINE
SPILL DURING SUMMER**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xii) Shoreline Cleanup Plan	The tundra is cleaned over 30 days to ADEC's satisfaction. The pipeline and vertical support members (VSMs) are cleaned with a high-pressure wash. Contaminated vegetation is burned to reduce re-oiling of adjacent habitat or left in place. Monitoring programs are established for these areas.	R-21, B-1, B-2 SH-1, 2, 3, 4, 5, 7, 10, 11 and 12

Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

TABLE 1-23: CAPABILITY OF OIL RECOVERY – CRUDE OIL TRANSMISSION PIPELINE SPILL DURING SUMMER

A	B	C	D	E	F	G
SPILL RECOVERY TACTIC, ACS TECHNICAL MANUAL	NUMBER OF RECOVERY SYSTEMS	RECOVERY SYSTEM	OIL RECOVERY RATE PER UNIT (boph)	MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE ¹ (hours)	OPERATING TIME (hours per 24-hour shift)	OIL RECOVERY CAPACITY (bopd) B X D X F
Lake Recovery						
R-8	1	Crucial Disc C 13/24	24 ²	6	20	480
R-8	1	MI-30 Skimmer	10	6	20	200
R-8	1	MI-30 Skimmer	10	6	20	200
R-24	1	Vacuum Truck (transfer from Fastanks)	100 ³	6	20	2,000
Source Area Recovery						
R-6	2	Vacuum Truck	100 ²	6	20	4,000
R-4 and R-7	2	Vacuum Truck with Manta Ray Skimmer	34	96	20	1,360
R-8	3	Rope Mop	3	48	20	180

¹ The sum of the mobilization, deployment, and transit time is not the fastest time possible; rather, it is the time that each specific tactic is first employed in this specific scenario.

² Based on the equipment manufacturer's nameplate capacity of 121 boph, the derated recovery rate is 24 boph (20% x 121 boph = 24 boph).

³ Vacuum truck recovery calculation: Time = (miles to disposal * 2) / 35 mph + 2(T_c / S_r),
 Time = (0.5 miles from Milne Point Road to CFP * 2) / 35 mph + 2 (300 bbl / 200 boph) = 3 hours, where,
 Miles to disposal = 2 miles from Milne Point Road to CFP at 35 mph
 T_c = Vacuum Truck Capacity = 300 bbl
 S_r = Suction Rate = 200 boph
 Oil recovery rate (ORR) = (vacuum truck capacity/time),
 ORR = (300 bbl/3 hours) = 100 boph



TABLE 1-24: MAJOR EQUIPMENT EQUIVALENTS TO MEET THE RESPONSE PLANNING STANDARD

RECOVERY TACTIC	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
Containment		
C-3	Inflatable Culvert Plug	3
C-4	Sandbags	10
C-4	Shoreseal Boom	800 feet
C-5	Containment Boom	1,000 feet
Lake Recovery		
R-8	Crucial Disc C 13/24	1
R-8	MI-30 Skimmer	2
R-24	Fastank Trash Pump with suction hose and discharge hose	3 Fastanks 1 each suction hose and discharge hose
R-24	Vacuum Truck (Transfer)	1
Source Area Recovery		
R-6	Vacuum Truck (Direct Suction)	2
R-4	Water Truck (Flushing)	1
R-7	Vacuum Trucks with Manta Ray skimmers (Flushing)	2
R-8	Rope Mops	3

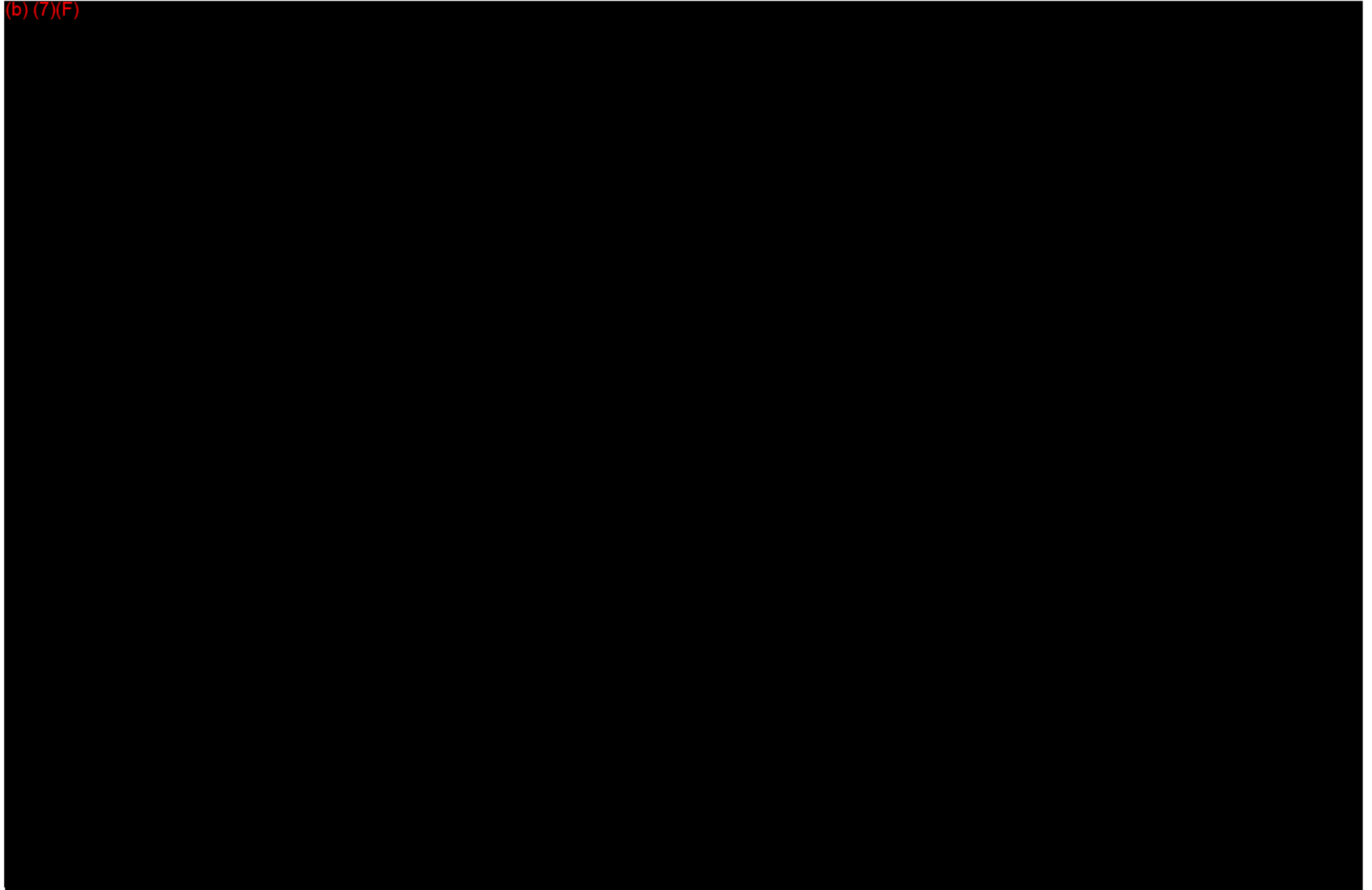
*Milne Point Unit ODPCP, Volume 1 – Response Action Plan***TABLE 1-25: STAFF TO OPERATE OIL RECOVERY AND TRANSFER EQUIPMENT**

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	DAY 1, NO. STAFF PER SHIFT	DAY 2 AND AFTER, STAFF PER SHIFT
Containment					
Team Lead	Containment	-	-	2	0
General Technician	C-3	1	2	2	0
General Technician	C-4	1	6	6	0
General Technician	C-5	3	3	9	0
Lake Recovery					
Team Lead	Lake Recovery	-	-	3	3
General Technician	R-8	3	2	6	6
General Technician (set up)	R-24	2	12	24	0
Equipment Operator	R-24	3	2	6	6
Equipment Operator (Vacuum Truck)	R-24	1	2	2	2
Source Area Recovery					
Team Lead	Source Area Recovery	-	-	2	2
Equipment Operator (Vacuum Truck)	R-6	2	2	4	4
Equipment Operator (Water Truck)	R-4	1	2	2	2
Equipment Operator (Vacuum Truck)	R-7	2	2	4	4
General Technician	R-8	3	2	6	6
Total:				78	35

Note: Equipment operators are not members of the North Slope SRT.

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

(b) (7)(F)



RESPONSE STRATEGY 1

PRODUCTION WELL BLOWOUT DURING OPEN WATER CONDITIONS

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY PARAMETERS

The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from a well blowout at F Pad. In this scenario, the blowout plume is assumed to impact portions of the pad, adjacent tundra, and open water. Refer to Figure I-1 for the location of F Pad.

**TABLE 1-26: RESPONSE STRATEGY – PRODUCTION WELL BLOWOUT
DURING OPEN WATER CONDITIONS**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	Production is shut down, closing in the wells at the surface and subsurface. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls. The affected ADW Well manager calls well control specialists to obtain initial guidance for source control.	A-1, A-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The On-Scene Commander sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the On-Scene Commander, with the assistance of the Site Safety Officer and Fire Chief, verify no ignition sources in the area. The Site Safety Officer determines response workers' PPE needs and provides hot and warm zone access information. Access to the spill site is carefully controlled and the scene is secured by Security. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the Site Safety Officer at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations, oil field operations, and traffic are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	The extent of oil on the pad and tundra is delineated on land with lathe and/or hand-held GPS units. The slick is tracked by an aircraft, which records with FLIR system. The infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. The map is updated at least once a day. The system works during day or night conditions. Once conditions allow, the deployment of tracking buoys is considered. The buoys are capable of transmitting position information and other pertinent data to satellites for retransmission to Unified Command.	T-1, T-2, T-4, T-7

Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

TABLE 1-26 (CONTINUED): RESPONSE STRATEGY – PRODUCTION WELL BLOWOUT DURING OPEN WATER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit's cultural resource specialist issues an advisory and the Operations Chief directs that a Shoreline Task Force member guide response crews in avoiding cultural sites, based on a shoreline cleanup plan approved by the Unified Command and the State Historic Preservation Officer. The Environmental Unit Leader identifies priority protection sites, relying on the <i>ACS Technical Manual</i> descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major concern. Protective exclusion tactics are used at Priority Site 24 and the tidal inlet west of the pad.	ACS Map Atlas Sheet 36, W-6 C-14
(vi) Spill Containment and Control Actions	A decontamination area, temporary shoreside transfer site, and staging area are established at Oliktok Dock to receive recovered liquids from the On-Water Task Force. The BPXA Field Command Post is established at L Pad. A Pad Task Force excavates trenches and constructs berms of gravel on the pad. The trenches and berms divert flowing oil away from the wells and toward the low-lying area near the southern edge of the pad and the access road ramp.	L-2 C-4
(vii) Spill Recovery Procedures	As part of the Pad Task Force, vacuum trucks at the southern corner of the pad pump from the pool of accumulating oil. The trucks drive under the fine oil mist that has a particulate matter concentration within permissible safety limits. The trucks carry the oil to the ORT. The On-Water Task Force has the objective of recovering oil moving in windrows toward the mainland shoreline. Boom boats and skimmer boats work in "J" or "U" configurations, utilizing Tactics R-17, R-18, and R-20 as appropriate. Once the blowout has been controlled, Pad Task Force begins cleanup of the pad and its structures. After the surface structures have been cleaned, the oil-contaminated gravel is removed.	R-6 ACS Map Atlas Sheet 36, R-17, R-18, R-20 R-21 R-26
(viii) Lightering Procedures	Not applicable.	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Mini barges with tanks and vacuum trucks can transfer oily liquids. Stored liquids are gauged with ullage tape in mini barges. The recovered liquids are manifested and logged with the assistance of the Waste Management Team.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Recovered liquids from onshore cleanup operations are hauled to the CFP and injected for recycling at the ORT upon approval of the waste management plan. Recovered liquids from offshore operations can be offloaded at the temporary staging area at Oliktok Dock. Liquids are hauled to the CFP and injected for recycling at the ORT. Oiled gravel is stockpiled at D Pad Gravel Storage temporarily. Oiled snow and gravel is ultimately transported to GPB DS4 G & I on a non-emergency basis for disposal. Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly.	D-1 D-4 D-2 D-3

TABLE 1-26 (CONTINUED): RESPONSE STRATEGY – PRODUCTION WELL BLOWOUT DURING OPEN WATER CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xi) Wildlife Protection Plan	Priority protection areas are boomed to exclude oil from critical habitats. - The wildlife protection strategy is implemented. - Wildlife hazing teams are deployed by boat along shorelines near F Pad and standby to haze if the shorelines become oiled. The teams re-deploy with ATVs and on foot southwest of F Pad. - The Wildlife Stabilization Center is made operational. A Wildlife Capture Team deploys by boat on the lagoon to monitor and capture wildlife if they become oiled. The Wildlife Capture Team re-deploys with ATVs southwest of F Pad.	A-3, W-6 W-1 W-2B W-5 W-3
(xii) Shoreline Cleanup Equipment	The Shoreline Task Force Team deploys a small skimmer and hook boom at Priority Site 24. A mini barge is part of the task force, and shuttles stored liquids to Ol tok Point. A Tundra Task Force deploys southwest of F Pad. Sorbent boom is deployed up-gradient of marsh fringes to keep flushed oil out of the marsh areas. Access is on plywood walkways. Shoreline Cleanup and Assessment Technology (SCAT) Team surveys the area and determines that burning of pooled oil and oiled vegetation is preferred over mechanical recovery methods so tundra damage from equipment movement can be minimized.	R-17 R-16, R-25 R-4 R-9 B-1, 2, 3, 5

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY 2

PRODUCTION WELL BLOWOUT TO BROKEN ICE

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY PARAMETERS

The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from a well blowout at F Pad during June. In this scenario, the blowout plume is assumed to impact portions of the pad, adjacent tundra, and the marine environment. Site conditions are assumed to be spring breakup conditions. Broken ice coverage is approximately 100 percent. The transition to open water conditions occurs during the next 30 days. Refer to Figure I-1 for the location of F Pad.

**TABLE 1-27: RESPONSE STRATEGY - PRODUCTION WELL BLOWOUT
DURING BROKEN ICE CONDITIONS**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	Production is shut down, closing in the wells at the surface and subsurface. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls. The affected ADW Well manager calls well control specialists to obtain initial guidance for source control.	A-1, A-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The On-Scene Commander sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the On-Scene Commander, with the assistance of the Site Safety Officer and Fire Chief, verify no ignition sources in the area. The Site Safety Officer determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment, and source control teams. It quickly evolves to include spill recovery teams. Access to the spill site is carefully controlled and the scene is secured by Security. Monitoring protocol is established by the Site Safety Officer at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are allowed without respiratory protection in areas where safety criteria are met. Recovery operations, oil field operations, and traffic are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	The extent of oil on snow or tundra is delineated on land with lathe and/or hand-held GPS units. The slick is tracked by an aircraft, which records with FLIR system. The infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. The map is updated at least once a day. The system works during day or night conditions. Once conditions allow, the deployment of tracking buoys is considered. The buoys are capable of transmitting position information and other pertinent data to satellites for retransmission to Unified Command.	T-1, T-2 T-4

Milne Point Unit ODCPC, Volume 1 – Response Action Plan

TABLE 1-27 (CONTINUED): RESPONSE STRATEGY - PRODUCTION WELL BLOWOUT DURING BROKEN ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit's cultural resource specialist issues an advisory and the Operations Chief directs that a Shoreline Task Force member guide response crews in avoiding cultural sites, based on a shoreline cleanup plan approved by the Unified Command and the State Historic Preservation Officer. There are no cultural sites in the area within the projected plume from F Pad. The Environmental Unit Leader identifies priority protection sites, relying on the ACS <i>Technical Manual</i> descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major concern. Protective exclusion tactics are used at Priority Site 24 and the tidal inlet west of the pad.	ACS Map Atlas Sheet 36 C-14
(vi) Spill Containment and Control Actions	A decontamination area, temporary shoreside transfer site, and staging area are established at Oliktok Dock to receive recovered liquids from the On-Water Task Force. The BPXA Field Command Post is established at L Pad. Land Containment: A Containment Task Force excavates trenches and constructs snow berms on and off the pad. The berms divert flowing oil away from the wells and toward areas that allow the easiest recovery. When ice-reinforced snow berms are useful to contain oil that melts during breakup. During breakup lengths of conventional boom can be deployed on lakes or flooded tundra once there is enough water available. The boom deployment techniques are the same as those in open water. Offshore Containment: The broken ice provides a limited natural containment. Offshore containment does not occur while ice precludes vessel operation. Containment and recovery operations are not conducted directly under the fallout plume, but as closely to the plume as safety protocols allow.	L-2 C-1, C-5
(vii) Spill Recovery Procedures	Land-based Containment: A Pad Recovery Task Force uses vacuum trucks to recover accumulating oil from trenches and low-lying areas. The trucks transfer the oil to the ORT. Once the blowout has been controlled, Pad Task Force begins cleanup of the pad and its structures. After the surface structures have been cleaned, the oil-contaminated gravel is removed. Offshore-based Recovery: When broken ice prevents the deployment of vessels, the overall strategy is to look for quiet-water areas that are amenable to mechanical recovery or burn opportunities. The heli-torch can be used to ignite inaccessible pockets, while skimmers (i.e., rope mops) can be used to recover in areas with road or vessel access. Rope mop skimmers can be deployed from a vessel or a crane. Once conditions allow, an On-Water Task Force has the objective of recovering oil moving in windrows toward the mainland shoreline. When vessels first start operations, there is not enough open water for boom boats, so skimmer boats utilize Tactics R-31 and R-32, as appropriate. As the amount of ice diminishes, boom boats are employed and work with skimmer boats in "J" or "U" configurations, utilizing Tactics R-17, R-18, and R-20 as appropriate.	R-6, R-7 R-26 R-12, B-3 B-3 R-31, R-32 R-17, R-18, and R-20
(viii) Lightering Procedures	Not applicable.	Not applicable

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-27 (CONTINUED): RESPONSE STRATEGY - PRODUCTION WELL BLOWOUT DURING BROKEN ICE CONDITIONS

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Mini barges with tanks and vacuum trucks can transfer oily liquids. Stored liquids are gauged with ullage tape in mini barges. The recovered liquids are manifested and logged with the assistance of the Waste Management Team.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Recovered liquids from onshore cleanup operations are hauled to the CFP and injected for recycling at the ORT upon approval of the waste management plan. Recovered liquids from offshore operations can be offloaded at the temporary staging area at Oliktok Dock. Liquids are hauled to the CFP and injected for recycling at the ORT. Oiled gravel is stockpiled at D Pad Gravel Storage temporarily. Oiled snow and gravel is ultimately transported to GPB DS4 G & I on a non-emergency basis for disposal. Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly.	D-1 D-4 D-2 D-3
(xi) Wildlife Protection Plan	Priority protection areas are boomed to exclude oil from critical habitats. - The wildlife protection strategy is implemented. - Wildlife hazing teams are deployed by boat along shorelines near F Pad and standby to haze if the shorelines become oiled. The teams re-deploy with ATVs and on foot southwest of F Pad. - The Wildlife Stabilization Center is made operational. A Wildlife Capture Team deploys by boat on the lagoon to monitor and capture wildlife if they become oiled. The Wildlife Capture Team re-deploys with ATVs southwest of F Pad.	A-3, W-6 W-1 W-2B W-5 W-3
(xii) Shoreline Cleanup Equipment	The Shoreline Task Force Team deploys a small skimmer and hook boom at Priority Site 24. A mini barge is part of the task force, and shuttles stored liquids to Oliktok Point. A Tundra Task Force deploys southwest of F Pad. Sorbent boom is deployed up-gradient of marsh fringes to keep flushed oil out of the marsh areas. Access is on plywood walkways. Shoreline Cleanup and Assessment Technology (SCAT) Team surveys the area and determines that burning of pooled oil and oiled vegetation is preferred over mechanical recovery methods so tundra damage from equipment movement can be minimized.	R-17 R-16, R-25 R-4 R-9 B-1, 2, 3, 5

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY 3
**FLOWLINE RUPTURE OVER CENTRAL CREEK
TO OPEN WATER**

THIS PAGE INTENTIONALLY LEFT BLANK

Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

RESPONSE STRATEGY PARAMETERS

The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from the 14-inch flowline into Central Creek between the Tract 14 Road and CFP. See Figure 1-10.

**TABLE 1-28: RESPONSE STRATEGY - FLOWLINE RUPTURE OVER
CENTRAL CREEK TO OPEN WATER**

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Well Pad Operator proceeds to the Tract 14 Road intersection/Spine Road tie-in to close the (b) (7)(F) [REDACTED].	A-1, A-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the On-Scene Commander, with the assistance of the Site Safety Officer, verifies that sources of ignition are shut down or removed from the area. The Site Safety Officer provides access zone information and determines PPE requirements. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment, and source control teams. It quickly evolves to include spill recovery teams. 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 work areas to ensure personnel protection.	S-1 through S-6
(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 FLIR-capable aircraft is dispatched to monitor for oil in Simpson Lagoon.	T-1, T-2, T-4
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	Boom pre-staged at MPU-5, shown as Containment Site (CS) 5, is deployed to contain and recover oil before escaping from Central Creek to open water.	ACS Technical Manual Map Atlas, Map 34, 37, 43 C-15
(vi) Spill Containment and Control Actions	The Operations Section Chief initiates on-water containment procedures by deploying boom at three containment sites (CS2, CS3, and CS4) shown in Figure 1-10. Shoreline protection, exclusion and containment boom are placed at the mouth of Central Creek (CS5). See Sheet 37 of the ACS Map Atlas for pre-staged equipment and locations. ACS is requested on scene. ACS assumes primary open water containment and cleanup activities with assistance from the North Slope Spill Response Team (NSSRT). Application for burn permits and documentation of spill volume estimates are immediately undertaken. ACS is requested to arrive with fire boom for potential in situ burning operations between CS2 and CS3. CS2. Boom (<100 feet) and equipment are deployed at CS2 by spill response staff.	Map Atlas Sheet 37 B-1 C-8 C-8, C-9

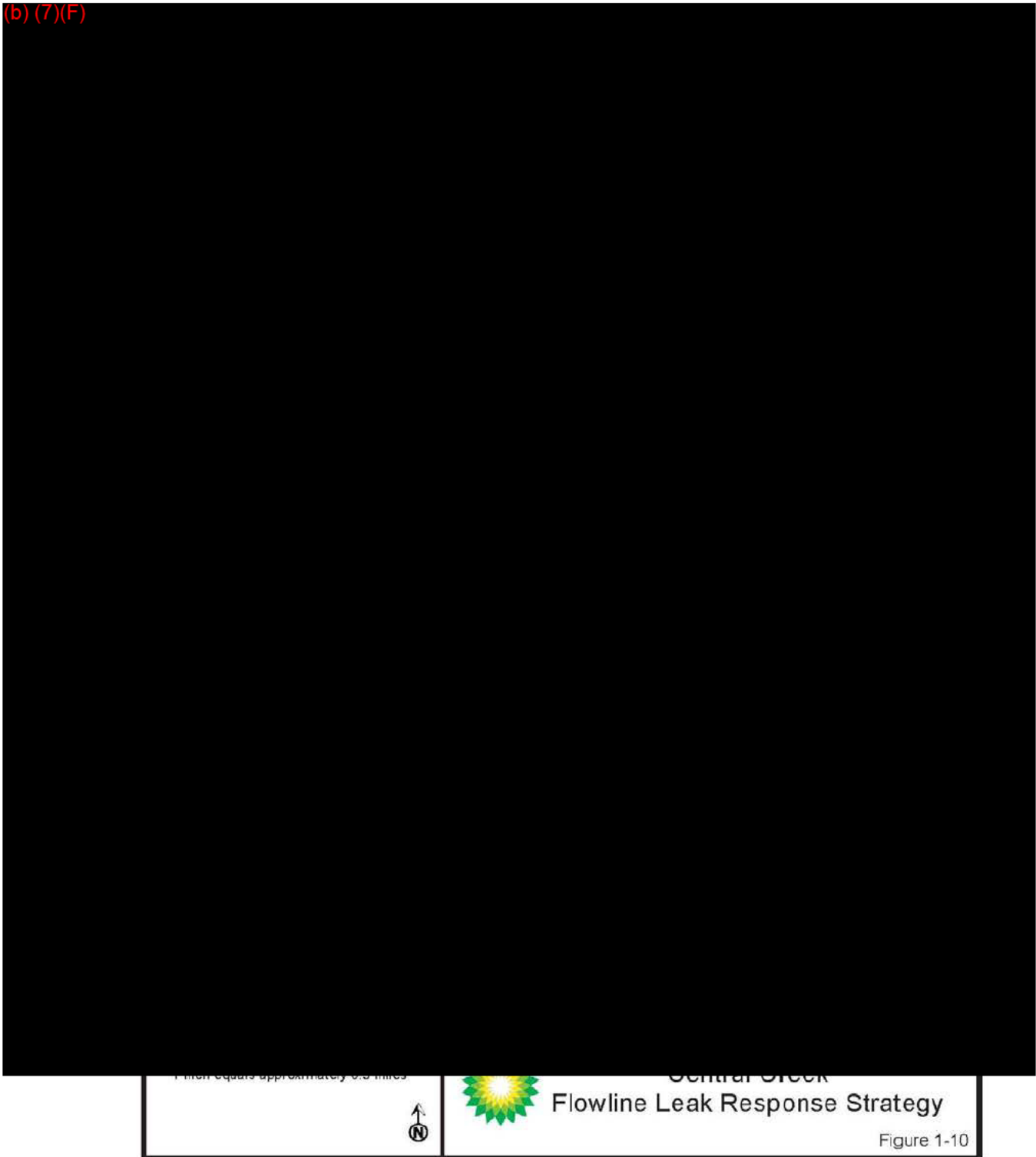
Milne Point Unit ODP,CP, Volume 1 – Response Action Plan

TABLE 1-28 (CONTINUED): RESPONSE STRATEGY - FLOWLINE RUPTURE OVER CENTRAL CREEK TO OPEN WATER

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions (continued)	CS3 and CS4. Boom (1,000 feet) and equipment are deployed at CS3 and CS4 by spill response staff. Staff reach the site by driving to D Pad and walking across the tundra and through the shallow water to the pre-staged equipment at CS3 and CS4. CS5. Pre-staged shoreline protection, exclusion and containment boom and equipment are deployed at CS5 by ACS response staff from Deadhorse. Staff reach the site by driving from Deadhorse to D Pad, then walking to the prestaged equipment at CS5.	C-8, C-9, L-2
(vii) Spill Recovery Procedures	Recovery operations are set up at CS2, CS3, and CS5. At CS2 and CS3, pre-staged and additional skimmers are deployed. Recovered liquids are stored in a Fastank at each site. At CS3 and CS5, prestaged and other skimmers are deployed and begin recovery when oil arrives. A Fastank is deployed at CS5.	R-8
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Liquids are transferred 500 feet from the Fastanks at CS2 to waiting vacuum trucks on A Pad. Liquids are transferred 1,000 feet from the Fastanks at CS3 to waiting vacuum trucks on D Pad. Liquids are transferred 2,000 feet from the Fastanks at CS5 to waiting vacuum trucks on D Pad. Liquids are transferred from the Fastanks to the vacuum trucks with hose and pump in series. Liquids are stored in the Fastanks until the hose and pumps are established. Oil and oily liquids are gauged in tanks and logged on manifests by the Waste Management Team.	R-6 R-24 D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	Recovered liquids are hauled to the CFP and injected for recycling at the ORT following approval of the waste management plan. Non-liquid oily wastes are classified and disposed of according to classification. Non-oily wastes are classified and disposed of accordingly.	D-1 D-2 D-3
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. A wildlife task force excludes birds and mammals from entering oiled areas onshore and on water, monitors the oil trajectory area, recovers oiled carcasses, and captures oiled wildlife. The task force operates from ATVs, skiffs, and on foot. A wildlife stabilization and treatment center is made operational, and is staffed by IBRRC staff.	W-1 through W-6
(xii) Shoreline Cleanup Plan	Shorelines from the leak site to the mouth of the creek are cleaned to ADEC's satisfaction. Crews flush low-pressure water into collection pits or shoreseal boom areas where the oil is collected with skimmers and sorbents.	SH-1, 2, 3, 5, 7, and 10 R-4, R-9

FIGURE 1-10: MILNE POINT UNIT CENTRAL CREEK FLOWLINE LEAK RESPONSE STRATEGY

(b) (7)(F)



1.7 NON-MECHANICAL RESPONSE OPTIONS [18 AAC 75.425(e)(1)(G)]

BPXA will request approval for in situ burning from the State and Federal On-Scene Coordinators (SOSC and FOSC, respectively) when mechanical response methods prove ineffective or as a tool to minimize environmental damage.

Burning will not be initiated without approval of state and federal agencies. Authorization to burn will be received after completing the “Application and Burn Plan” form in Revision 1 of the “In Situ Burning Guidelines” within Annex F of the Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases (Unified Plan), Volume 1. The form is retrieved via the internet at <http://www.akrrt.org> and <http://www.state.ak.us>.

In situ burning of spilled oil will be considered under conditions such as those that follow:

- 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; and
- A successful test burn has been conducted.

If the BPXA Incident Commander decides to use in situ burning and obtains the necessary authorization, ACS will carry out the response. ACS maintains the equipment and personnel for in situ burning. The equipment and personnel are described in the ACS *Technical Manual*, Tactics B-2 to B-7, incorporated here by reference.

1.8 FACILITY DIAGRAMS

Facility diagrams are located in Volume 2 of the MPU ODPCP. The Milne Point Unit Central Facilities Pad location map is included as Figure I-1.

1.9 RESPONSE SCENARIO FOR AN EXPLORATION OR PRODUCTION FACILITY [18 AAC 75.425(e)(1)(I)]

1.9.1 RESPONSE STRATEGY FOR WELL BLOWOUT CONTROL

A summary of planned methods, equipment, logistics, and timeframes to control a well blowout within 15 days, required by 18 AAC 75.425(e)(1)(I), is provided below.

The estimated timeframe to secure a well blowout by means of a well-capping program is 15 days, excluding weather days and other contingencies. Mobilization of specialist teams, initial equipment, and initiation of well intervention planning would be expected to take 3 to 4 days. On-site preparations would take another 3 to 4 days. Concurrently, access and safety, well capping engineering, and well re-entry would be planned and decontamination facilities and off-site operations facilities would be set up. Then, between Days 4 and 8 in some scenarios, the drilling rig substructure would be prepared and the rig would be moved. Uncontrolled fluids may be diverted for collection and handling to create a safe working environment and minimize pollution. The blowout prevention equipment (BOPE) would be removed from the well if necessary. The capping stack would be installed within several days to provide containment, and high pressure pumps would kill the well with mud or cement by Day 15.

Well control specialists will be notified in the event of a well control situation with the potential to escalate. BPXA's Alaska Drilling and Wells (ADW) currently has an agreement with Boots and Coots Services, a single point of contact to provide services for well control response. Such services include, but are not limited to, firefighting equipment and services, specialty blowout control equipment and services; directional drilling services, high-pressure pumping services; and specialty fluids, chemicals and additives. The 24-hour phone numbers for Boots and Coots Services are found in Table 1-2.

BPXA maintains and has available on the North Slope most of the major equipment for well firefighting, to initiate well-capping, or other surface control options. Additional equipment, which may be required on a case by case basis, will be supplied through well control specialists or other vendors. Specialized equipment for well firefighting and well-capping is summarized in Table 1-29. BPXA may loan well control equipment to other North Slope operators in emergencies. The equipment mobilization and travel times in Table 1-29 do not apply to equipment loaned to other operators.

The equipment list provided in Table 1-29 presents a broad spectrum of resources that could be used during a well blowout response. Not all pieces of equipment are required to be at the staging area concurrently. The well capping team conducts activities in a preferred sequence, so tools and deliverables are onsite when they are needed in the well capping process.

BPXA certifies that it maintains a separate well blowout contingency plan applicable for the MPU that is not part of this plan. It will be made available to ADEC upon request for inspection as stipulated by 18 AAC 75.425(e)(1)(I), .445(d)(2), and .480.

The decision logic regarding well-capping response to a blowout at surface is described in Figure 1-11.

1.9.2 RESPONSE SCENARIOS FOR WELL BLOWOUTS

See Section 1.6 for well blowout scenarios.

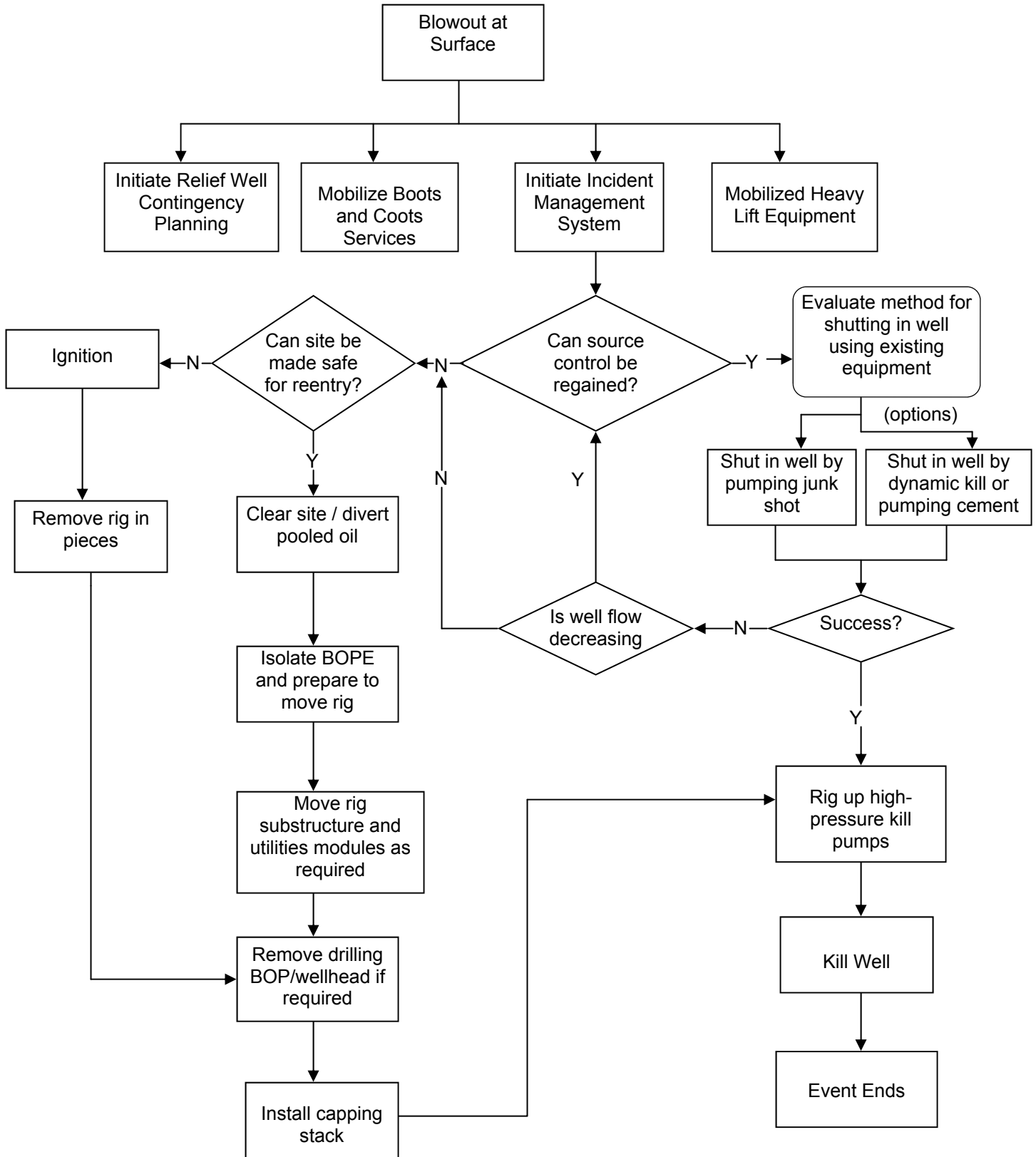
Milne Point Unit ODPCP, Volume 1 – Response Action Plan

TABLE 1-29: WELL FIREFIGHTING AND CAPPING EQUIPMENT LIST

COMPONENT	WELL CAPPING USAGE	ORIGIN
6,000 gallons per minute (gpm) Fire Pump	Fire and heat suppression	North Slope
Athey Wagon	Tractorized booms for manipulation of tools in and around blowout well	
Bulldozer	Power for Athey wagons and backup for heavy equipment, rig moving Can also be used for constructing berms to aid in spill containment.	
Backhoe	Drainage ditch, berm construction	
100-200-ton Crane	Heavy equipment lifting capability If well blow out is ignited, may be needed to facilitate rig move	
50-75-ton Crane	Smaller, mobile units for spotting support equipment	
500-ton Drilling Block	Block and tackle system for moving or dragging heavy equipment	
Drilling Line	Component of block and tackle system if rig moving system is inoperable	
20-inch and 30-inch Casing	Used to construct Venturi tubes to divert blowing well bore fluids (ignited and un-ignited)	
Miscellaneous Equipment	High-pressure chickens, flexible hoses, valves, containment boom, absorbent, hand tools	
Junk Shot Manifold	Manifold system constructed to pump small-leak sealing materials into well	
Hot Tap Tool	Manifold used to gain safe access to pressurized tubulars at surface	
Crimping Tool	Sized device used to pinch tubulars closed to seal off internal flow	Houston, Texas
Abrasive Cutter	High-pressure cutting tool used to sever leaking blowout preventers (BOPs) and rig structures	Duncan, Oklahoma
Kill Pump	Back-up to rig pumps	North Slope
Capping Stack	Various high-pressure BOP stacks (to replace leaking, damaged, or severed primary BOPs)	Houston, Texas
Heavy-Lift Helicopter	Helicopters capable of lifting loads of 18,000-21,000 pounds into remote or offshore locations	U.S. Pacific Northwest

Note: The equipment list above presents a broad spectrum of resources that could be used during a well blowout response. Not all pieces of equipment would necessarily be required. Equipment will be made available on site as needed during the well capping process.

FIGURE 1-11: WELL CAPPING DECISION TREE



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

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

Part 2, Prevention Plan, is in Volume 2.

THIS PAGE INTENTIONALLY LEFT BLANK.

PART 3. SUPPLEMENTAL INFORMATION

[18 AAC 75.425(e)(3)]

3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW

[18 AAC 75.425(e)(3)(A)]

See Volume 2, Prevention Plan.

3.2 RECEIVING ENVIRONMENT [18 AAC 75.425(e)(3)(B)]**3.2.1 POTENTIAL ROUTES OF DISCHARGES [18 AAC 75.425(E)(3)(B)(I)]**

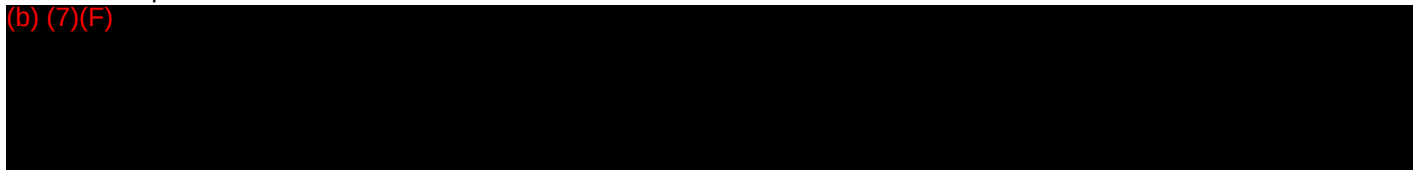
The ACS *Technical Manual* Map Atlas contains maps and information on the potential routes of oil discharged from BPXA's operations. It distinguishes sensitive receiving environments, and shows the latitude and longitude coordinates. Drainage from individual facilities and pad is illustrated on the facility diagrams in Volume 2, Appendix B.

The receiving environment consists of man-made gravel pads, tundra, and open water. Large spills have the potential of reaching open water. Potential routes of discharge are: tundra, ponds, and shorelines down-slope of oil pipelines, wells, and tanks; streams and stream banks down-gradient from shoreline facilities; marine waters; and shorelines of the Beaufort Sea adjacent to the industrialized North Slope.

3.2.2 ESTIMATE OF RESPONSE PLANNING STANDARD VOLUME TO REACH OPEN WATER [18 AAC 75.425(E)(3)(B)(II)]

Approximately 75 bbl of oil from the tank rupture scenario is projected to reach small ponds adjacent to the pad. The ponds do not drain directly to the Beaufort Sea. Zero percent of oil from a well blowout would reach open water.

(b) (7)(F)



3.3 COMMAND SYSTEM [18 AAC 75.425(e)(3)(C) AND 40 CFR 112.20(h)(7)]

The oil spill response command system is compatible with the Alaska Regional Response Team (ARRT) *Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges / Releases (Unified Plan)*. The organizational structure is based on the National Incident Management System (NIMS). It provides clear definition of roles and lines of command, together with the flexibility for expansion or contraction of the organization. The MPU Incident Management Team (IMT) through the leadership level is illustrated in Figure 1-2. Additional details of the BPXA management structure, including Incident Command System (ICS) positional roles and responsibilities, are provided in the BPXA Incident Management System (IMS) Manual.

In most Level I incidents, the spill response team (SRT) can control the incident. The Environmental Advisor fulfills the role of On-Scene Commander. The SRT steps down into the Operations Section and additional personnel become involved to fill support roles.

Level II/III responses are initiated by the On-Scene Commander. The Incident Management Team (IMT) is activated and begins to provide support to the field responders (Operations Section) and coordinates the collection and distribution of information. ACS provides personnel and equipment resources from Deadhorse to assist in spill containment and recovery. The BPXA Business Support Team may be activated to provide additional support to the IMT. See Section 1.1 for titles of IMT members and their contact information.

ACS will be activated to stand by for spills until an assessment is performed. Once the assessment is complete, ACS is either released or mobilized. The North Slope operators coordinate with ACS to ensure a reserve of trained personnel is available for an extended spill response.

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. For the North Slope Subarea, the Unified Command is typically comprised of the Federal On-Scene Coordinator (FOSC), the State On-Scene Coordinator (SOSC), the Local On-Scene Coordinator (LOSC), and the Responsible Party Incident Commander (RPIC). The North Slope Borough is the LOSC.

The primary responsibilities of the Unified Commanders are as follows:

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

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

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

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 may be established and superimposed at the top of the IMT. In this position, the On-Scene Coordinators are ideally situated to carry out the responsibilities cited above. They provide overall direction by establishing strategic objectives and response priorities addressed by the IMT through the planning process. Moreover, they review and approve the products of the planning process (i.e., Incident Action Plans) developed by the IMT to address the objectives and priorities.

The Unified Command position at the top of the IMT also facilitates 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.

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

3.4.1 INTRODUCTION

Realistic maximum response operating limitations that might be encountered at the facility are described in the *ACS Technical Manual*, Volume 1, Tactic L-7, incorporated here by reference. Tactic L-7 analyzes the frequency and duration, expressed as a percentage of time, of limitations that would render mechanical response methods ineffective, as required by 18 AAC 75.425(e)(3)(D). The analysis considers weather, sea conditions, ice, daylight hours, and other environmental conditions that might influence the efficiency of the oil spill response.

Broken ice conditions limit mechanical oil containment boom and recovery skimmers. As ice coverage increases, it becomes more and more difficult to maintain containment boom configurations and skirts to concentrate oil for recovery. Conversely, broken ice conditions can promote oil removal with in situ burning by limiting oil spreading and slowing weathering processes.

3.4.2 WEATHER AND ICE CONDITIONS DURING THE SHOULDER SEASONS

The following general description of breakup and freeze-up describes typical marine environment conditions in the Prudhoe Bay region. They cover the chronology of breakup and freeze-up. See Dickins et al. (2000) and tables in Atwater (1991) for further site-specific details.

MAY

The Sagavanirktok River and Kuparuk River overflows commence on average May 20 and 27, respectively, based on 16 years of analysis.

JUNE

June 1-10: Landfast ice is intact beyond the Kuparuk River and Sagavanirktok River overflow boundaries. Within the overflow zones immediately off the river deltas, fast ice lifts off the bottom of the Beaufort Sea and rapidly melts in place from the relatively warm water discharge. The peak of major flooding occurs during the period June 4-7 (± 6 days), at which point the Kuparuk River overflow may reach within one mile of the Northstar Island. Routine ice road operations might cease at this time. Open water first appears offshore of the Sagavanirktok River and Kuparuk River by June 6-13, respectively, on average. Fast ice beyond the overflow zones and outside the barrier islands is still intact and more than 5 feet thick in early June.

June 15-20: Nearshore lagoon areas affected by the Kuparuk overflow and shallow waters off the Sagavanirktok delta become mostly free of ice. Fast ice offshore remains intact (e.g., Stump Island to Northstar) and continues to melt. Solid ice 4 to 5 feet thick still surrounds Northstar Island. The soft surface is 25 percent covered by melt water pools.

Air temperatures average 35°F and range from 20°F to 40°F. The wind is variable, but blows 60 percent of the time from the east and northeast, averaging 10 knots.

The ice can support response vehicles up to several weeks before breakup. The effect of deteriorating sea ice on access with specific equipment is illustrated in *ACS Technical Manual*, Tactic L-7, based on field trials by Coastal Frontiers (2001).

JULY, AUGUST, AND SEPTEMBER

July 1: A completely intact, deteriorated ice cover 3 to 4 feet thick, with many cracks and approximately 40 to 50 percent of its surface covered by melt pools and holes still exists in deeper water in the vicinity of Northstar.

July 4 (Typical): Break-up begins with fracturing and movement in the floating landfast ice.

July 8-12: Remaining fast ice outside the barrier islands, off the Sagavanirktok River delta and in Prudhoe Bay decreases to less than 7 tenths coverage.

July 15-26: Open, ice-free water out to Northstar and surrounding West Dock and Endicott causeway.

Air temperatures average 40°F in July.

The median number of days with flooded and/or broken ice at breakup at production facilities range from 12 days at Point McIntyre to 22 days at Northstar.

OCTOBER

October 4 ±8 days: Freeze-up begins along shore in shallow water. Ice becomes shorefast for the season within one week following freeze-up in the nearshore lagoons (e.g., Point McIntyre 2 and Niakuk) and by October 25 offshore.

Additional time is required for the young ice sheet to gain sufficient thickness and stability to be judged safe for over-ice operations. Time from initial freeze-up to being able to commence on-ice operations with response equipment ranges on average from 40 to 43 days at coastal or nearshore locations, such as Point McIntyre 1, Niakuk, and Endicott, to 55 days at Northstar.

Air temperatures at freeze-up range from 5°F to 15°F. Daylight is 9 to 10 hours per day.

3.4.3 IN SITU BURNING RESPONSE MEASURES TO REDUCE ENVIRONMENTAL CONSEQUENCES OF A SPILL IN ICE CONDITIONS

Oil spill removal during the shoulder seasons can be greatly enhanced by in situ burning. Cold water and ice limit the spread of oil and slow the weathering process, thereby increasing the response equipment's encounter rate with the oil. The ice also provides natural containment, concentrating the oil for burning and recovery. In situ burning in shoulder season ice conditions generally involves selective burning of oil on melt pools and in leads between floes, followed by manual recovery of residue.

OPERATIONAL CAPABILITY FOR IN SITU BURNING IN ICE

ACS maintains an inventory of specialized equipment for in situ burning operations during shoulder season ice conditions. The ACS *Technical Manual* describes response strategies, procedures, and equipment to implement a successful burn in a mix of solid ice, broken ice, and open water situations. The tactics descriptions are listed below and are incorporated by reference into the plan.

- B-2 - Burning Oily Vegetation
- B-3 - In Situ Burning with Helitorch and Other Igniters
- B-4 - Deployment and Use of Fire Containment Boom
- B-5 - Burning Oil Pools on any Solid Surface
- B-6 - Residue Recovery
- B-7 - Burn Extinguishment on Water (applicable to fire booms in light ice cover)

ACS conducts spill response training involving classroom and field exercises to practice the burn tactics described in the ACS *Technical Manual* several times a year at North Slope locations.

EFFECTIVENESS OF IN SITU BURNING IN ICE

The consensus of research on spill response in broken ice conditions is that in situ burning is an effective response technique with removal rates exceeding 90 percent in many situations (Shell et al. 1983, SL Ross 1983, SL Ross and DF Dickins 1987, Singasaas et al. 1994, SL Ross et al. 1998, DF Dickins et al. 2000, Sørstrøm et al. 2010). The research includes several smaller-scale field and tank tests (SL Ross et al. 2003, Shell et al. 1983, Brown and Goodman 1986, Buist and Dickins 1987, Smith and Diaz 1987, Bech et al. 1993, Guénette and Wighus 1996, Sørstrøm et al. 2010) and a few large field tests (Singasaas et al. 1994, Sørstrøm et al. 2010). Most of the tests involved large volumes of oil placed in a static test field of broken ice resulting in substantial slick thicknesses for ignition. The few tests in unrestricted ice fields or in dynamic ice have indicated that the efficacy of in situ burning is sensitive to ice concentration and dynamics. Important variables include: the tendency for the ice floes to naturally contain the oil, the thickness (or coverage) of oil in leads between floes, and the presence or absence of brash or frazil ice which can absorb the oil.

Brash ice is the debris created when larger ice features interact and degrade. Frazil ice is the “soupy” mixture of very small ice particles that forms as seawater freezes.

Oil spilled on solid ice or among broken ice in concentrations equal to or greater than 6 tenths has a high probability of becoming naturally contained in thicknesses sufficient for combustion. In lower ice concentrations, oil spill response methods can be used to create and maintain sufficient film thickness to facilitate burning. Fire-resistant booms are examples. Field experience has shown that it is the small ice pieces (e.g., the brash and frazil, or slush, ice) that accumulate with the oil against the edges of larger ice features (floes) and control the concentration (e.g., thickness) of oil in an area, and control the rate at which the oil subsequently thins and spreads. Other factors affecting burn effectiveness include oil weathering processes (e.g., evaporation and emulsification) and mixing energy from waves.

The following discussion summarizes the scientific principles and physical processes for in situ burning of oil on melt pools during the ice-melt phase in June or on-water between floes during the breakup period in July, based on SL Ross et al. (2003). Further discussion also covers in situ burning of thinner slicks in mobile broken ice comprised of brash or frazil ice during the freeze-up shoulder season in October.

The success of an in situ burning operation is highly dependent upon slick thickness. For an oil slick on water or ice to become ignited, the oil must be thick enough to insulate itself from the water beneath it. The igniter can heat the surface of thickened oil to the flash point temperature at which the oil produces sufficient vapors to ignite. The rules of thumb for minimum ignition thickness are listed in Table 3-2.

TABLE 3-2: MINIMUM IGNITABLE THICKNESS ON WATER
(Buist et al. 2003)

OIL TYPE	MINIMUM THICKNESS
Light Crude and Gasoline	1 mm ¹ (0.04 inch)
Weathered Crude and Middle-Distillate Fuel Oils (Diesel and Kerosene)	2 to 3 mm (0.08 to 0.12 inch)
Residual Fuel Oils and Emulsified Crude Oils	10 mm (0.4 inch)

¹ mm = millimeters

The oil removal rate for in situ oil fires is a function of fire size (or diameter), slick thickness, oil type, and ambient environmental conditions. For most large (greater than 3-meter diameter) fires of unemulsified crude oil on water, the “rule of thumb” is a burning consumption rate of 3.5 millimeters per minute (mm/min). Lighter fuels burn faster, and heavier oils and emulsions burn slower, as shown in Table 3-3.

Burn rate also is a function of the size of the fire. Crude oil burn rates increase from 1 mm/min with 3-foot diameter fires to 3.5 mm/min for 15-foot fires and greater. In situ burns on melt pools typically consume oil at 1 mm/min. For very large fires, on the order of 50 feet in diameter and larger, burn rates may decrease slightly because there is insufficient air in the middle of the fire to support combustion at 3.5 mm/min. As fire size grows to the 50-foot range, oil type ceases to affect burn rate for the same reason.

An in situ oil fire extinguishes naturally when the slick burns down to a thickness that allows sufficient heat to pass through the slick to the water to cool the surface of the oil below the temperature required to sustain combustion. The thickness at which an oil fire on water extinguishes is related to the type of oil and initial slick thickness. The rules of thumb are presented in Table 3-4. Secondary factors include environmental effects, such as: wind (winds greater than 20 knots preclude in situ burning in most cases), current herding of slicks against barriers, and oil weathering.

With an estimate of the initial thickness of a fully contained slick, thickness of the residue remaining, and area of the slick's surface that was on fire, it is relatively easy to estimate oil removal efficiency by burning.

**TABLE 3-3: BURN/REMOVAL RATES FOR LARGE FIRES ON WATER
(Buist et al. 2003)**

OIL TYPE/CONDITION	BURN/REMOVAL RATE
Gasoline >10 mm (0.4 inch) thick	4.5 mm/min (0.18 in/min ¹)
Distillate Fuels (diesel and kerosene) >10 mm (0.4 inch) thick	4.0 mm/min (0.16 in/min)
Crude Oil >10 mm (0.4 inch) thick	3.5 mm/min (0.14 in/min)
Heavy Residual Fuels >10 mm (0.4 inch) thick	2.0 mm/min (0.08 in/min)
Slick 5 mm thick ²	90 percent of rate stated above
Slick 2 mm thick ²	50 percent of rate stated above
Emulsified oil (percent of water content) ³	Slower than above rates by a factor equal to the water content percent
Estimates of burn/removal rate based on experimental burns and should be accurate to within ±20 percent.	

¹ inches per minute

² Thin slicks will naturally extinguish, so this reduction in burn rate only applies at the end of a burn.

³ If ignited, emulsions will burn at a slower rate almost proportional to their water content (a 25 percent water-in-crude-oil emulsion burns about 25 percent slower than the unemulsified crude).

**TABLE 3-4: FIRE EXTINGUISHING SLICK THICKNESS
(Buist et al. 2003)**

OIL TYPE/INITIAL SLICK THICKNESS	EXTINGUISHING THICKNESS
Crude Oil up to 20 mm (0.8 inch) thick	1 mm (0.04 inch)
Crude Oil 50 mm (2 inch) thick	2 to 3 mm (0.08 to 0.12 inch)
Distillate Fuels any thickness	1 mm (0.04 inch)

Oil thickness is maintained by water current in the apex of a fire-resistant boom under tow, or against an ice edge in wind or current. When burning in a current, the fire slowly decreases in area until it reaches a size that can no longer support combustion. This herding effect can increase overall burn efficiencies, but it extends the time required to complete each burn.

The residue from a typical, efficient (greater than 85 percent removal) in situ burn of crude oil 10 to 20 millimeters thick is a semi-solid, tar-like layer that has an appearance similar to the skin on an old, poorly-sealed can of latex paint that has gelled. For thicker slicks, typical of what might be expected in a towed fire boom (about 150 to 300 millimeters), the residue can be a solid. Burn residue is usually denser than the original pre-burn oil, and usually it does not spread due to its increased viscosity or solid nature.

Tests indicate that the burn residues from efficient burns of heavier crude oils less than 32 degrees American Petroleum Institute (API) may sink once the residue cools, but their acute aquatic toxicity is very low or nonexistent. The "In Situ Burning Guidelines for Alaska, Revision 1" (ADEC, Environmental

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

Protection Agency [EPA] and U.S. Coast Guard [USCG]), 2008) state: "In general, however, the effects [biological effects of burn residues] are less severe than those from a large, uncontained oil spill, and no specific biological concerns have been identified to date (ASTM, 2003)."

Compared with unemulsified slicks, emulsions are much more difficult to ignite and, once ignited, display reduced flame spreading and more sensitivity to wind and wave action. Stable emulsion water contents are typically in the 60 to 80 percent range with some up to 90 percent. The oil in the emulsion cannot reach a temperature higher than 100°C until the water is either boiled off or removed. The heat from the igniter or from the adjacent burning oil is used initially to boil the water rather than heat the oil.

The following points summarize the effect of water content on the removal efficiency of weathered crude emulsions:

- Little effect on oil removal efficiency (i.e., residue thickness) for water contents up to 12.5 percent by volume;
- A noticeable decrease in burn efficiency with water contents above 12.5 percent, the decrease being more pronounced with weathered oils;
- Zero burn efficiency for emulsion slicks having water contents of 25 percent or more, and
- Some crudes form meso-stable emulsions that can burn efficiently at much higher water contents. Paraffinic crudes appear to fall into this category.

Fortunately, emulsion formation is slowed dramatically by high ice concentrations and may not be a significant operational factor in planning in situ burns on solid ice or naturally contained in higher concentrations of broken ice.

SL Ross et al. (2003) provides guidelines for burning thin slicks in broken ice with brash and slush, particularly relevant during the breakup and freeze-up shoulder seasons. General rules for minimum ignitable thickness and oil removal rates for burning thin slicks of crude oils on brash and/or slush with broken ice are as follows:

- The minimum ignitable thickness for fresh crude on frazil ice or small brash ice pieces is up to double that on open water, or about 1 to 2 millimeters.
- The minimum ignitable thickness for weathered crude oil on frazil ice or small brash ice pieces can be higher than on open water, but is still within the range quoted for weathered crude on water, about 3 millimeters with gelled gasoline igniters.
- For a given spill diameter, the burn rate in calm conditions is about halved on relatively smooth frazil/slush ice and halved again on rougher, brash ice. Wave action slightly reduces the burn rate on open water, but the halving rule appears to apply in waves as well.
- The residue remaining on broken ice in calm conditions is about 50 percent greater than that on open water, or 1.5 millimeters. The residue remaining on brash or frazil ice in waves is slightly greater than in calm conditions, at about 2 millimeters.

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

In summary, in situ burning of oil is efficient and rapid in broken ice conditions under the following conditions:

- The spilled oil is thicker than the minimum ignitable (a thickness of 2 to 3 millimeters results in 50 to 66 percent removal efficiency: 10-millimeter thickness, a typical thickness for wind-herded slicks on melt ponds on ice, gives 90 percent removal efficiency);
- Larger areas can be ignited (a 100-square foot slick on a melt pool will burn at 3.5 barrels of oil per hour [boph], a 50-foot diameter, 10-millimeters thick slick will burn at 300 boph, and a 100-foot diameter slick will burn at 1,200 boph);
- The oil is not more than 25 percent emulsified, and
- Herding in a current and enlarging fire diameters can increase burning rates.

3.5 LOGISTICAL SUPPORT [18 AAC 75.425(e)(3)(E) AND 40 CFR 112.20(h)(7)]

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 contracts for operational logistical support to support a spill response.

ACS Technical Manual Tactics L-3, L-4, L-8 through L-10 are incorporated here by reference.

3.6 RESPONSE EQUIPMENT [18 AAC 75.425(e)(3)(F) AND 40 CFR 112.20(h)(7) AND (h)(8)]

3.6.1 EQUIPMENT LISTS

Contracted or other oil discharge containment, control, cleanup, storage, transfer, lightering, and related response equipment used to meet the applicable response planning standard in Part 1 is listed as required by 18 AAC 75.425(e)(3)(F)(i) to (vii). Listed equipment also includes that used to protect environmentally sensitive areas and areas of public concern identified in Section 3.10. The equipment protects areas that may suffer an impact from a spill of the response planning standard volume as described in Part 1. The location, inventory, and ownership of ACS-managed equipment listed in the response planning standard scenarios in Part 1 is listed in the *ACS Technical Manual*, Tactic L-6, and in the *Technical Manual's* tactics descriptions incorporated by reference in the scenarios in Part 1. The timeframe for delivery and startup of response equipment and trained personnel located outside the North Slope is outlined in the response scenarios in Part 1. The manufacturer's rated capacities, limitations, and operational characteristics for each item of oil recovery equipment listed in the scenarios in Part 1 are listed in the *ACS Technical Manual*, Tactic L-6, and in the *Technical Manual* tactics descriptions incorporated by reference in the scenarios. Each vessel and the equipment for transferring oil from tanks mentioned in the scenarios in Part 1 is listed in Tactic L-6 as well.

3.6.2 MAINTENANCE AND INSPECTION OF RESPONSE EQUIPMENT

Response equipment is maintained so it can be deployed rapidly and in condition for immediate use. The on-site response equipment is routinely inspected and tested by ACS. In addition, ACS performs routine maintenance of its response equipment. Inspections, tests, and maintenance follow ACS written standard operating procedures.

ACS holds Oil Spill Removal Organization (OSRO) classifications for facilities and vessels. See the Federal Facility Response Plans at the end of Volume 1. ACS has fulfilled the equipment maintenance and testing criteria that the classifications require.

3.6.3 PRE-DEPLOYED AND PRE-STAGED EQUIPMENT

The *ACS Technical Manual*, Volume 2, Map Atlas lists the contents of pre-staged response equipment. At MPU, boom and other spill response equipment are pre-staged in connex boxes along Central Creek and other locations. Boom is pre-deployed on Central Creek each open water season.

The open-water timeframe for spill response activities follows spring breakup, typically occurring late May to early June, and ending prior to the fall freeze-up, typically in mid-September to early October. Initial boom pre-staging takes approximately two weeks. Prior to fall freeze-up, predeployed boom is removed from the river systems and placed in the connexes.

Due to seasonal changes of the river channels and fluctuating river currents, specific boom-laying configurations and exact footage lengths of boom prestaged at sites may vary. Boom sections and

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

anchors are staged on the shoreline in a manner that optimizes its intended use for containment and recovery.

3.7 NON-MECHANICAL RESPONSE INFORMATION [18 AAC 75.425(e)(3)(G) AND 40 CFR 112.20(h)(7)]

In situ burning equipment inventory and deployment is described in the ACS *Technical Manual*, Tactics L-6 and B-2 through B-7, which are incorporated here by reference.

MPU's lighter, 38-degree API gravity oil exhibits specific properties making it amenable to burning (ACS, 2006). Its density ranges from 0.92 to 0.96 grams per cubic centimeter, increasing at lower temperatures and with evaporation losses. At 1 degree Celsius (°C), its viscosity ranges from 357 millipascals per second (mPa/s) (382 square millimeters per second) for fresh oil to 6,685 mPa/s (6,939 square millimeters per second) for oil weathered by 19 percent evaporation loss. The pour point determined by American Society for Testing and Materials (ASTM) D97 is colder than the method limit of -18°C. The flash point increases from -8°C for fresh oil to 106°C for oil weathered by 19 percent evaporation loss. Fresh oil and oil with 10 percent loss by evaporation at temperatures near freezing are likely to emulsify and have a water content up to 29 percent. However, oil weathered by 19 percent loss and near freezing is not likely to emulsify. In contrast, at a higher temperature, e.g., 15°C, the fresh and 10 percent weathered oil is unlikely to emulsify. At that higher temperature, 19 percent weathered oil will emulsify, with up to 23 percent water content.

3.7.1 ENVIRONMENTAL CONSEQUENCES

The environmental consequences of in situ burning will be assessed by monitoring the downwind trajectory of the smoke. A trial burn will indicate the path of the smoke. Monitoring the downwind position of the smoke plume will be accomplished by a ground- or air-based member of the IMT.

Appropriate measures, as required by the Unified Command, natural resource agencies, and public safety agencies will be carried out to protect nearby human populations and environmentally sensitive areas. In situ burns will be limited to sites that are a minimum safe distance, generally several miles, upwind of human populations. The safe distance will be plotted as outlined in the "In Situ Burning Guidelines for Alaska, Revision 1" (ADEC, EPA, USCG, 2008). The determination takes into account a trial burn, wind conditions, and size of the expected burn area. In addition, public notifications and warnings will be issued in cooperation with agency emergency staff.

In situ burns conducted according to the *Unified Plan* are not expected to harm environmentally sensitive areas and areas of public concern. Heat from in situ burning affects only the upper few centimeters of the water column in contact with the oil. Smoke has not been found harmful to wildlife populations. In situ burning smoke is reduced to concentrations that are safe to people by means of burning only at safe distances.

In situ burn operations receive constant visual monitoring of the smoke plume's behavior. The burn operations team visually monitors the smoke plume. The federal and state on-scene coordinators may authorize a trial burn to confirm anticipated plume drift direction and dispersion distances downwind before authorizing the proposed burn. Burn operations may be stopped if the plume contacts or threatens to contact the ground in a populated area.

A step-by-step process in establishing safe distances for burning is fully presented in the “In Situ Burning Guidelines for Alaska, Revision 1” (ADEC, EPA and USCG, 2008). The state and federal on-scene coordinators determine whether the burn lies at a safe distance from human populations. In situ burning is not authorized if it does not meet public health regulatory standards. The safe distance separating human populations from in situ oil burns is the downwind radius from the fire at which smoke particulate matter concentrations at the ground diminish to limits established by National Ambient Air Quality Standards. The safe distance guidelines are based on the predictions of a National Institute of Standards and Technology ALOFT-Flat Terrain computer model. The safe distance meets the National Ambient Air Quality Standards for particulate matter over a one-hour time period and is also used as the indicator that human populations will not be exposed to unsafe levels of other smoke components. Table 3-5 lists the general safe distances separating an in situ burn and downwind, populated areas in flat terrain.

TABLE 3-5: SAFE DISTANCES BETWEEN IN SITU BURNS AND DOWNWIND HUMAN POPULATIONS ON FLAT TERRAIN: LOCATION OF FIRE ZONES

LOCATION OF FIRE	GREEN ZONE	YELLOW ZONE	RED ZONE
Flat terrain on land	>3 miles	1 to 3 miles	<1 mile
Water <3 miles from shore			
Water >3 miles from shore	>1mile	Not applicable	<1 mile

Burning at a green zone safe distance from the public is acceptable following public notification.

The “In Situ Burning Guidelines for Alaska, Revision 1” allows the results of the NIST modeling to be used to authorize burning on the North Slope. The results show that for fires up to 10,000 square feet in area (about 100 feet in diameter, in all wind speeds modeled over land or water in typical winter and summer atmospheric conditions) the surface concentrations of particulate matter decline below the target concentration in less than 0.6 mile of the burn. Fifty-six scenarios in Cook Inlet and the North Slope were modeled using the ALOFT-Flat Terrain computer model, and the worst-case predictions were used to develop the safe distances for those specific locations.

3.7.2 OPERATIONAL CAPABILITY

ACS maintains specialized equipment to conduct in situ burning operations during all seasons and all ice conditions. The extensive inventory of response equipment is specifically designed to support a large-scale burning operation. See Section 3.4.3, In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions, for details.

3.7.3 EFFECTIVENESS OF IN SITU BURNING IN ICE

The consensus of research on spill response in broken ice conditions is that in situ burning is an effective response technique with removal rates exceeding 90 percent in many situations (Shell et al. 1983, SL Ross 1983, SL Ross and DF Dickins 1987, Singsaas et al. 1994, SL Ross et al. 1998, DF Dickins et al. 2000, Sørstrøm et al. 2010). See Section 3.4.3, In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions, for details.

3.8 RESPONSE CONTRACTOR INFORMATION

[18 AAC 75.425(e)(3)(H) AND 40 CFR 112.20(h)(3)]

BPXA will activate ACS and the North Slope members of ACS to provide the initial manpower and resources for a large or lengthy spill response. The address and phone number for ACS is shown in Section 1.1. If additional resources are required, they will be accessed through Master Services Agreements maintained by ACS. BPXA's Statement of Contractual Terms with ACS is provided in the Introduction.

3.9 RESPONSE TRAINING AND DRILLS [18 AAC 75.425(e)(3)(I) AND 40 CFR 112.20(h)(8)]

3.9.1 NORTH SLOPE SPILL RESPONSE TEAM TRAINING

The North Slope Spill Response Team (NSSRT) consists of workers who volunteer as emergency spill response personnel. Each team member is required to have initial emergency response training and annual refresher training, which meets or exceeds the requirements in the Hazardous Waste Operations and Emergency Response (HAZWOPER) regulations, 29 Code of Federal Regulation (CFR) 1910.120(q). Annual requirements for HAZWOPER refreshers, medical physicals, and a respiratory fit test are tracked by ACS through weekly reports from the database. At intervals not exceeding 15 months, but at least once each year, BPXA makes changes to its emergency response training program to maintain its effectiveness in compliance with 49 CFR 195.403(b). The NSSRT training program is provided to responders from all production units on the North Slope.

Response training and attendance is documented and available for review. The yearly training schedule is also available at the facility and ACS Base. Current NSSRT training schedules are posted on the ACS website.

The minimum NSSRT staffing level on the North Slope illustrated in Table 3-6 represents the largest shift demand within the first 72 hours for each responder classification derived from all BPXA North Slope oil discharge prevention and contingency plans' scenarios and therefore exceeds the total personnel requirements of any single scenario. Responders are classified into five categories each with minimum training requirements as noted below.

TABLE 3-6: NORTH SLOPE SPILL RESPONSE TEAM MINIMUM STAFFING LEVELS

RESPONDER CLASSIFICATION	NUMBER
General Technician	58
Skilled Technician	51
Team Leader	Included among vessel operators
Vessel Operator-Nearshore	10
Vessel Operator-Offshore	9
Total Responders	128

GENERAL TECHNICIAN

The General Technician is a responder with minimal or no field experience in spill response. Duties are associated with mobilization, deployment, and support functions for the response. Support tasks, such as deployment of boom sections; assembly of anchors systems; assembly of temporary storage devices; loading and unloading equipment, and decontamination of equipment are typical tasks undertaken by this

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

responder classification. Responders in this classification must have a current 24-hour (or higher) HAZWOPER certificate.

Over time, the NSSRT training program brings NSSRT members from General Technician to at least the Skilled Technician level.

SKILLED TECHNICIAN

The Skilled Technician is a responder who has experience in spill response activities at a higher level through specific training, related activities as part of regular employment, or in spill response incidents. Tasks such as the operation of skimmers, powerpacks, and transfer pumps are typical tasks undertaken by this responder. Responders in this classification have documentation of training as listed below:

- Minimum training requirements for the General Technician, and
- Completion of 16 hours of training or equivalent experience in any combination of the following categories:
 - Response equipment deployment and use,
 - Response tactics and equipment requirements,
 - Emergency response management (Incident Command System),
 - Staging area management and support,
 - Boat safety, navigation, or operations, and
 - Contingency plan familiarization.
- Completion of 16 hours of actual spill response, response exercise, or field deployment time in any combination of the following positions:
 - Operation of recovery equipment systems,
 - Operation of transfer and storage equipment systems,
 - Deployment and use of containment systems,
 - Decontamination procedures,
 - Wildlife hazing, capture, and stabilization, and
 - Ten completed equipment proficiency checks.

TEAM LEADER

Team Leader roles may include such categories as Task Force Leader, Containment or Recovery Site Team Leader, or Staging Area Manager. A team leader is described as an individual who has attended additional training in the actions, responsibilities, and tasks associated with managing portions of an incident. Responders in this classification have documentation of training as follows:

- Training requirements for the General Technician,
- Training requirements for the Skilled Technician,

- Current eight-hour (or higher) HAZWOPER Supervisor Certification, and
- Twenty completed equipment proficiency checks.

VESSEL OPERATOR - NEARSHORE

Responders qualified as Vessel Operator - Nearshore are tasked with safe operation of vessels less than 30 feet long. The vessels have a hull design and electronics primarily intended for operation in nearshore environments, or occasionally, in conjunction with larger vessels in an offshore response. Typical duties include: towing and placement of containment booms; setting and tending anchors, and movement of equipment to remote sites. Responders in this classification have documentation of training as listed below:

- Training requirements for the General Technician,
- Criteria for any one of the following categories:
 - Completion of the ACS, Captain and Crew or Boat Safety and Handling Training Programs;
 - Completion of 40 hours of equivalent training or experience on vessels smaller or greater than 30 feet, including navigation, charting, vessel electronics and docking, and maneuvering procedures;
 - Current USCG Operator Uninspected Passenger Vessel, or higher license, and
 - Completion of Nearshore Vessel proficiency check.

VESSEL OPERATOR - OFFSHORE

Responders qualified as Vessel Operator - Offshore are tasked with the safe operation of vessels larger than 30 feet in length. The vessels have a hull design and electronics capable of sustaining operations in an offshore environment. Typical duties include: the towing of containment booms; working in conjunction with barge containment operations; towing mini-barges; operating skimmers to recover oil; providing ice management support, and providing logistical support to offshore operations. Responders in this classification have documentation of training as follows:

- Training requirements of the General Technician, and
- Criteria for any one of the following:
 - Completion of the ACS, Captain and Crew Training Program;
 - Completion of 40 hours of equivalent training or experience on vessels larger than 30 feet, including navigation, anchoring, vessel electronics and docking and maneuvering procedures;
 - Current USCG 25-Ton Near Coastal or larger license, and
- Completion of Offshore Vessel proficiency check.

ACTIVE MEMBER REQUIREMENTS

NSSRT members must complete minimum annual training activities to be considered an active member of the NSSRT. The training requirements include eight-hour HAZWOPER refresher certification and plan review.

The NSSRT training program offers weekly classes at each field. The classes emphasize hands-on experience, field exercises, and team-building drills. The courses are selected by the ACS Environmental Lead Technician in conjunction with field management and use BPXA, ACS, and external training consultants. Table 3-8 lists typical NSSRT training courses. Many are divided by subject area and taught in the two- or three-hour timeframe of an NSSRT meeting.

3.9.2 INCIDENT MANAGEMENT TEAM MEMBER TRAINING

A description of the North Slope IMT training program is provided in the ACS Technical Manual, incorporated by reference. The training program is compliance with the National Incident Management System (NIMS), which is described in detail in the U.S. Coast Guard Incident Management Handbook, COMDTPUB P3120.17A (available online at www.gop.gov).

North Slope incident management system training is provided by ACS or other NIMS-Certified 300 and 400 level trainers and includes an introduction to new members of the IMT, basic, intermediate, and advanced ICS training, as well as position-specific training. The program is designed to be provided in a progressive manner that leads personnel through the entire operational planning period for an incident.

Table 3-7 provides a summary of the training modules. Current training schedules are available on the ACS website at <http://www.alaskacleanseas.org/>.

Tabletop exercises and drills test knowledge and competency of the system. As new training needs are identified, they are developed and incorporated into the ICS training program. Training records of NSSRT response team members and contractors are maintained and available for inspection at the ACS Base in Deadhorse.

BPXA trains its IMT members based in Anchorage, called the Alaska Response Team. BPXA maintains a database of the training courses taken by each employee. Training includes ICS overview, section specific training, and tabletop drills. Records are kept for a minimum of three years or for the entire time that the employee is assigned responsibilities in this plan. The database provides a brief description of the course and the date completed. Current training status of employees is available upon request.

TABLE 3-7: NORTH SLOPE INCIDENT MANAGEMENT SYSTEM TRAINING MODULES

MODULE NUMBER	COURSE
ICS-100	Introduction to the Incident Command System
ICS-200	Basic Incident Command System
ICS-300	Intermediate Incident Command System
ICS-400	Advanced Incident Command System
ICS-236	Staging Area Manager Workshop
ICS-341	Incident Response Planning Workshop
ICS-342	Documentation Unit Leader Workshop
ICS-346	Situation Unit Leader Workshop
ICS-348	Resources Unit Leader Workshop
ACS-1	Plan Development Unit Leader Workshop
ACS-2	Tabletop Exercise
ACS-3	Integrated Field Deployment and IMT Tabletop Exercise

TABLE 3-8: 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
	Quarterly Drills 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

TABLE 3-8 (CONTINUED): NORTH SLOPE SPILL RESPONSE TEAM TRAINING PROGRAM COURSES

CATEGORY	COURSE TITLE
Safety/Survival	Arctic Cold Weather Survival
	Arctic Safety
	HAZWOPER
	Spill Site Safety
	Weather Port and Survival Equipment
	Arctic Cold Water Survival
Vessel-Related	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

3.9.3 SPILL RESPONSE EXERCISES

BPXA has fully adopted the NPREP guidelines. Participation in the NPREP and use of its guidelines ensure federal exercise requirements mandated by Oil Pollution Act of 1990 (OPA 90) are met.

Internal exercises are conducted within BPXA to test the components of this plan for response to a spill. Components tested through the exercise program are as follows:

- Quarterly Qualified Individual Notification Drills are conducted 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 are conducted to ensure personnel are familiar with the contents of this plan, including the Incident Command System, crisis response procedures, mitigating measures, notification telephone numbers and procedures, and individual roles in the response structure.
- Semi-Annual Equipment Deployment Exercises are conducted to ensure internal and contractor-operated response equipment is fully functional and can be deployed in an efficient and productive manner.
- A triennial exercise of entire plan is conducted.
- Government-Initiated unannounced exercises are conducted.

The North Slope Crisis Management / Emergency Response (CM/ER) Coordinator is responsible for ensuring that an internal unannounced exercise meeting NPREP requirements occurs annually. The Planning Section Chief is responsible for documenting actions taken during an actual event for NPREP

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

credit if it involves one of the following: use of emergency procedures to mitigate or prevent a discharge or threat of a discharge, activation of the field IMT, or deployment of spill response equipment.

With the exception of government-initiated unannounced exercises, the 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 five years. Exercise documentation is in written form, signed by the ACS Environmental Lead Technician for each exercise, and available for review on request. The CM/ER Coordinator will be responsible for coordinating exercise documentation.

The North Slope CM/ER Coordinator and the ACS Environmental Lead Technician or designee is responsible for the scheduling, development and evaluation of oil spill response training programs and exercises and for ensuring that regulatory requirements are met.

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. The response community comprises the OSRO (ACS); state, federal and local agencies, and local community representatives.

BPXA participates in an annual Mutual Aid Drill (MAD). In addition to actively participating in the MAD, federal, state, and local agencies are involved in the development and evaluation of the drill. Components tested through the MAD exercise are as follows:

ORGANIZATIONAL DESIGN

- Notifications (includes training on 24-hour notifications and reporting to the National Response Center),
- Staff mobilization, and
- 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, and
- Disposal of recovered product.

RESPONSE SUPPORT

- Communications,
- Transportation,
- Personnel support,

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

- Equipment maintenance and support,
- Procurement, and
- Documentation.

3.10 PROTECTION OF ENVIRONMENTALLY SENSITIVE AREAS

[18 AAC 75.425(e)(3)(J)]

Milne Point crude oil is a persistent product. Many of its aromatic hydrocarbon compounds are toxic to fish, wildlife, and humans at various exposures. In addition, oil can coat plants and animals, injuring them by suffocation. Animals can also be affected by ingestion of oil.

Environmentally sensitive areas and areas of public concern that may suffer an impact from a spill of the response planning standard volume are identified in the simulated spill trajectories in the Response Planning Standard (RPS) scenarios in Part 1. The areas are selected based on mapped predictions of oil spill trajectories provided in the scenarios. The effect of seasonal conditions on the sensitivity of wildlife and areas to be given priority attention are depicted in “Information on Seasonal Sensitivities” and on Sheets 36, 37, 38, 43, 44, 47, 48, and 52, respectively, in Volume 2 of the ACS *Technical Manual*, incorporated by reference. Protection strategies are described in the ACS *Technical Manual*, Volume 1, Tactics W-1 through W-6, incorporated by reference, and in Sheets 36, 37, 38, 43, 44, 47, 48, and 52 in Volume 2.

On a regional scale, environmentally sensitive areas are incorporated by reference from the North Slope Subarea Contingency Plan. The maps include (but are not limited to): biologically sensitive areas maps, Most Environmentally Sensitive Areas (MESA) maps, and Environmental Sensitivity Index (ESI) maps. The most current maps can be accessed at the following link:

<http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope>

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

Not applicable.

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

- Alaska Clean Seas. 2010. *Technical Manual*. Prudhoe Bay, Alaska.
- Alaska Clean Seas. 2006. Spill-Related Properties for 11 Crude Oils from the North Slope of Alaska.
- Alaska Department of Environmental Conservation, U.S. Environmental Protection Agency and U.S. Coast Guard. *The Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharge/Releases – Unified Plan*.
- Alaska Department of Environmental Conservation, U.S. Environmental Protection Agency and U.S. Coast Guard. 2008. In Situ Burning Guidelines for Alaska, Revision 1; within Annex F of the Unified Plan, Volume 1. Anchorage. http://www.akrrt.org/ISB_GuidelinesRev1/Final/Final-Aug-08.pdf
- Alaska Regional Response Team (ARRT). 1999. North Slope Subarea Contingency Plan. <http://www.akrrt.org/NSplan/nstoc.shtml> and <http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope>
- ARRT. 2002. Wildlife Protection Guidelines for Alaska, Annex G, Rev. 4. Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases (Unified Plan, Volume 1). <http://www.akrrt.org/UnifiedPlan/index.shtml>
- Atwater, S.G. 1991. 1990 Endicott Environmental Monitoring Program Final Report: Ice Break-up and Freeze-up. Prepared by SAIC for the U.S. Army Corps of Engineers, Anchorage, Alaska.
- Atwater, S.G. 1991. 1989 Endicott Environmental Monitoring Program Final Report: Ice Break-up and Freeze-up. Prepared by SAIC for the U.S. Army Corp of Engineers, Anchorage, Alaska.
- BP Exploration (Alaska), Inc. 2010. *2010 BP Team Alaska Safety Handbook*, Anchorage, Alaska.
- Bech, C., P. Sveum, and I. Buist. 1993. The Effect of Wind, Ice and Waves on the In situ Burning of Emulsions and Aged Oils. Proceedings of the Sixteenth Arctic and Marine Oilspill Program Technical Seminar, Calgary, AB. pp 735-748.
- Bronson, M. 1998. In Situ Burning Safe Distance Predictions with ALOFT-FT model. Prepared by EMCON Alaska, Inc., for the Alaska Department of Environmental Conservation.
- Bronson, M., Thompson, E, McAdams F., and J. McHale. 2002. Ice Effects on Barge-based Oil Spill Response Systems in the Alaskan Beaufort Sea. Proceedings 25th Arctic and Marine Oilspill Program Technical Seminar (AMOP), Calgary, pp 1253-1268.
- Brown, H.M. and R.H. Goodman. 1986. In Situ Burning of Oil in Experimental Ice Leads. Environmental Studies Revolving Funds Report 064. National Energy Board, Calgary.

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

- Buist, I.A. and D.F. Dickins. 1987. Experimental Spills of Crude Oil in Pack Ice. Proceedings of the 1987 Oil Spill Conference, April 6-9, Baltimore, Maryland. American Petroleum Institute, Washington, D.C., pp 373-382.
- Buist, I., T. Coe, D. Jensen, S. Potter, L. Anderson, K. Bitting and K. Hansen. 2003. In Situ Burn Operations Manual. USCG Report CG-D-06-03, U.S. Coast Guard Research and Development Center, Groton, CT., pp 157.
- Campbell, T.E., Taylor, E. and D. Aurand. 1994. Ecological Risks Associated with Burning as a Spill Countermeasure in a Marine Environment. Proceedings of the 17th AMOP Technical Seminar, June 8-10, Vancouver, British Columbia, pp. 707-716.
- Coastal Frontiers. 2001. Spring Breakup Equipment Access Test Program (Draft and Final), prepared for BP Exploration (Alaska) Inc., Anchorage. August.
- ConocoPhillips Alaska, Inc. and BP Exploration (Alaska) Inc., 2005. North Slope Environmental Field Handbook, February.
- Danenberger, E.P. Minerals Management Service. 1993. Outer Continental Shelf Drilling Blowouts 1971 – 1991. Presented at the 25th Annual Offshore Technology Conference in Houston, Texas, U.S.A., 3-6 May 1993.
- DF Dickins Associates Ltd., Vaudrey & Associates Inc., and SL Ross Environmental Research Limited. 2000. *Oil Spills in Ice Discussion Paper*. Prepared for Alaska Clean Seas, Prudhoe Bay, AK. September.
- Izon, D., Danenberger, E.P. and Mayes, M.. Minerals Management Service. 2007. Absence of Fatalities in Blowouts Encouraging in MMS Study of OCS Incidents 1992-2006. Article based on a presentation for the IADC Well Control Conference of the Americas, 28-29 August 2007, Galveston, Texas.
- Guénette, C.C. and R. Wighus. 1996. In Situ Burning of Crude Oil and Emulsions in Broken Ice. Proceedings of the 19th AMOP Technical Seminar. Calgary, AB. pp 895 - 906.
- McCourt, J., I. Buist, S. Buffington. 2001. Results of Laboratory Tests on the Potential for Using In Situ Burning on Seventeen Crude Oils. Proceedings of the 2001 International Oil Spill Conference, pp. 529 to 532.
- Scandpower A/S. 2001. Blowout Frequency Assessment of Northstar. Report No. 27.83.01/R1. July 2, 2001. By H. Johnen, T. E. Nielsen and J. Olsen for BP Exploration (Alaska) Inc. 40 pages and appendices.
- Scandpower A/S. 2010. Blowout and Well Release Frequencies based on SINTEF Offshore Blowout Database 2009. Report No. 80.005.003/2010/R2. October 8, 2010. By T. Nordvik. 67 pages.

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

- SL Ross Environmental Research Ltd. 1983. Evaluation of Industry's Oil Spill Countermeasures Capability in Broken Ice Conditions in the Alaskan Beaufort Sea. For Alaska Department of Environmental Conservation, Anchorage.
- SL Ross Environmental Research Ltd. and DF Dickins Associates Ltd. 1987. Field Research Spills to Investigate the Physical and Chemical Fate of Oil in Pack Ice. Environmental Studies Revolving Funds Report No. 062. 95 pages.
- SL Ross Environmental Research Ltd. 1997. Oil Deposition Modeling for Surface Oil Well Blowouts. June.
- SL Ross Environmental Research Ltd., D.F. 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. Alaska Clean Seas and Dept. of the Interior Minerals Management Service on behalf of the North Slope Spill Response Project Team. Prudhoe Bay, Alaska.
- SL Ross Environmental Research Ltd., 2000. In-air Evaporative Losses of Oil from Surface Blowouts. Prepared for Alaska Clean Seas, Prudhoe Bay, Alaska.
- SL Ross Environmental Research Ltd., DF Dickins Associates Ltd. and Alaska Clean Seas. 2003. Tests to Determine the Limits of In Situ Burning of Thin Oil Slicks in Broken Ice. Report prepared for the U.S. Minerals Management Service and ExxonMobil Upstream Research.
- Shell Oil Company, Sohio Alaska Petroleum Company, Exxon Company, U.S.A., Amoco Production Company. 1983. Oil Spill Response in the Arctic - Part 2: Field Demonstrations in Broken Ice., Shell Oil Company, Sohio Alaska Petroleum Company, Exxon Company, U.S.A., Amoco Production Company. Anchorage, Alaska.
- Singsaas, I., P. Brandvik, P. Daling, M. Reed and A. Lewis. 1994. Fate and Behaviour of Oils Spilled in the Presence of Ice - a Comparison of the Results from Recent Laboratory, Mesoscale Flume and Field Tests. Proceedings of the 17th AMOP Technical Seminar, June 8-10, Vancouver, British Columbia, pp 355-370.
- Sørstrøm, S.E., P.J. Brandvik, I. Buist, P. Daling, D. Dickins, L. Faksness, S. Potter, J.F. Rasmussen and I. Singsaas. 2010. Oil in Ice – Joint Industry Program on Oil Spill Contingency for Arctic and Ice Covered Waters, Summary Report.
- Smith, N.K. and A. Diaz. 1987. In-Place Burning of Crude Oils in Broken Ice. Proceedings of the 1987 Oil Spill Conference, April 6-9, Baltimore, Maryland. American Petroleum Institute, Washington, D.C., pp 383-387.
- Veltkamp, B. and Wilcox, J.R. 2007. Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis Project. Prepared for the U.S. Department of the Interior, Minerals Management Service, Alaska OCS Region. September.
- Zhang, T., T. E. Osterkamp, and K. Stamnes. 1996. Some characteristics of the climate in northern Alaska, Arctic and Alpine Res., 28(4), 509-518.

PART 4. BEST AVAILABLE TECHNOLOGY

[18 AAC 75.425(e)(4)]

Part 4 addresses best available technology (BAT) requirements in 18 Alaska Administrative Code (AAC) 75.425(e)(4)(A), (B), and (C). This Part also addresses technologies not subject to response planning standards or performance standards in 18 AAC 75.445(k)(1) and (2). The discussion of each technology complies with the requirement to analyze applicable technologies and to provide justification that the technology is the best available.

4.1 COMMUNICATIONS [18 AAC 75.425(e)(4)(A)(i)]

The communications system for use in a spill response is described in the Alaska Clean Seas (ACS) *Technical Manual*, Volume 1, Tactic L-11, incorporated here by reference.

4.2 SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(ii)]

4.2.1 WELL SOURCE CONTROL

The two methods of regaining well control once an incident has escalated to a blowout scenario are well capping and relief well drilling. BP Exploration (Alaska), Inc. (BPXA) investigations indicate that well capping constitutes the BAT for source control of a blowout.

WELL CAPPING

Well capping techniques have proven efficient and effective in regaining well control and reducing environmental impacts. BPXA conducted a thorough investigation of well capping to regain control of a well blowout. The investigation used the response planning standard (RPS) conditions for exploration or production drilling as the evaluation case. Inherent in this evaluation were the assumptions that primary and secondary levels of well control have failed and that all dynamic and mechanical attempts to regain primary or secondary well control have been ineffective. The assessment considered best available techniques and methods to control a deep well blowout with the potential of releasing liquid hydrocarbons at the surface.

Well capping response operations are highly dependent on the severity of the well control situation. BPXA has the ability to move specialized personnel and equipment, including capping stack or cutting tools, to North Slope locations within 24 to 36 hours upon declaration of a well control event. The materials to execute control, such as junk shots, hot tapping, freezing or crimping, are small enough that they can be quickly made available to remote locations, even by aircraft, as necessary.

BPXA has an inventory of well control fire-fighting equipment warehoused on the North Slope. This equipment includes two 6,000-gallons per minute (gpm) fire pumps, associated piping, lighting, transfer pumps, Athey wagons, specialized nozzles and fire monitor shacks. The equipment represents a standard array of fire-fighting and well-control equipment normally mobilized by well control specialists in a blowout event. Maintaining this equipment on the North Slope significantly minimizes the time to mobilize and transport well control equipment in an actual blowout event.

Bulldozers, cranes, tanks, pumps, block and tackle, large diameter casing and other equipment for well capping operations are commonly available items on the North Slope. Mobilization of like equipment to Milne Point in an emergency can be made available within a few hours after requests are submitted.

Well capping is both compatible and feasible with drilling operations because the technology is applied at the surface. There are no sensitivities to well type (e.g., extended reach drilling or horizontal) or location (e.g., remote, island). Well capping techniques have been applied both on land and at offshore locations and have historically proven successful in regaining well control within a short duration. Well capping techniques are preferred over the more time-consuming alternative of drilling a relief well.

BPXA maintains an operating agreement with Boots and Coots Services, a worldwide well control specialist organization that can assist in the intervention and resolution of a well control emergency. This alliance of global service providers gives BPXA access to the best fit-for-purpose technology in response to a variety of emergency responses.

In an actual blowout event, well capping operations would commence with BPXA's activation of Boots and Coots Services and mobilization of key Incident Management Team personnel, as well as deployment of select equipment. Dynamic and surface well control methods may continue in the interim only if it is approved and safe to do so. If the well capping option were selected and approved, safe re-entry to the wellhead area would be established and rig equipment would be moved to allow safe access. If the rig moving system were unavailable or inactive, then heavy bulldozers, block and tackle, or cranes would be used to remove the rig from the wellhead area. Once safe access to the wellhead is regained, well capping operations would commence.

Other than the initial cost of the well control equipment currently stationed on the North Slope, maintaining an open contract with Boots and Coots Services is a minimal annual cost. Additional services required during an actual response would be provided at previously agreed upon rates.

The Bureau of Ocean Energy Management, Regulation and Enforcement ([BOEMRE], formerly Minerals Management Service), and SINTEF Civil and Environmental Engineering (Norway) data indicate that well capping technologies provide the shortest duration and most effective option for regaining well control and minimizing environmental impacts. This is seen in the more consistent application of well capping in response to well control events and the correspondingly shorter durations to successfully regain well control as compared to the few relief wells that have been attempted.

BPXA, in conjunction with well control experts from Boots and Coots Services, developed a schedule of events for conducting a well capping operation to be accomplished within 15 days. This estimate does not take into account the high probability that well flow may be significantly reduced or stopped in the interim by formation bridging, dynamic kill operations, or surface well control actions. Forward plans require an iterative review process as well conditions change.

If involuntary ignition has not occurred, voluntary ignition of the blowout may also be considered as a method to reduce the volume of oil that falls to water or the surrounding tundra as well as reduce the potential of secondary explosive events in and around the rig complex. The decision of voluntary ignition must be a carefully considered option as it may result in an explosive event due to trapped compartmentalized gasses within the rig complex. Voluntary ignition with subsequent explosive events may impact safe access to the wellhead area, which may in turn alter response operations.

RELIEF WELL DRILLING

None of the wells within the Milne Point Unit (MPU) currently flow to the surface. All of the production wells in the MPU employ assisted lift technologies; consequently, relief well drilling would be a highly unlikely solution to the unlikely event of a blowout.

Relief well drilling technology is compatible to North Slope drilling operations although it may be sensitive to both the well location and well types. Multiple drilling rigs are under contract on the North Slope. Downhole and surface equipment, including tubulars and wellheads, are also available to support relief well drilling operations.

Relief well drilling is similar to current methods used to drill and complete North Slope wells today, and advances in directional drilling technology that allow for more precise wellbore placement increase the likelihood of success of a relief well. However, relief well attempts would be more sensitive to blowout well locations or blowout well types for a facility having unique logistical challenges. For extended reach wells or remote locations with limited access, relief well drilling would be both challenging and time-consuming.

Well control events where relief well drilling would be the preferred source control method involve events in which the potential to release liquid hydrocarbons to surface is highly unlikely. Such events include shallow gas; compromised surface casing or surface casing cement jobs; broaching or reasonable concern of broaching, and inaccessible wellhead and/or casing.

Government (Danenberger, 1993 and Izon, Danenberger, Mayes, 2007) and industry data (Scandpower A/S, 2001 and 2010) indicate that for a vast majority of the occurrences, well control was regained through conventional dynamic kill procedures, surface control measures, well capping, or by natural means, such as formation bridging.

Optimum surface locations are rarely available on the North Slope and, as such, relief well drilling is often the least desirable option.

Relief well drilling to a deep zone blowout below surface casing can be a time-consuming and costly process. If access to the blowout location is unavailable, alternative locations must be sourced and/or constructed, such as access roads, gravel pads in the summer, or ice pads in the winter. After permitting, site construction, well planning and rig mobilization, the relief well must still be drilled. Onshore North Slope relief well durations are often estimated in the 40 to 90 day range. These lengthy timelines add to the overall environmental impact (spill volume) of the blowout well. Based on historical data (Scandpower A/S, 2001), it is estimated that more than 97 percent of blowouts would be under control by other means by the time the relief well drilling rig could be mobilized.

Relief wells provide the longest duration alternative of effectively regaining well control. In addition to the longer blowout duration, the relief well itself introduces additional environmental risks. If access to a site near the blowout well is limited, a new gravel or ice site must be quickly constructed. If gravel is required there would be an impact to the tundra where gravel is placed. During equipment mobilization or relief well drilling operations, additional risks of spills and tundra impacts are possible. During the drilling of the relief well itself, the risk for a second well control event is introduced.

BPXA believes well capping constitutes the BAT for well source control. In the event of a blowout, BPXA deems it prudent to also activate a separate team to pursue a relief well plan parallel and independent of the primary well capping plan. This action is to ensure an alternate plan is being formulated and maturing for quick implementation, if required. Table 4-1 summarizes well capping as the BAT. Historical evidence clearly indicates well capping has greater reliability and application for well blowout control compared to that of relief well drilling.

TABLE 4-1: BEST AVAILABLE TECHNOLOGY ANALYSIS – WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	EXISTING METHOD: WELL CAPPING	ALTERNATE METHOD: RELIEF WELL DRILLING
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Well capping is in use globally. Fit-for-purpose well capping and well control equipment is located on the North Slope. Additional equipment can be on location within 24 to 36 hours.	Relief well drilling equipment (rigs, down hole tools, etc.) is available, though not widely used. If extended reach drilling (ERD) is required to intercept the affected wellbore rig selections become limited.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Equipment is currently available on the North Slope or on retainer via Boots and Coots Services contract.	Multiple drilling rigs are currently under contract and current rig sharing agreement has been signed by North Slope operators.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Numerous global companies provide successful applications of well capping. After natural bridging and conventional methods (BOP, mud, cementing, equipment repairs, etc.), well capping is the most frequent blowout control measure. Application of well capping provides best opportunity for minimizing pollution impacts. Estimated duration for well capping is approximately 15 days.	Rare successful application of relief well drilling has been documented in industry. Industry data suggest a very small percentage of blowouts are successfully controlled with this technique. Relief well drilling at 40 to 90 days is the longest pollution mitigation measure possible. Relief wells may be preferred response method in some well control events (shallow gas, compromised surface casing or surface casing cementing, broaching, etc.), but these events are highly unlikely to result in the release of liquid hydrocarbons.
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	Fit-for-purpose equipment is already owned or under long-term contract. Well capping requires the maintenance of open-end contracts with trained specialists to implement well control/capping operations.	Time and cost of permitting, location construction, well planning and executing relief wells is estimated at 2 to 3 times the cost of well capping, excluding any lost production.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Well capping technology has made improvements since its frequent application during the Iraq-Kuwait conflict in the early 1990s. Fire-fighting equipment is in place on the North Slope.	Relief well drilling technology is similar to current methods used to drill and complete North Slope wells. Potentially sensitive to blowout well types (ERD) and location.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Technology is compatible and applied at surface (no sensitivity to well type).	Technology is compatible though potentially sensitive to blowout well types (ERD, remote locations, etc.). Survey uncertainty on high departure wells may result in problems intersecting target wellbore.

TABLE 4-1 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS – WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	EXISTING METHOD: WELL CAPPING	ALTERNATE METHOD: RELIEF WELL DRILLING
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible with all drilling operations. Applied at surface – no sensitivities to well type (ERD, remote locations, etc.). Prior proven success in offshore environments. Demonstrated success in historical well control efforts.	Method feasibility contingent upon geographical access near area of blowout. Lack of year-round access to some locations (offshore Beaufort) limits application. Very little evidence of successful application of relief well drilling as the primary mitigation measure of control. Relief wells may be the preferred response method in some well control events (shallow gas, compromised surf casing or surf casing cementing, broaching, etc.), but these events are highly unlikely to result in the release of liquid hydrocarbons.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	Technology provides the best-proven opportunity to quickly reduce environmental impacts. Estimated duration is significantly less than conventional alternative technologies. Impacted area is localized to the affected well site and surrounding area.	Technology provides additional exposure and environmental risks during application (additional well control problems). Technology application may be seasonally limited, leading to durations of 60 to 180 days. Relief wells may require additional gravel placement and mobilization or demobilization pressures on the local environment. Drilling a relief well is accompanied by the additional risk of a second well control event.

(b) (7)(F)



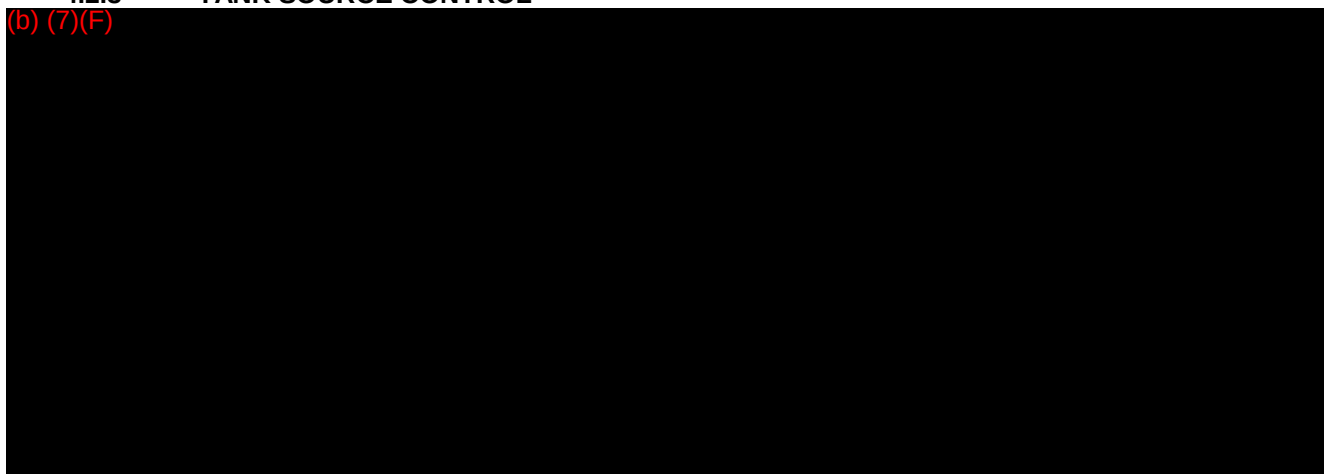
**TABLE 4-2: BEST AVAILABLE TECHNOLOGY ANALYSIS –
CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL**

BAT EVALUATION CRITERIA	EXISTING METHOD: AUTOMATIC LEAK DETECTION, PRESSURE SWITCH SHUTDOWN AND ISOLATION VALVES	ALTERNATE METHOD: ADDITIONAL AUTOMATIC SHUTDOWN VALVES
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	(b) (7)(F)	
TRANSFERABILITY: Whether each technology is transferable to applicant's operations		
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits		
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		
AGE AND CONDITION: The age and condition of technology in use by the applicant		
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant		
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects		
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits		

Milne Point Unit ODPCP, Volume 1 – Response Action Plan

4.2.3 TANK SOURCE CONTROL

(b) (7)(F)



**TABLE 4-3: BEST AVAILABLE TECHNOLOGY ANALYSIS –
TANK SOURCE CONTROL**

BAT EVALUATION CRITERIA	EXISTING METHOD: MANUAL VALVE CLOSURE	EXISTING METHOD: AUTOMATIC VALVE CLOSURE
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	(b) (7)(F)	
TRANSFERABILITY: Whether each technology is transferable to applicant's operations		
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits		
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		
AGE AND CONDITION: The age and condition of technology in use by the applicant		
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant		
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects		
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits		

4.3 TRAJECTORY ANALYSES AND FORECASTS

[18 AAC 75.425(e)(4)(A)(i)]

Trajectory analyses and forecasts are described in the ACS *Technical Manual*, Tactics T-1 to T-6 and L-11, which are incorporated here by reference.

In the event of a spill, trajectory models will be based on observed and modeled currents, wind speed and direction, and observed oil tracking data. Vector addition and trajectory modeling are used to forecast oil movement on a real-time basis.

Several research and development programs are improving industry's capability to track environmental conditions in real-time. An industry- and agency-funded program is developing the capability of measuring ocean current speed and direction using high frequency radar. In 2009, the data was available in real-time via the internet (Weingartner, 2010).

Under certain conditions, satellite-based Synthetic Aperture Radar (SAR) could be used to track large slicks on water in very open ice cover (<4/10). The current generation of all-weather SAR satellites can resolve targets to 1 meter resolution or less independent of cloud cover or light conditions. Consequently, SAR can play a valuable role in mapping detailed ice conditions and directing marine resources safely and efficiently (Sørstrøm et al., 2010). Existing commercial GPR systems can be used from a low-flying helicopter to detect oil trapped under snow on the ice and to detect oil trapped under solid ice (Sørstrøm et al., 2010).

4.4 WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS

[18 AAC 75.425(e)(4)(A)(i)]

Wildlife capture, treatment, and release programs are described in the ACS *Technical Manual*, Volume 1, Tactics W-1 through W-6 and L-11, which are incorporated here by reference. The wildlife protection strategies are based on the *Wildlife Protection Guidelines for Alaska* (Annex G of the Alaska Regional Response Team Unified Plan).

See Volume 2 (Prevention Plan), Part 4, for BAT analysis pertaining to:

- Section 4.5 – Cathodic Protection for Field-Constructed Oil Storage Tanks
- Section 4.6 – Leak Detection System for Field-Constructed Oil Storage Tanks
- Section 4.7 – Liquid Level Determination for Oil Storage Tanks
- Section 4.8 – Maintenance Practices for Buried Facility Piping
- Section 4.9 – Protective Coatings and Cathodic Protection
- Section 4.10 – Maintenance Practices for Buried Facility Piping – Corrosion Surveys
- Section 4.11 – Leak Detection for Crude Oil Transmission Pipelines

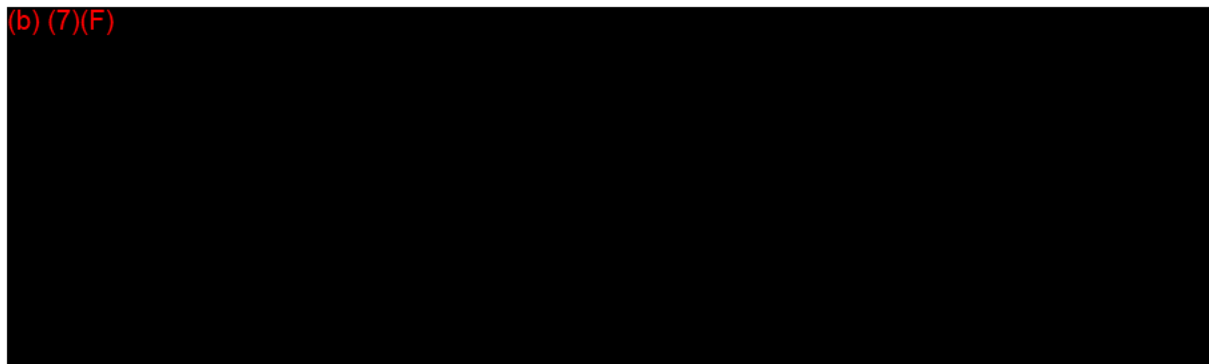
PART 5. RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

Calculations of the applicable response planning standards set out in 18 AAC 75.432, .434, and .436, including a detailed basis for the calculation reductions to be applied to the response planning standards, are presented below.

5.1 OIL STORAGE TANK [18 AAC 75.432]

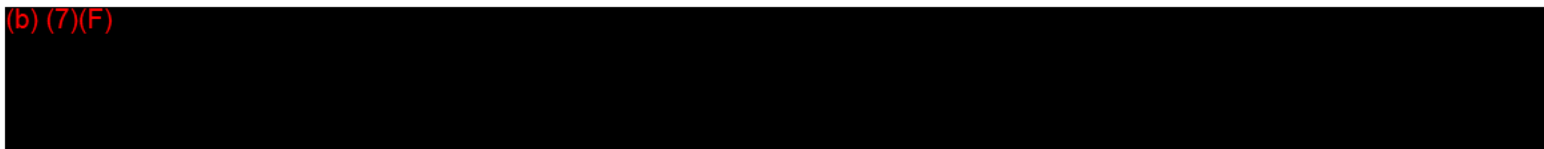
The adjusted response planning standard (RPS) volume for oil reserve tank (b) (7)(F) (bbl), as calculated below. The tank's diked secondary containment area is sufficient to contain 110 percent of tank volume and prevent oil from reaching open water.

(b) (7)(F)



5.2 WELL BLOWOUT [18 AAC 75.434]

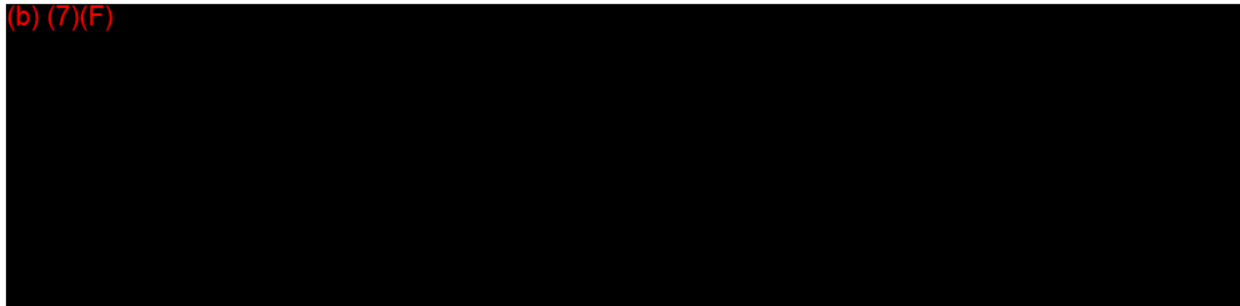
(b) (7)(F)



None of the wells within the Milne Point Unit (MPU) currently flow to the surface. All of the production wells in the MPU employ assisted lift technologies. In fact, MPU is a leader in the application of enhanced oil recovery technologies. The field employs recent advances such as Undersaturated Water-Alternating-Gas (WAG) injection, low salinity waterflooding, Brightwater gel injection for improved waterflood sweep, and a viscosity-reducing WAG flood for viscous oil. The net effect is that it would be extremely unlikely that well control would be lost within the MPU.

5.3 CRUDE OIL TRANSMISSION PIPELINE [18 AAC 75.436]

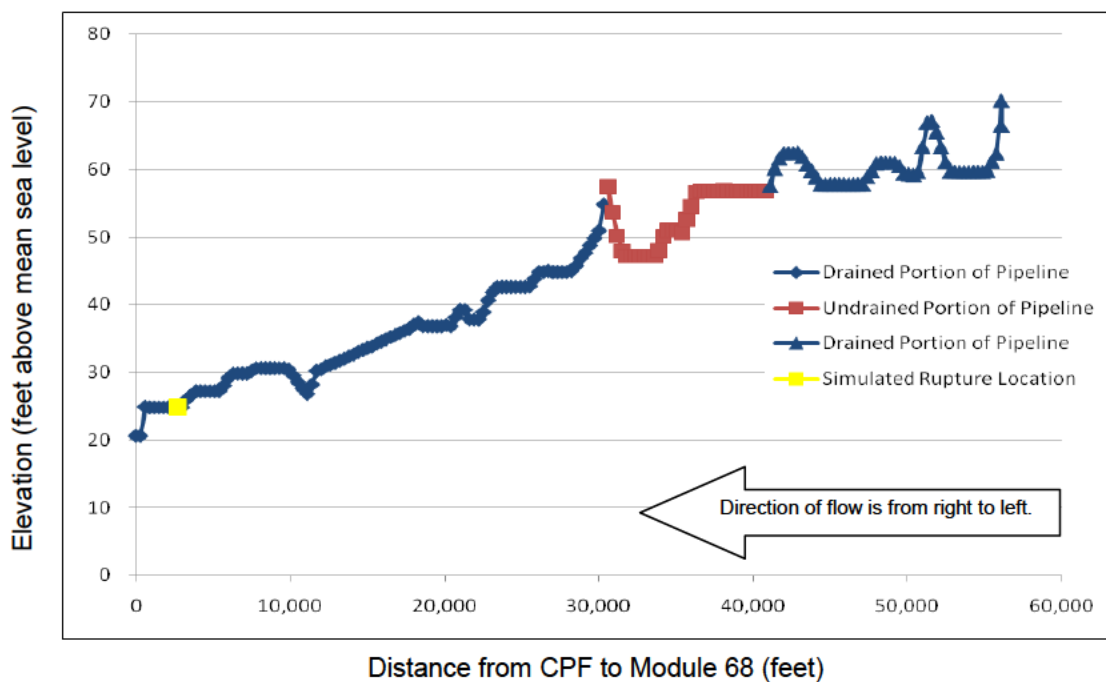
(b) (7)(F)



(b) (7)(F)

The time to detect a spill is 30 minutes. This timeframe includes receiving an alarm from the crude oil transmission pipeline leak detection system and dispatching Security to the suspected leak location to verify a spill. From the time of spill verification, the time to shut down the crude oil transmission pipeline is 15 minutes.

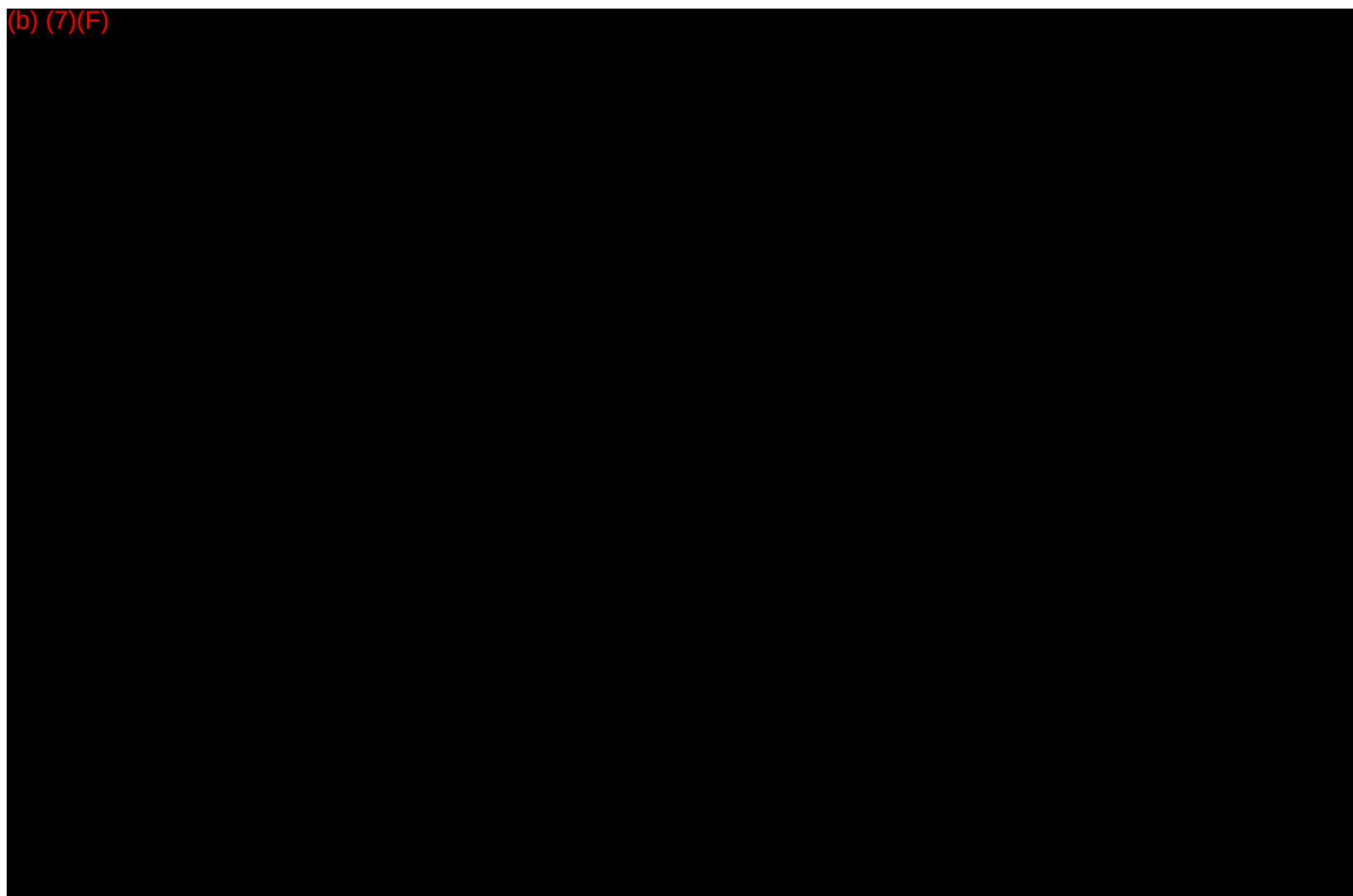
**FIGURE 5-1: CROSS SECTION OF MILNE POINT UNIT
CRUDE OIL TRANSMISSION PIPELINE**



Milne Point Unit ODPCP, Volume 1 – Response Action Plan

Therefore,

(b) (7)(F)



THIS PAGE INTENTIONALLY LEFT BLANK

FEDERAL

FACILITY RESPONSE PLANS

OPA 90 ADDENDUM

**U.S. Department of Transportation
U.S. Environmental Protection Agency**

Milne Point Unit facilities will be constructed, operated, and maintained in compliance with the terms and conditions of the U.S. Fish and Wildlife Service Letter of Authorization 06-02 regarding the incidental “take” of polar bears and walrus issued to BPXA on August 10, 2006.

U.S. DEPARTMENT OF TRANSPORTATION

**MILNE POINT UNIT
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN**

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

REGULATION SECTION (49 CFR)	SECTION TITLE	PLAN SECTION
194.109	Submission of state response plans	
(b)(1)	Have an information summary required by §194.113;	U.S. DOT information Summary.
(b)(2)	List the names or titles and 24-hour telephone numbers of the qualified individual(s); and	Table 1-2 in State of Alaska Oil Discharge Prevention and Contingency Plan (ODPCP).
(b)(3)	Ensure through contract or other approved means the necessary private personnel and equipment to respond to a worst case discharge or a substantial threat of such a discharge.	Section 3.8 in ODPCP and Statement of Contractual Terms with oil spill response organization in Introduction of ODPCP.

U.S. DOT CERTIFICATION OF RESPONSE PREPAREDNESS

CERTIFICATE OF RESPONSE PREPAREDNESS FOR MILNE POINT UNIT

BP EXPLORATION (ALASKA) INC.
MILNE POINT CRUDE OIL TRANSMISSION PIPELINE

Response Plans Officer
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
400 Seventh Street, SW, Room 2103
Washington, DC 20590

BP Exploration (Alaska) Inc. hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has identified, and ensured by contract or other means to be approved by the Pipeline and Hazardous Materials Safety 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.

Mike Utsler

for Mike Utsler
VP Operations
BP Exploration (Alaska) Inc.

7/23/2010

Date

This certification of Response Preparedness was acknowledged before me on July 23, 2010,
by ~~Mike Utsler~~ *Bruce Williams* on behalf of said corporation.



Joni Jordheim

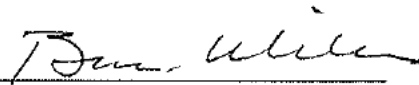
3-20-12

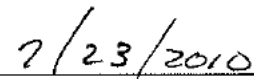
Date commission expires

NCP / ACP CONSISTENCY CERTIFICATION FOR MILNE POINT UNIT

BP EXPLORATION (ALASKA) INC.
MILNE POINT CRUDE OIL TRANSMISSION PIPELINE

BP Exploration (Alaska) Inc. hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has reviewed the National Contingency Plan (NCP) and applicable Area Contingency Plans (ACPs) and found the Milne Point Unit's Oil Discharge Prevention and Contingency Plan to be consistent with them. The NCP/ACPs reviewed include the NCP as set forth in 40 CFR 300, as published in 59 FR 47416, September 15, 1994 and the *Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharge/Releases* (Unified Plan), Volume I and Volume II (North Slope Subarea Contingency Plan).

For 
Mike Utsler
VP Operations
BP Exploration (Alaska) Inc.


Date

U.S. DOT INFORMATION SUMMARY

Name and Address of Operator:

BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612
Phone: (907) 564-5111

Street Address:
900 East Benson Boulevard
Anchorage, AK 99508
Fax: (907) 564-5180

Response Zone Description:

BP Exploration (Alaska) Inc.'s Milne Point Unit (MPU) consists of a single response zone containing the Milne Point oil sales line from Module 58 at the Central Facilities Pad (CFP) to the Kuparuk River pipeline, in the North Slope Borough of Alaska.

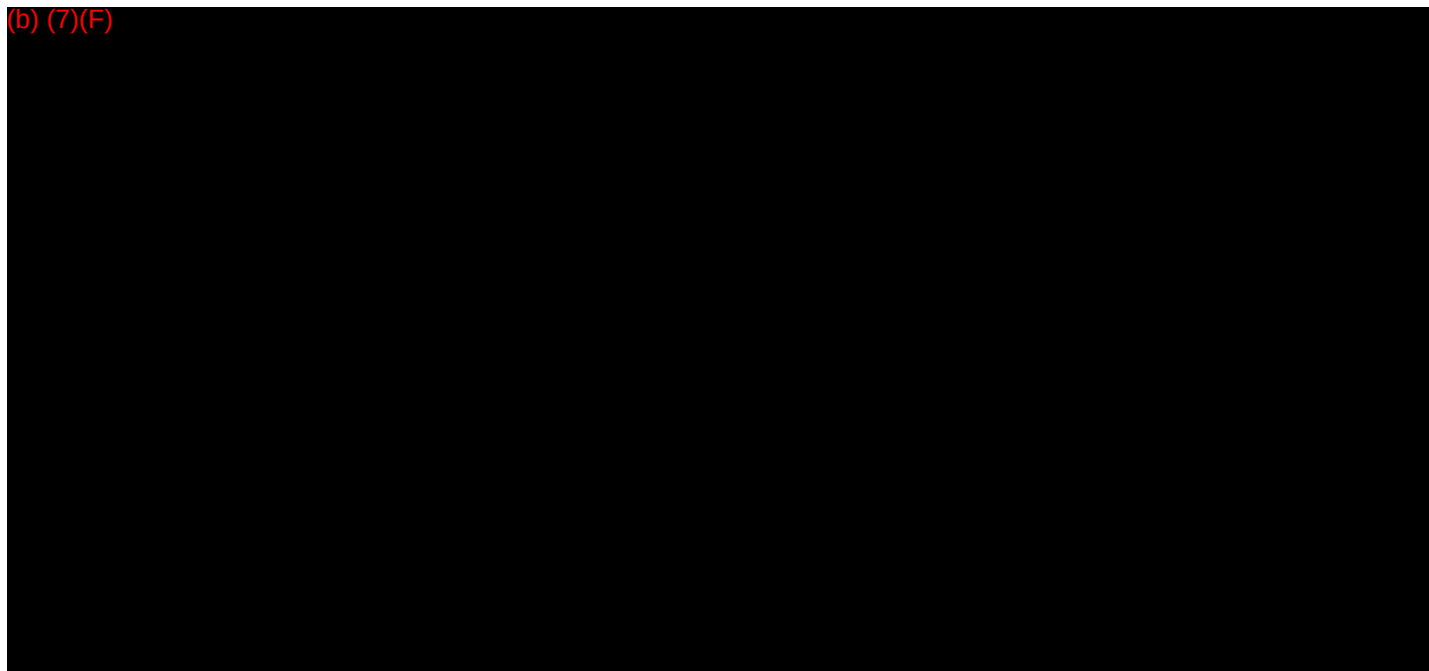
Name and Telephone Number of Qualified Individual:

See Table 1-2 (BPXA Contact List) in the MPU Oil Discharge Prevention and Contingency Plan for the names and telephone numbers of Qualified Individuals.

Worst Case Discharge

In accordance with 49 CFR 194.105(b)(1), the worst case discharge (WCD) of Alaska North Slope Crude 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 barrels (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:

(b) (7)(F)



Substantial Threat

Events and conditions that can pose a substantial threat of a WCD and procedures to eliminate or mitigate threat of a discharge are identified in BP Pipelines (Alaska) Inc., "Milne Point Pipeline USDOT Operations Manual," November 2000, Part III Abnormal Operations. This manual is reviewed yearly. All pipelines within the Milne Point Unit are accessible by road and are maintained year-round. Consequently, there is no threat to pipeline leak detection and emergency shutdown procedures regardless of weather conditions.

Description of the Line Sections

The Milne Point crude oil transmission pipeline is 9.43 miles in length, from Module 58 at the Central Facilities Pad (CFP) to the ConocoPhillips Kuparuk pipeline tie-in point at Module 68.

Basis for Determination of Significant and Substantial Harm

The Milne Point crude oil transmission pipeline lies in the proximity of the Milne Site B drinking water source. As such, the pipeline is determined to pose significant and substantial harm to the environment, if a spill should occur.

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

Sufficient response personnel and equipment are available to respond to a WCD or threat of such a discharge. This information is provided in Sections 1.6.4, Response Scenarios and Strategies; 3.5, Logistical Support; 3.6, Response Equipment; and 3.8, Response Contractor Information. The oil recovery capability for a pipeline spill is 7,940 bopd, as shown in Table 1-23.

Drinking Water and Camp Emergency Response

Oil Spill Fate and Transport (F&T) Analyses were conducted for BPXA crude oil transit pipelines in December 2006. The F&T Analyses for the crude oil transit pipelines showed that the maximum release volume from any individual location along the pipelines would not impact more than one drinking water source. Alternative drinking water sources are permitted and available in the areas where a drinking water high consequence area may be impacted.

The F&T Analyses also evaluated impacts to personnel camps, i.e., "other populated areas," that may be affected by an aerosol discharge from the crude oil transit pipelines. Each facility on the North Slope, including personnel camps, has an emergency response plan which describes alarms, evacuation procedures and accountability. Additionally, the field Incident Management Team (IMT) would be mobilized immediately for significant events. The On-Scene Commander makes an initial evaluation of the magnitude of the incident and notifies potentially impacted facilities through the IMT. Should a personnel camp be a potentially impacted facility, they would monitor the incident and activate the facility emergency response plan as necessary.

THIS PAGE INTENTIONALLY LEFT BLANK

Melanie M. C. Barber
United States Department of Transportation
Office of Pipeline Safety
Room E22-210
1200 New Jersey Avenue, S.E.
Washington, D.C. 20590

December 17, 2008

Ms. Eppie V. Hogan
Crisis Management Advisor
BP Exploration Alaska
P.O. Box 196612
Anchorage, AK 99519-6612

Dear Ms. Hogan:

I have approved four Facility Response Plans that BP Exploration Alaska submitted to the United States Department of Transportation Office of Pipeline Safety under the Oil Pollution Act of 1990: (1) Greater Prudhoe Bay, PHMSA Sequence Number 1742, (2) Milne Point Unit, PHMSA Sequence Number 404, (3) Endicott-Badami Operations, PHMSA Sequence Number 707, and (4) Northstar, PHMSA Sequence Number 1410.

Sincerely,

A handwritten signature in black ink, appearing to read "Melanie M. C. Barber". The signature is fluid and cursive, with the first name "Melanie" being the most prominent part.

Melanie M. C. Barber
Environmental Planning Officer

U.S. ENVIRONMENTAL PROTECTION AGENCY

**MILNE POINT
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN**

**U.S. ENVIRONMENTAL PROTECTION AGENCY
CROSS REFERENCE
[40 CFR 112, APPENDIX F]**

REGULATION SECTION (Appendix F)	SECTION TITLE	PLAN SECTION NUMBER
1.1	Emergency Response Action Plan 112.20 (h)(1)	Sections 1.1, 1.2
1.1.1	Qualified Individual Information	Section 1.2.3, Table 1-2
1.1.2	Emergency Notification Phone List	Sections 1.1, 1.2, Tables 1-1, 1-2, 1-3
1.1.3	Spill Response Notification Form	Sections 1.2, Figure 1-3
1.1.4	Response Equipment List and Location	Section 3.6
1.1.5	Response Equipment Testing and Deployment	Sections 1.5, 3.6.2
1.1.6	Facility Response Team	Sections 1.2, 3.3, Table 1-1, Figure 1-2
1.1.7	Evacuation Plan	Maintained on BPXA website
1.1.8	Immediate Actions	Section 1.1
1.1.9	Facility Diagram(s)	Section 1.8 and Figures SPCC-1 through SPCC-16
1.2	Facility Information 112.20 (h)(2)	EPA Response Plan Cover Sheet, Section 3.1
1.2.1	Facility Name and Location	EPA Response Plan Cover Sheet and Information Form, Section 3.1
1.2.2	Latitude and Longitude	ACS <i>Technical Manual</i> , Map Atlas
1.2.3	Wellhead Protection Area	Not applicable
1.2.4	Owner/Operator	Section 3.1
1.2.5	Qualified Individual	Section 1.2.3, Table 1-2
1.2.6	Date of Oil Storage Start-up	Section 3.1
1.2.7	Current Operation	Section 3.1
1.2.8	Dates and Type of Substantial Expansion	Section 3.1
1.3	Emergency Response Information 112.20 (h)(3)	Sections 1.1, 1.2, 3.3, 3.6, 3.7, 3.8
1.3.1	Notification	Sections 1.1, 1.2, 3.3, Tables 1-1, 1-2, 1-3
1.3.2	Response Equipment List	Section 3.6
1.3.3	Response Equipment Testing/Deployment	Sections 1.5, 3.6.2, 3.6.3
1.3.4	Personnel	Sections 3.3, 3.8, Table 1-2, Figure 1-2
1.3.5	Evacuation Plans	Maintained on BPXA website
1.3.6	Qualified Individual's Duties	Section 1.2.3

REGULATION SECTION (Appendix F)	SECTION TITLE	PLAN SECTION NUMBER
1.4	Hazard Evaluation 112.20 (h)(4)	
1.4.1	Hazard Identification	Sections 2.3, 2.4
1.4.2	Vulnerability Analysis	Section 3.10
1.4.3	Analysis of the Potential for an Oil Spill	Section 2.3, Table 2-4
1.4.4	Facility Reportable Oil Spill History	Section 2.2, Table 2-5, Appendix B
1.5	Discharge Scenarios 112.20 (h)(5)	Sections 1.6.4, 1.9
1.5.1	Small and Medium Discharges	Sections 1.6.4, 1.9
1.5.2	Worst Case Discharge	EPA Response Plan Facility Cover Sheet and Information Form; Sections 1.6.4, 1.9
1.6	Discharge Detection Systems 112.20 (h)(6)	Section 2.5
1.6.1	Discharge Detection by Personnel	Section 2.5, Table 2-6
1.6.2	Automated Discharge Detection	Section 2.5
1.7	Plan Implementation 112.20 (h)(7)	Introduction
1.7.1	Response Resources for Small, Medium and Worst Case Spills	Sections 1.6.4, 1.9, 3.3, 3.5, 3.6, 3.7, 3.8
1.7.2	Disposal Plans	Section 1.6.3
1.7.3	Containment and Drainage Planning	Section 1.6.4
1.8	Self-Inspection, Drills/Exercises and Response Training 112.20 (h)(8)	Section 3.9
1.8.1	Facility Self-Inspection	Section 2.5, Table 2-6
1.8.1.1	Tank Inspection	Section 2.5.3, Table 2-6
1.8.1.2	Response Equipment Inspection	Section 3.6.2
1.8.1.3	Secondary Containment Inspection	Section 2.1.9, Table 2-6
1.8.2	Facility Drills/Exercises	Section 3.9
1.8.2.1	Qualified Individual Notification Drill Logs	Section 3.9
1.8.2.2	Spill Management Team Tabletop Exercise Logs	Section 3.9
1.8.3	Response Training	Section 3.9
1.9	Diagrams 112.20 (h)(9)	Section 1.8
1.10	Security 112.20 (h)(10)	Section 2.1.4

**U.S. ENVIRONMENTAL PROTECTION AGENCY
RESPONSE PLAN COVER SHEET****Page 1 of 3****GENERAL INFORMATION**Owner/Operator of Facility: BP Exploration (Alaska) Inc.Facility Name: Milne Point UnitFacility Address (street address or route): P.O. Box 196612 (Mailing address)

The Milne Point Unit is located on the North Slope of Alaska.

City, State, and U.S. Zip Code Anchorage, AK 99519-6612 (Mailing address)Facility Phone No.: (907) 670-3300

(b) (7)(F)

Dun & Bradstreet Number: 151452066Standard Industrial Classification (SIC) Code: 1330

(b) (7)(F)

Number of Aboveground Oil Storage Tanks: 516

(b) (7)(F)

Facility Distance to Navigable Water. Mark the appropriate line.

0-1/4 mile X 1/4-1/2 mile 1/2-1 mile >1 mile

**U.S. ENVIRONMENTAL PROTECTION AGENCY
RESPONSE PLAN COVER SHEET****Page 2 of 3****APPLICABILITY OF SUBSTANTIAL HARM CRITERIA**Facility Name: Milne Point Unit

Does the facility transfer oil over-water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?

Yes No X

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation within any aboveground oil storage tank area?

Yes No X

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Appendix C or a comparable formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments?

Yes X No

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Appendix C or a comparable formula) such that a discharge from the facility would shut down a public drinking water intake?

Yes No X

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil spill in an amount greater than or equal to 10,000 gallons within the last 5 years?

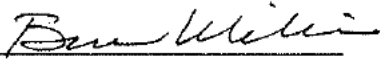
Yes No X

U.S. ENVIRONMENTAL PROTECTION AGENCY
RESPONSE PLAN COVER SHEET

Page 3 of 3

CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based upon my inquiry of those individuals responsible for obtaining information, I believe the submitted information is true, accurate and complete.



For Mike Utsler
VP Operations
BP Exploration (Alaska) Inc.

7/23/2010
Date

THIS PAGE INTENTIONALLY LEFT BLANK

U.S. EPA INFORMATION SUMMARY

Name and Address of Operator:

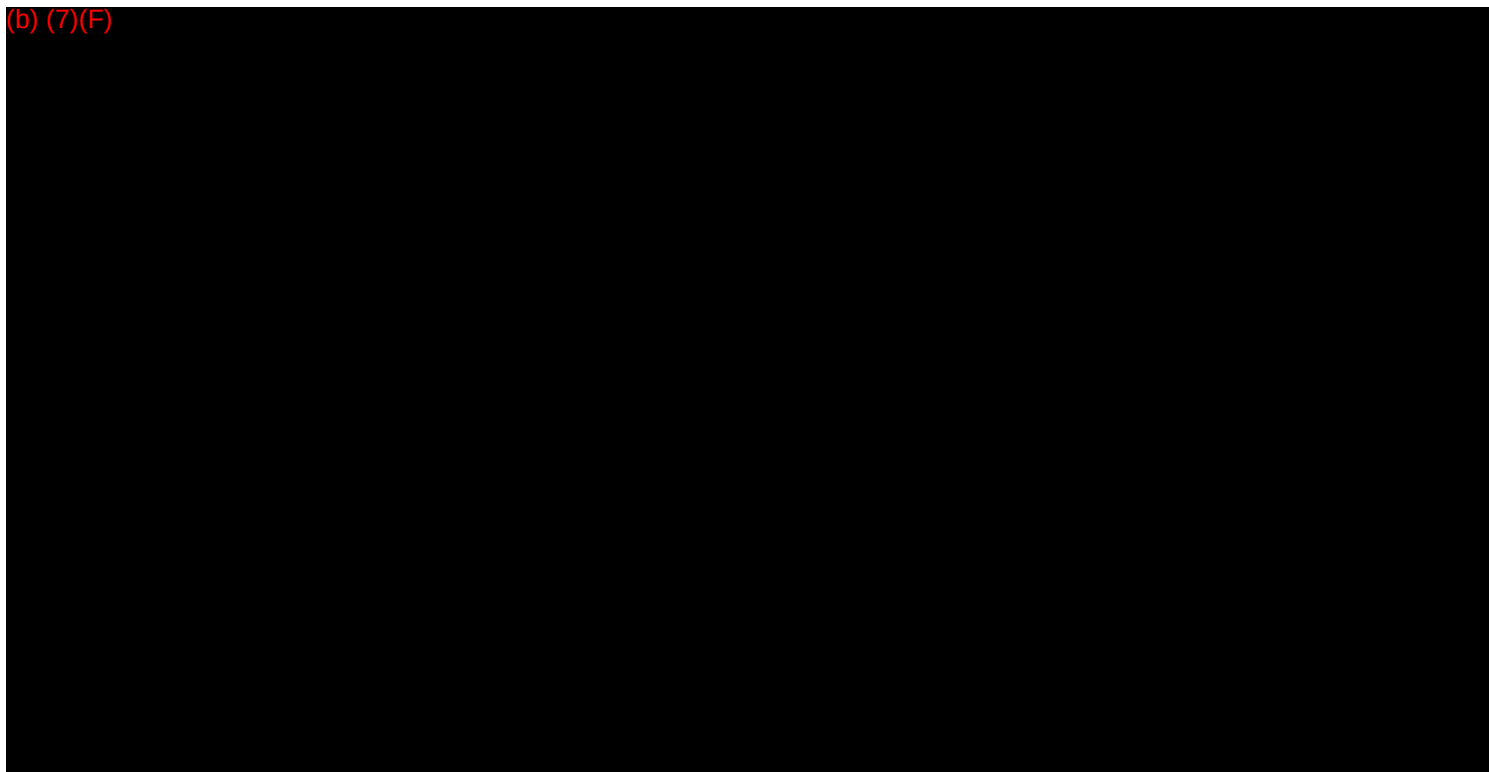
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612
(907) 561-5111

Name and Telephone Number of Qualified Individual:

See Table 1-2 (BPXA Contact List) in the MPU Oil Discharge Prevention and Contingency Plan for the names and telephone numbers of Qualified Individuals.

Worst Case Discharge:

(b) (7)(F)



Combining the capacity of the largest tank and the production volume of the highest producing oil well results in a (b) (7)(F)) of hydrocarbon material.

Basis for Determination of Significant and Substantial Harm

MPU operations have the potential to spill hydrocarbon material on tundra (wetlands) and into navigable waters of the United States. As such, it is determined to pose significant and substantial harm should a spill occur.

The Alaska Clean Seas *Technical Manual* presents a summary of major spill response equipment available to BPXA on the North Slope through its contract with ACS. In addition to BPXA contracted equipment, other spill response equipment is available to BPXA on the North Slope through ACS and Mutual Aid.

Certification of Response Personnel and Equipment:

ACS holds Oil Spill Removal Organization (OSRO) classifications for facilities and vessels:

- River/Canal – MM, W1, W2, and W3
- Inland – MM, W1, W2, and W3
- Open Ocean – MM, W1, and W2
- Offshore – MM, W1, and W2
- Nearshore – MM, W1, and W2

MPU Crude

Attachment E-1 --

Worksheet to Plan Volume of Response Resources

ATTACHMENT E-1: Worksheet to Plan Volume of Response Resources for Worst Case Discharge - Petroleum Oils

Part I Background Information

MPU Crude - 2 pages

Step (A) Calculate Worst Case Discharge in barrels (Appendix D)

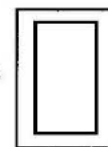
(b) (7)(F)

(A)

Step (B) Oil Group¹ (Table 3 and section 1.2 of this appendix)

2

Step (C) Operating Area (choose one)

Near
shore/Inla
nd Great
Lakesor Rivers
and
Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

Percent Lost to
Natural Dissipation

50

(D1)

Percent Recovered
Floating Oil

50

(D2)

Percent
Oil Onshore

30

(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2)} \times \text{Step (A)}}{100}$

100

2,586

(E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3)} \times \text{Step (A)}}{100}$

100

1,552

(E2)

Step (F) Emulsification Factor

(Table 3 of this appendix)

1.8

(F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor

(Table 4 of this appendix)

Tier 1

0.15

(G1)

Tier 2

0.25

(G2)

Tier 3

0.40

(G3)

¹ A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent or less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil group must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-1 (continued) --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Petroleum Oils

Part II On-Water Oil Recovery Capacity (barrels/day)

Tier 1	Tier 2	Tier 3
698	1,164	1,862
Step (E1) x Step (F) x Step (G1)	Step (E1) x Step (F) x Step (G2)	Step (E1) x Step (F) x Step (G3)

Part III Shoreline Cleanup Volume (barrels)

2,794

Step (E2) x Step (F)

Part IV On-Water Response Capacity By Operating Area
 (Table 5 of this appendix)
 (Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3
12,500	25,000	50,000
(J1)	(J2)	(J3)

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3
-11,802 (0)	-23,836 (0)	-48,138 (0)
Part II Tier 1 - Step (J1)	Part II Tier 2 - Step (J2)	Part II Tier 3 - Step (J3)

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

MPU Diesel

Attachment E-1 --

Worksheet to Plan Volume of Response Resources

ATTACHMENT E-1: Worksheet to Plan Volume of Response Resources for Worst Case Discharge - Petroleum Oils

Part I Background Information

MPU Diesel - 2 pages

Step (A) Calculate Worst Case Discharge in barrels (Appendix D)

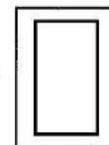
(b) (7)(F)

(A)

Step (B) Oil Group¹ (Table 3 and section 1.2 of this appendix) .

1

Step (C) Operating Area (choose one)

Near
shore/Inla
nd Great
Lakesor Rivers
and
Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

Percent Lost to
Natural Dissipation

80

(D1)

Percent Recovered
Floating Oil

20

(D2)

Percent
Oil Onshore

10

(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2)} \times \text{Step (A)}}{100}$

100

700

(E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3)} \times \text{Step (A)}}{100}$

100

350

(E2)

Step (F) Emulsification Factor

(Table 3 of this appendix)

1.0

(F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor
(Table 4 of this appendix)

Tier 1

0.15

(G1)

Tier 2

0.25

(G2)

Tier 3

0.40

(G3)

¹ A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent or less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil group must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-1 (continued) --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Petroleum Oils

Part II On-Water Oil Recovery Capacity (barrels/day)

Tier 1	Tier 2	Tier 3
105	175	280
Step (E1) x Step (F) x Step (G1)	Step (E1) x Step (F) x Step (G2)	Step (E1) x Step (F) x Step (G3)

Part III Shoreline Cleanup Volume (barrels)

350
Step (E2) x Step (F)

Part IV On-Water Response Capacity By Operating Area
 (Table 5 of this appendix)
 (Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3
12,500	25,000	50,000
(J1)	(J2)	(J3)

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3
-12,395 (0)	-24,825 (0)	-49,720 (0)
Part II Tier 1 - Step (J1)	Part II Tier 2 - Step (J2)	Part II Tier 3 - Step (J3)

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.



**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10**

Alaska Operations Office
Room 537, Federal Building
222 W. 7th Avenue, #19
Anchorage, Alaska 99513-7588

October 4, 2010

Reply to
Attn of: AOO/A

Ms. Eppie V. Hogan
Oil Spill Response Compliance Authority
BP Exploration (Alaska) Inc.
900 E. Benson Boulevard
PO Box 196612
Anchorage, AK 99519-6612

Re: ***BP Exploration (Alaska) Inc. – Milne Point Unit, North Slope, Alaska***, Facility Response Plan Review and Re-Approval, #FRPAKA0106

Dear Ms. Hogan:

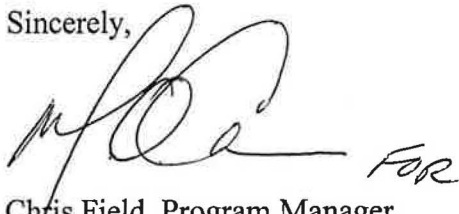
The U.S. Environmental Protection Agency's Alaska Operations Office reviewed the ***BP Exploration (Alaska) Inc. – Milne Point Unit, North Slope, Alaska***, Facility Response Plan (FRP) for compliance with EPA's 40 CFR § 112.20 regulations. It appears that this fuel storage facility could reasonably be expected to cause "Significant and Substantial Harm" to the environment in the event of an oil spill into or on the navigable waters, adjoining shorelines, or exclusive economic zone. The FRP was being reviewed for EPA re-approval purposes. The reviewed document consists of Revision #14 issued in July 2010 and includes the draft revisions provided by e-mail to EPA on October 4, 2010. This correspondence is to inform you that EPA has completed a review of that document. Based on the information provided, the FRP for this facility is ***re-approved for five years until October 4, 2015.***

Please continue to provide the EPA with routine revisions as they arise. Any material facility change must be reflected by revisions to the FRP within 60 days of that change. These revisions must be submitted to this office within that same time frame (**40 C.F.R. §112.20(d)(1), (2) and (3)**). In addition, be aware that the Oil Pollution Prevention regulations have been revised and require regulated facilities to amend their SPCC and Facility Response Plans, if necessary, to bring them into compliance with the revised regulations.

Prior to the expiration of the approval date above, and with advance notification, the EPA may conduct a facility inspection. Based on inspection results or any other pertinent information that may become available to the EPA indicating that the facility is not in compliance with 40 C.F.R. §112 regulations, the EPA reserves the right to require Plan revisions or revoke the FRP approval status.

Your organization's efforts in the preparation and implementation of the above-mentioned Facility Response Plan are greatly appreciated. If you have any questions regarding this matter, you may call Matt Carr in Anchorage at (907) 271-5083 or (800) 781-0983 (in-State only).

Sincerely,

A handwritten signature in black ink, appearing to read "Chris Field", followed by the word "For" in a cursive script.

Chris Field, Program Manager
Emergency Management Program
U.S. Environmental Protection Agency
Region X, Seattle, WA

cc: CAPT Jason Fosdick, USCG Sector Anchorage, Anchorage, AK;
Mary Matthews, US EPA/ECL-116, Seattle, WA;
Scott Pexton, ADEC EPR Section, Anchorage, AK.





BP EXPLORATION (ALASKA), INC.

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

**MILNE POINT UNIT
NORTH SLOPE, ALASKA**

VOLUME 2 OF 2, PREVENTION PLAN

OCTOBER 2011



BP EXPLORATION (ALASKA), INC.

**MILNE POINT UNIT
OIL DISCHARGE PREVENTION
AND
CONTINGENCY PLAN**

Volume 2 of 2, Prevention Plan

OCTOBER 2011

RECORD OF REVISIONS – VOLUME 2

REVISION NUMBER	REVISION DATE	SUMMARY OF REVISION CHANGE
1	January 2012	Part 2: - Daily secondary containment area inspection requirements during Phase 2 and Phase 3 weather conditions waiver updated; Appendix A: - Updates were made to Appendix A (ADEC-Regulated Portable, Shop-Fabricated Storage Tank Data for Tanks greater than 10,000 gallons on BPXA Leases) including removal of Badami tanks BAD-01, END-03, and O-17. Appendix D: - SPCC Regulated Equipment List was updated; - December 20, 2011 SPCC Regulated Equipment List certification was added; and - December 20, 2011 ADEC and EPA regulated tanks greater than 10,000 gallons certification was added.
2	July 2012	Part 3: Changes to Table 3-1 (Regulated Stationary Oil Storage Tanks greater than 10,000 gallons) included the following: - CIC Tank Integrity external inspection dates were updated for tanks T-6001 and T-6101B, and - Clarifier tank CL-5401 was taken out of service. Appendix D: - Language was added to the SPCC Conformance discussion to reflect changes in the guidance for typical failure modes of bulk storage containers and secondary containment for produced water containers. Additionally, the SPCC Regulated Equipment List was updated with those changes noted in the amendment stamped on June 11, 2012.
3	February 2013	Part 3: Changes to Table 3-1 (Regulated Stationary Oil Storage Tanks greater than 10,000 gallons) included the following: - CIC Tank Integrity inspection dates were updated for tanks T-6001 and T-6101A. - Secondary containment capacities were updated for tanks T-1102 and T-1128 and the associated tank truck loading and permanent unloading area. Appendix B: - SPCC equipment updates were made to Figure B-4, A Pad Location Map. Appendix D: - SPCC Regulated Equipment List was updated; and - December 18-19, 2012 SPCC Regulated Equipment List certification was added.
4	April 2013	Appendix A: The following changes were made to the Portable Shop-Fabricated Tank Table: - CIC Tank Integrity Inspection updates were updated; - Tank T-100420 was removed; and - Tanks T-20451 and T-20452 were tagged as not in service.
5	June 2013	Appendix D: - SPCC Regulated Equipment List was updated, and - Certification of SPCC Regulated Equipment List dated June 14, 2013 was added.

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS – VOLUME 2

RECORD OF REVISIONS – VOLUME 2	ROR-1
LIST OF FIGURES – VOLUME 2.....	TOC-4
LIST OF TABLES – VOLUME 2	TOC-4
LIST OF ACRONYMS – VOLUME 2.....	TOC-5
INTRODUCTION.....	I-1
Plan Distribution	I-1
Updating Procedures.....	I-1
Plan Renewal	I-2
Acknowledgments	I-2
PART 1. RESPONSE ACTION PLAN [18 AAC 75.425(e)(1)]	See Volume 1
PART 2. PREVENTION PLAN [18 AAC 75.425(e)(2)].....	2-1
2.1 PREVENTION, INSPECTION, AND MAINTENANCE PROGRAMS [18 AAC 75.425(e)(2)(A)]	2-1
2.1.1 Oil Discharge Prevention Training Programs [18 AAC 75.020(a) Through (c) and 40 CFR 112.7(f)]	2-1
2.1.2 Substance Abuse Programs [18 AAC 75.007(e)].....	2-2
2.1.3 Medical Monitoring [18 AAC 75.007(e)].....	2-3
2.1.4 Security Programs [18 AAC 75.007(f)]	2-3
2.1.5 Fuel Transfer Procedures [18 AAC 75.025]	2-3
2.1.6 Operating Requirements for Exploration and Production Facilities [18 AAC 75.045]	2-4
2.1.7 Leak Detection, Monitoring, and Operating Requirements for Crude Oil Transmission Pipelines [18 AAC 75.055]	2-4
2.1.8 Oil Storage Tanks [18 AAC 75.065 and 18 AAC 75.066].....	2-5
2.1.9 Secondary Containment Areas for Oil Storage Tanks and Tank Truck Loading and Permanent Unloading Areas [18 AAC 75.075].....	2-7
2.1.10 Flow Lines and Facility Oil Piping [18 AAC 75.047 and 18 AAC 75.080].....	2-8
2.2 DISCHARGE HISTORY [18 AAC 75.425(e)(2)(B) AND 40 CFR 112.20(h)(4)]	2-20

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

2.3	POTENTIAL DISCHARGE ANALYSIS [18 AAC 75.425(e)(2)(C) AND 40 CFR 112.20(h)(4)]	2-22
2.4	CONDITIONS INCREASING RISK OF DISCHARGE [18 AAC 75.425(e)(2)(D)]	2-26
2.5	DISCHARGE DETECTION [18 AAC 75.425(e)(2)(E) AND 40 CFR 112.20(h)(6)]	2-27
2.5.1	Discharge Detection During Drilling Operations.....	2-27
2.5.2	Well Discharge Detection	2-27
2.5.3	Flow Lines and Facility Piping Discharge Detection.....	2-27
2.5.4	Automated Methods of Discharge Detection	2-28
2.5.5	Discharge Detection for Oil Storage Tanks	2-28
2.5.6	Crude Oil Transmission Pipeline Discharge Detection	2-29
2.5.7	Visual Inspections.....	2-30
2.6	WAIVERS [18 AAC 75.425(e)(2)(F)]	2-33
PART 3.	SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)].....	3-1
3.1	FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]	3-1
3.1.1	Facility Ownership and General Site Description	3-1
3.1.2	Facility Storage Containers [18 AAC 75.425(e)(3)(A)(i) and (ii)].....	3-1
3.1.3	Transfer Procedures [18 AAC 75.425(e)(3)(A)(vi)].....	3-1
3.1.4	General Description of Oil Pipelines and Processing Facilities [18 AAC 75.425(e)(3)(A)(vii)]	3-4
3.1.5	Facility Diagrams [18 AAC 75.425(e)(1)(H) and 40 CFR 112.20(h)(9)]	3-8
PART 4.	BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]	4-1
4.1	COMMUNICATIONS [18 AAC 75.425(e)(4)(A)(i)].....	See Volume 1
4.2	SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(i)]	See Volume 1
4.3	TRAJECTORY ANALYSES AND FORECASTS [18 AAC 75.425(e)(4)(A)(i)]	See Volume 1
4.4	WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS [18 AAC 75.425(e)(4)(A)(i)]	See Volume 1
4.5	CATHODIC PROTECTION FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)].....	4-1
4.6	LEAK DETECTION SYSTEM FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)].....	4-1
4.7	LIQUID LEVEL DETERMINATION FOR OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]	4-1
4.8	MAINTENANCE PRACTICES FOR BURIED FACILITY PIPING [18 AAC 75.425(e)(4)(A)(ii)]	4-11

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

4.9	PROTECTIVE COATINGS AND CATHODIC PROTECTION [18 AAC 75.425(e)(4)(A)(ii)	4-11
4.9.1	Protective Coatings for Buried, Submerged, and Aboveground Facility Oil Piping....	4-11
4.9.2	Cathodic Protection Systems for Buried Facility Piping	4-11
4.10	MAINTENANCE PRACTICES FOR BURIED FACILITY PIPING – CORROSION SURVEYS [18 AAC 75.425(e)(4)(A)(ii)]	4-11
4.11	LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.425(e)(4)(A)(iv)]	4-12
PART 5. RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)].....		See Volume 1

APPENDICES

APPENDIX A	SHOP-FABRICATED TANK TABLE
APPENDIX B	FACILITY DIAGRAMS
APPENDIX C	MILNE POINT UNIT SPILL HISTORY TABLE
APPENDIX D	OPA 90 ADDENDUM

LIST OF FIGURES – VOLUME 2

2-1:	Number of Reported Milne Point Unit Oil Spills 1994-2010.....	2-21
2-2:	Reported Milne Point Unit Oil Spills Associated with Equipment	2-23
2-3:	Reported Milne Point Unit Oil Spills Associated with Operator Error	2-23

LIST OF TABLES – VOLUME 2

2-1:	Flow Line Requirements of 18 AAC 75.047 and BPXA Compliance.....	2-9
2-2:	Facility Oil Piping Requirements of 18 AAC 75.080 and BPXA Compliance	2-11
2-3:	Internal Corrosion Mechanisms Relevant to Production System	2-13
2-4:	Internal Corrosion Mechanisms Relevant to Produced Water Injection System.....	2-14
2-5:	Milne Point Unit Piping in Culverts or Utiliways	2-17
2-6:	Milne Point Unit Oil Spill Reports, 1994-2010.....	2-22
2-7:	Potential Oil Spills from Major Sources	2-24
2-8:	Visual Surveillance Schedule.....	2-31
3-1:	Milne Point Unit Regulated Stationary Oil Storage Tank Data (Tanks Greater than 10,000 Gallons).....	3-2
4-4:	Best Available Technology Analysis – Field-Constructed Storage Tank Liquid Level Determination.....	4-3
4-5:	Best Available Technology Analysis – Portable Oil Storage Tank Liquid Level Determination System.....	4-9
4-6:	Best Available Technology Analysis – Leak Detection in Crude Oil Pipeline.....	4-14

LIST OF ACRONYMS – VOLUME 2

AAC	Alaska Administrative Code
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
AE	acoustic emissions
ANSI	American National Standards Institute
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ASCCP	Asset Specific Corrosion Control Program
ASME	American Society of Mechanical Engineers
ATP	Authorization to Proceed
BAT	best available technology
bbbl	barrels
bopd	barrels of oil per day
BOPE	blow out prevention equipment
BPXA	BP Exploration (Alaska), Inc.
BS&W	basic sediment and water
°C	degrees Celsius
CFP	Central Facilities Pad
CFR	Code of Federal Regulations
CIC	Corrosion, Inspection and Chemicals
COTP	crude oil transmission pipeline
DOT	U.S. Department of Transportation
DP	differential pressure
DRT	digital radiographic testing
EAP	Employee Assistance Program
EFA	Ed Farmer and Associates
EPA	U.S. Environmental Protection Agency
ESD	emergency shutdown
°F	degrees Fahrenheit
FBE	fusion-bonded epoxy
GAnB	general anaerobic bacteria
GUL	guided wave ultrasonic testing
HCP	Hearing Conservation Program
HSSEE	Health, Safety, Security, Environment and Engineering
ILI	in line inspection
MBLPC	mass balance line pack compensation
MIC	microbially induced corrosion
mmscfd	million standard cubic feet per day
MoC	Management of Change

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

MPU	Milne Point Unit
NGL	natural gas liquid
NPWM	negative pressure wave monitoring
NSTC	North Slope Training Cooperative
ODPCP	oil discharge prevention and contingency plan
ORT	oil reserve tank
OSHA	Occupational Safety and Health Administration
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLC	programmable logic controller
PPA	pressure point analysis
psi	pounds per square inch
psig	pounds per square inch gauge
PSV	pressure safety valve
PW	produced water
ROM	rough order of magnitude
RP	Recommended Practice
RPP	Respiratory Protection Program
RTTM	real time transient model
SCADA	Supervisory Control and Data Acquisition
SPCC	spill prevention, control, and countermeasures
SRB	sulfate-reducing bacteria
SSV	subsurface safety valve
STI	Steel Tank Institute
TRT	tangential radiographic testing
UT	ultrasonic testing
VT	visual testing
VSM	vertical support members

INTRODUCTION

Volume 2 of this Oil Discharge Prevention and Contingency Plan (ODPCP) addresses oil spill prevention requirements promulgated by the State of Alaska in Title 18, Chapter 75 of the Alaska Administrative Code (AAC). As allowed under 18 AAC 75.425(e)(2), the ODPCP is represented by two volumes: Volume 1, Response Action Plan, and Volume 2, Prevention Plan. The Prevention Plan, Volume 2 of 2, is contained herein.

The Prevention Plan also addresses federal oil spill prevention regulations of the U.S. Environmental Protection Agency (EPA) under 40 Code of Federal Regulation (CFR) Part 112.7, Spill Prevention, Control, and Countermeasures Plan.

PLAN DISTRIBUTION

The Prevention Plan is maintained on the BP Exploration (Alaska), Inc. (BPXA) intranet website, accessible by BPXA employees and contractors. Hard copies of the plan are distributed to regulatory agencies and emergency operations centers. Additional copies are in the Anchorage Crisis Center, the Health, Safety, Security, Environment and Engineering (HSSEE) Department, and at Alaska Clean Seas (ACS). A record of plan distribution is maintained by the HSSEE Department.

UPDATING PROCEDURES

The Prevention Plan is reviewed annually and revised and updated when changes occur. Pursuant to spill prevention, control, and countermeasures (SPCC) requirements, the SPCC plan is also reviewed on an annual basis. Below is a list of key factors that may cause revisions to the plan:

- New developments
- New pipeline construction or purchase
- Change in commodities transported
- Change in prevention procedures
- Change in ownership

Modifications to the plan are considered amendments and must be reviewed and approved by the Alaska Department of Environmental Conservation (ADEC). Plan amendments are submitted within 30 days of revising the plan.

Revisions to the plan are documented in the Record of Revisions table at the beginning of this volume and posted on the BPXA intranet site for BPXA employee and contractor reference. Hardcopies of the changed pages are distributed to regulatory agencies and emergency operations centers. Upon receipt of revisions, the copy holder replaces pages as instructed. It is the responsibility of each plan recipient to ensure that updates are promptly incorporated into the plan.

PLAN RENEWAL

The plan is renewed every five years, based on the State of Alaska's renewal cycle.

ACKNOWLEDGMENTS

Gratitude is extended to the many contributors who helped revise Volume 2 of the ODPCP. The following BPXA personnel oversaw revisions:

Armstrong, Randy; Johnson, Elden Stelly, Travis	Sections 2.1.10, 2.5.8, 4.8, 4.9, and 4.10
Boyd, T. David	Section 3.1.4
Bronson, Mike	Entire volume
Dreyer, Pamela	Appendix C, Discharge History
Cocklan-Vendel, Mary Pomeroy, Glen	Sections 2.1.10, 2.5.8
Dunn, Joe McLeod, Shane	Section 4.7 and Tables 4-4 and 4-5
Fleming, Ray Clancy, Robert	Table 2-3
Gross, Terry	Section 2.1.8 and Table 3-1
Heebner, Deborah	Sections 2.1.5, 2.5.7, 3.1.2, 3.1.3, 3.1.4, and Tables 2-3 and 2-6; Appendix B facility diagrams
Maxson, Tory	Sections 2.5.4 and 3.1.4
O'Malley, Mark	Appendix A, Portable Tank Table
Sanford, Darryl; Schnell, Chris	Sections 3.1.2 and 3.1.4 regarding the S Pad (heavy oil) operations description
Smith, Angi	Sections 2.1.2 and 2.1.3

Additional contributors were as follows:

Carr, Aaron. AeroMetric Cartographer	Provided the facility diagrams in Appendix B.
Hermon, Neil. ACS	Sections 2.1.5, 2.5.7, 3.1.2, and 3.1.4 regarding the S Pad (heavy oil) operations description.
Miner, Lydia. SLR International Corp	Entire volume

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

1.1 EMERGENCY ACTION CHECKLIST
[18 AAC 75.425(e)(1)(A) AND 40 CFR 112.20(h)]

Part 1, Response Action Plan, is in Volume 1.

THIS PAGE INTENTIONALLY LEFT BLANK

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

This part's description of facilities and activities reflects internal documents that are not incorporated into the plan.

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

The facility's oil spill prevention programs consist of the equipment and activities required by applicable parts of ADEC's oil spill prevention regulations (18 AAC 75 Article 1) and EPA's Spill Prevention, Control and Countermeasure regulations (40 CFR 112).

2.1.1 OIL DISCHARGE PREVENTION TRAINING PROGRAMS [18 AAC 75.020(A) THROUGH (C) AND 40 CFR 112.7(F)]

BP Exploration (Alaska) Inc. (BPXA) employees with job duties directly involving inspection, maintenance or operation of oil storage and transfer equipment on BPXA leases are trained by way of BPXA's Oil Discharge Prevention Regulation Training course or discipline-specific modules. BPXA requires contractor "oil handlers" also to have training required by the regulations. Contractors may train by way of BPXA's program or by way of their own programs. (The terms oil storage and transfer equipment means tanks and secondary containment areas as described in Part 3 of this plan, plus the facility piping and truck fluid transfer equipment on BPXA leases and as described in 18 AAC 75, Article 1.)

Oil handlers also receive training on the operation and maintenance of oil equipment, oil spill protocols, and general facility operations. Oil spill prevention training and oil spill prevention briefings for oil-handling personnel are held annually. In addition, unescorted workers on BPXA leases receive spill prevention training through the North Slope Training Cooperative (NSTC) program.

BPXA employees and contractor personnel working on the North Slope receive copies of the *North Slope Environmental Field Handbook*. It provides an overview of state and federal spill prevention regulations and programs applicable to the North Slope oil fields and summarizes procedures to comply with those regulations. In particular, the handbook explains fluid transfer procedures, drip liner usage, secondary containment, and spill reporting.

Facility and response personnel are provided a mandatory site orientation that includes familiarization with facility Emergency Response Plans.

Facility personnel also receive training on the BPXA Environmental Management System Awareness. BPXA's Environmental Management System promotes continual improvement in environmental performance. The system uses direct input from technical specialists and field personnel and information developed through routine loss control and incident investigations to minimize the potential recurrence of events. Environmental communications and bulletins are regularly distributed to ensure specific environmental issues are communicated. Most supervisors discuss environmental communications and bulletins with their crews during daily and weekly toolbox safety meetings.

BPXA maintains records of its employees' oil spill prevention training required by 18 AAC 75 Article 1. Records are kept for at least 5 years. They are provided to the Alaska Department of Environmental Conservation (ADEC) upon request. 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 substance abuse, related accidents, and emergencies. 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 and alcohol policy promotes the safety of employees, contractors, and non-employees, and provides a safe working environment. The company prohibits the following in the workplace or on the job:

- Possession of illicit drugs or alcohol,
- Possession of controlled substances without a physician assistant's knowledge,
- Under the influence of any illicit drug, alcohol, or the misuse of prescription medications, and
- Distribution or sale of drugs or alcohol.

BPXA complies with the U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) drug and alcohol testing regulations set forth in 49 CFR Part 199, and the DOT Procedures for Transportation Workplace Drug & Alcohol Testing Programs in 49 CFR Part 40. BPXA employees involved in safety-sensitive positions within natural gas, liquefied natural gas, and hazardous liquid pipeline operations are required to undergo pre-employment biological testing and testing for reasonable cause, post accident (per the definition stated in the respective drug testing procedure), return to duty, follow up alcohol or drug testing (post-rehabilitation), and on a random basis in accordance with this regulation. Other BPXA employees fall under the company's drug testing program. Each of these groups is randomly tested at a rate of a minimum of 25 percent per year. Contract personnel maintain their own drug testing programs and records. The testing must meet the minimum standards set by BPXA in the contract language found in the HSE Exhibit of the contract.

BPXA employees and contract personnel must be free from the influence of drugs or alcohol on company premises. Implementation of the BPXA Substance Abuse Program is divided into three parts as follows:

- **Education.** Training is available to both employees and supervisors to teach them to detect signs of abuse in themselves and the people with whom they work. Information is provided on the available rehabilitation programs.
- **Intervention.** The company has jurisdiction to perform a drug or alcohol test on employees when there is legitimate cause, such as medical surveillance following rehabilitation, or as periodic drug screening. The company makes every effort to support its employees and strongly encourages medical rehabilitation.

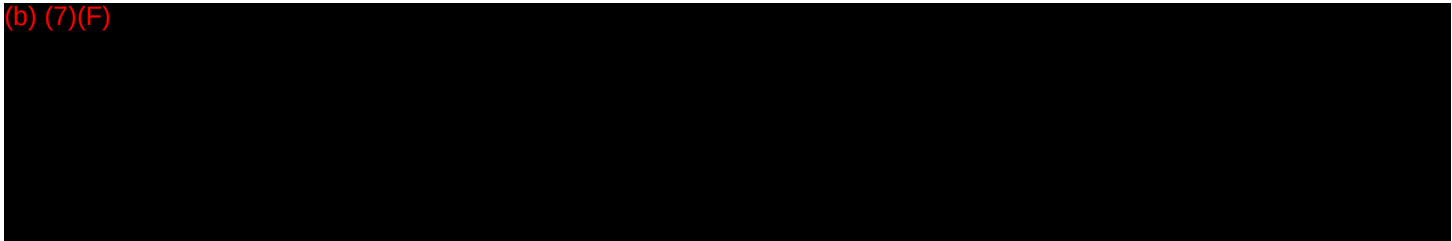
- **Discipline.** Upon the discovery of illicit drug use, controlled substance abuse, or alcoholic beverage possession, an employee will be subject to disciplinary action up to and including termination.

The BPXA Work Life and Employee Assistance Program (EAP) is an elemental part of rehabilitation. EAP is a confidential counseling and referral service provided free-of-charge to employees and their families. BPXA also supports medical rehabilitation programs outside of the EAP program, which are covered by the BPXA medical plan.

2.1.3 MEDICAL MONITORING [18 AAC 75.007(E)]

New BPXA employees receive an entrance physical to establish baseline health conditions. Under federal Occupational Safety and Health Administration (OSHA) and Alaska Department of Occupational Safety and Health requirements, medical monitoring is conducted as required by the type of work performed. Emergency response personnel have annual medical examinations, which include a physical exam, audiogram, respiratory exam, electrocardiogram, x-rays (when applicable), and blood work. All other BPXA employees who are field workers receive annual respiratory exams and audiograms if required to be in the company's Hearing Conservation Program (HCP) and/or the Respiratory Protection Program (RPP) by the Industrial Hygiene team.

(b) (7)(F)



2.1.5 FUEL TRANSFER PROCEDURES [18 AAC 75.025]

Measures are taken to prevent spills or overfilling during a transfer of oil. Loading rates are reduced at the beginning and end of a transfer, as required by 18 AAC 75.025(a). "Transfer" means oil movement between a tank and tank truck, tank vessel, or tank barge.

Each person involved in a transfer of oily fluids is capable of clearly communicating orders to stop a transfer at any time during the transfer, as required by 18 AAC 75.025(d).

A positive means is provided to stop a transfer of oily fluid in the shortest possible time, as required by 18 AAC 75.025(e).

Before beginning a transfer at an area not protected by secondary containment, the valves in the transfer system are checked to make sure they are in the correct position. Manifolds not in use are blank flanged or capped. Transfer piping and hoses used in the transfer are checked for damage or defects before the transfer and during the transfer.

The lowermost drain and the outlets of a truck's oily fluid cargo tank are examined for leaks before the truck's tank is filled and again before the truck departs, as required by 18 AAC 75.025(g). The truck's

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

manifold is blank flanged or capped and valves are secured before it leaves the transfer area. Surface liners at inlet and outlet points are the primary prevention mechanisms against discharge to the ground during the transfer of liquids.

Effective communication and planning are key factors in preventing spills. Trucks are continuously staffed during fluid transfers, and transfer personnel have radios. Manual shutoff valves are available to the truck operator to stop transfers.

2.1.6 OPERATING REQUIREMENTS FOR EXPLORATION AND PRODUCTION FACILITIES [18 AAC 75.045]

Produced oil from flow tests and other drilling operations is handled in a manner to prevent spills [18 AAC 75.045(a)]. Oil produced from flow tests may be flowed directly to the plant or stored in mobile tanks.

The requirements for platform integrity inspections and isolation valves for pipelines leaving platforms do not apply [18 AAC 75.045(b) and (c)].

A typical well house includes a cellar box (sump) which helps contain fluid leaks and facilitates cleanup [18 AAC 75.045(d)].

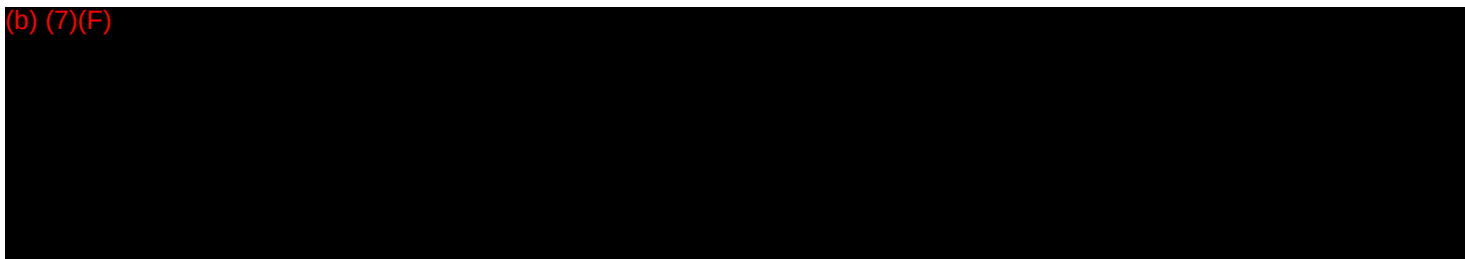
Catch tank requirements do not apply [18 AAC 75.045(e)].

Information pertaining to oil storage tanks, flow lines, and facility oil piping is found below in this Part and in Part 3 [18 AAC 75.045(f) through (g)].

2.1.7 LEAK DETECTION, MONITORING, AND OPERATING REQUIREMENTS FOR CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.055]

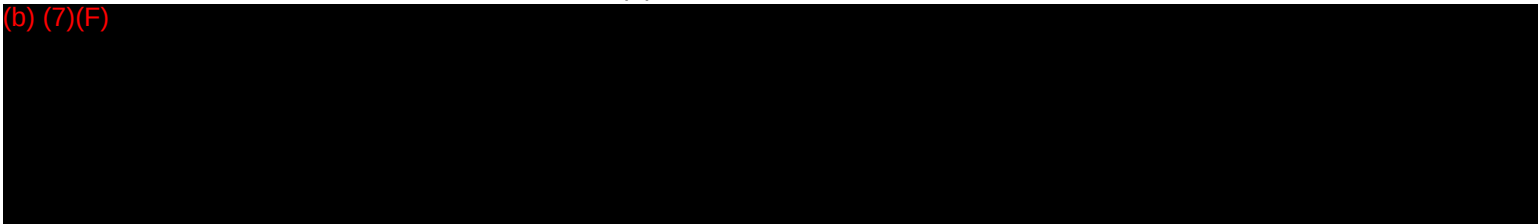
The crude oil transmission pipeline moves oil from the Milne Point Unit (MPU) Central Facilities Pad to the Kuparuk crude oil transmission pipeline tie-in south of the Spine Road.

(b) (7)(F)



Smith liquid turbine flow meters at Milne Point Unit's Central Facilities Pad and at Kuparuk measure the flow of sales oil in the crude oil transmission pipeline.

(b) (7)(F)



rupture, the board operator would immediately detect a total loss of pressure while simultaneously sensing no reduction in flow. See also Section 2.5.6.

2.1.8 OIL STORAGE TANKS [18 AAC 75.065 AND 18 AAC 75.066]

This section describes the management of ADEC-regulated tanks, i.e., oil storage tanks greater than 10,000-gallon capacity that are “in service.” In this oil discharge prevention and contingency plan (ODPCP), the term “in service” describes oil tanks that remain in regular inspection and maintenance programs. In contrast, American Petroleum Institute (API) Standard 653 uses the term “in service” to mean storing product or ready to store product. Part 3 provides information for oil storage tanks greater than 10,000 gallons, as required by 18 AAC 75.425(e)(3)(A).

Containers are constructed of materials compatible with the stored products. Tanks for processing drilling muds and cuttings are not oil storage tanks.

INSPECTIONS

Oil storage tanks greater than 10,000 gallons, in service, and on BPXA leases are maintained and inspected consistent with API Standard 653, Third Edition 2001, Addendum 1, September 2003, or API Recommended Practice 12R1, Fifth Edition 1997. Inspection intervals for field-constructed tanks are not based on similar service as outlined in API 653. However, a tank’s inspection interval may be risk-based as outlined in API 653 if the risk based inspection assessment is submitted to ADEC for approval.

Inspections and maintenance of shop-built tanks follow the Steel Tank Institute (STI) SP001 or API 653 or another equivalent approved by ADEC. Inspection intervals for shop-built tanks may be based on similar service and risk-based inspection procedures outlined in API 653. Shop-built tanks are listed in Appendix A.

Inspection results and corrective action descriptions of field-constructed oil storage tanks greater than 10,000 gallons are kept for the service life of the tanks, except API 653 walk-around in-service inspections that are kept for 5 years. Records of inspections, tests, maintenance and repairs of shop-built ADEC-regulated tanks are kept for 5 years. Copies of these records are provided to ADEC upon request.

NOTIFICATIONS AND SERVICE STATUS

BPXA’s Corrosion, Inspection and Chemicals (CIC) group follows its written procedure to notify ADEC before a BPXA-owned, field-constructed oil storage tank greater than 10,000 gallons and on a BPXA lease undergoes “major repair” or “major alteration,” as defined in API 653, Section 12.3.1.2, and again before the tank is filled [18 AAC 75.065(e)].

A field-constructed oil tank with greater than 10,000 gallons capacity that has been removed from a maintenance and inspection program required by 18 AAC 75.065 for more than 1 year is made free of accumulated oil, marked with the words “Out of Service” and the date taken out of service, secured to prevent unauthorized use, and blank flanged or disconnected from facility piping. BPXA notifies ADEC when those tasks are complete.

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

Similar notices reflecting repair and removal from service are not required for shop-built tanks.

CONSTRUCTION

Internal steam heating coils are designed to control leakage through defects, as required by 18 AAC 75.065(f).

The field-constructed oil storage tanks greater than 10,000 gallons at the Central Facilities Pad (CFP) were installed before May 14, 1992. As required by 18 AAC 75.065(h), (b) (7)(F)

secondary catchment under the tank (visual surveillance) and tank level monitoring in the control room.

Cathodic protection is not required or effective because the tanks are not in contact with soil. Anodes or internal linings provide internal corrosion protection.

Shop-built, ADEC-regulated oil tanks first placed in service before December 30, 2008, are not subject to an ADEC requirement for construction standards.

The ADEC-regulated shop-fabricated oil storage tanks at S Pad installed after December 30, 2008, were constructed under the API 620 construction standard. The tanks are elevated and have a leak detection system that an observer from outside the tank can use to detect leaks in the tank bottom, including lined secondary catchment under the tank (visual surveillance), and monitoring the tank level in the control room.

(b) (7)(F)

OVERFILL PROTECTION DEVICE INSPECTIONS

Overfill protection devices on ADEC-regulated tanks that are storing oil are tested before each transfer to them or monthly, whichever is less frequent.

A test of the overfill protection device is a manipulation of part of the system for the purpose of eliciting a response. Devices are tested in a variety of ways depending on how they are used and frequency of use. Overfill protection devices are tested by any of the following: level transmitter calibration, level transmitter calibration with annunciation of the alarm, level transmitter calibration with annunciation of the alarm and strapping, testing the level indicators and alarms by lowering the high liquid level alarm set point to below the actual liquid level to force a false alarm, checking the circuit continuity, changing the level in the tank to verify the level transmitter or alarm enunciator, strapping to calibrate the continuous level indicator in the control room, and comparing sight glasses to a measured volume. Some methods are part of regular preventative maintenance procedures.

Inspections for each type of overfill protection device on continuous-flow oil storage tanks over 10,000 gallons whose operation would be interrupted by a test are visual observations of one or more parts of the device's system that are visible from the outside of the tank. An example is daily reading sheets which show recordings of the tank liquid level heights reported by the level sensor from the control room readout.

2.1.9 SECONDARY CONTAINMENT AREAS FOR OIL STORAGE TANKS AND TANK TRUCK LOADING AND PERMANENT UNLOADING AREAS [18 AAC 75.075]

OIL STORAGE TANKS SECONDARY CONTAINMENT

Single-wall oil storage tanks greater than 10,000 gallons are located within secondary containment with the capacity to hold the volume of the largest tank within the containment plus precipitation. Secondary containment areas are constructed of bermed, diked, or retaining walls.

The containment areas are lined with materials resistant to damage and are impermeable as required by 18 AAC 75.075.

The outer wall of a double-walled aboveground oil storage tank is considered secondary containment. Additional bermed, lined, secondary containment is not required for tanks of a vaulted, self-diked or double-walled design if they are equipped with catchments that positively hold overflow due to tank overfill or divert it into an integral secondary containment area [18 AAC 75.075(h)]. The overfill catchment may be of welded construction or other fixed containment such as a lined pit.

Secondary containment systems are maintained free of debris, vegetation, and other materials or conditions, including excessive accumulated water that interferes with the effectiveness of the system as required by 18 AAC 75.075. BPXA typically leaves water in the containment area so it will freeze and add a smooth layer of ice to facilitate removal of leaks and spills in the winter. Some fabric liner bottoms are held in place with a gravel layer.

Facility personnel visually check for the presence of oil leaks or spills within secondary containments for single-wall ADEC-regulated oil storage tanks daily. The containments are further inspected for debris and vegetation, proper alignment and operation of drain valves, visible signs of oil leaks or spills, and defects or failures (e.g., tears and holes) weekly. The records of daily and weekly inspections are entered weekly. Weekly means once in a calendar week, Sunday morning through Saturday night. Double-wall tanks holding oil and not required to have further secondary containment are inspected for oil leaks into the annulus monthly. See Section 2.5.7 for visual inspection description.

Snowmelt runoff, debris, and accumulated rainwater in outdoor secondary containment for oil tanks are vacuumed out, or dewatered, and disposed of through the waste handling procedure.

Shop-fabricated oil storage tanks that are temporarily not in use and operationally empty are stacked without secondary containment in designated storage areas on gravel pads. Storage is away from the pad edge and behind a sign indicating the area is not to be used for storing oil. The stored tanks remain subject to integrity inspections according to the BPXA tank integrity management program.

BPXA notifies ADEC in writing within 24 hours if a significant change occurs in or is made to an ADEC-regulated secondary containment system and if, as a result of the change, the system no longer meets the ADEC performance requirement [18 AAC 75.475(d)].

TANK TRUCK LOADING AND PERMANENT UNLOADING AREAS SECONDARY CONTAINMENT

The ADEC-regulated tank truck loading and permanent unloading areas are identified in Table 3-1. ADEC-regulated tank truck loading and permanent unloading areas are those involving frequent transfers of oil to and from ADEC-regulated tanks. Truck sites with infrequent use; seasonal use; for temporary projects or emergency generators; solely for tank maintenance; or serving non-ADEC regulated tanks are not regulated tank truck loading and permanent unloading areas.

The tank truck loading and permanent unloading areas meet 18 AAC 75.075(g) by several means. They have secondary containments designed to contain the maximum capacity (e.g., gross volume) of the largest single compartment of the tank trucks using each containment area. Those secondary containment structures are paved, surfaced or lined with sufficiently impermeable materials.

The tank truck loading and permanent unloading areas are also maintained free of debris, vegetation, excessive accumulated water, or other materials or conditions that interfere with the effectiveness of the system. The areas have warning signs or physical barriers to prevent premature vehicular movement.

The tank truck loading and permanent unloading areas are visually inspected before transfers or at least monthly, whichever is less frequent.

2.1.10 FLOW LINES AND FACILITY OIL PIPING [18 AAC 75.047 AND 18 AAC 75.080]

The facility's oil spill prevention programs consist of the equipment and activities required by applicable parts of ADEC's oil spill prevention regulations (18 AAC 75 Article 1) and EPA's Spill Prevention, Control and Countermeasure regulations (40 CFR 112).

Table 2-3 and Table 2-4 describe how flow lines and facility oil piping comply with 18 AAC 75.047 and 18 AAC 75.080.

TABLE 2-1: FLOW LINE REQUIREMENTS OF 18 AAC 75.047 AND BPXA COMPLIANCE

CITATION 18 AAC 75.047	REGULATORY STANDARD	ADEC- REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(b)	The design and construction of each flow line placed in service after December 30, 2008 is consistent with ... ASME B31.4-2002 ... or B31.8-2003.	ASME B31.4-2002 ASME B31.8-2003	BPXA Pipelines internal guidance stipulates design procedures consistent with the standard.
(c)(1)	Measures for controlling corrosion in flow lines are ... a corrosion monitoring and control program consistent with Chapter VIII of ... ASME B31.4-2002	ASME B31.4-2002	BPXA CIC internal guidance stipulates a corrosion monitoring and control consistent with the standard.
(c)(2)	External corrosion control of buried ... flow lines consistent with ... NACE, RP0169-2002.	NACE RP0169-2002	The facility has no buried flow lines.
(c)(3)	External corrosion control of aboveground flow lines by ... protective coating, ... corrosion resistant alloys, ... or another method; ... or the anticipated extent of corrosion will not affect the flow line's fitness for service.	None	The anticipated extent of external corrosion of aboveground flow lines will not affect fitness for service. Furthermore, aboveground flow lines installed after 2006 are protected from atmospheric corrosion by fusion bonded epoxy and/or are made of corrosion resistant alloy.
(c)(4)	Flow lines are in a program designed to minimize internal corrosion, including maintenance pigging and chemicals.	None	Internal facility-specific corrosion control plans stipulate internal corrosion control techniques.
(d)(2)(B)	Preventative maintenance program ... for buried flow lines is consistent with Chapters VII and VIII of ... ASME B31.4-2002.	ASME B31.4-2002 Chapters VII and VIII	MPU has no buried flow lines.
(d)(2)(C)	For aboveground flow lines, as appropriate, a preventative maintenance program consistent with ... API 570 and ... Chapters VII and VIII of ... ASME B31.4-2002	API 570* ASME B 31.4-2002 Chapters VII and VIII	BPXA internal guidance stipulates preventative maintenance procedures consistent with the standards.
(d)(2)(D)	For all flow lines, procedures to review proposed changes in operations to evaluate potential impacts on pipe integrity.	None	BPXA's internal management of change procedures address operational changes and effects on flow lines.
(e)	Line markers shall be installed ... and maintained over each onshore flow line at each road crossing and at one-mile intervals along the remainder of the pipe to identify and, for buried pipe, properly locate each flow line.	None	Under a waiver received from ADEC on September 12, 2007, BPXA has flow line markers at road crossings in lieu of one-mile intervals.

**TABLE 2-1 (CONTINUED):
FLOW LINE REQUIREMENTS OF 18 AAC 75.047 AND BPXA COMPLIANCE**

CITATION 18 AAC 75.047	REGULATORY STANDARD	ADEC- REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(f)	Flow lines removed from service for more than one year and not maintained in accordance with [18 AAC 75.047] (c) and (d) ...must be free of accumulated oil and isolated from the system....Notify the department when flow lines are removed from service [and when they are free of accumulated oil]....A flow line removed from service is free of accumulated oil if in the case of a piggable pipe, a cleaning pig is run through the pipe; [or] in the case of a pipe that is not piggable but that can be drained entirely of its contents by gravity, the pipe is completely drained of oil; or in all other cases, air is blown through the pipe or another method is used to flush or evacuate standing oil accumulated in low spots. "Removed from service" means the flow line is not in regular use for its intended service (i.e., hydrocarbon service) and no longer in a regular maintenance and inspection program required by ADEC.	None	BPXA Pipeline group internal guidance stipulates how to remove oil and isolate the system. Flow lines no longer maintained under an ADEC-required corrosion monitoring and preventive maintenance program are, within one year, made free of accumulated oil and isolated from the system. The pipe is treated with a cleaning pig, completely drained of oil, or blown with air or with another method to evacuate standing oil. The out-of-service notices are made by BPXA's Pipelines group by way of reports to ADEC SPAR IPP.
(g)	Aboveground flow lines must be supported consistent with the requirements of...ASME B31.4-2002.	ASME B31.4-2002	Aboveground flow line support design is consistent with the standard's requirements.
(h)(1)	Verify compliance with [18 AAC 75.047]...(c) ... for corrosion control measures ... by documentation of dates and locations of inspections and tests; inspections and test data evaluation including analysis of weight loss coupons and electrical resistance probes; and corrosion inspections; data and analysis of chemical optimization activities; analysis of corrosion trends that affect the fitness for service of the flow line; and a list and description of repair activities undertaken.	None	BPXA internal database documents corrosion control and maintenance.
(h)(2)	Verify compliance with [18 AAC 75.047]...(d)(2) ... for a preventative maintenance program by documentation to validate the effectiveness of that program, including the procedures for program implementation, dates and locations of inspections and tests; inspections and test data evaluation including analysis, pipewall thickness measurements and remaining life calculations; and internal audit procedures of the program, including descriptions of controls and corrections for identified defects.	None	BPXA internal database documents corrosion control and maintenance.

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

TABLE 2-2: FACILITY OIL PIPING REQUIREMENTS OF 18 AAC 75.080 AND BPXA COMPLIANCE

CITATION 18 AAC 75.047	REGULATORY STANDARD	ADEC- REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(b)	Maintain metallic facility oil piping in accordance with a corrosion control program.	None	Corrosion control of facility piping is guided by BPXA internal procedures
(c)	Facility oil piping placed in service after December 30, 2008 is designed and constructed in accordance with ...ASME B31.3-2004 ... ASME B31.4-2002 ... or ASME B31.8-2003	ASME B31.3-2004 ASME B31.4-2002 ASME B31.8-2003	BPXA internal guidance stipulates design procedures consistent with the standards.
(d)	Buried metallic facility oil piping placed in service between May 14, 1992 and December 30, 2008, is protected from corrosion by installing protective coating and cathodic protection appropriate for local soil conditions and is of all welded construction with no clamped, threaded, or similar connections for lines larger than a one inch nominal pipe size.	None	Facility has no in-service buried facility piping placed in service between May 14, 1992, and December 30, 2008.
(e)	Buried facility oil piping placed in service after December 30, 2008, is of all welded construction with no clamped, threaded, or similar connections for lines larger than one inch nominal pipe size; and Unless constructed of a corrosion-resistant material approved by the department is protected from corrosion by installing protective coating; and cathodically protected.	None	BPXA internal guidance stipulates design procedures consistent with the regulation.
(f)	Cathodic protection systems installed after 2008 meet NACE RP0169-2002, designed by a corrosion expert, and installation supervised by a corrosion expert.	NACE RP0169-2002	No equipment is subject to the requirement.
(g)	If a piping segment of a buried facility oil piping installation is exposed for any reason, the segment is carefully examined, for damaged coating or corroded piping in accordance with Section 9.2.6 of ...API 570 ...If active corrosion is found during that examination, the owner or operator shall implement actions for control of future corrosion; and significant repairs or replacements must meet the requirements of [ADEC's 18 AAC 75.080] (c) and (e).	API 570,* Section 9.2.6	Buried facility oil piping is inspected for damage and corrosion any time it is exposed in accordance with API 570, Section 9.2.6. If active corrosion is found, corrosion control is implemented. Buried facility oil piping replacement will be corrosion-protected and welded with no clamped or threaded connections in accordance with 18 AAC 75.080(d).
(h)	Buried facility oil piping installation of metallic construction without cathodic protection shall ensure that the piping is electrically inspected by a corrosion expert for active corrosion at least once every three years, but with intervals between inspections not exceeding 39 months; and in areas in which active corrosion is found, cathodically protected.	None	Buried facility oil piping of metallic construction without cathodic protection is electrically inspected by a corrosion expert for active corrosion at least once every three years, with intervals between inspections not exceeding 39 months, or have a waiver and an alternative approved by ADEC. If active corrosion is found, the piping is cathodically protected, or alternatives comply with an ADEC waiver.

**TABLE 2-2 (CONTINUED):
FACILITY OIL PIPING REQUIREMENTS OF 18 AAC 75.080 AND BPXA COMPLIANCE**

CITATION 18 AAC 75.047	REGULATORY STANDARD	ADEC- REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(i)	Aboveground facility oil piping is supported consistent with the requirements of Paragraph 321 of ...ASME B31.3-2004.	ASME B31.3-2004 Paragraph 321	Aboveground facility piping support design is consistent with the requirements of the ASME code used to design the piping.
(j)	Facility oil piping is maintained and inspected under a program developed in accordance with API 570.	API 570*	BPXA Pipeline and CIC group's internal guidance stipulates inspection and repair procedures in accordance with API 570, or an alternative approved by ADEC.
(k)	Cathodic protection systems consistent with NACE RP0169, Section 10, survey, maintain test leads.	NACE RP0169, Section 10	No equipment is subject to this requirement
(l)	Aboveground facility piping ... is protected from atmospheric corrosion by ... protective coating ... use of corrosion-resistance material ... or ... demonstrate ...by...experience... that atmospheric corrosion of GPB facility piping...does not affect the safe operation of the piping before the next scheduled inspection.	None	Experience shows that atmospheric corrosion of aboveground facility oil piping does not affect safe operation between inspections.
(m)	At a soil-to-air interface, piping is protected against external corrosion through the application of a protective coating or ...corrosion-resistant materials.	None	BPXA internal procedures applicable to the piping's soil-to-air interface stipulate coating or corrosion-resistant materials.
(n)	Aboveground facility oil piping and valves must ensure that the piping and valves are visually checked for leaks or damage during routine operations or at least monthly, and appropriately protected from damage by vehicles.	None	BPXA procedures call for regular visual inspection of pipelines. Traffic barriers are in place where appropriate.
(o)	Facility oil piping that is removed from service for more than one year shall [be] free of accumulated oil, identified as to origin, marked on the exterior with the words "Out of Service" and the date taken out of service, secured in a manner to prevent unauthorized use, and either blank flanged or otherwise isolated from the system. Notify the department when facility oil piping is removed from service and when the actions required...are completed. Removed from service means the pipe is not used for its intended purpose of moving oil and is no longer maintained or inspected per API 570.	None	Facility piping removed from service for more than one year is free of accumulated oil, identified as to origin, marked with the words "Out of Service" or "Removed from Service" and the date taken out of service, secured to prevent un-authorized use, and blank-flanged or isolated from the system. Notifications of the out-of-service status are made by way of BPXA Pipeline group reports to ADEC SPAR IPP.

* API 570, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003.

CORROSION SURVEYS

MPU's Corrosion Control Program is a part of the Milne Point Corrosion Management Program that covers flow lines, well lines, headers, pressure vessels, and tanks, as well as other field and facility piping systems. The program is documented by an Asset Specific Corrosion Control Plan (ASCCP) described specifically for the Milne Point production facility.

The Milne Point Corrosion Management Program or ASCCP uses smart pigging, electromagnetic and guided wave inspections, and excavation and visual inspection methods for corrosion surveys.

Corrosion control measures reflect the active or potential corrosion mechanisms in the system. For MPU's pipeline network, these can be broadly subdivided into internal and external corrosion mechanisms.

External corrosion is further subdivided into one of two mechanisms: 1) atmospheric corrosion, or 2) buried or submerged corrosion. Atmospheric corrosion affects aboveground piping, piping at road crossings protected by a metal culvert, and piping in utilitiways. There are no buried or submerged pipelines at Milne Point.

Internal corrosion mechanisms depend on the type of pipeline service, whereas external corrosion mechanisms are similar for each service, but may vary in intensity as a function of temperature and protective coating type.

CONTROLLING INTERNAL CORROSION AND EROSION OF THE PRODUCTION SYSTEM

The production system transports multiphase oil, water, and gas fluids whose temperature, pressure, and velocity vary. Water cut, gas-to-oil ratio, and solids content also vary from line to line. Table 2-3 summarizes the significant internal corrosion mechanisms.

TABLE 2-3: INTERNAL CORROSION MECHANISMS RELEVANT TO PRODUCTION SYSTEM

CORROSION MECHANISM	SEVERITY OF MECHANISM	CONTROL METHOD
Carbon dioxide corrosion	Low	Corrosion inhibitor
Velocity enhanced carbon dioxide corrosion	Low	Corrosion inhibitor Velocity control
Erosion	Medium	Velocity Well place on production procedure Solids monitoring
Under-deposit corrosion	Medium	Maintenance pigging
Microbially induced corrosion	Medium	Corrosion inhibitor/pigging
Chemical attack	Low	Chemical selection Operating procedures Equipment design

Carbon dioxide and under-deposit corrosion are the primary corrosion mechanisms in the MPU system. Under-deposit corrosion in production flow lines is controlled by regularly scheduled maintenance

involving pigging to remove solids buildup from the lines. Carbon dioxide and velocity enhanced carbon dioxide corrosion are considered low severity at MPU. The control of carbon dioxide corrosion is achieved via chemical injection. Corrosion inhibitor is injected into some of the individual flow lines on a continuous basis. The chemical treatment volumes are based on the water production of the well and the corrosivity of the fluids.

Erosion is associated with extremely high velocities and solids production. The solids production is unpredictable because it is the result of an event downhole, such as the breakdown of a cement job or production of unconsolidated reservoir rock. The extreme velocities have tended to be associated with well Put-on-Production procedures, rather than normal production. Velocity limits for erosion control are defined using the approach in API Recommended Practice (RP) 14E, using the C-factor of 100. Lines are ranked in terms of risk using the ratio V/V_e , where V is the mixture velocity and V_e is the calculated erosion velocity limit. An operating limit of 2.0 is used. The limits are subject to revision as more experience is gained at managing erosion.

Microbially induced corrosion (MIC) has not been accurately quantified in the production systems, but it is known that sulfate-reducing bacteria (SRB) and general anaerobic bacteria (GANB) are present. Control of MIC is through the same chemical program as carbon dioxide corrosion. The corrosion inhibitor chemical is a strong biocide and biostat to both SRB and GANB classes of bacteria.

Chemical attack has been associated with highly corrosive scale inhibitor pooling in production pipework during shut-ins. There have also been instances of injection quill failure, leading to contact of the neat chemical with the pipewall during normal operations. Chemical attack is controlled via the use of a low corrosivity scale inhibitor and improved operating procedures that shut off the chemical supply during shut-ins. The injection quill problem has been overcome by specifying heavier wall quills.

CONTROLLING INTERNAL CORROSION OF THE PRODUCED WATER SYSTEM

The produced water injection system is defined as starting at the water outlets off the separation vessels and ending at the reservoir. It therefore includes the process piping, storage tanks, injection pumps, flow lines and well lines that store or transport produced water and the injection wells. Table 2-4 summarizes the major internal corrosion mechanisms relevant to this system.

TABLE 2-4: INTERNAL CORROSION MECHANISMS RELEVANT TO PRODUCED WATER INJECTION SYSTEM

CORROSION MECHANISM	SEVERITY OF MECHANISM	CONTROL METHOD
Carbon dioxide corrosion	Low	Inhibitor carry-over
MIC	High	Supplemental injection Maintenance pigging
Chemical attack	Low	Chemical selection Operating procedures Equipment design

A supplemental corrosion inhibitor is specifically designed to control corrosion and provide cleaning action in the produced water lines. Additionally, because carbon dioxide corrosion is a low severity issue for the upstream system, and because the oil stabilization process further reduces the vast majority of the carbon dioxide and its partial pressure, the severity of carbon dioxide corrosion is also reduced further in the produced water system. The carbon dioxide corrosion inhibitor is dosed at individual flow lines to control corrosion at the higher partial pressure in the three-phase system; therefore, the residual carry-over into the produced water system is capable of providing additional inhibition in controlling carbon dioxide corrosion.

MIC is an issue in produced water systems because the low fluid velocities in tanks and pipework allow bacteria colonies to become established and thrive. The current three-phase corrosion inhibitor is known to be toxic to SRBs and GAnBs. The produced water flow lines are regularly pigged to displace solids and bacteria.

Oxygen corrosion is not an issue in the produced water system.

Chemical attack is managed in a manner similar to the production system.

CONTROLLING EXTERNAL CORROSION ON ABOVEGROUND PIPING

Measures to control external corrosion of flow lines and facility piping include in line inspection (ILI) technique on piggable pipelines and external inspection followed by nondestructive testing techniques where lines are not piggable. Pipeline repairs are made where inspection indicates the existence of defects or anomalies potentially impacting the pipeline's fitness for service. Inspection and repairs meet the API 570 standards as required by 18 AAC 75.047(c)(3) and 18 AAC 75.080(l).

Atmospheric corrosion in the Arctic is a slow process due to the low relative humidity, lack of rainfall, and low temperatures. External corrosion is therefore a significant issue only for insulated equipment, where the polyurethane foam insulation traps moisture next to the pipewall. This warm, moist environment together with oxygen in the air can lead to corrosion under insulation.

Insulation-and-jacket systems or barrier coatings, including fusion bonded epoxy (FBE), that exclude water serve as one means of protective coating. The pipeline insulation system is a combination of shop-applied polyurethane foam on the linepipe spools with an external galvanized steel jacket. The insulation is completed at weld joints using a range of methods, but all involve the application of polyurethane foam and galvanized steel jacketing. The insulation is generally resistant to moisture ingress, except in damaged areas. Once external corrosion is detected, it can be easily and effectively mitigated by removing wet insulation.

CONTROLLING EXTERNAL CORROSION ON BELOW-GRADE PIPELINES

MPU has below-grade pipe but no buried flow lines or facility piping in contact with soil. (The term "buried" means covered or in contact with soil according to 18 AAC 75.047(i) and 75.080(p).) Piping that runs through road crossings or lies in gravel pads is installed in culverts or utilitiways, respectively. The piping is in contact with atmosphere and is not in direct or indirect contact with soil. Consequently, piping in culverts and utilitiways is treated as aboveground piping for corrosion control purposes.

INSPECTION OF PIPING IN CULVERTS OR UTILIWAYS

Piping installed below-grade is not in direct contact with soil and therefore is not subject to corrosion mechanisms associated with “buried” piping. Piping in culverts and utiliways is subject to atmospheric corrosion mechanisms instead. MPU has two types of below-grade piping: that which is accessible for visual inspection and piping that is not (see Table 2-5).

Examinations of oil piping in culverts or utiliways are achieved through in-line inspection or non-destructive examination technologies such as guided wave. Guided wave ultrasonic inspections of pipeline crossings involve inspections of the pipeline from each end of the below-grade casing. If a guided wave anomaly is found, the road crossing is excavated, and the pipe exposed for visual inspection. Utiliways are inspected by removing the cover and conducting radiographic inspections. Radiographic anomalies are stripped of insulation and visually inspected for corrosion. In-service piping in culverts or utiliways has been incorporated into a 5-year rolling inspection plan since 2007. Table 2-5 outlines the Corrosion Survey Program for pipeline segments in culverts or utiliways.

FLOW LINE SIGNAGE REQUIREMENTS

BPXA operates under a waiver received from ADEC on September 12, 2007, which requires flow line markers at road crossings in lieu of 1 mile intervals. The waiver, including applicable conditions, is provided in Section 2.6.

TEMPORARY PIPING

Temporary hardline piping is used for intermittent well testing. It does not meet the definition of facility piping in 18 AAC 75.990(171) and is not subject to ADEC regulations.

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

TABLE 2-5: MILNE POINT UNIT PIPING IN CULVERTS OR UTILIWAYS

AREA / FLOW LINE OR FACILITY PIPING	LOCATION	SIZE (INCHES)	EQUIPMENT ID	LENGTH IN CULVERT OR UTILIWAY (FEET)	SERVICE	CULVERT OR UTILIWAY	INSPECTION METHOD	COMMENTS
A Pad								
N/A	No hydrocarbon lines listed for A Pad							
B Pad								
Flow Line	B Pad to CFP STA 7+20.97 (road crossing)	8	WI-2864-FNC7	72	PW	Culvert	ILI	New 2008; FBE coating
Flow Line	B Pad to CFP STA 7+20.97 (road crossing)	14	PC-096-B2-16	72	crude	Culvert	GUL	
Flow Line	B Pad to CFP (pad crossing)	14	PC-098-B2-16-14"-H	98	crude	Culvert	DRT/TRT/UT/VT	Excavated 98/06/09/10
Flow Line	CFP to B Pad (pad crossing)	8	WI-2864-FNC7	98	PW	Culvert	ILI	New 2008; FBE coating
C Pad								
Flow Line	C Pad to CFP L/C Pad road tie (road crossing F/L Junction)	8	WI-063-F2-5	90	PW	Culvert	GUL / ILI	
Flow Line	C Pad to CFP STA 78+43.15 (ice road crossing)	8	WI-063-F2-5	90	PW	Culvert	GUL / ILI	
Flow Line	C Pad to CFP STA 118+43.41 (road crossing TR-14 Junction)	8	WI-063-F2-5	80	PW	Culvert	GUL / ILI	
Flow Line	C Pad to CFP STA 141+36.29 (road crossing near bridge)	8	WI-063-F2-5	60	PW	Culvert	GUL / ILI	
Flow Line	C Pad to CFP STA 118+43.41 (road crossing TR-14 Junction)	14	PC-2027-B2-16	80	crude	Culvert	GUL	
Flow Line	C Pad to CFP STA 141+36.29 (road crossing near bridge)	14	PC-2027-B2-16	60	crude	Culvert	GUL	
Flow Line	C Pad to CFP new pipeline (pad crossing)	24	PC-3049-BKP7-24"-H	104	crude	Utiliway	DRT/UT/VT	New 2006; FBE coating
Flow Line	F & L Pads to C Pad (pad crossing)	14	PC-2418-B2-16-14"-H	138	crude	Culvert	TRT/UT/VT	Excavated 2007
Flow Line	CFP to C Pad (pad crossing)	8	WI-109-F2-5-8"-H	104	PW	Culvert	TRT/UT/VT	Excavated 2007
D Pad								
N/A	All lines abandoned in place							
E Pad								
Flow Line	E Pad to CFP STA 604+08.23 (road crossing at E Pad)	14	PC-3084-BKP7-14"	100	crude	Culvert	ILI	New 2007; FBE coating
Flow Line	E Pad to CFP STA 7+68.49 (road crossing edge of CFP)	14	PC-3084-BKP7-14"	85	crude	Culvert	ILI	New 2007; FBE coating
Flow Line	E Pad to CFP STA 604+08.23 (road crossing at E Pad)	8	WI-2758-FNC7	100	PW	Culvert	GUL	New 2001
Flow Line	E Pad to CFP STA 7+68.49 (road crossing edge of CFP)	8	WI-2758-FNC7	85	PW	Culvert	GUL	New 2001
Flow Line	E Pad to Heaters to K/S tie in (pad crossing)	10	PC-2210-D2-11-10"-E	140	crude	Culvert	GUL	
Flow Line	CFP to E Pad (pad crossing)	8	WI-2758-FNC7	250	PW	Culvert	GUL	New 2002; FBE coating



Milne Point Unit ODPCP, Volume 2 – Prevention Plan

TABLE 2-5 (CONTINUED): MPU PIPING IN CULVERTS OR UTILIWAYS

AREA / FLOW LINE OR FACILITY PIPING	LOCATION	SIZE (INCHES)	EQUIPMENT ID	LENGTH IN CULVERT OR UTILIWAY (FEET)	SERVICE	CULVERT OR UTILIWAY	INSPECTION METHOD	COMMENTS
F Pad								
Flow Line	F Pad to C Pad (road crossing at F Pad)	14	PC-2201-BKP7	95	crude	Culvert	ILI	New 2010; 1,000 ft of new pipe; FBE coating
G Pad								
Flow Line	G Pad Header to Main line	6	WI-2904-FNC7	156	PW	Utiliway	DRT/TRT/UT/VT	New 2010; FBE coating
Flow Line	G Pad Header to Main line	8	PC-3153-DNC7	156	crude	Utiliway	DRT/TRT/UT/VT	New 2010; FBE coating
H Pad								
Flow Line	H Pad Header to Main line	6	WI-2905-FNC7	203	PW	Utiliway	DRT/TRT/UT/VT	New 2010; FBE coating
Flow Line	H Pad Header to Main line	6	PC-3154-DNC7	203	crude	Utiliway	DRT/TRT/UT/VT	New 2010; FBE coating
I Pad								
Flow Line	I Pad Header to Main line	6	PC-2765-DNC7	42	crude	Utiliway	DRT/UT/TRT/VT	New 2006
Flow Line	I Pad Header to Main line	6	WI-2549-FNC7	42	PW	Utiliway	DRT/UT/TRT/VT	New 2006
J Pad								
Flow Line	J Pad Header to Main Line	6	PC-2782-D2-11	40	crude	Utiliway	DRT/UT/TRT/VT	New 2006
Flow Line	J Pad Header to Main line	6	WI-2589-F2-2	40	PW	Utiliway	DRT/UT/TRT/VT	New 2006
Flow Line	Tract 14 J Pig trap to TR-14 Junction Pig Trap (TR-14 Road crossing)	10	PC-3138-DNC7	85	crude	Culvert	ILI	New 2010; FBE coating
Flow Line	Tract 14 J Pig trap to TR-14 Junction Pig Trap (TR-14 Road crossing)	6	WI-2888-FNC7	85	PW	Culvert	ILI	New 2010; FBE coating
Flow Line	Tract 14 J Pig trap to I J intersection new casing	10	PC-3138-DNC7	125	crude	Culvert	ILI	New 2010; FBE coating
Flow Line	Tract 14 J Pig trap to I J intersection new casing	6	WI-2888-FNC7	125	PW	Culvert	ILI	New 2010; FBE coating
K Pad								
Flow Line	K Pad to S Pad tie-in @ Pig Pad	8	PC-3083-BKP7-8"-H	172	crude	Utiliway	ILI	New 2007
L Pad								
Flow Line	L Pad crude to F/C tie-in	8	PC-2271-D2-11-8"-E	110	crude	Culvert	GUL	Pad limit
Facility Piping	L Pad Production Header	3	PC-2284-DNC7-3"	70	crude	Utiliway	DRT/UT/TRT/VT	New 2007
Facility Piping	L Pad Test Header	3	PC-2272-DNC7-3"	70	crude	Utiliway	DRT/UT/TRT/VT	New 2007



TABLE 2-5 (CONTINUED): MPU PIPING IN CULVERTS OR UTILIWAYS

AREA / FLOW LINE OR FACILITY PIPING	LOCATION	SIZE (INCHES)	EQUIPMENT ID	LENGTH IN CULVERT OR UTILIWAY (FEET)	SERVICE	CULVERT OR UTILIWAY	INSPECTION METHOD	COMMENTS
S Pad								
Flow Line	MPU access road, crossing near K Pad intersection	12	Production	80	crude	Culvert	ILI	New 2002
Flow Line	MPU access road, crossing near K Pad intersection	8	Water Injection	80	PW	Culvert	GUL	New 2002
Flow Line	S Pad to S/K tie in @ Pig Pad	12	PC-2853-BKP7-12"-H	40	crude	Utiliway	ILI	New 2002
Flow Line	CFP to S Pad Pipeline	8	WI-2644-FNC7-8"-IH	40	PW	Utiliway	UT/VT	New 2002
CFP Pad								
N/A	No hydrocarbon lines listed for CFP Pad							

KEY:

DRT - Digital Radiographic Testing
 FBE - Fusion Bonded Epoxy
 GUL - Guided Wave Ultrasonic Testing
 ILI - In Line Inspection
 N/A – Not Applicable

NEW - New Piping
 PW - Produced Water
 TRT - Tangential Radiographic Testing
 UT - Ultrasonic Testing
 VT - Visual Testing

2.2 DISCHARGE HISTORY [18 AAC 75.425(e)(2)(B) AND 40 CFR 112.20(h)(4)]

The discharge history of reported MPU oil spills greater than 55 gallons, and spills of any volume to water or tundra, for the period January 1994 through September 2010 is provided in Appendix C and includes the following information:

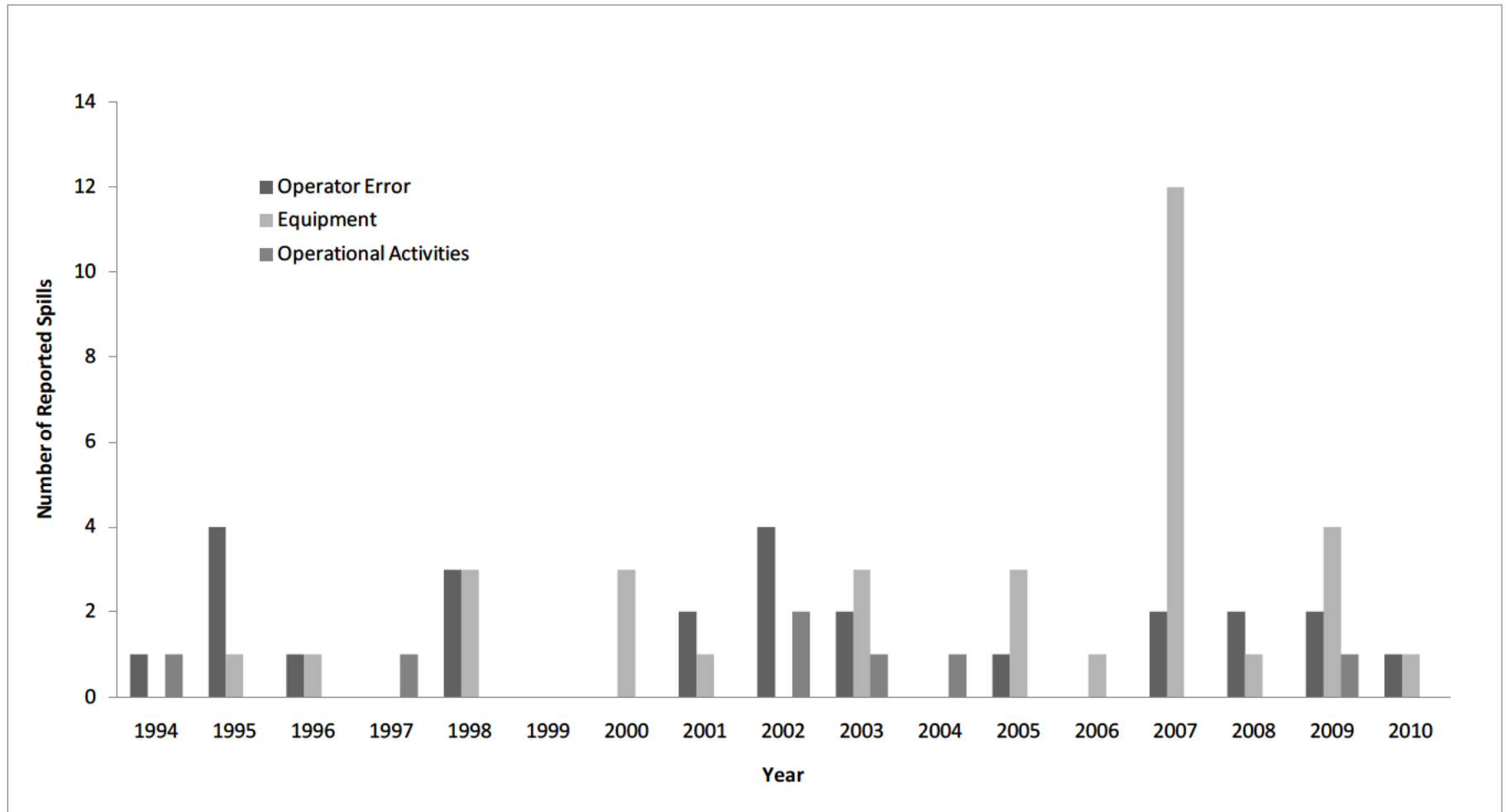
- Date of discharge;
- Material discharged;
- Estimated amount discharged, including the estimated volume that reached navigable waters as applicable;
- Description of the spill event;
- Environmental impact, and
- Corrective and preventive actions taken.

This discharge history includes the information outlined in 40 CFR Part 112, Appendix F, Section 1.4.4, for spills that are identified by 40 CFR Part 110.

The history of reported discharges of volumes greater than 55 gallons is maintained in the BPXA spill database for the life of the facility. Most spills at Milne Point are small events that are contained on gravel pads and rarely reach the tundra or water environment.

Figure 2-1 shows the annual number of reported spills associated with equipment, operator error, and operational activities (shutdowns and well work).

**FIGURE 2-1: NUMBER OF REPORTED MILNE POINT UNIT OIL SPILLS
1994-2010**



2.3 POTENTIAL DISCHARGE ANALYSIS [18 AAC 75.425(e)(2)(C) AND 40 CFR 112.20(h)(4)]

The potential for oil spills is understood from historical spill data. Table 2-6 summarizes reports of spills greater than 55 gallons. The historical data assist in identifying operations or equipment that is prone to spills.

Spills associated with equipment problems make the largest category of reported spills greater than 55 gallons (48%), followed by operator error (41%), and operational activities (11%) among oil spills reported January 1994 through September 2010.

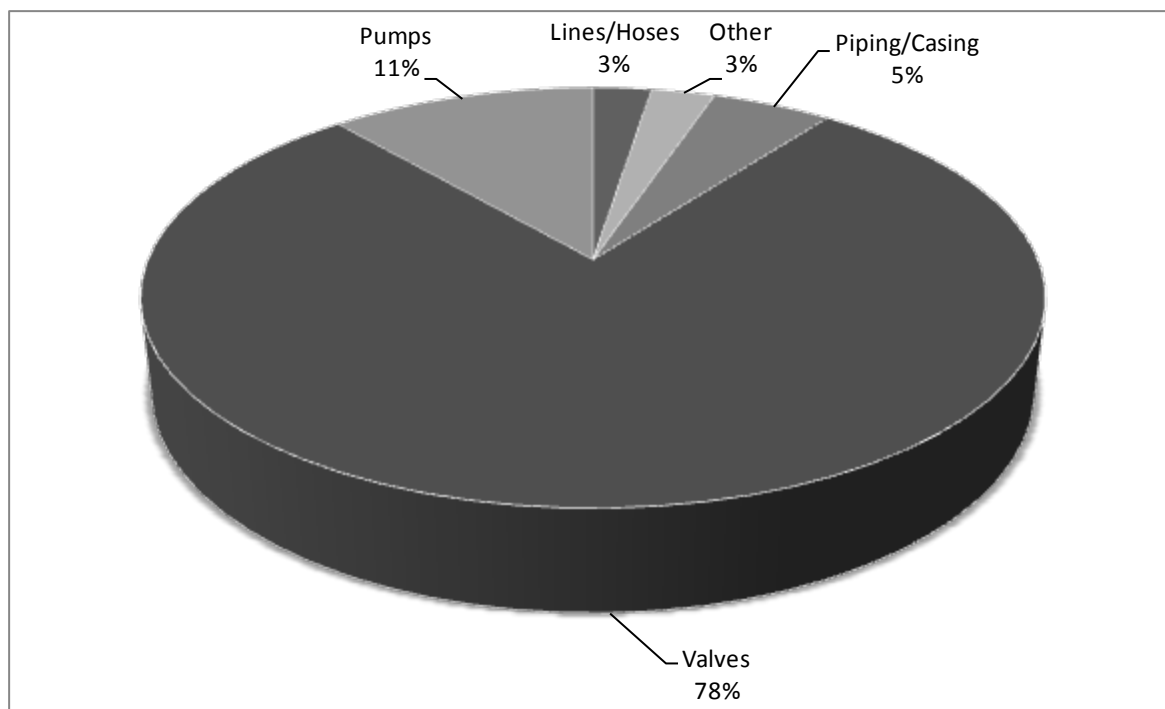
TABLE 2-6: MILNE POINT UNIT OIL SPILL REPORTS, 1994-2010

CATEGORY	SOURCE	NUMBER OF SPILLS (>55 GALLONS) REPORTED	ESTIMATED CUMULATIVE VOLUME (GALLONS)
Equipment	Valves	6	18,790
	Pumps	2	2,710
	Piping/Casing	3	1,225
	Lines/Hoses	5	596
	Other (includes fill device, choke, seals, sight glass)	5	650
Operator Error	Vehicles/Heavy Machinery	3	10,710
	Portable Tanks	9	1,892
	Valves	2	1,200
	Other (includes fluid transfers, response activity, installation)	4	847
Operational Activities	Shutdowns, well work	5	5,653

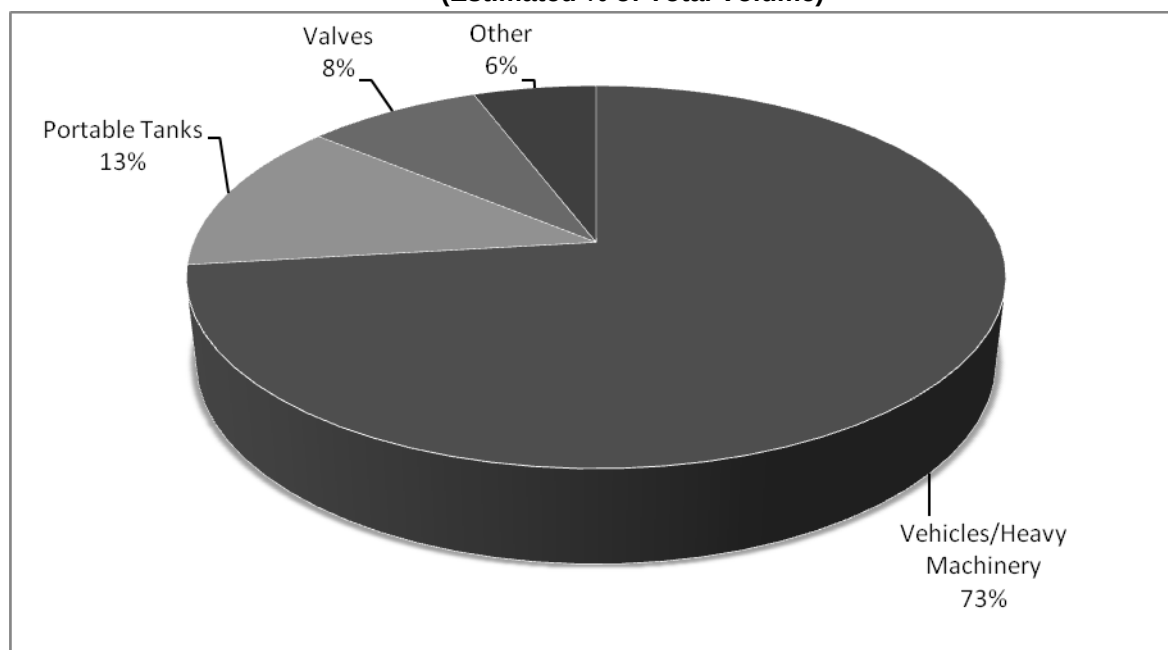
Figure 2-2 depicts the percentage of estimated volumes spilled associated with equipment. Valve problems accounted for more than 75 percent of the total estimated volume. Valves are present on nearly all oil-containing equipment. Two reported valve-related releases contributed to more than 90 percent of the total estimated volume. These releases were associated with a leaking valve, and communication problem with a valve, both on sand slurry vessels.

Figure 2-3 depicts the percentage of estimated volumes spilled associated with operator errors. Vehicles and heavy machinery account for nearly 75 percent of the total estimated volume. These reported spills involved improper placement or spilling of drill cuttings and drilling mud on the tundra in two incidents, and a loader hitting a tank valve in the third. No spills in this sub-category have been reported since 1998.

**FIGURE 2-2: REPORTED MILNE POINT UNIT OIL SPILLS ASSOCIATED WITH EQUIPMENT
(Estimated % of Total Volume)**



**FIGURE 2-3: REPORTED MILNE POINT UNIT OIL SPILLS ASSOCIATED WITH OPERATOR ERROR
(Estimated % of Total Volume)**



Milne Point Unit ODCPCP, Volume 2 – Prevention Plan

Potential and past spills are discussed during the Authorization to Proceed (ATP) process while analyzing job hazards. Environmental advisors attend project kick-off and operations support meetings where spill mitigation measures and reporting procedures are discussed. Environmental advisors also work with responsible parties to ensure timely and accurate reporting and clean up of spills.

At Milne Point, oil spill causes are shared throughout the facility and other BPXA facilities. As an example, a spill occurred in February 2007 due to a “dead leg” in a produced water injection flow line which froze and split after the pipe was switched to gas injection service. When the pipeline was switched back to produced water service, the pipe was thawed and water reached the split section of the flow line, resulting in a produced water spill. Dead legs were subsequently identified across the field in order to reduce the potential for a similar spill. A field-wide bulletin was circulated across the BPXA North Slope fields so that the other assets could be made aware of this issue. Six valve-related releases make up 78 percent of the total estimated volume of releases attributed to equipment failure. Regular preventative maintenance involves inspection of valves, which are repaired or replaced if required. The effectiveness of the preventative maintenance program is demonstrated by the absence of reported valve-related releases since 2005.

Simulated examples of potential oil spills at Milne Point are described in Table 2-7.

TABLE 2-7: POTENTIAL OIL SPILLS FROM MAJOR SOURCES

SOURCE	SIZE	CAUSE	DURATION	LOCATION	PREVENTATIVE MEASURES
Oil Reserve Tank	3,500 barrels (bbl)	Rupture, overflow, or valve leak	Rupture – instantaneous Overflow/Valve Leak – 25 gallons/minute	CFP	Secondary containment, overflow protection device, tank inspection program
Fuel Transfer	325 bbl	Rupture, overflow, or valve leak	Overflow/Valve Leak – 14 gallons/minute	CFP	Secondary containment, tank truck maintenance
Pipeline	Varies depending on pipeline size	Rupture	Varies depending on pipeline size	MPU Asset	Pipeline corrosion control program
Fuel Delivery Vehicle	4,200 gallons	Rupture or broken hose	Broken Hose – instantaneous draining of hose [~28 gallons; $(V=3.14*(0.167)^2*40 \text{ feet} = 28 \text{ gallons})]$	MPU Asset	Driver training, fuel transfer procedures, check valves between hose and tank to prevent draining of tank in the event of a broken hose
Transport truck carrying produced sands from S Pad	Truck capacity	Roll over	Instantaneous	MPU Road	Driver training
Well	789 bbl	Sheared off	1 day	L-20	MPU wells produce oil only by submersible pump; discharge can be stopped by cutting power to the pump

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

Spill prevention actions involve the training, operating procedures, leak detection, inspections, and secondary containment outlined in Part 2. Milne Point participates proactively in spill prevention programs including campaigns, investigations, and training to increase employee awareness levels.

BPXA North Slope operations employ multiple learning processes as part of the Alaska Incident Investigation program to help prevent potential discharges. Proven techniques, such as “Root Cause Failure Analysis”, are utilized during the investigation process to ensure that the highest value actions are implemented to prevent reoccurrence. Lessons learned are broadly shared across BPXA and the contractor community to promote spill prevention. Depending on the incident, the review team may include: personnel responsible for the operation causing the spill, their foreman or supervisor, a safety representative, field environmental compliance personnel, a facility supervisor, and/or a corrosion engineer. The investigation process is aimed at addressing the root cause of the incident and thereby eliminating workplace risk, reducing personnel exposure to spilled materials, preventing reoccurrence of spills, and identifying additional early detection opportunities. Spill investigation results are communicated to BPXA and contractor field personnel to promote spill prevention. Periodically, teams are developed to conduct an analysis of potential trends in spill causes, locations, materials, volumes, and frequencies. The analysis of these trends offers the opportunity to proactively implement additional continual improvement measures to further reduce the potential for discharge.

2.4 CONDITIONS INCREASING RISK OF DISCHARGE

[18 AAC 75.425(e)(2)(D)]

Conditions specific to BPXA's North Slope operations that increase the potential risk of an oil spill, and actions taken to reduce the risk of a spill, are as follows:

- Heat may cause gases to expand, increasing the likelihood of discharge. North Slope facilities are engineered to accommodate temperature fluctuations.
- Cold snaps present obvious threats to field operations. North Slope facilities are engineered to withstand Arctic conditions.
- Icy roads, white-out conditions, and changes in traffic patterns may increase the risk of vehicle collisions. BPXA Security's strict adherence to vehicle safety, speed limits, and the posting of warning signs or traffic cones helps to minimize the potential for vehicular accidents that may result in a spill.
- If the Trans Alaska Pipeline System unexpectedly shuts down the pipeline, the risk to BPXA systems increases. BPXA's advanced communication system enables immediate communication between the Trans Alaska Pipeline System and the North Slope operators, which allows for the coordination of impacts and minimizes the risks due to a shutdown of the pipeline.
- High winds could increase the risk of discharge during fuel transfers. If wind speed appears to pose a threat to communications or hoses, transfer operations will be postponed until the wind subsides.
- As the field ages, the discharge potential increases. To minimize spills related to aging facilities, BPXA uses a computerized preventative maintenance program, has a corrosion control program, performs valve inspections in accordance with Alaska Oil and Gas Conservation Commission (AOGCC) regulations, has leak detection monitoring, and conducts regular visual inspections.
- High water and/or ice during breakup could increase the risk of discharge over river crossings. The pipeline support members have been designed to withstand worst-case ice conditions expected at the river crossings.

2.5 DISCHARGE DETECTION [18 AAC 75.425(e)(2)(E) AND 40 CFR 112.20(h)(6)]

2.5.1 DISCHARGE DETECTION DURING DRILLING OPERATIONS

Each drilling rig has a system of controls, monitors, alarms, and procedures to assist in the early detection of potential discharges. For both downhole and surface operations, these detection systems include automated monitoring devices as well as standard operating procedures governing the monitoring, handling, and containment of fluids.

During downhole operations, much of the discharge detection effort centers on well control with an emphasis on detecting wellbore influxes (kicks). The primary control to prevent a discharge associated with a kick is the density of the hydrostatic column of drilling fluid in the wellbore. The drilling fluid density and other critical parameters are closely monitored by drilling fluid specialists and trained members of the rig crew. Modifications to the mud density are made in accordance with the AOGCC-approved well plan to maintain the proper fluid density at various intervals.

For surface operations, discharge detection systems utilize automated equipment, visual, audio, or manual detection in combination with policies and procedures governing the handling and containment of fluids. Rig pit systems are equipped with pit volume totalizers that constantly monitor and record pit volume gains and losses. Unexpected gains or losses of drilling fluids initiate alarms, which sets in motion initial crew responses to secure the well.

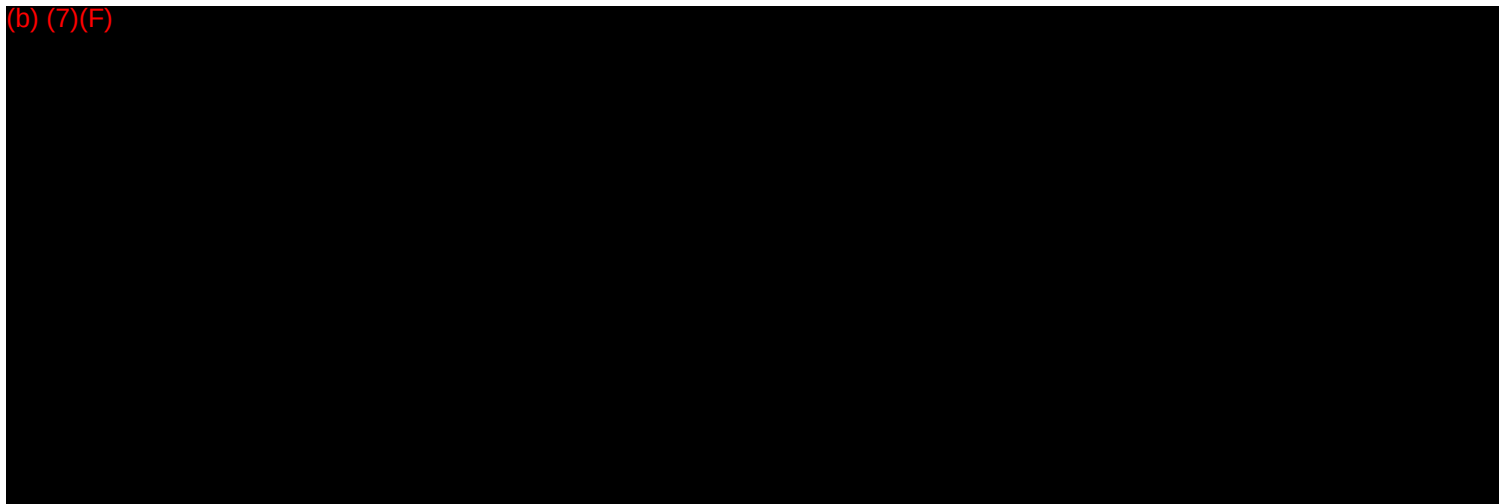
Rig surface systems are continuously monitored for external leakage as well. Fluid transfers associated with drilling operations are carefully planned, permitted, and monitored using BPXA and contractor fluid transfer guidelines. Strict adherence to these procedures ensures immediate detection of spills associated with fluid transfer operations, which significantly reduces the probability of occurrence.

(b) (7)(F)

2.5.3 FLOW LINES AND FACILITY PIPING DISCHARGE DETECTION

Flow line locations are identified in Appendix B, Figure B-3. The primary leak detection method for the flow lines is regular, scheduled visual inspections by the field operators and Security personnel and instructions to personnel on how to report a leaking or ruptured line. In addition, each flow line has a set of (b) (7)(F)

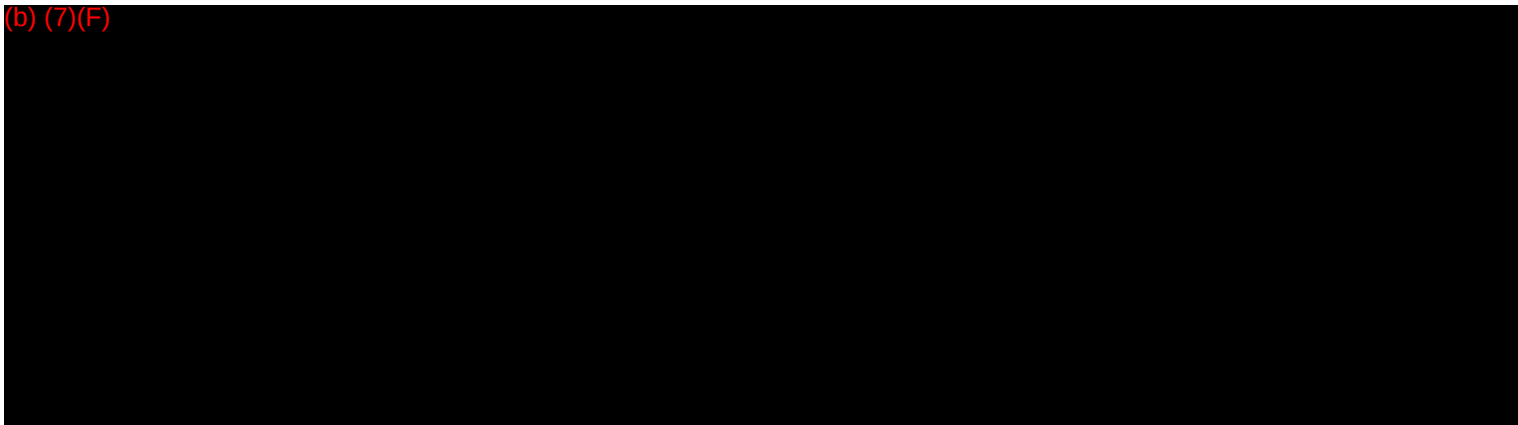
(b) (7)(F)



Field operators routinely inspect facility oil piping for leaks, spills, and ruptures on a scheduled basis, which is at least monthly. They document their findings on their daily report sheets. Additionally, personnel are instructed on how to contact the front desk to report a spill or flow line rupture. They are instructed to observe the flow lines and report anything unusual when they are traveling on the lease.

2.5.4 AUTOMATED METHODS OF DISCHARGE DETECTION

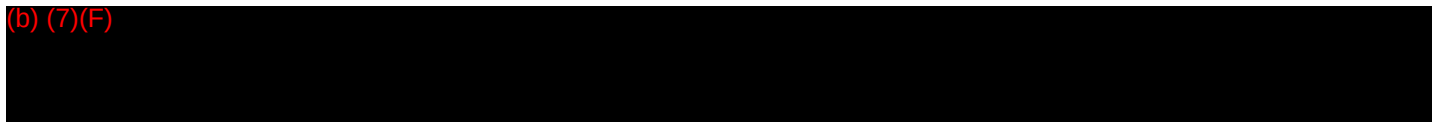
(b) (7)(F)



2.5.5 DISCHARGE DETECTION FOR OIL STORAGE TANKS

OIL STORAGE TANKS GREATER THAN 10,000 GALLONS

(b) (7)(F)



During fluid transfers, portable oil storage tanks are continuously monitored by on-site personnel.

Double-walled ADEC-regulated shop built tanks are equipped with an interstitial monitoring system, e.g., sight glass, view port, or drain port that enables an outside observer to detect oil leaks and water accumulations.

Oil storage tanks are described in Part 3 and visually inspected for leaks as described in Table 2-8.

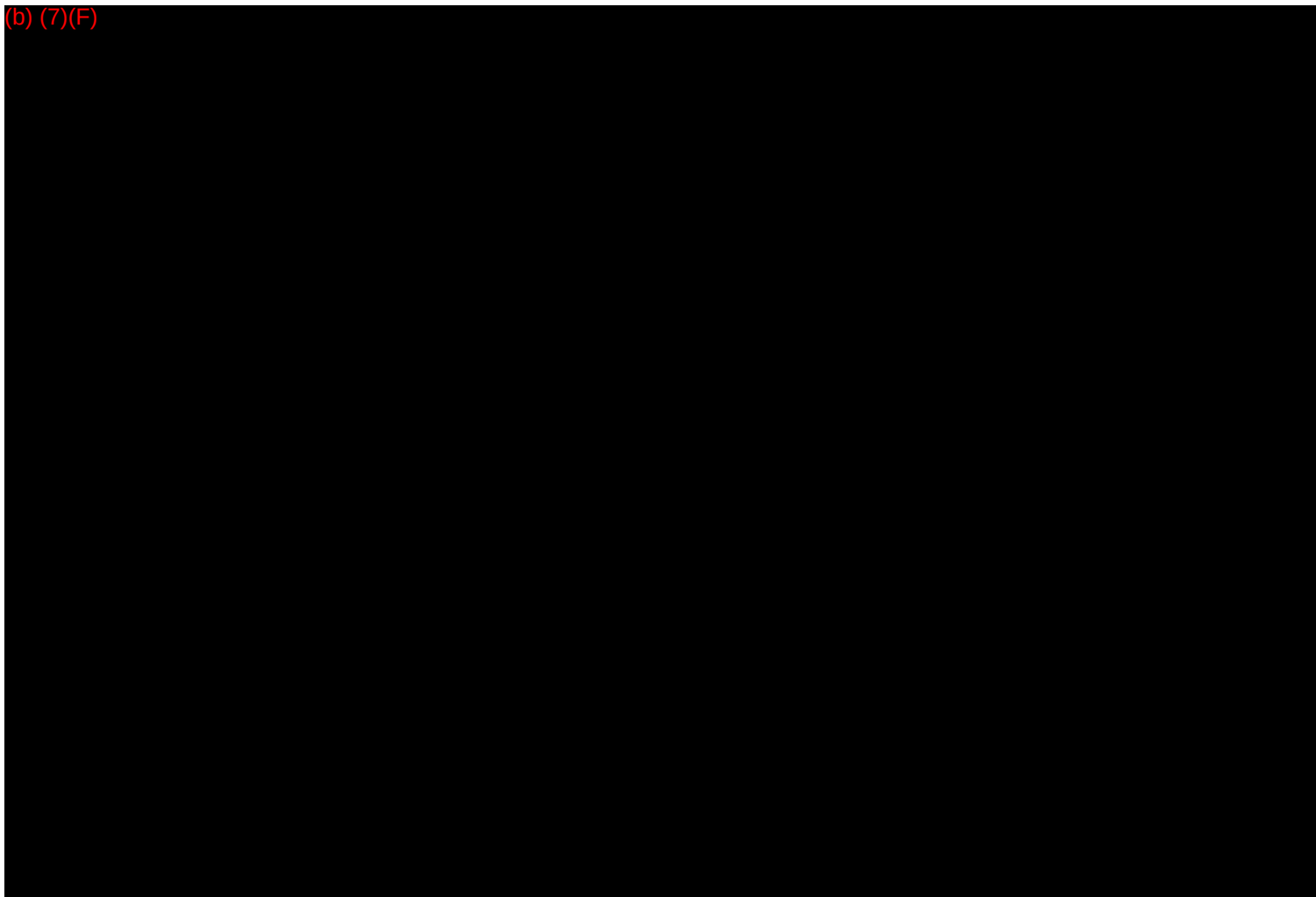
OIL STORAGE TANKS LESS THAN 10,000 GALLONS

Milne Point's oil storage tanks less than 10,000 gallons, and regulated by EPA under 40 CFR Part 112, are described in Appendix D. Tanks are monitored during routine operations and during fluid transfers for discharges. See Section 2.1.5.

2.5.6 CRUDE OIL TRANSMISSION PIPELINE DISCHARGE DETECTION

Leak detection as required by 18 AAC 75.055 is discussed in Section 2.1.7. Other leak detection for the sales oil line consists of visual inspection and instrument monitoring of flow and pressure variations in the line. In the event of an alarm, the control board operator proceeds through a series of steps to determine its cause. Ground-based surveillance may be requested. Visual spill detection for the pipeline is facilitated by its aboveground construction. Figure B-3 in Appendix B indicates the location of the crude oil transmission pipeline between the CFP manifold building in Module 58 and the Kuparuk pipeline tie-in near Module 68.

(b) (7)(F)



BPXA notifies ADEC in writing within 24 hours if a significant change occurs in, or is made to the COTP leak detection system and if, as a result of the change, the system no longer meets the ADEC performance requirements in 18 AAC 75.055 (18 AAC 75.475). A significant change is based on equipment or communication failure that prevents the effective functioning of the leak detection system. Transient events, such as water slugs or throughput swings, are not significant changes. Suspension of the leak detection capability triggers a notice to ADEC if it precludes detection within 24 hours of a leak equal to 1 percent of the annual rolling average of daily throughput.

2.5.7 VISUAL INSPECTIONS

Table 2-8 summarizes the ADEC- and EPA-required visual inspections performed on regulated equipment.

TABLE 2-8: VISUAL SURVEILLANCE SCHEDULE

EQUIPMENT	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION	FREQUENCY	REGULATORY CITATION	RECORD KEEPING
Oil Storage Tanks, 55 gallons or greater Tanks >10,000 gallons are listed in Table 3-1 and Appendix A Smaller tanks are listed in the SPCC Plan in Appendix D	Facility Personnel	ADEC	Visual inspection of external conditions of oil storage tanks ≥10,000 gallons in operation	Monthly	18 AAC 75.065 and .066 for API 653	PRIDE or Figure A in BPXA's Criteria for Tank Integrity Management Program (CRT-AK-06-96). Retain for 5 years.
		EPA	Visual inspection of oil containers >55 gallons, valves, and piping	Annually between January 1 and December 31.	40 CFR 112.7(e), 112.8(c)(6), 112.9(c)(3), and Appendix F Section 1.8.1.1	PRIDE or Figures B1 and B3 in BPXA's Criteria for Tank Integrity Management Program (CRT-AK-06-96). Retain for 3 years.
Secondary Containment Areas at Regulated Tanks	Facility Personnel	ADEC	Visual inspection for tank oil leaks, spills, defects, vegetation and debris	Daily for leaks or spills without record, unless precluded by safety or weather. Weekly with record for leaks or spills, defects, and interference by debris or vegetation, unless precluded by safety or weather.	18 AAC 75.075(c)	PRIDE or Appendix B form in ADEC Secondary Containment Inspection Procedure. Retain for 5 years.
		EPA	Visual inspection	Annually	40 CFR 112.7(e), 112.8(c)(6), and Appendix F Section 1.8.1.3	PRIDE or Figures B1 and B3 in BPXA's Criteria for Tank Integrity Management Program (CRT-AK-06-96). Retain for 3 years.
Secondary Containment at ADEC Tank Truck Loading and Permanent Unloading Areas	Facility Personnel	ADEC	Visual inspection	Monthly	18 AAC 75.075(g)	PRIDE or Appendix B form in ADEC Secondary Containment Inspection Procedure. Retain for 5 years.

TABLE 2-8 (CONTINUED): VISUAL SURVEILLANCE SCHEDULE

EQUIPMENT	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION	FREQUENCY	REGULATORY CITATION	RECORD KEEPING
Overfill protection device on oil storage tanks over 10,000 gallons	Facility Personnel	ADEC	Visual inspection and testing of overfill protection device	Monthly	18 AAC 75.065(l) and 066(h)	PRIDE or Figure A in BPXA's Criteria for Tank Integrity Management Program (CRT-AK-06-96). Retain for 5 years.
Aboveground Regulated Facility Oil Piping and Valves	Facility and Field Personnel, and Security	ADEC	Visual inspection of visible piping and valves for leaks or damage	Monthly	18 AAC 75.080(n)(1)	Inspection Log; retain for 5 years.
		EPA	Visual inspection of aboveground oil piping, valves and appurtenances	Regularly	40 CFR 112.7(e), 112.8(d)(4), and 112.9(d)	Inspection Log; retain for 3 years.

2.6 WAIVERS [18 AAC 75.425(e)(2)(F)]

Waivers follow this section. Waiver content is as follows:

- Waiver of Daily Secondary Containment Area Inspection Requirements during Phase 2 and Phase 3 weather conditions (November 3, 2011);
- Wording Change for Marking Facility Piping Waiver (March 26, 2009).
- Flow Line Marker Waiver (September 12, 2007).

STATE OF ALASKA

**DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries**

SEAN PARNELL, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
<http://www.state.ak.us/dec>

November 3, 2011

File No: 305.35 BPXA/GPB
File No: 305.35 BPXA/MPU
File No: 305.35 BPXA/End-Bad

Mike Bronson
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. Oil Discharge Prevention and Contingency Plans; Waiver Approval (Revised) for the following Plans:**
Endicott/Badami, ADEC Plan No. 06-CP-4130
Greater Prudhoe Bay, ADEC Plan No. 06-CP-5079
Milne Point Unit, ADEC Plan No. 10-CP-4132

Dear Mr. Bronson:

The Alaska Department of Environmental Conservation (department) has reviewed your February 14, 2005 request for a waiver of the daily secondary containment area (SCA) inspection requirements of 18 AAC 75.075(c) at facilities covered by the three Oil Discharge Prevention and Contingency Plans (plans) referenced above during Phase 2 and 3 weather conditions. Safety of the inspectors is the highest priority for the department, and we understand that conducting these inspections during occasional severe weather on the North Slope could be hazardous.

Phase 2 weather conditions restricts vehicle travel to convoys only, and foot travel is allowed only with a supervisor's consent. Level II road conditions include moderate to heavily drifting snow, water over the road, sheet ice, and blowing snow. Phase 3 weather conditions allows only critical and emergency travel with heavy equipment escorts. Level III road condition examples include roadways that are completely drifted over, washouts, or road or construction work closing the access roadway. Once the severe weather conditions have subsided, it may take a day or two for snow removal crews to clear the snow from the access roads, again precluding inspections.

When weather precludes conducting the daily inspections, the tank liquid level indicators on most tanks can be monitored in the control room.

Mr. Mike Bronson
BP Exploration (Alaska), Inc.

2

November 3, 2011

We recognize that other agencies with similar inspection requirements have weather and safety allowances, such as the Alaska Oil & Gas Conservation Commission and the North Slope Borough. In fact, our own regulations for crude oil transmission pipeline system weekly overflights include a provision for safety or weather conditions [18 AAC 75.055(a)(3)].

Based on the above information, the department is granting the waiver for SCAs located at the referenced facilities during Phase 2 and 3 weather conditions and associated road conditions. This waiver is subject to the following conditions:

1. For each day that inspections are precluded by weather or road conditions, the inspection record will include a notation that such conditions prevented the inspection, such as "Wx" or "No safe access" with a description of the condition.
2. Copies of the security logs that record Phase 2 and 3 times will be made available to the department upon request for those days in which inspections were precluded.
3. This letter supersedes the March 4, 2005 waiver letter, which should be replaced in the plan with this letter at the next routine update.

This waiver does not exempt BP Exploration (Alaska) Inc. (BPXA) from any other state, federal, or local requirements that may apply. The department reserves its rights to pursue administrative and judicial remedies for future violations in the event BPXA does not comply with the conditions of this waiver

If you have questions or need assistance, please contact Karen McDermott at 269-7569.

Sincerely,



Scott Pexton
Section Manager

Enclosure: Waiver, March 4, 2005

Electronic cc:
Laurie Silfven, ADEC
Karen McDermott, ADEC
Jeanne Swartz, ADEC
Tom DeRuyter, ADEC

STATE OF ALASKA

**DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries**

SARAH PALIN, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
<http://www.dec.state.ak.us>

March 26, 2009

File No.: 305.35
(BPXA – GPB, End,
Milne, Northstar)

Ms. Mary E. Cochlan-Vendl
Pipeline Programs Coordinator
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: BP Exploration (Alaska) Inc. (BPXA) Oil Discharge Prevention and Contingency Plans (Plans). Wording Change for Marking Facility Piping – Waiver for the Following Plans:
Endicott/Badami, ADEC Plan No. 06-CP-4130
Greater Prudhoe Bay, ADEC Plan No. 06-CP-5079
Milne Point Unit, ADEC Plan No. 06-CP-4132
Northstar, ADEC Plan No. 06-CP-4136

Dear Ms. Cochlan-Vendl:

The Alaska Department of Environmental Conservation (ADEC) has reviewed your March 25, 2009 request for a waiver from the facility piping marking requirements in 18 AAC 75.080(o) for BPXA's North Slope facilities associated with the above-listed plans. In addition to other requirements, 18 AAC 75.080(o) specifies that facility oil piping removed from service for more than one year be marked with the words "Out of Service" and the date taken out of service. BPXA has requested our approval to use the wording "Removed From Service" rather than "Out of Service."

In accordance with 18 AAC 75.015, ADEC may waive a requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18 AAC 75.085. Since ADEC considers the two phrases to be equivalent in meaning and since the wording is used interchangeably in our regulations, ADEC approves this waiver request.

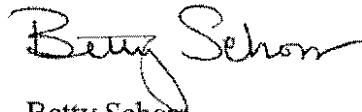
If you have any question, please contact Laurie Silfven at (907) 269-7540 or me at (907) 269-3054.

Ms. Mary E. Cochlan-Vendl
BP Exploration (Alaska), Inc.

2

March 26, 2009

Sincerely,

A handwritten signature in black ink, appearing to read "Betty Schorr". The signature is fluid and cursive, with the first name "Betty" and last name "Schorr" clearly distinguishable.

Betty Schorr
Program Manager

cc: Laurie Silfven, ADEC, EPR
Graham Wood, ADEC, EPR
Bob Tisserand, ADEC, EPR
Gary Evans, ADEC, EPR
Sam Saengsudham, ADEC, PTI
Ed Meggert, ADEC, PERP Fairbanks
Mike Bronson, BPXA
Glen Pomeroy, BPXA

STATE OF ALASKA

SARAH PALIN, GOVERNOR

**DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries**

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
<http://www.dec.state.ak.us>

September 12, 2007

File No.: 305.35
(BPXA – GPB, End, Milne)

Glen Pomeroy
BP Exploration (Alaska)
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. (BPXA) Oil Discharge Prevention and Contingency Plans. Flow Line Marker Waiver for the Following Plans:**
Endicott/Badami, ADEC Plan No. 06-CP-4130
Greater Prudhoe Bay, ADEC Plan No. 06-CP-5079
Milne Point Unit, ADEC Plan No. 06-CP-4132

Dear Mr. Pomeroy:

The Alaska Department of Environmental Conservation (ADEC) has reviewed your July 27, 2007 request for a waiver from the flow line marker requirements in 18 AAC 75.047(e) for Endicott, Greater Prudhoe Bay, and Milne Point facilities. Additional information was given in a follow-up phone call with you on August 24 and in a meeting with Mary Cocklan-Vendl and Eppie Hogan on August 30, 2007.

Under 18 AAC 75.047(e), line markers must be installed and maintained over each onshore flow line at road crossings and at one-mile intervals along the remainder of the pipe by December 30, 2007. BPXA is planning to install line markers at all road crossings by December 30, 2007, but is seeking a waiver from the requirement for line markers at one-mile intervals along the cross-country portions of flow lines. In accordance with 18 AAC 75.015, ADEC may waive a requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18 AAC 75.085.

To meet the intent of 18 AAC 75.047(e), BPXA is developing a set of field maps identifying the location of each cross-country flow line for use by security, surveillance, and other personnel during routine and emergency operations. Based on the draft field maps brought in for our meeting, the scheduled flow line markers will be spaced with sufficient frequency that additional marking where flow lines approach drill pads or other infrastructure is not deemed necessary.

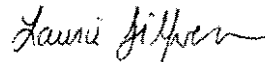
July 19, 2007

ADEC approves this waiver based on the following condition:

- BPXA must finalize a set of field maps identifying the location of each cross-country flow line for use by security, surveillance, and other personnel during routine and emergency operations and must provide ADEC with a set of the maps and provide updates as they occur.

If you have any question, please contact me at (907) 269-7640.

Sincerely,



Laurie Silfven
Acting Section Manager

cc: Betty Schorr, ADEC, IPP Program Manager
Graham Wood, ADEC, EPR
Tanya Verbyla, ADEC, EPR
Gary Evans, ADEC, EPR
Ed Meggert, ADEC, PERP Fairbanks
Mike Bronson, BPXA
Gordon Brower, North Slope Borough
Carol Fries, ADNR, Anchorage
Jack Winters/Mac McLean, ADNR, Fairbanks
Carl Lautenberger, EPA
Capt. Mark DeVries, USCG
Melanie Barber, USDOT-RSPA
Todd Nichols, ADFG, Fairbanks
Christy Bohl, MMS
Mike Thompson, JPO
Pam Miller, Northern Alaska Environmental Center
Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska

PART 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 GENERAL SITE DESCRIPTION

BP Exploration (Alaska), Inc. (BPXA) owns 100 percent of Milne Point Unit (MPU).

The MPU is located in the North Slope Borough, on the Arctic coast of Alaska, 280 miles north of the Arctic Circle, 200 miles west of the Alaska-Canada border, and 25 miles northwest of Prudhoe Bay. BPXA operates MPU. Oil storage at MPU began in 1985.

Figures B-1 and B-3 in Appendix B show the location of the major facilities in the MPU field. The main elements are as follows:

- Central Facilities Pad (CFP) containing the operations center and central processing facility,
- 13 gravel well pads with approximately 120 wells,
- A gravel pit, and
- Associated infrastructure and lighting to aid in the discovery of a discharge during hours of darkness.

Sales oil is transported via the MPU crude oil transmission pipeline, which ties into the ConocoPhillips Alaska, Inc. Kuparuk Pipeline.

Drainage is inferred based on aerial photography. Drainage diagrams are found in the Alaska Clean Seas (ACS) *Technical Manual Map Atlas*, Volume 2.

3.1.2 FACILITY STORAGE CONTAINERS [18 AAC 75.425(E)(3)(A)(I) AND (II)]

Table 3-1 describes the type, capacity, installation date, design, construction, stored product, inspection date, and other information for each Alaska Department of Environmental Conservation (ADEC)-regulated stationary oil storage tank. Appendix A contains similar information for ADEC-regulated shop-fabricated oil storage tanks. See Figure B-2 in Appendix B for a facility diagram of the CFP and its tank locations, and Figure B-16 for the S Pad facility diagram and tank locations.

3.1.3 TRANSFER PROCEDURES [18 AAC 75.425(E)(3)(A)(VI)]

Fluid transfer procedures are discussed in Section 2.1.5.

**TABLE 3-1: MILNE POINT UNIT REGULATED STATIONARY OIL STORAGE TANK DATA
(TANKS GREATER THAN 10,000 GALLONS)**

LOCATION TANK NO.	PRODUCT TYPE DESCRIPTION NOMINAL DESIGN CAPACITY (GALLONS)	FABRICATION/ INSTALLATION DATE CONSTRUCTION STANDARD	INFLOW CONTROL VALVE	OVERFILL PROTECTION DEVICE (OFPD) FREQUENCY OF TESTING	LEAK DETECTION SYSTEMS AND PROCEDURES DESCRIPTION	CIC TANK INTEGRITY INSPECTION (API 653) LAST, NEXT INSPECTION	TANK SECONDARY CONTAINMENT DESCRIPTION CAPACITY (GALLONS)	TANK TRUCK LOADING & PERMANENT UNLOADING AREA SECONDARY CONTAINMENT DESCRIPTION CAPACITY (GALLONS) MEASURES TO PREVENT VEHICULAR MOVEMENT
CFP Module 60 T-6001	(b) (7)(F)							
CFP Module 61A T-6101A								
CFP Module 61B T-6101B								
CFP Module 54 CL-5401								

**TABLE 3-1 (CONTINUED): MILNE POINT UNIT REGULATED STATIONARY OIL STORAGE TANK DATA
(TANKS GREATER THAN 10,000 GALLONS)**

LOCATION TANK NO.	PRODUCT TYPE DESCRIPTION NOMINAL DESIGN CAPACITY (GALLONS)	FABRICATION/ INSTALLATION DATE CONSTRUCTION STANDARD	INFLOW CONTROL VALVE	OVERFILL PROTECTION DEVICE (OPFD) FREQUENCY OF TESTING	LEAK DETECTION SYSTEMS AND PROCEDURES DESCRIPTION	CIC TANK INTEGRITY INSPECTION (API 653) LAST, NEXT INSPECTION	TANK SECONDARY CONTAINMENT DESCRIPTION CAPACITY (GALLONS)	TANK TRUCK LOADING & PERMANENT UNLOADING AREA SECONDARY CONTAINMENT DESCRIPTION CAPACITY (GALLONS) MEASURES TO PREVENT VEHICULAR MOVEMENT
S Pad T-1102	(b) (7)(F)							
S Pad T-1128								

3.1.4 GENERAL DESCRIPTION OF OIL PIPELINES AND PROCESSING FACILITIES [18 AAC 75.425(E)(3)(A)(VII)]

PROCESSING

Milne Point has a single gathering center handling approximately 27,000 barrels of oil per day (bopd), 90,000 barrels of water per day, and 35 million standard cubic feet of gas daily (mmscfd).

After passing through the first-stage separator or slug catcher, produced fluids are processed via dual separation trains to separate gas and water from crude oil. The first stage separator or slug catcher operates at approximately 150 pounds per square inch gauge (psig) and removes the majority of the produced gas and water. Two second-stage separators operate at about 50 psig and remove more gas but very little water. Finally, the third stage of separation includes two chem-electric treaters that have electric grids in the vessels to aid coalescing and removal of water before pumping the crude oil into the pipeline. Levels and pressures in each separator are regulated by pneumatic and computer controls.

To improve the oil/water separation, fluids are further heated to about 180°F downstream of the first-stage separator/slug catcher. After separation in the trains, the crude oil is cooled to comply with pipeline agreements and pumped into the Kuparuk Pipeline for eventual transfer into the Trans Alaska Pipeline System at Pump Station 1.

Process water reinjection helps maintain reservoir pressure. The produced water is injected. Source water also is pumped into the facility and combined with produced water to provide more pressure. The produced water is directed to the waterflood plant module. After comingling with supplemental water from the Prince Creek water-bearing formation, the water is chemically treated to inhibit corrosion and bacterial growth and piped to the well pads for reinjection as waterflood support. The water handling facility is designed to receive and treat 80,000 barrels per day of produced and supplemental water.

Hydrocarbon gases removed from the various stages of separation are scrubbed and compressed to approximately 1,340 psig for gas lifting of wells on the B and C gas injection only well pads. After compression, produced gas is dehydrated in a triethylene glycol package unit, and a portion of the gas is used to produce additional oil by gas lifting several wells. Gas dehydration is needed to ensure hydrates do not form in North Slope ambient conditions during further gas cooling and compression for injection. An additional 10 to 30 mmscfd of gas is compressed to approximately 4,800 psig and injected into the reservoir as part of an intermittent water and gas injection program which recovers more oil than water injection alone. Finally, approximately 8 mmscfd of the produced gas has its pressure reduced so it can be used for fuel gas, purging, and as a utility gas.

The heavy oil facility is designed to process heavy oil laden with sand, water, and gas. Heating the heavy oil up to ~180°F allows separation into phases. As the production fluids flow into the separation tank, the oil and gas rise upward while the larger granular sediments fall downward. Finer sands that are carried upward with the oil and gas are eventually separated out and fall to the bottom of the tank. Once a sufficient amount of treated oil is produced, containing no more than 1 percent solids, it is transferred from the tank to the S Pad production heater where it commingles with the lighter S Pad oil and is piped to Milne Point CFP for further separation. The sand that is separated out is collected in the conical bottom

of the tank. During sand jetting operations, jet rings inside the tank turn the condensed sand into a slurry. Once the sand has become agitated, a drain valve is opened and the sand is forced from the tank to either a transport vehicle or the sand transfer tank.

WELLS/WELL PADS

Oil production wells are directionally drilled from the gravel drill sites. Insulated piping from the wells is combined into manifold networks on each drill site. Downhole electric submersible pumps provide artificial lift to flow 80 percent of MPU wells. The jet pump wells are lifted with water power fluid. Artificial lift for the remaining wells is provided by a lift gas system. The heavy oil project at S Pad utilizes top drive units providing power to down-hole progressing cavity pumps.

Production and injection wells are located on these pads, typically in rows with wellhead spacing that varies between 15 feet and 110 feet. Pads are graded with the shoulders elevated in an effort to direct spilled material to containment areas. Space is provided for the drill site manifolds, well test equipment, wellhead shelters, an area for rig movement, and an area for tubular storage (drill pipe, casing, etc.). The drill site facilities at MPU are typical of existing North Slope drill site facilities, which consist of wellheads, well lines, and truckable modules.

Produced fluids from each production well on B and C pads flow from the wellhead, through facility oil piping, to a manifold building that contains adjustable chokes and divert valves. Manifold buildings are considered to be an interconnection if the buildings provide weather protection to the piping, include monitors and alarms for detecting abnormal conditions, and have floors, sills or other components that would contain most oil spills originating from piping within the building. As such, piping within manifold buildings that meet these criteria is not considered facility oil piping under 18 AAC 75.080.

Wells on pads F, G, H, I, J, K, and L have adjustable chokes and divert valves in each wellhouse.

Produced fluids from individual wells combine into a low-pressure flow line that connects the well pad to the CFP production facility. (b) (7)(F)

Most well pads have water injection wells. Water enters the pad in a common flow line, enters a manifold building and is run through individual injection well chokes.

Pads B and C also have gas lift which enters the pad from a common flow line to the manifold building choke valves or individual wells with adjustable choke valves on the other pads. Gas chokes are located in the manifold building and the fluid is routed to the wells via individual flow lines.

FLUID TRANSPORT FROM S PAD

Transportation of the sand/slurry via trucks to the Grind and Inject facility is conducted only as required. Oil produced from the heavy oil facility that does not meet basic sediment and water (BS&W) specifications may be transported by truck to a disposal site.

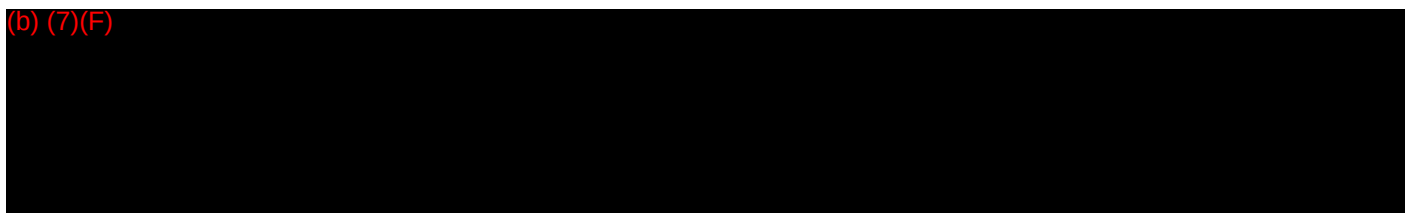
Transfer procedures are described in Section 2.1.5.

PIPELINES

Below is a description of the MPU crude oil transmission pipeline and flow lines. See Figure B-3 in Appendix B for a schematic of pipeline locations.

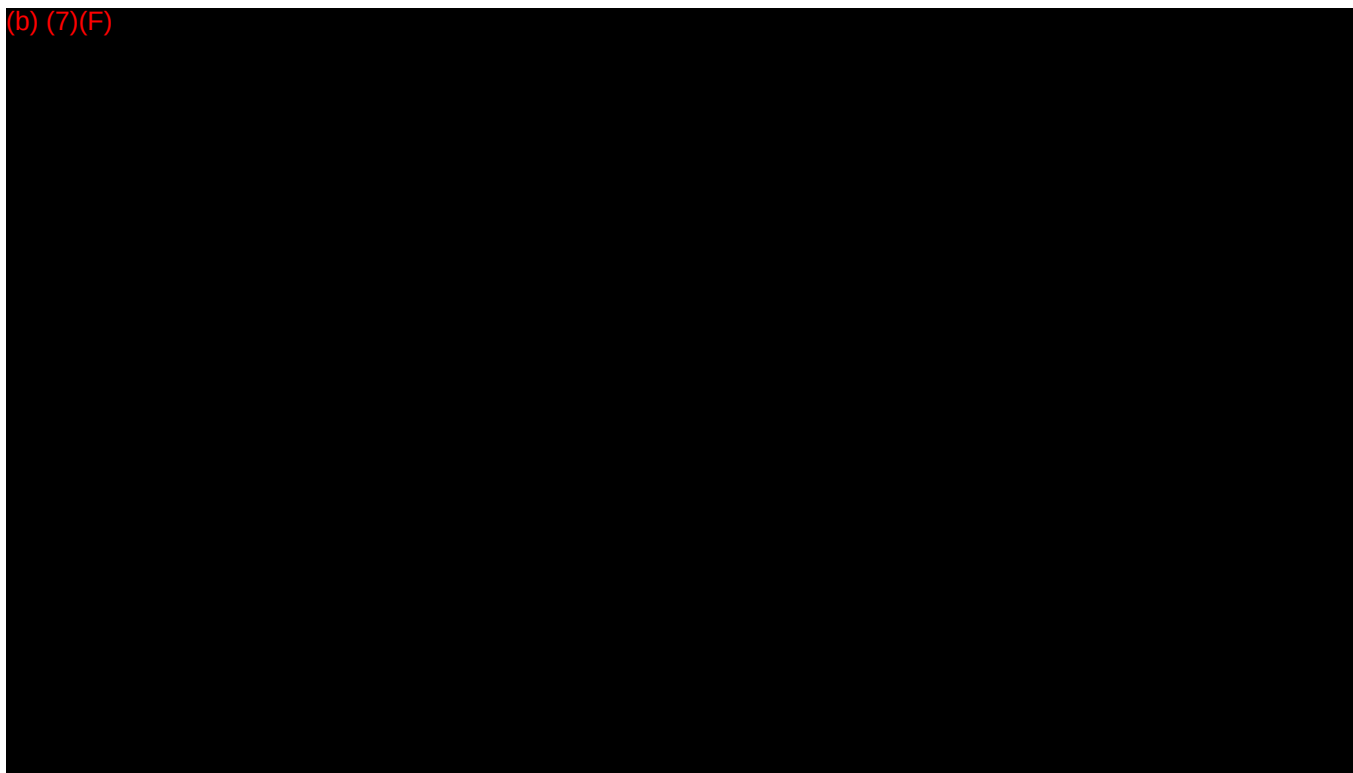
14-Inch Crude Oil Transmission Pipeline from CFP to Kuparuk Tie-In. The aboveground crude oil transmission pipeline was designed and built to American Society of Mechanical Engineers (ASME) Standard B31.4. The pipeline is constructed of corrosion-resistant alloy (stainless steel). At the road crossings, the pipeline passes through culverts above the active water layer. The line has fusion-bonded epoxy (FBE) and is insulated with polyurethane foam bonded directly to the steel pipe. A galvanized steel jacket protects the insulation and pipe. The line is equipped with valves as follows:

(b) (7)(F)

A large black rectangular redaction box covering the text following the first paragraph.

Flow Lines – Produced Water Injection. These aboveground lines were designed and built to ASME B31.4 unless otherwise noted.

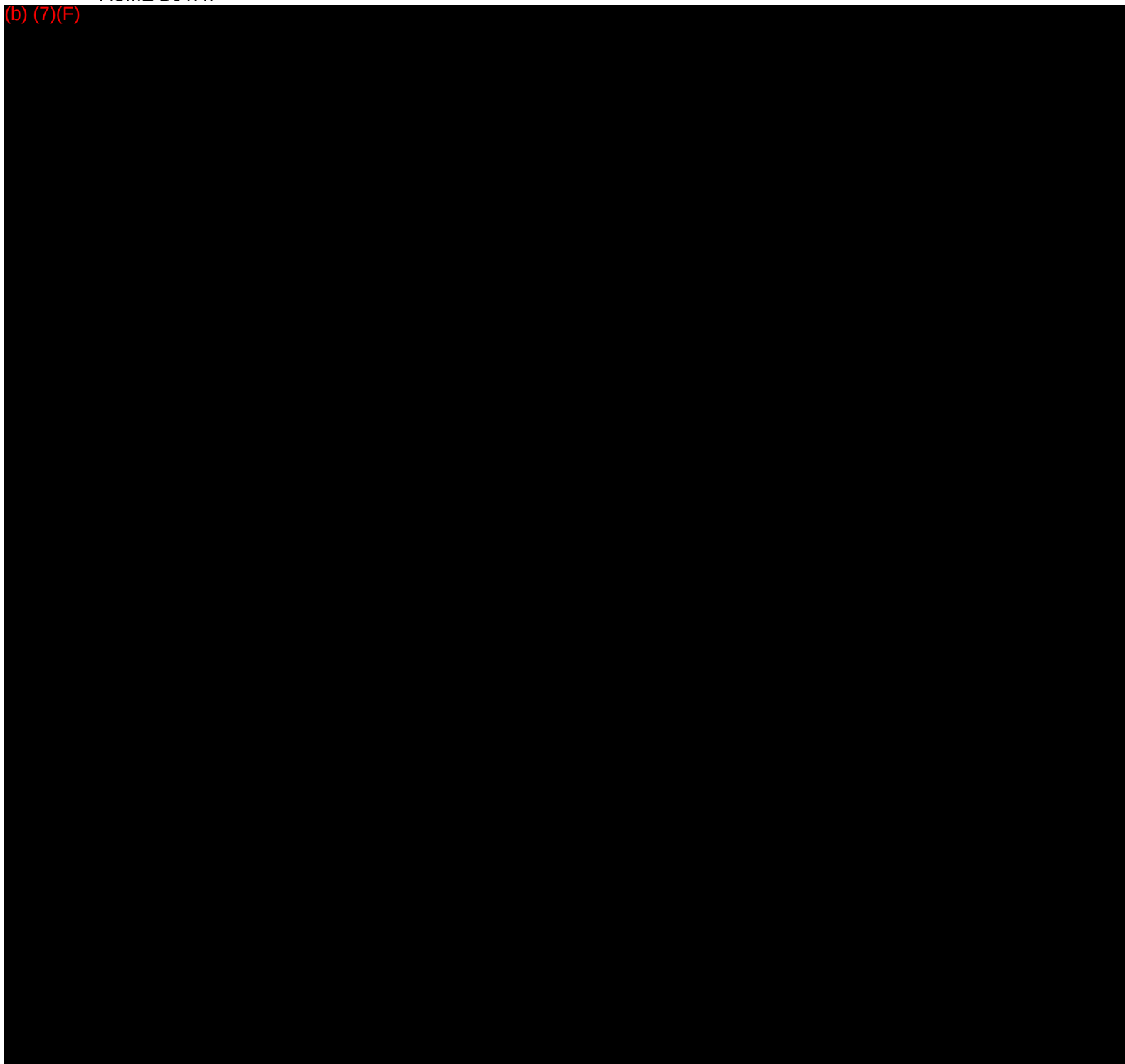
(b) (7)(F)

A large black rectangular redaction box covering the text following the second paragraph.

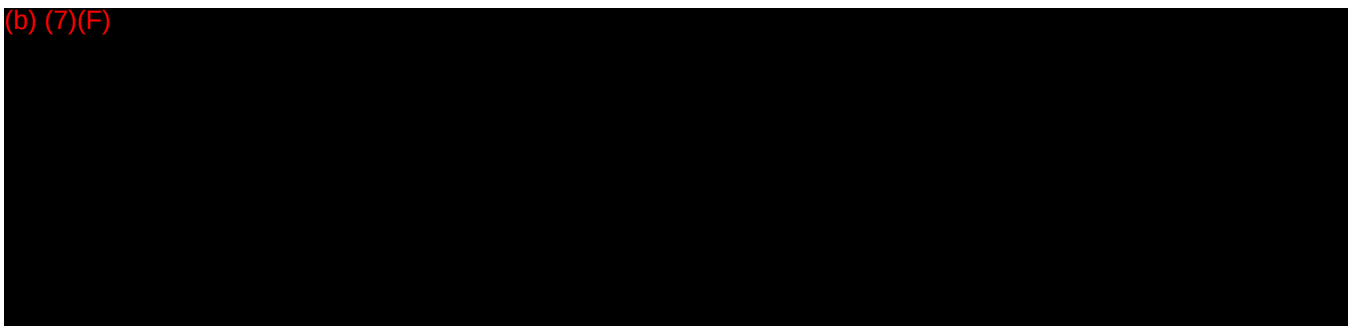
Milne Point Unit ODPCP, Volume 2 – Prevention Plan

Flow Lines - Production. Production flow lines are primarily aboveground and are designed and built to ASME B31.4.

(b) (7)(F)



(b) (7)(F)



Natural Gas Liquid Line:

- 8-Inch Natural Gas Liquid (NGL) flow line from Oliktok to CFP. This line is out of service.

3.1.5 FACILITY DIAGRAMS [18 AAC 75.425(E)(1)(H) AND 40 CFR 112.20(H)(9)]

Facility diagrams are presented in Appendix B, as follows:

- MPU Area Map – Figure B-1
- MPU CFP – Figure B-2
- MPU Pipeline Schematic and Isolation Valves – Figure B-3
- MPU A Pad – Figure B-4
- MPU B Pad – Figure B-5
- MPU C Pad – Figure B-6
- MPU D Pad – Figure B-7
- MPU E Pad – Figure B-8
- MPU F Pad – Figure B-9
- MPU G Pad – Figure B-10
- MPU H Pad – Figure B-11
- MPU I Pad – Figure B-12
- MPU J Pad – Figure B-13
- MPU K Pad – Figure B-14
- MPU L Pad – Figure B-15
- MPU S Pad – Figure B-16
- MPU Kuparuk Junction Diagram – Figure B-17

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

See Volume 1 for the following sections:

- 4.1 Communications
- 4.2 Source Control
- 4.3 Trajectory Analyses and Forecasts
- 4.4 Wildlife Capture, Treatment and Release Programs

4.5 CATHODIC PROTECTION FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

Milne Point Unit (MPU) oil storage tanks are elevated and therefore are not subject to the cathodic protection requirements of 18 AAC 75.065(h)(1)(B and C).

4.6 LEAK DETECTION SYSTEM FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

Alaska Department of Environmental Conservation (ADEC)-regulated oil storage tanks are elevated above the pad and as such are accessible to direct observation of leaks. They do not require additional leak detection equipment. The leak detection system for these tanks is in accordance with 18 AAC 75.065(h)(1)(A) and (D). The field-constructed oil storage tanks were installed in 1985; the requirements of 18 AAC 75.065(i)(4) and (j)(4) do not apply.

4.7 LIQUID LEVEL DETERMINATION FOR OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

The stationary bulk oil storage tanks, 10,000 gallons and larger, have high liquid level alarms and level indications that show remotely in the Central Facilities Pad (CFP). The BAT analysis for liquid level determination in bulk storage tanks is provided in Table 4-4.

The internal level-determining devices considered BAT and currently in use are as follows:

- Oil Reserve Tanks (T-6001) – differential pressure (DP) continuous level, guided wave radar continuous level, high level pressure switch;
- Oil Reserve Tank (T-6101B) – DP continuous level transmitter and Magnetrol high level ultrasonic switch;
- Bulk Diesel Tank (T-6101A) – DP continuous level transmitter and Magnetrol high level displacer switch,
- Clarifier Tank (CL-5401) – continuous level and high level capacitance switch;

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

- S Pad Separator Tanks (T-1102 and T-1128) – continuous level, guided wave radar continuous level, ultrasonic gap high level switch

It should be noted that the BAT conclusion for tank liquid level determination is a function of the liquid in the tank and the operational history of the level technology used in that tank. As such, Table 4-4 lists technologies that are presently used in regulated tanks and have been in use for many years.

TABLE 4-4: BEST AVAILABLE TECHNOLOGY ANALYSIS – FIELD-CONSTRUCTED STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	EXISTING METHOD: DIFFERENTIAL PRESSURE (DP) TRANSMITTERS CONTINUOUS LEVEL	EXISTING METHOD: DISPLACER LEVEL SWITCH AND TRANSMITTERS	EXISTING METHOD: PRESSURE SWITCH FOR LEVEL	EXISTING METHOD: CAPACITANCE PROBES LEVEL SWITCH	EXISTING METHOD: ULTRASONIC SWITCH (ALTERNATIVE: CONTINUOUS LEVEL)
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	DP transmitters are used universally on many level applications. Density variations can affect accuracy; therefore trip points are set so availability is not compromised. The units are heat-traced for outdoor use.	Magnatrol displacers are used universally for point level detection. Fisher displacer level transmitters are used universally on many level applications. The units are heat-traced for outdoor use.	CCS pressure switch functions the same way the DP transmitter does. They are used universally on many level applications.	Capacitance probes are used universally on many level applications. They are equally reliable to other technologies when applied correctly.	Ultrasonic is reliable and accurate in certain applications. They are used universally on many level applications. A discrete high high switch is in use, and has proven reliable.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Currently installed.	Currently installed.	Currently installed.	Currently installed.	Currently installed.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	The DP transmitters have an accuracy of 0.25%. Continuous monitoring of level provides excellent indication of level and provides warning if unit fails. Operators set high/low liquid level alarms as well as high high software interlocks.	Designed for the oil and gas industry, it will work within the design specifications. Susceptibility to density fluctuation does not prevent unit from detecting a high high level.	It is used as a back-up to the level transmitter. Proven technology for level detection.	Requires fewer fittings where possible leakage could occur. Do not need to insulate or heat-trace device.	Continuous level is non-contact and not pressure, temperature or density dependent. Can be affected by mist, steam, foam or turbulence.
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	Already in service.	Already in service.	Already in service.	Already in service.	Already in service.

TABLE 4-4 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS – FIELD-CONSTRUCTED STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	EXISTING METHOD: DIFFERENTIAL PRESSURE (DP) TRANSMITTERS CONTINUOUS LEVEL	EXISTING METHOD: DISPLACER LEVEL SWITCH AND TRANSMITTERS	EXISTING METHOD: PRESSURE SWITCH FOR LEVEL	EXISTING METHOD: CAPACITANCE PROBES LEVEL SWITCH	EXISTING METHOD: ULTRASONIC SWITCH (ALTERNATIVE: CONTINUOUS LEVEL)
AGE AND CONDITION: The age and condition of technology in use by the applicant	Although the units are an older model, the only benefit of going to a newer model would be an increase in the accuracy, not reliability.	Already in service.	Already in service.	Already in service.	Already in service
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	DP transmitters are completely compatible with Milne Point.	Yes, this technology is compatible with existing operations and technologies.	Yes, this technology is compatible with existing operations and technologies.	Yes, this technology is compatible with existing operations and technologies.	Yes, this technology is compatible with existing operations and technologies.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Currently installed. The DP transmitters are easy to install and maintain. Also they are proven to operate reliably.	Currently installed.	Currently installed.	Currently installed.	Currently installed
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	Currently installed.	Currently installed.	Currently installed.	Currently installed.	Currently installed.

TABLE 4-4 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS – FIELD-CONSTRUCTED STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	EXISTING METHOD: GUIDED WAVE RADAR CONTINUOUS LEVEL	ALTERNATE METHOD: NUCLEONIC LEVEL TRANSMITTER	ALTERNATE METHOD: FLOAT GAUGE	ALTERNATE METHOD: ELECTRO- MAGNETIC GAUGING	ALTERNATE METHOD: MECHANICAL SHUT-OFF VALVE
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	(b) (7)(F)				
TRANSFERABILITY: Whether each technology is transferable to applicant's operations					
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits					
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					

TABLE 4-4 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS – FIELD-CONSTRUCTED STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	EXISTING METHOD: GUIDED WAVE RADAR CONTINUOUS LEVEL	ALTERNATE METHOD: NUCLEONIC LEVEL TRANSMITTER	ALTERNATE METHOD: FLOAT GAUGE	ALTERNATE METHOD: ELECTRO- MAGNETIC GAUGING	ALTERNATE METHOD: MECHANICAL SHUT-OFF VALVE
AGE AND CONDITION: The age and condition of technology in use by the applicant	(b) (7)(F)				
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant					
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects					
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits					

Table 4-5 presents the BAT analysis for liquid level determination for portable storage tanks, 10,000 gallons and larger. Electronic types typically employ ultrasonic or microwave frequency transducers. In the context of portable and temporary tanks the effective utility of the devices is greatly compromised.

Portable, temporary tanks located on gravel pads, or on rigs, are subject to vibrations and jolts. Experience shows that use of the devices on portable and temporary tanks results in error in liquid level measurement and frequent false alarms in high level and leak detection contexts. Handling during loading, transportation, and unloading may result in physical damage to the level determination device or electronic components contained therein (as applicable). Float type devices are particularly prone to “jamming” under these conditions. While it is possible to tune associated controller outputs to mitigate the effects of vibration and jolts, such a state of tune would significantly decrease their accuracy and response times in terms of liquid level measurement and preclude their use as leak detection devices.

In addition, should these devices be used to control automatic shutoff valves or pump shutoff relays, unanticipated valve closures or pump shutdowns may occur, with potential oil spill consequences. The inability of these devices to function accurately and reliably on portable and temporary tanks, and the significant cost of custom construction, installation and maintenance preclude their use.

The multiphase nature of fluids adversely impacts the accuracy and reliability displayed by a variety of level determination devices. Flow test tank fluids are typically composed of oil, water, associated emulsions and suspended solids. Microwave frequency device accuracy is compromised by variations in liquid dielectric constant and electrical conductivity; accordingly, application in multiphase liquid contexts is contraindicated. Alternatively, ultrasonic devices require contact with the process fluid; solids buildup or emulsion adherence to the sensor will result in decreased accuracy and the need for frequent maintenance.

Float type devices are also subject to greatly reduced accuracy and reliability, resulting from solids content. These solids facilitate float “sticking” and “jamming.” In addition, extreme cold weather results in pulleys that may not roll freely or freeze up altogether, or associated cable systems that become inflexible. Any one or more of these effects will render the device unreliable in terms of accurate level determination.

Manufacturers of electronic devices indicate that temperatures lower than -30°F (-34°C) compromise the reliability and response time of the electronic components of these devices. Weather data for the subject North Slope locations indicate that extreme low temperatures range from -58°F to -85°F (Zhang, Osterkamp and Stamnes, 1996). Applications that are subject to these temperatures will not be warranted.

In addition to manual gauging and direct observation, the application of additional liquid level determination devices to portable and temporary tanks in remote Arctic environments is not desirable for the following reasons:

- Significant physical damage, or damage to associated electronic components, as a result of loading, unloading, or transportation;
- Requirement for power source – a potential source of ignition;
- Need for frequent maintenance;

Milne Point Unit ODPCP, Volume 2 – Prevention Plan

- Lack of warranty;
- Decreased accuracy;
- Decreased reliability; and
- Significant cost (e.g., device, power, installation, maintenance and replacement).

Two persons are involved in controlling the liquid level in an ADEC-regulated portable tank not equipped with a fixed level determination device while the tank is receiving oily liquids. One person operates the pump. The other person visually monitors the liquid level to prevent overfilling. The method is the best means of immediately determining the liquid level of ADEC-regulated portable bulk storage tanks as specified in 18 AAC 75.066(g)(1)(C) and (D).

TABLE 4-5: BEST AVAILABLE TECHNOLOGY ANALYSIS – PORTABLE OIL STORAGE TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	EXISTING METHOD: VISUAL INSPECTION	ALTERNATE METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	(b) (7)(F)			
TRANSFERABILITY: Whether each technology is transferable to applicant's operations				
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits				
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.				
AGE AND CONDITION: The age and condition of technology in use by the applicant				
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant				

TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS – PORTABLE OIL STORAGE TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	EXISTING METHOD: VISUAL INSPECTION	ALTERNATE METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	(b) (7)(F)			
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements offset any anticipated environmental benefits				

4.8 MAINTENANCE PRACTICES FOR BURIED FACILITY PIPING [18 AAC 75.425(e)(4)(A)(ii)]

Buried facility piping in direct contact with soil is not present at Milne Point. This requirement does not apply.

4.9 PROTECTIVE COATINGS AND CATHODIC PROTECTION [18 AAC 75.425(e)(4)(A)(ii)]

4.9.1 PROTECTIVE COATINGS FOR BURIED, SUBMERGED, AND ABOVEGROUND FACILITY OIL PIPING

No pipelines subject to buried or submerged corrosion service are present at Milne Point.

Shop-applied insulated systems with an outer sheet metal jacket are considered to meet protective coating requirements except where inspection finds a breach in the outer barrier. Where a breach is found, inspections are conducted by non-destructive means to determine if corrosion is present. Where corrosion is found, insulation is stripped, and the pipe inspected to determine fitness for service. The location then receives a protective barrier coating directly on the pipeline in accordance with re-insulation and coating specifications. New insulated pipelines utilize shop-applied fusion-bonded epoxy (FBE) coatings directly on the pipe or corrosion resistant alloys. Field coatings at weld joints or long pipe sections may include field-applied FBE, high performance liquid coating, or high performance tape coatings placed directly on the pipe. This also applies to facility piping in culverts or utilitiways installed after December 30, 2006, which is inaccessible for visual inspection.

4.9.2 CATHODIC PROTECTION SYSTEMS FOR BURIED FACILITY PIPING

This requirement does not apply. Buried facility piping is not present at Milne Point.

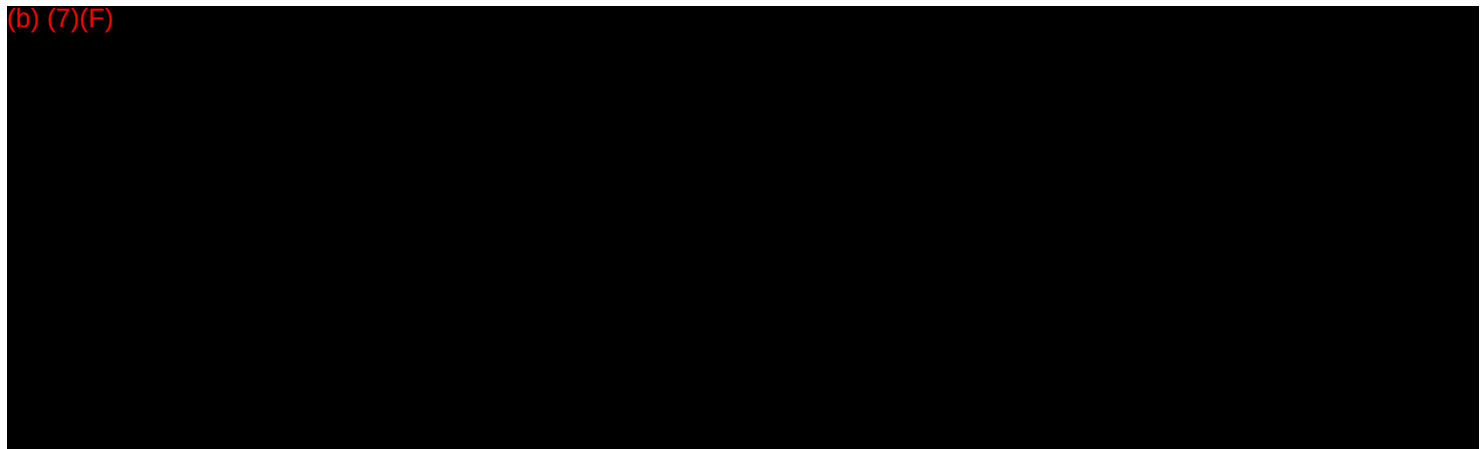
4.10 MAINTENANCE PRACTICES FOR BURIED FACILITY PIPING – CORROSION SURVEYS [18 AAC 75.425(e)(4)(A)(ii)]

This requirement does not apply. Buried facility piping is not present at Milne Point.

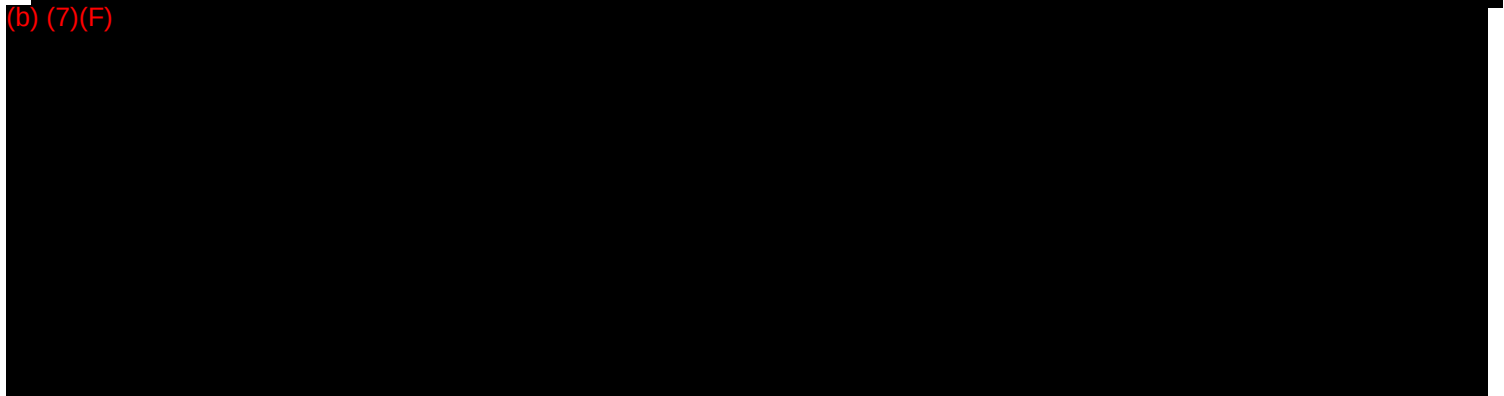
4.11 LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.425(e)(4)(A)(iv)]

The selected pipeline leak detection system depends on several technologies including flow measurement, instrumentation, communications, computer hardware and software, and ultimately, experience in operating a system under similar pipeline flow conditions. Because of environmental conditions on the North Slope and the variable flow conditions, it is essential that the selected system have an established track record among North Slope crude oil pipelines. In addition, the chosen system must be redundant, capable of immediately detecting a sudden large volume loss, and capable of detecting a low threshold chronic leak.

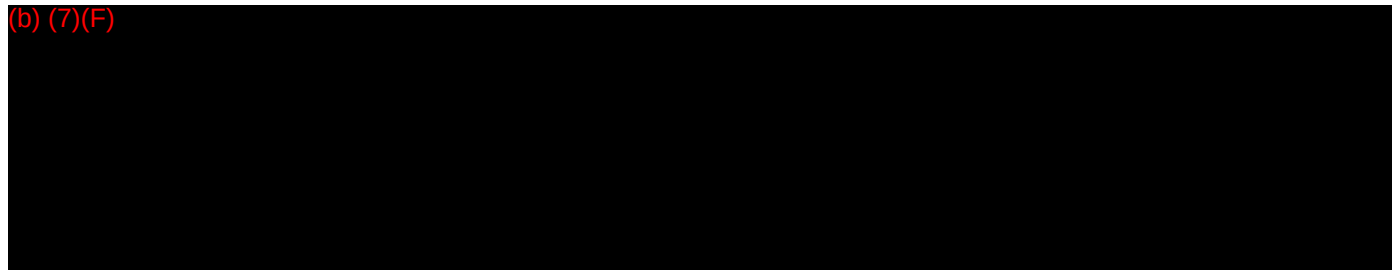
(b) (7)(F)



(b) (7)(F)



(b) (7)(F)

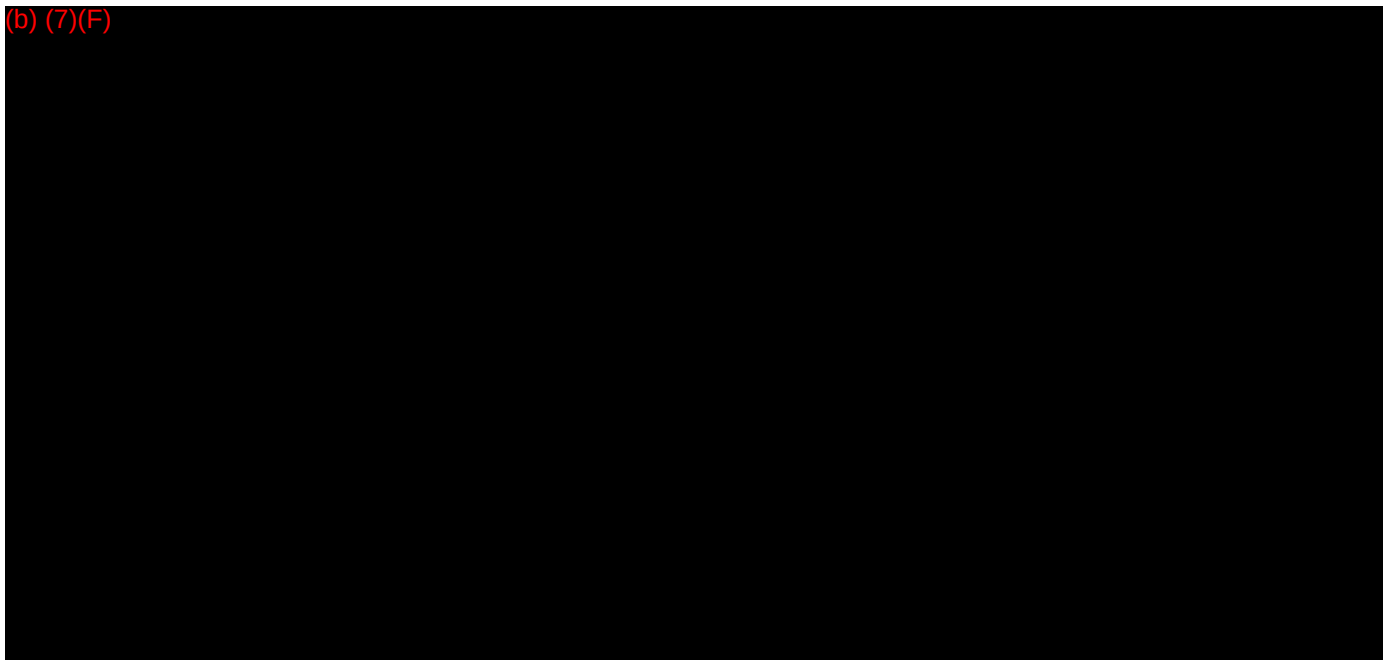


(b) (7)(F)



Milne Point Unit ODPCP, Volume 2 – Prevention Plan

(b) (7)(F)



**TABLE 4-6: BEST AVAILABLE TECHNOLOGY ANALYSIS –
LEAK DETECTION IN CRUDE OIL PIPELINE**

BAT EVALUATION CRITERIA	MASS BALANCE LINE PACK COMPENSATION (MBLPC)	PRESSURE POINT ANALYSIS (PPA)	ALTERNATE METHOD: VISUAL SURVEILLANCE	ALTERNATE METHOD: LINE VOLUME BALANCE SYSTEM	ALTERNATE METHOD: TRANSIENT VOLUME BALANCE SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	(b) (7)(F)				
TRANSFERABILITY: Whether each technology is transferable to applicant's operations					

**TABLE 4-6 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS –
LEAK DETECTION IN CRUDE OIL PIPELINE**

BAT EVALUATION CRITERIA	MASS BALANCE LINE PACK COMPENSATION (MBLPC)	PRESSURE POINT ANALYSIS (PPA)	ALTERNATE METHOD: VISUAL SURVEILLANCE	ALTERNATE METHOD: LINE VOLUME BALANCE SYSTEM	ALTERNATE METHOD: TRANSIENT VOLUME BALANCE
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	(b) (7)(F)				
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					
AGE AND CONDITION: The age and condition of technology in use by the applicant					

**TABLE 4-6 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS –
LEAK DETECTION IN CRUDE OIL PIPELINE**

BAT EVALUATION CRITERIA	MASS BALANCE LINE PACK COMPENSATION (MBLPC)	PRESSURE POINT ANALYSIS (PPA)	ALTERNATE METHOD: VISUAL SURVEILLANCE	ALTERNATE METHOD: LINE VOLUME BALANCE SYSTEM	ALTERNATE METHOD: TRANSIENT VOLUME BALANCE SYSTEM
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	(b) (7)(F)				
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects					
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits					

**TABLE 4-6 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS –
LEAK DETECTION IN CRUDE OIL PIPELINE**

BAT EVALUATION CRITERIA	ALTERNATE METHOD NEGATIVE PRESSURE WAVE MONITORING (NPWM)	ALTERNATE METHOD ACOUSTIC EMISSIONS (AE) MONITORING BASED ON MEASURED SOUND DATA	ALTERNATE METHOD: REAL TIME TRANSIENT MODEL (RTTM)
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	(b) (7)(F) t t		
TRANSFERABILITY: Whether each technology is transferable to applicant's operations			
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits			
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.			
AGE AND CONDITION: The age and condition of technology in use by the applicant			

**TABLE 4-6 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS –
LEAK DETECTION IN CRUDE OIL PIPELINE**

BAT EVALUATION CRITERIA	ALTERNATE METHOD NEGATIVE PRESSURE WAVE MONITORING (NPWM)	ALTERNATE METHOD ACOUSTIC EMISSIONS (AE) MONITORING BASED ON MEASURED SOUND DATA	ALTERNATE METHOD: REAL TIME TRANSIENT MODEL (RTTM)
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	(b) (7)(F)		
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects			
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits			

PART 5. RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

5.1 OIL STORAGE TANK [18 AAC 75.432]

Part 5, Response Planning Standard, is in Volume 1.

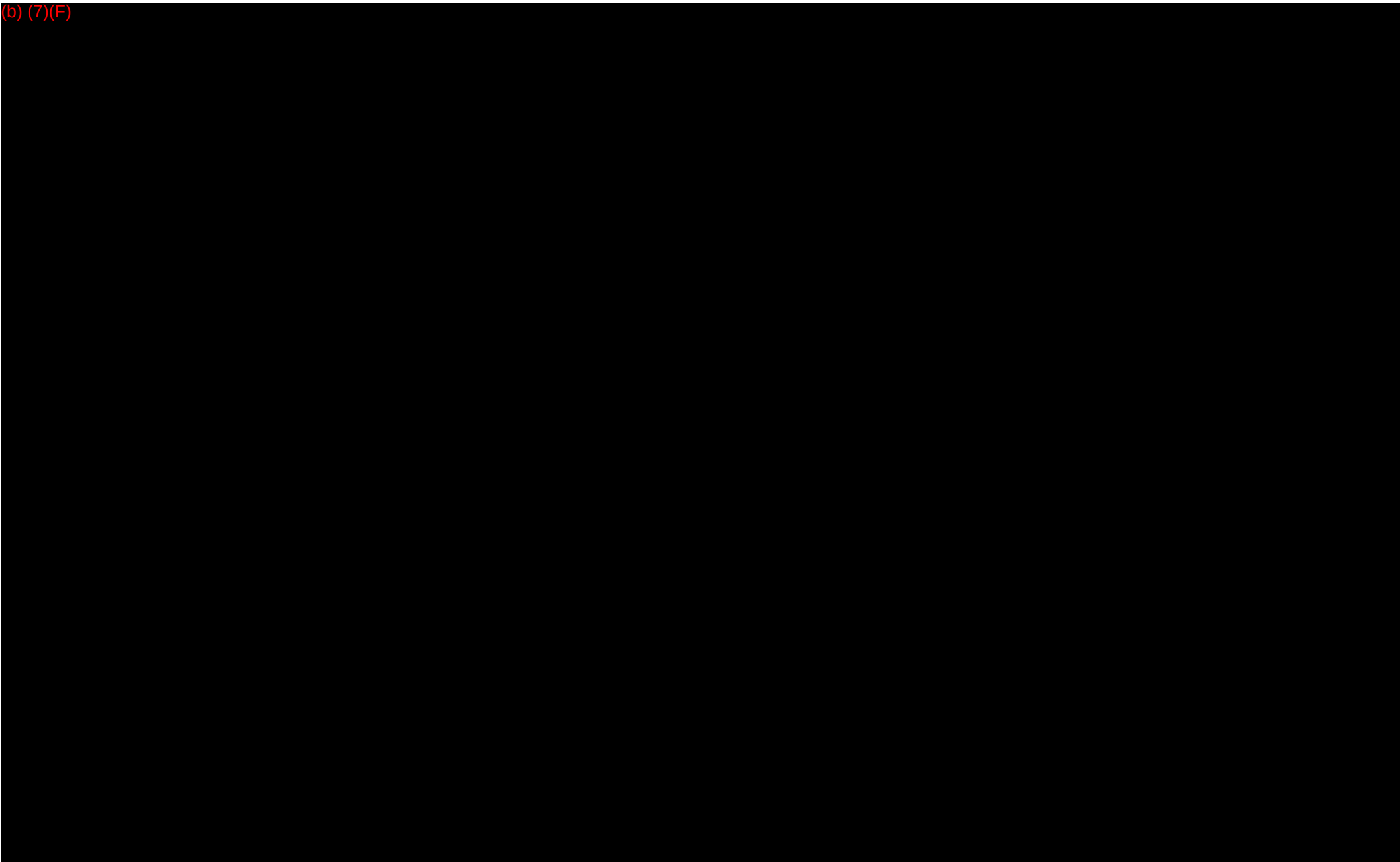
THIS PAGE INTENTIONALLY LEFT BLANK.

APPENDIX A

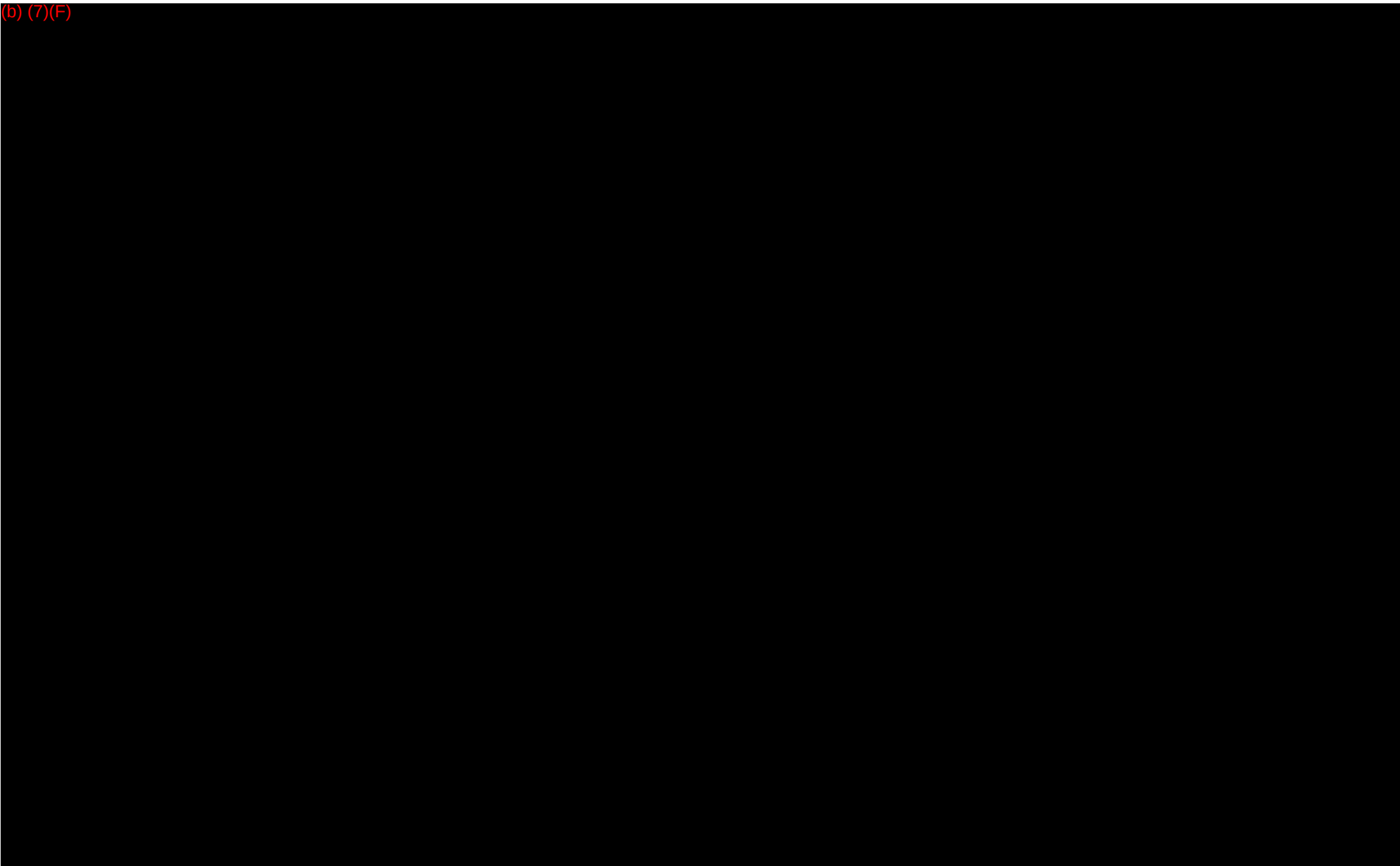
SHOP-FABRICATED TANK TABLE

**APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES**

(b) (7)(F)

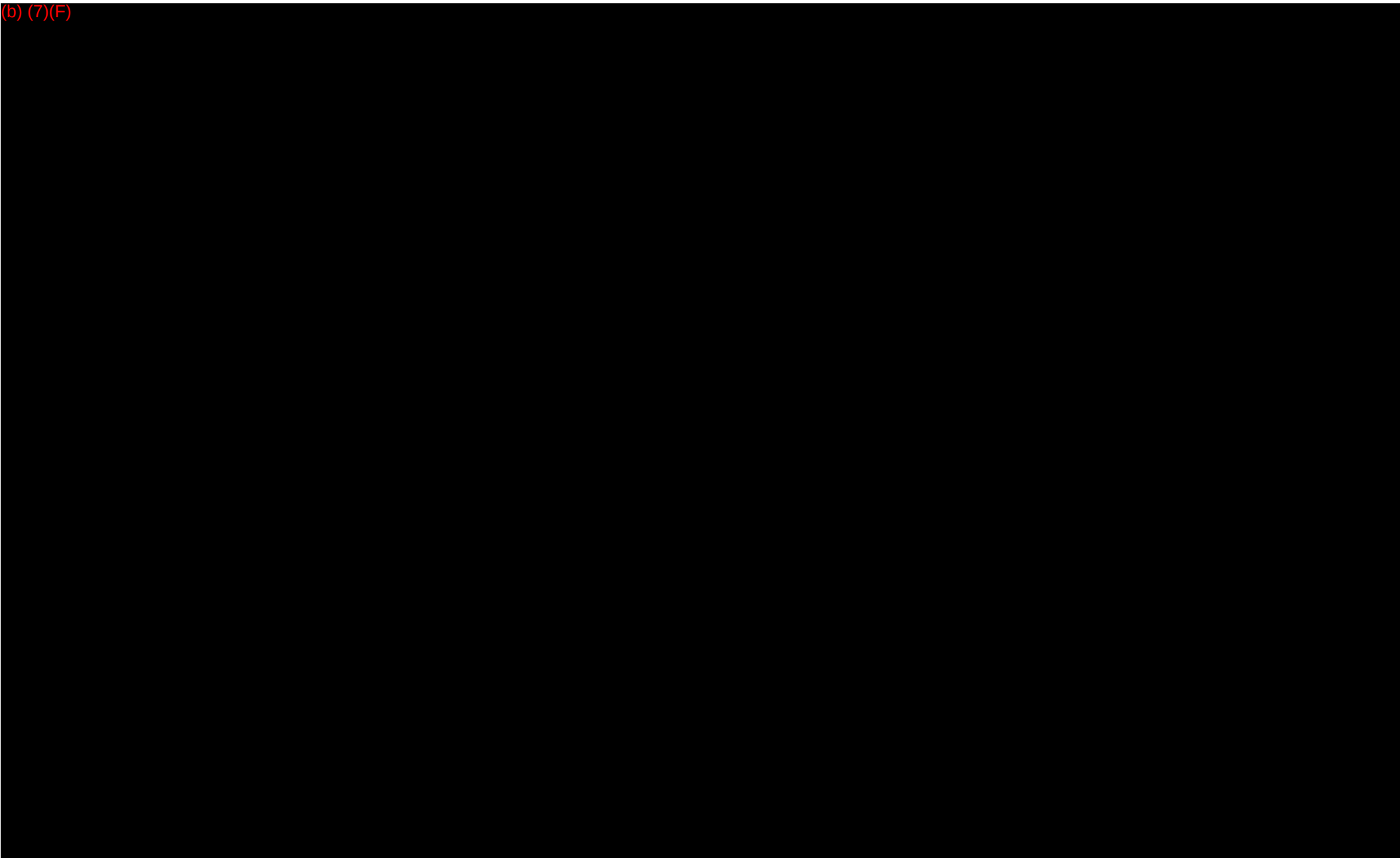


(b) (7)(F)

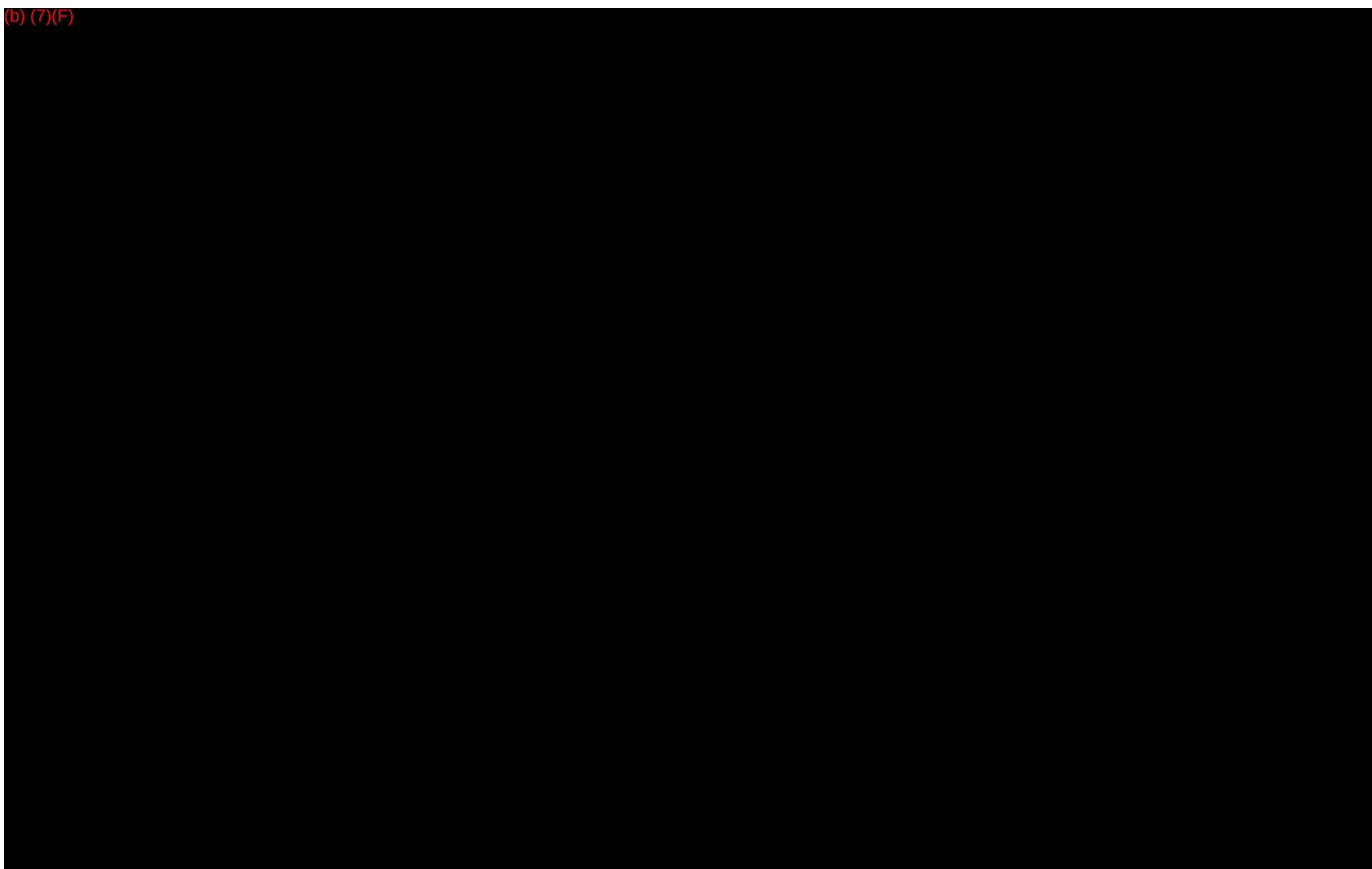


APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA

(b) (7)(F)



(b) (7)(F)

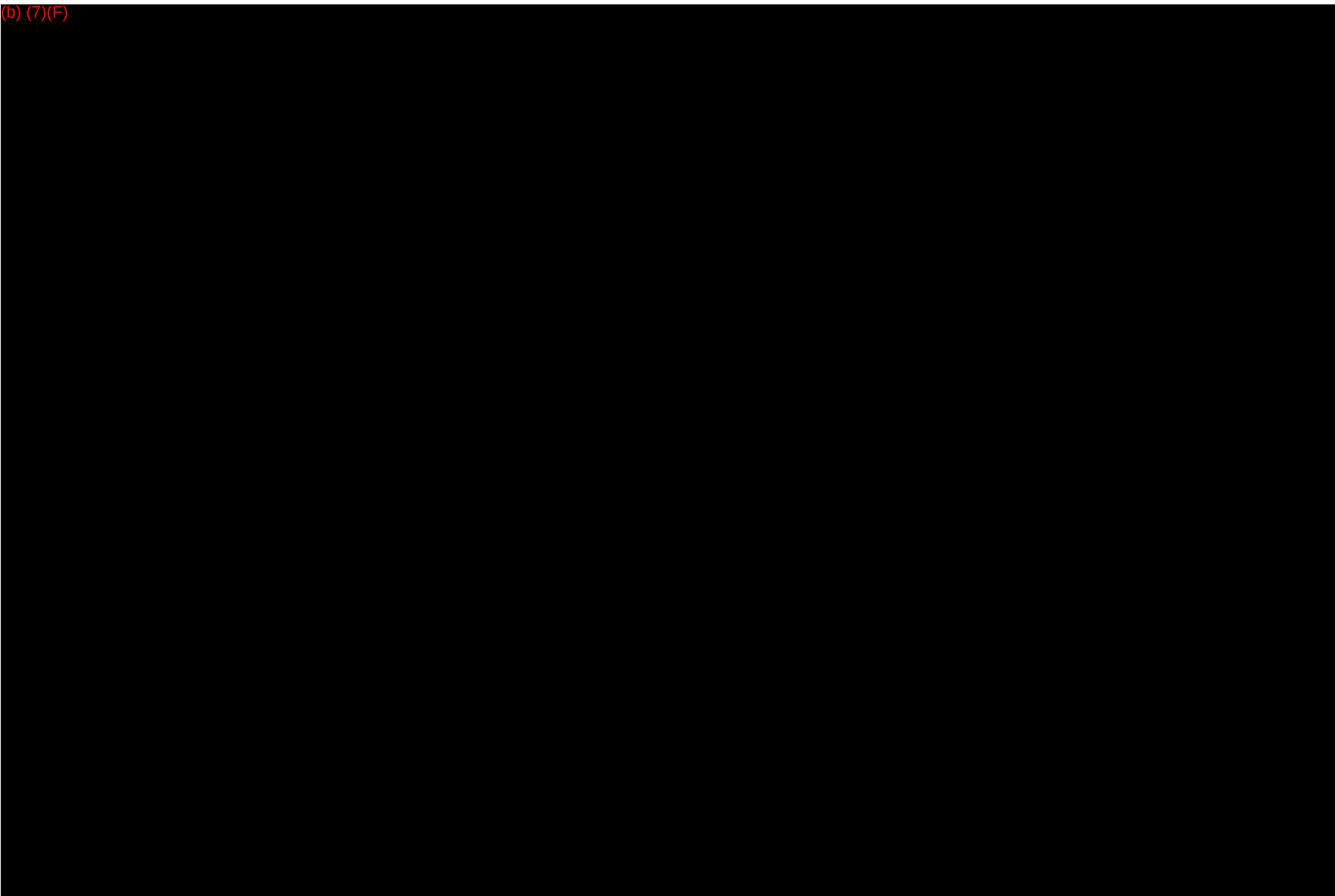


APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA

(b) (7)(F)



(b) (7)(F)

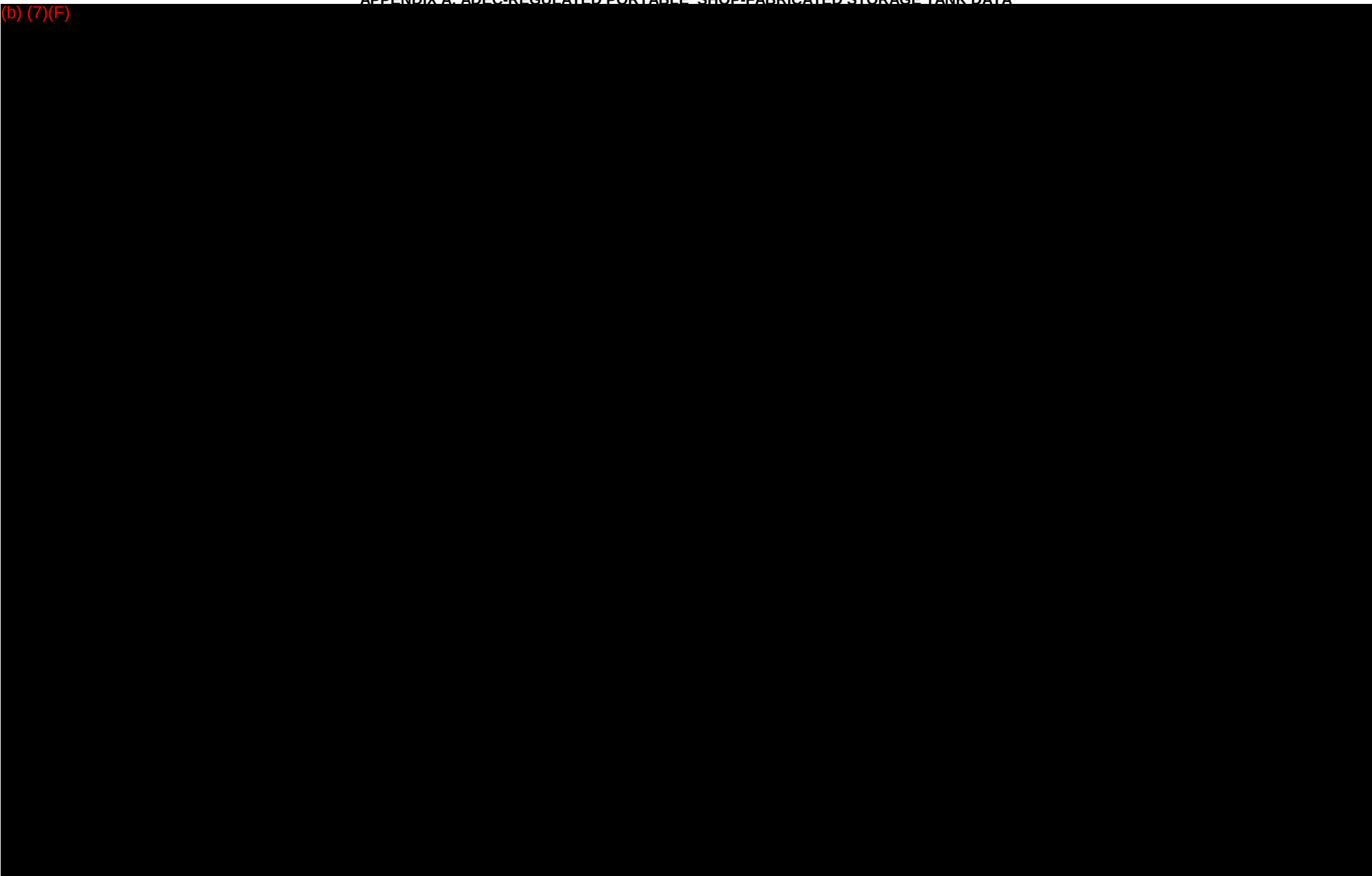


(b) (7)(F)

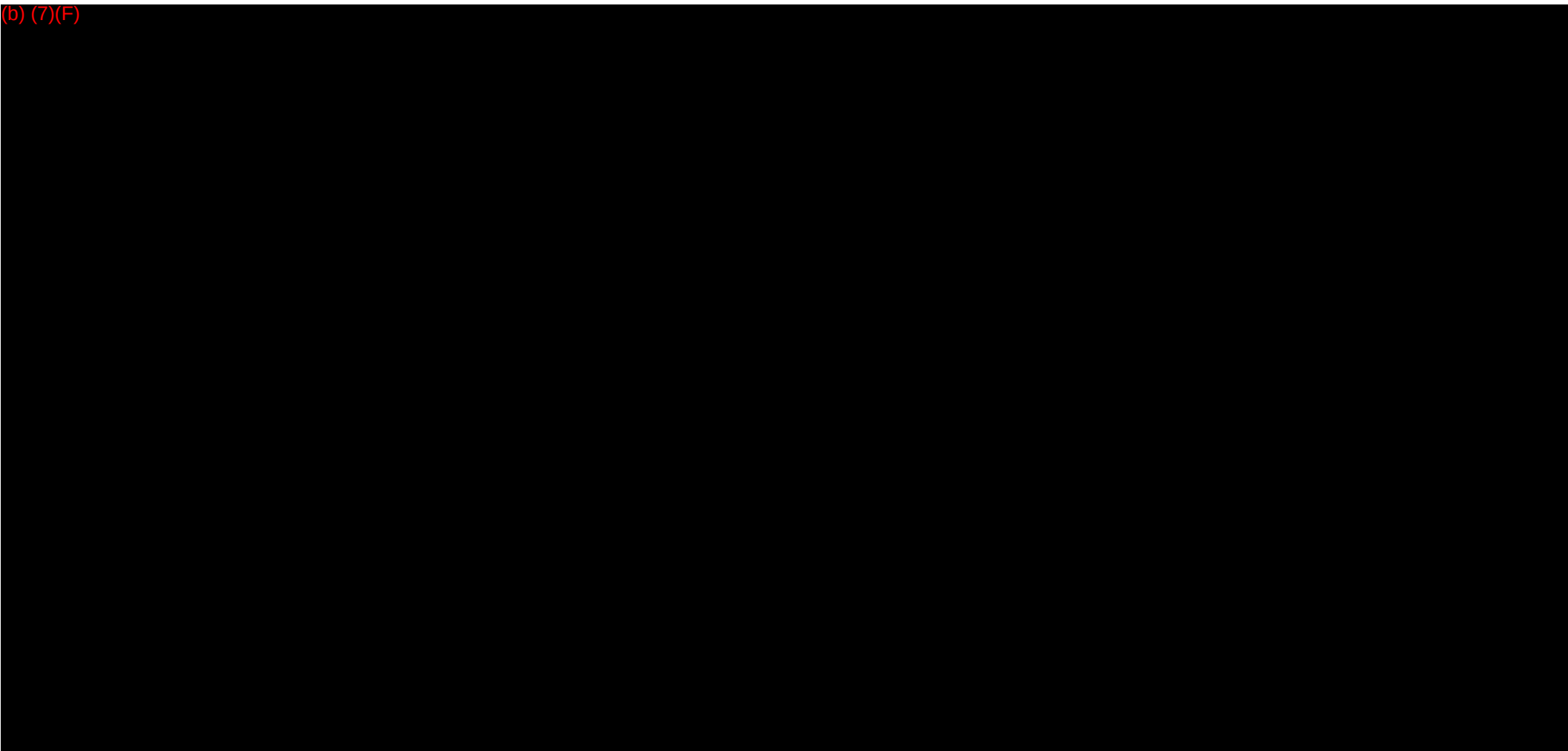


APPENDIX A: ADEC-REGULATED PORTABLE SHOP-FABRICATED STORAGE TANK DATA

(b) (7)(F)

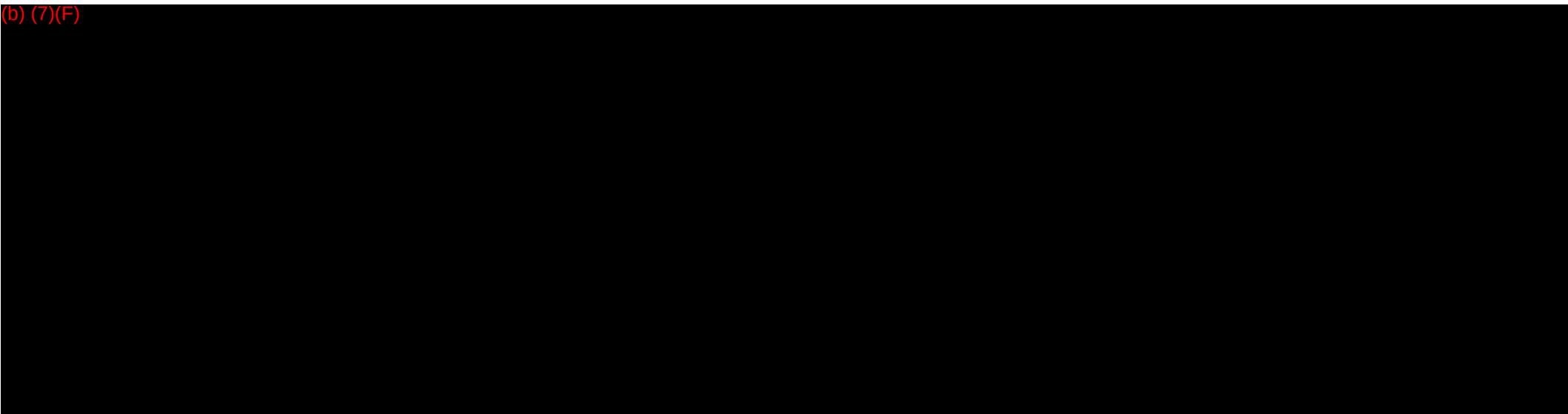


(b) (7)(F)



port) and a means to drain the inters i ial space, as required by 18 AAC 75.066(e).

(b) (7)(F)



required for double-walled tanks if they are equipped with a fixed overfill containment system, a means to monitor the interstitial space (e.g., view port) and a means to drain the inters i al space, as required by 18 AAC 75.066(e).

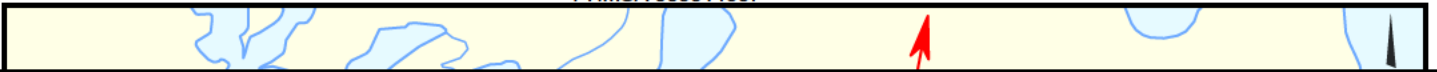
APPENDIX B

FACILITY DIAGRAMS

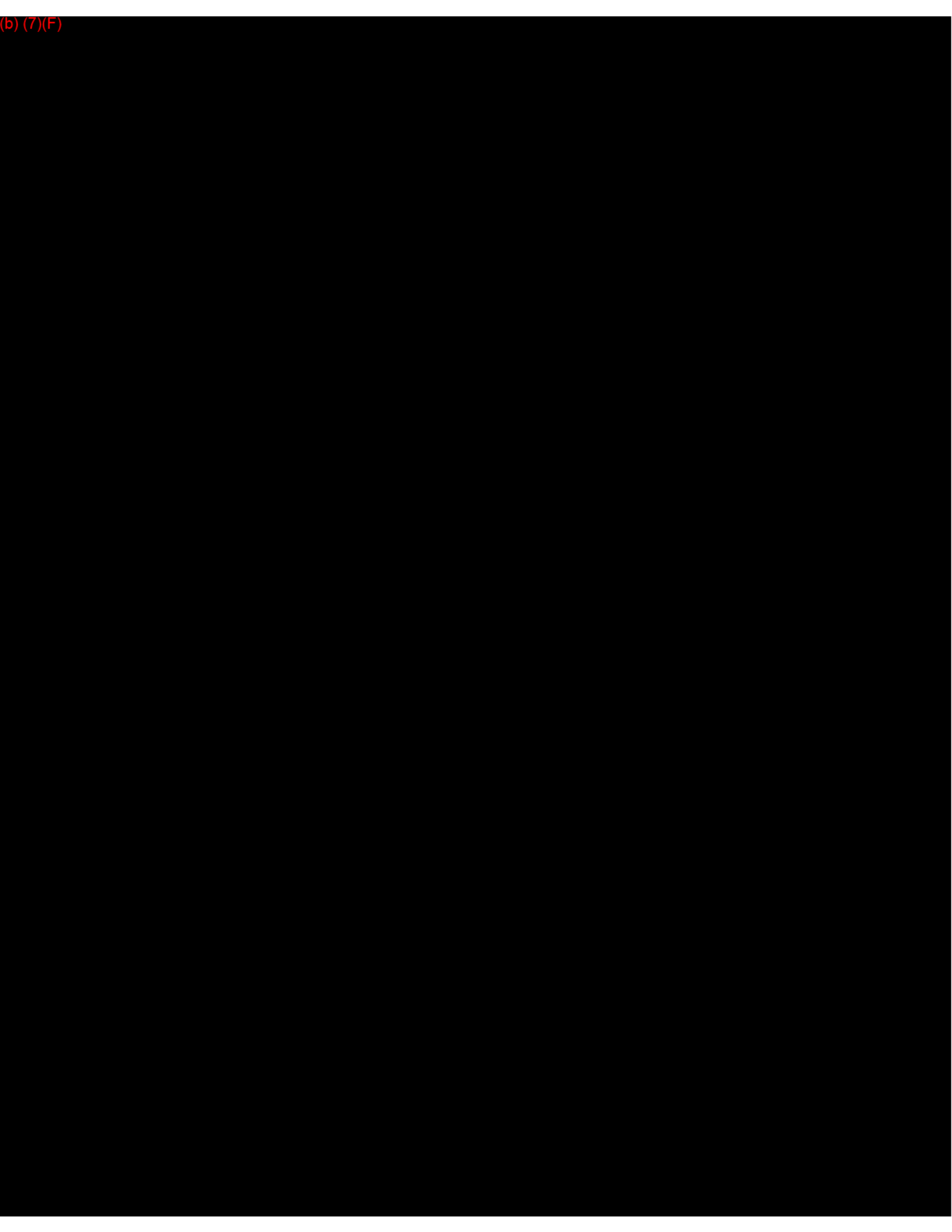
(b) (7)(F)

(b) (7)(F)

(b) (7)(F)

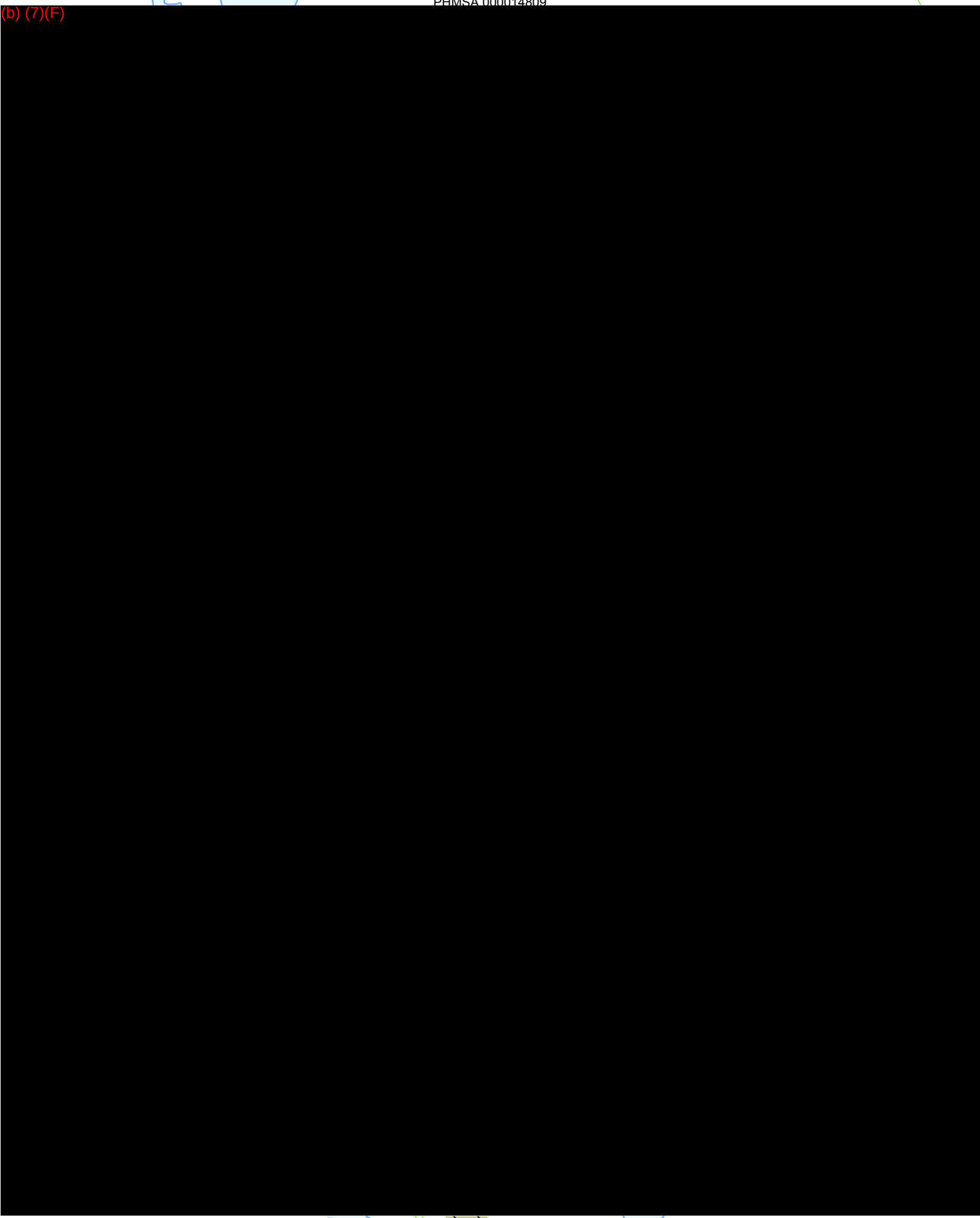


(b) (7)(F)

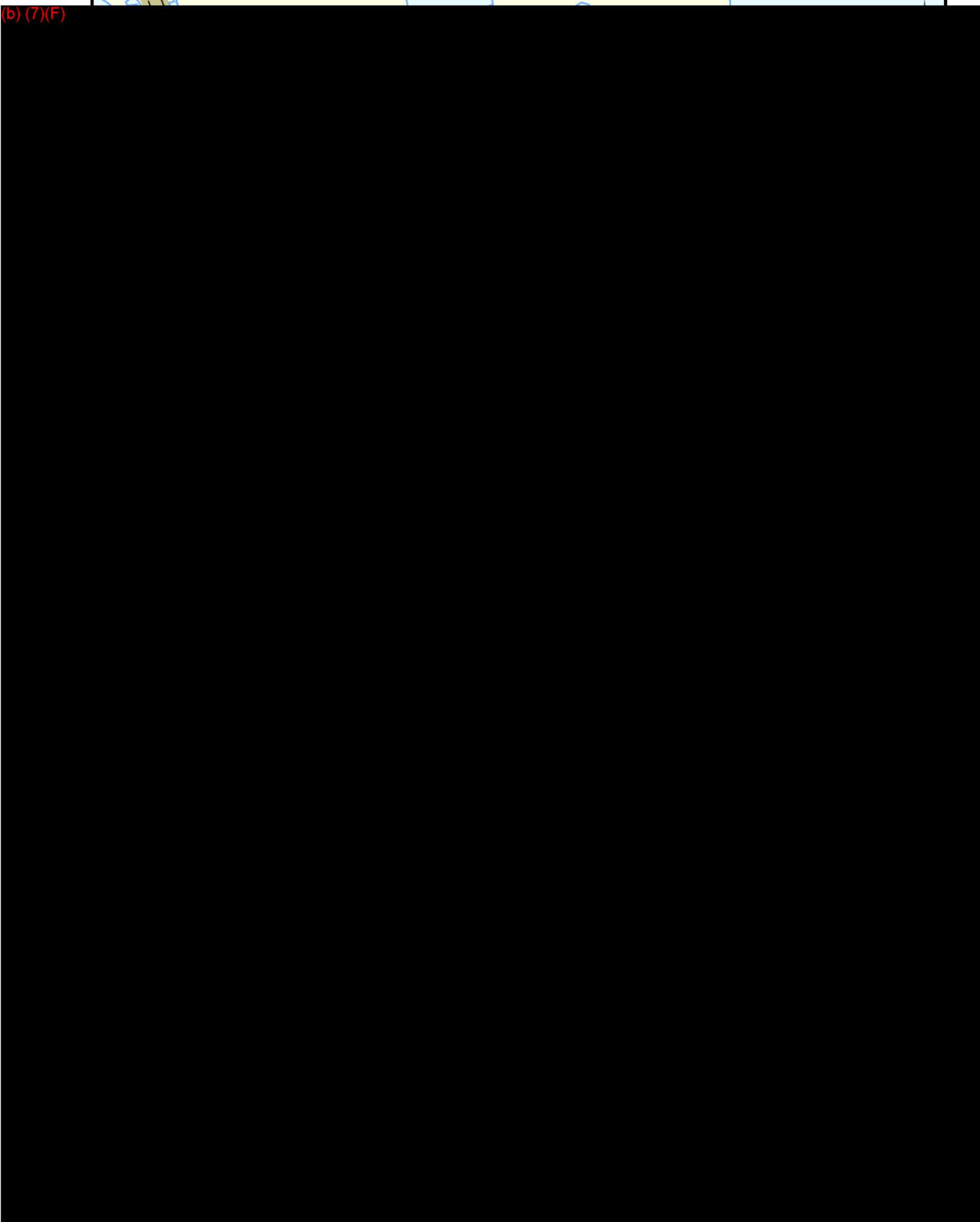


(b) (7)(F)

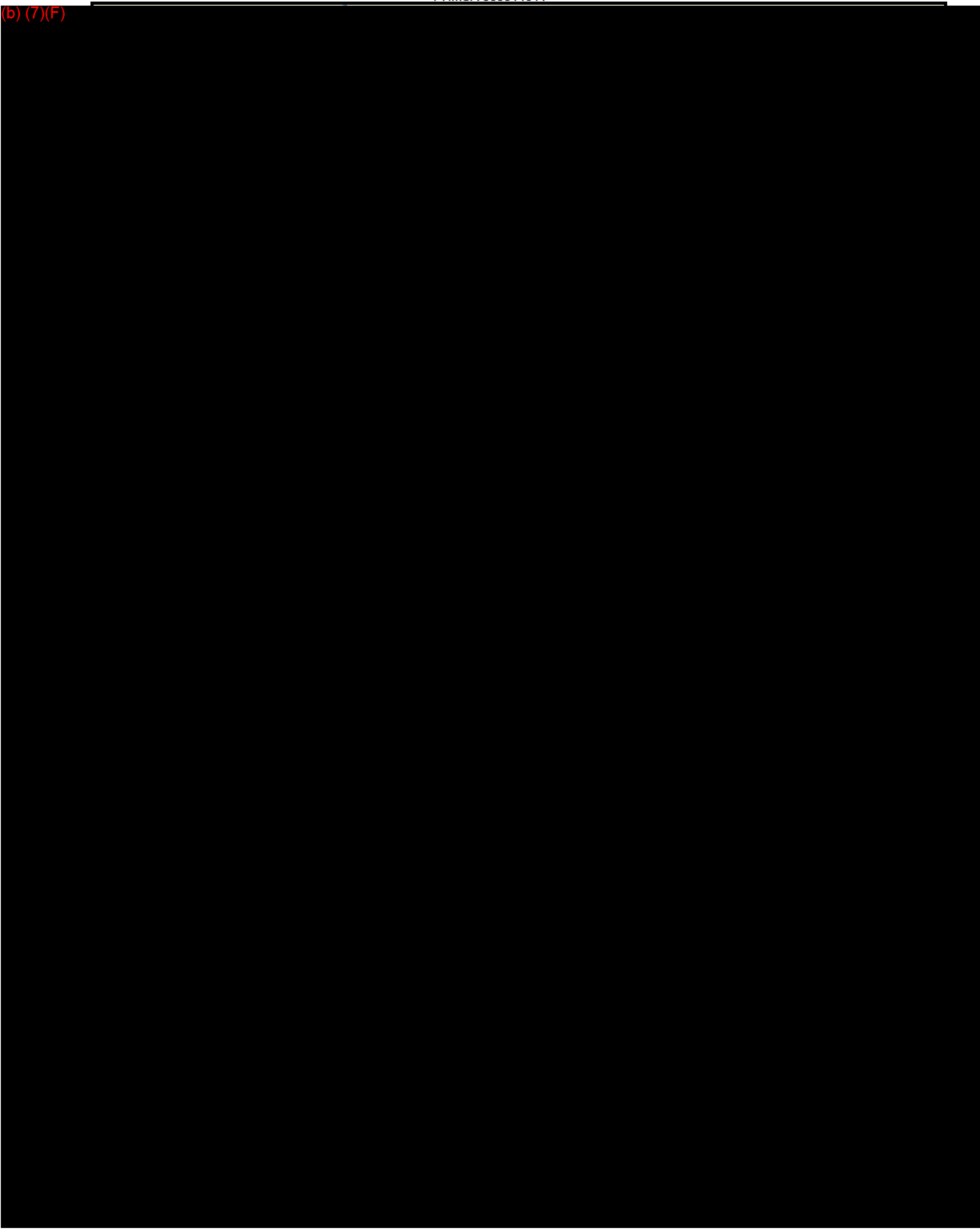
(b) (7)(F)

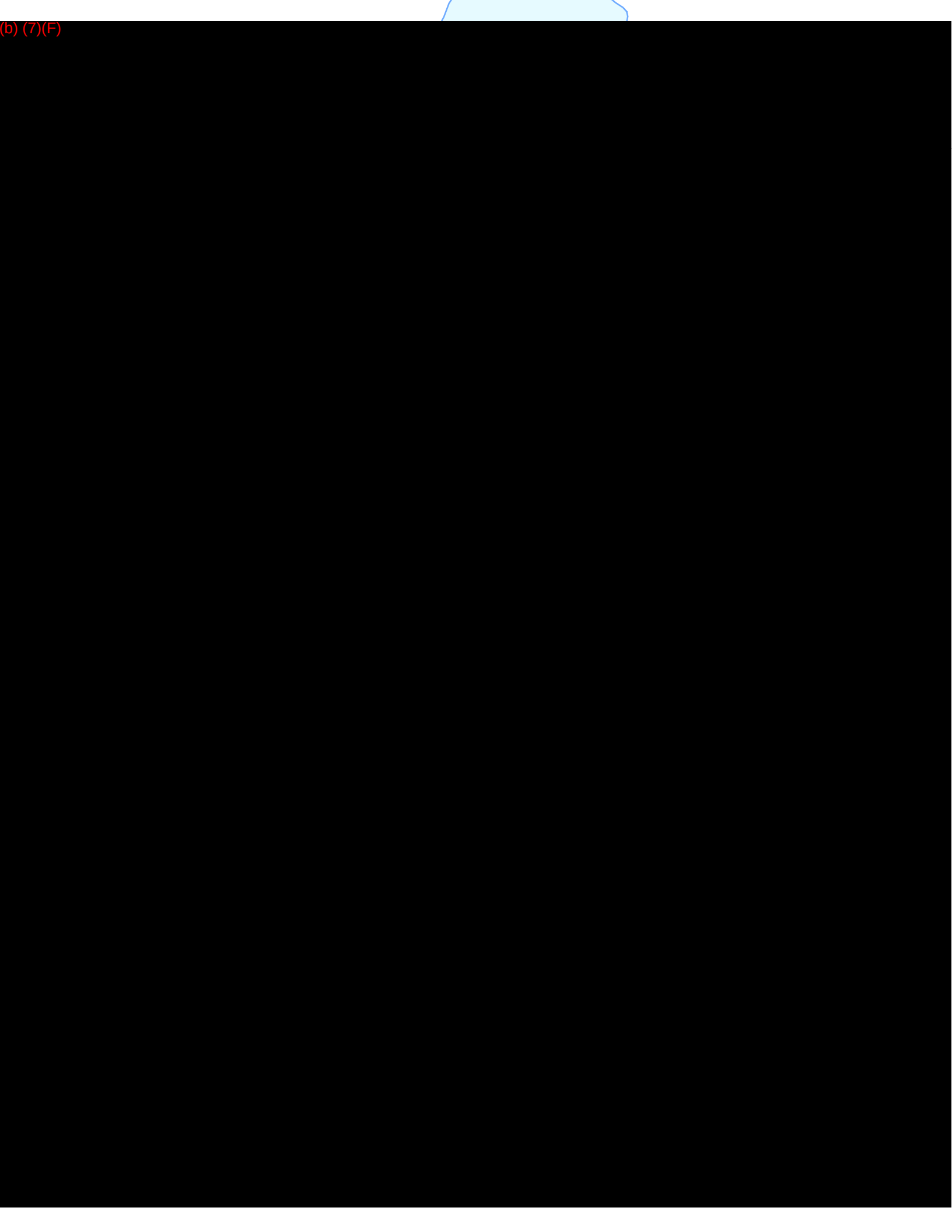


(b) (7)(F)

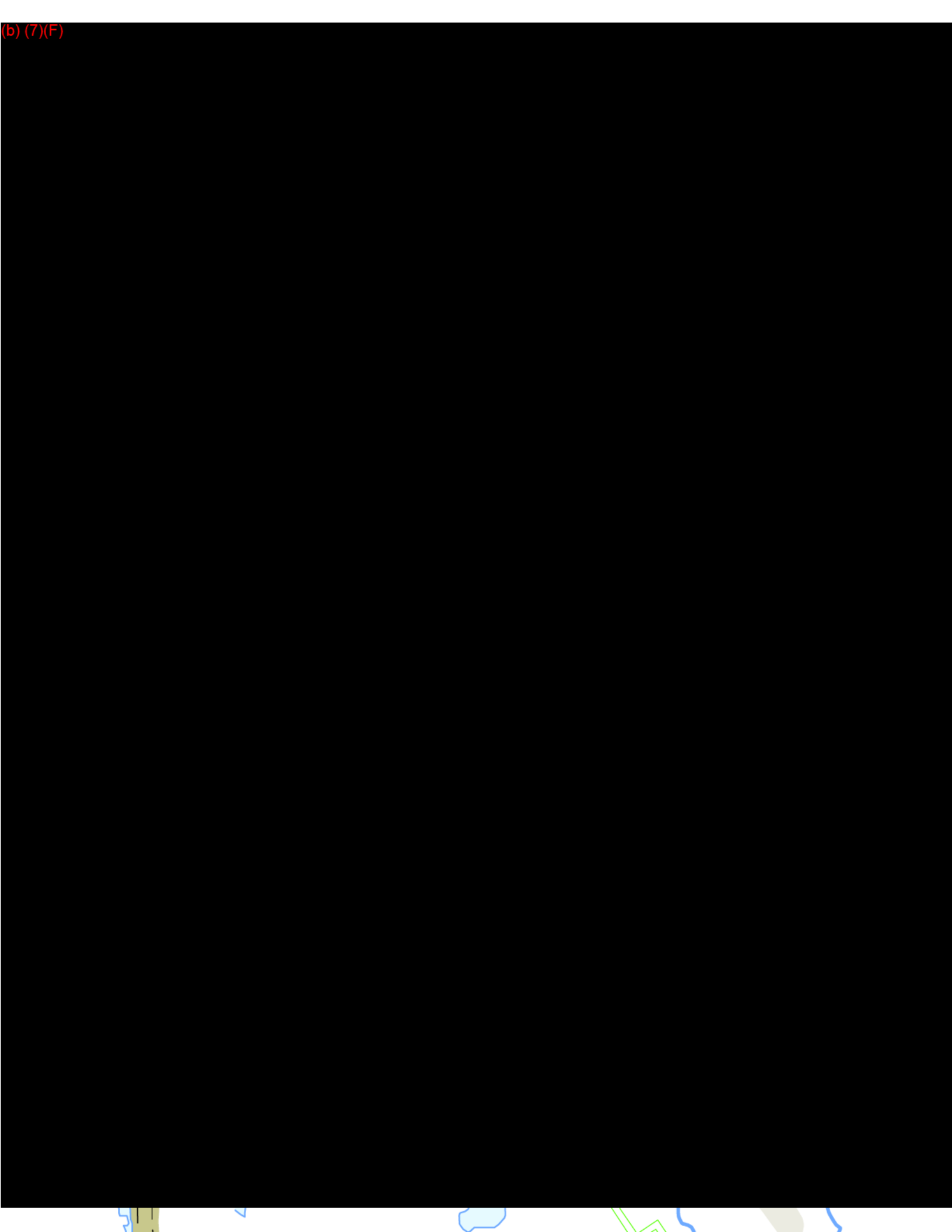


(b) (7)(F)

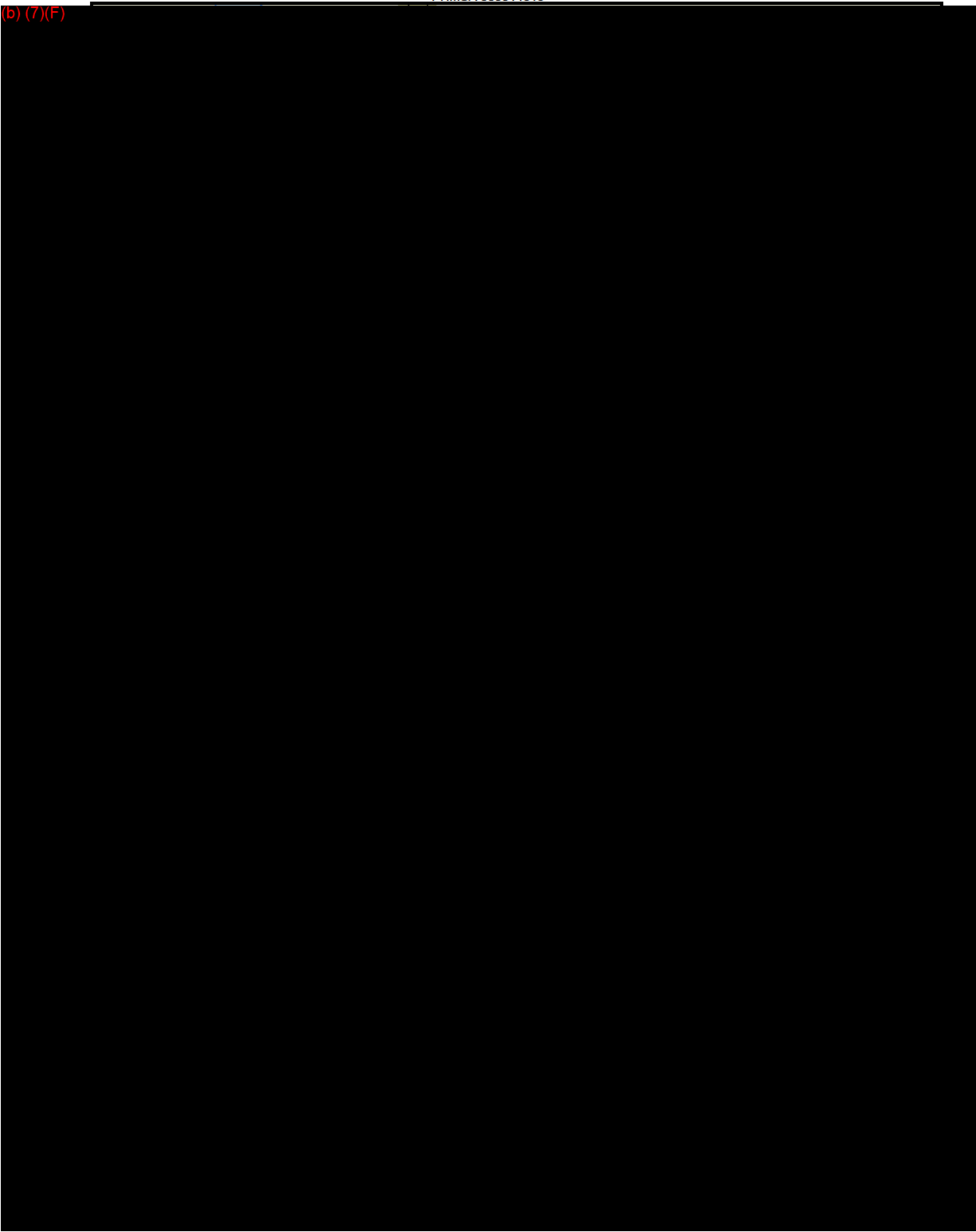




(b) (7)(F)

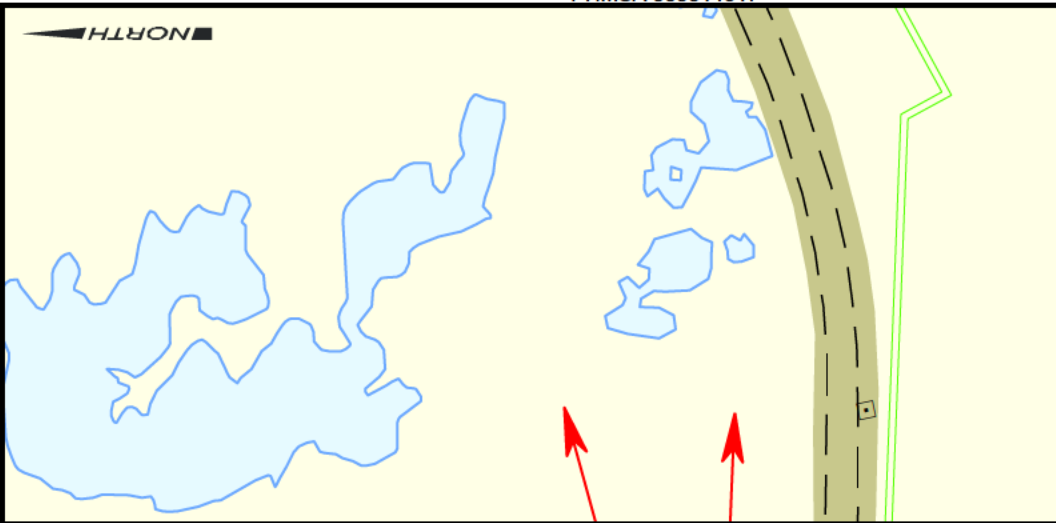


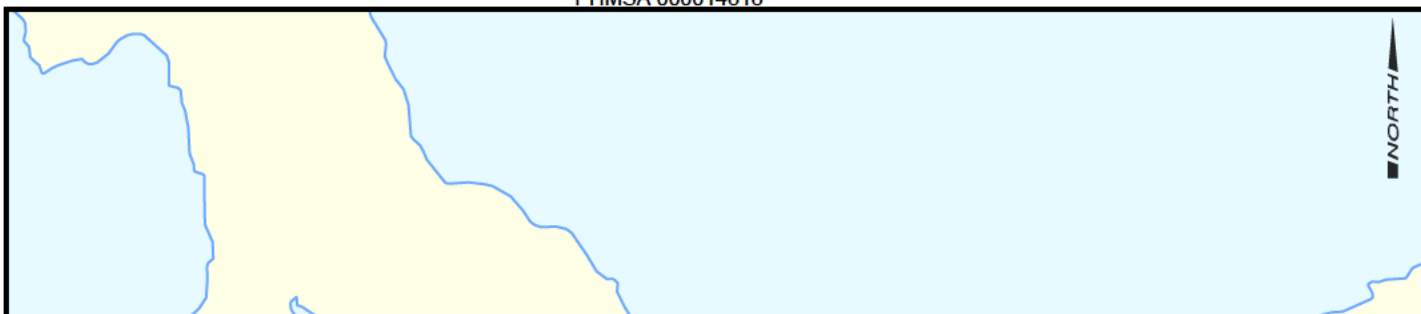
(b) (7)(F)





(b) (7)(F)



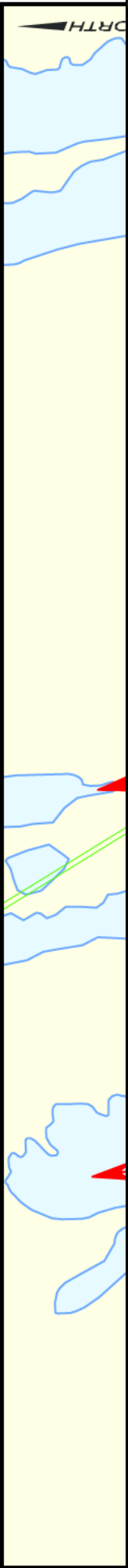


(b) (7)(F)



(b) (7)(F)

(b) (7)(F)





(b) (7)(F)

APPENDIX C

MILNE POINT UNIT DISCHARGE HISTORY

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
6-Feb-94	Diesel	20	Y	A water truck left the rig during Phase II conditions with a 966 loader as escort. The driving conditions worsened to Phase III, forcing the drivers to pull off and stop. While maneuvering vehicles to get shelter from the wind, the water truck bumped the blade of loader. Both drivers spent the night in the cab of the water truck. In the morning, a small puncture in the left front fuel tank was discovered, which had allowed diesel to leak out.	Approximately 3 square feet of tundra were contaminated with diesel.	Tank was repaired.	Diesel and all visibly contaminated snow were scraped up with 966 loader. During the summer months, the affected patch of tundra was burned to remove the diesel, re-seeded, and monitored by Environmental personnel. Tundra re-vegetation was successful.
12-Dec-94	Seawater/ Produced Water	126	N	Seawater was being transferred to temporary tank from rig to displace frac sand following a frac job and the hose into tank was not tied down. When fluid was transferred, the hose came out of tank and spilled an estimated 126 gallons of seawater onto the pad.	None. Fluid was contained on the pad and frozen in place.		Cleanup was initiated and the remainder of frozen ice removed with the use of a blade, loader and dump truck.
3-Jan-95	Hydraulic Fluid	110	N	During normal well operations, the HCR hose blew off at the valve connection. At the time of the incident, the line was pressured to 1500 psi from the accumulator. A roustabout noticed the leak and informed his supervisor immediately. The accumulator was shut down and clean up operations were implemented.	None. All contaminated material was contained inside the surface liner under the rig and in the well cellar. No tundra or water affected.	The company man stated that hydraulic pressure lines are pressure tested weekly. What happened here is extremely rare. Visual inspections as well as the regular inspections will be ongoing.	The hydraulic fluids were sucked up with sump pump and placed into 2-55 gallon drums. Remaining fluid was wiped up with sorbent material.
18-Feb-95	Crude Oil	210	N	Crude emulsion from flow back foamed and overflowed tank. Operating limit of tank is 45 bbls with a volume of 500 bbls. Following settlement of foam in the tank, the tank was strapped and the volume found to be 240 bbls.			The outside of the tank was wiped clean with absorbents. Snow affected with crude was collected and placed in the tank. The contaminated sorbents were double bagged and placed in a burnable dumpster.
27-Jun-95	Crude Oil	75	N	A tiger tank at B Pad was used to temporarily store fluids, which were to be either vacuumed off for production purposes or injected into B-12 injection well. Approximately 100 barrels of crude oil had accumulated in the tank. Tank design precluded removing the crude from the installed fittings on the bottom of the tank. Removal of the floating crude was to be accomplished from the top of the tank when enough water would cause the crude to rise closer to the top. While dewatering the B-Pad central reserve pit, the tank overflowed as the pump operator was checking the level.	None. Crude oil was contained in secondary containment.		
2-Dec-95	Drilling Mud	1680	N	A Veco Guzzler was loading drill cuttings from the rig. The operator discovered the tailgate was open and the load had spilled onto the iced gravel pad. The hydraulic and mechanical locking devices that lock the tailgate closed were not properly engaged. The driver was new to the operation with about one month experience. The cause was failure of the employee to follow proper procedures.	None. All the mud was contained on the pad. No water or tundra was affected.	The truck driver will be counseled to do a pre-inspection check of his equipment prior to loading.	A loader and hand tools were used to scrape the affected area. Another Guzzler was used to suck up the liquid mud.
20-Dec-95	Drilling Mud	5670	Y	Three Guzzler loads (108 bbls of drilling mud and 27 bbls of cuttings) were to be dumped into the A Pad reserve pit. Two Guzzlers and two forklifts were on the location, one F/L from 22E and one F/L from 4ES. The BP Pad Operator had shown the 4ES forklift driver where to dump the cuttings. The Veco Guzzler driver had a map of the pad showing the Reserve Pit location. The Rig 22E forklift operator cleared an area of snow away for the Guzzlers, having been given directions by the 4ES forklift operator who had to return to his rig. After crew change, the new forklift driver from 22E took a Guzzler over to dump a load into the A Pad Reserve Pit. He observed that the Guzzlers had been dumping cuttings onto the tundra instead of into the reserve pit, so he had this Guzzler driver dump his load into the reserve pit.	The tundra may exhibit stress from the spilled material. The area will be monitored next spring to determine if additional remedial actions are necessary.		

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
8-Jan-96	Oil	60	N	A Peak truck was unloading diesel into the rig fuel supply tank. As the tank filled up a float showing the amount of diesel in the tank stuck. When the tank was full it began to overflow and the motorman was not able to shut the necessary valves fast enough to prevent diesel from spilling.	None. Approximately 60 gallons of diesel was caught in the secondary containment.		The diesel was cleaned up by the rig crew and the environmental department was notified.
20-Feb-96	Oil	75	N	The rig crew was laying down drill pipe. Two MPU Support Techs driving by the rig noticed diesel fuel flowing from the vent line on the day tank. One of them went to the rig floor to report the spill and the other adjusted the herculite liner of the berm surrounding the area to prevent diesel from escaping onto the pad. The forklift driver drove by and observed diesel spilling from the day tank and the MPU Support tech holding up the herculite. He immediately called for the motorman to notify him of the spill. The driller overheard the call and ran down and shut off the fuel pump. He then returned to the rig floor, secured the well, and initiated crew spill response.	None. Diesel was fully contained in herculite berm under the day tank.		Feul was fully contained in a herculite berm and was immediately cleaned up and put into drums. The diesel fuel will be used for freeze protection. All appropriate parties were notified and an investigation team was formed.
16-Dec-97	Seawater/ Produced Water	63	N	The motorman observed pit 3 overflowing. He switched to pit 2 and notified driller. The trip in the hole was stopped and the well observed and shut in. t was noticed that the overflow had leaked out of the pits, and Enviro, Pad Operator and Drilling Superintendent were notified. A pit gain of 25 bbl had occurred. After the clean up was completed, the well was circulated dead and returned to planned operation.			
16-Jan-98	Seawater/ Produced Water	336	N	While flowing source water into an open top tank for disposal purposes, water escaped through two inlet lines due to the fact that there were no caps in place.			
29-Jan-98	Seawater/ Produced Water	210	N	While pulling out of the hole with the completion, and keeping the hole full with the charger pump, the bell nipple slipped down and out of place allowing fluids to spill into the cellar area, which migrated onto the pad under and around the sub structure.			
3-May-98	Seawater/ Produced Water	3360	N	While working next to the secondary containment pit of a 400 bbl upright tank, a loader accidentally hit one of the valves that was sticking out from the tank causing seawater to leak out onto the pad. The seawater flowed across the pad and into a reserve pit.			
19-Jul-98	Crude oil	168	N	On 7/18, ESP well C-09 was put on production to freeflow to production manifold. On 7/19, high gas alarms occurred at C pad module 26. The pad operator asked Production Control to ESD C pad remotely and announced a Code 99. Twenty four bottles of Halon dumped from the high gas alarms. ERT responded on standby at the staging area while field operation's personnel continued isolation and depressuring of process flows outside the module. IMT was activated with MPU Fire Chief as on-scene commander. Mutual Aid was put on alert. In 45 minutes, the ERT team was able to access the module and locate the leak source at C-09 choke at the bottom side outlet. Ventilation was started. Site safety officer monitored atmosphere for safe entry for cleanup crew. C-09 choke was blinded off. Fire suppression system was returned to normal and pad put on production. This incident was risk ranked as 2A (High) under the old Loss Potential Matrix system.	None. No tundra or waterways were affected.	Investigation team will be assembled to evaluate all contributing factors including past well history.	A vacuum truck was used to pick up the spilled material in the module and sorbents were used to wipe down the floors, walls and equipment.
25-Sep-98	Crude Oil	3	Y	During a safe out of IWAG suction piping, while bleeding down a portion of the IWAG package, suction scrubber liquid dump block valves were left open. When the pressure was relieved from the liquid dump system, the system pressure was reduced below the production header pressure, allowing produced fluids to flow through the IWAG compressor and associated piping. As a result of the introduction of produced fluids into the system, hydrocarbons were released to the vent pit during blowdown. Wind blew the hydrocarbons out of the secondary containment and on the surrounding pad and tundra. Additionally, while performing maintenance on the IWAG, a maintenance employee was sprayed with produced fluids when he removed a plug from a compressor pulsation bottle.	No visible contamination apparent.	Review the IWAG safe out procedure and discuss the importance of thoroughly following safe out procedures	The contaminated gravel was shoveled up and stored in a containment pit until incineration at a later date. The tundra that was affected no longer shows contamination. Spill closed per DeRuyter 7/6/99.

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
13-Nov-98	Source Water	1260	N	During the de-sanding project, heat trace had been turned off the jet water system. Two days prior to this incident the heat trace was returned to service. On 11/13/98, the Area Production Operator found standing water under module 53, and discovered a leaking valve on jet wash of slugcatcher on the east side of the facility. Operator isolated the system and reported the spill.	None. No waterways or tundra affected.	The damaged valve will be replaced and heat trace will be installed and checked.	The frozen source water will be left in place under the module in the center of the pad and flushed with fresh water in the Spring at a 5 to 1 ratio.
27-Jun-00	Oil	200	N	Oil stained gravel was discovered on the Central Facilities Pad, west side of Module #61, under the pipe-rack. Operations staff discovered leak to be on the Oil Reserve Tank(s) inlet line. Fast tanks were set up to contain the leak during the trouble shooting. A temporary clamp was attached and the leak controlled. Plans for a permanent repair are underway.	None.	Develop and install permanent repair for eroded line. Identify other locations that could have the potential to develop an erosion leak. These identified locations were delivered to the corrosion inspection group to be added to the inspection program.	Gravel was cleaned up using super sucker and hand tools.
20-Jul-00	Produced Water	84	N	Well I-O5i was on H2O injection since 6-6-96 and averaging 1500 BWPD. A leak was observed by lead Support tech. Proper notification was made and Production Control shut the well in. Initial investigation revealed a plug on the bottom of the check valve, immediately upstream of the wing valve, was leaking. Further investigation will be completed after removal of the check valve for inspection.	Approx two bbls produced water was released with most of the liquid contained within the well house and cellar. A small amount leaked through the bottom of the wellhouse to the ground outside. No water or tundra was affected.	Inspection of similar valves in the field will be performed.	Cleaned up using hand tools, loader.
10-Dec-00	Produced Water	7454	N	Environmental technician found source water spilling over Slurry Tank containment area. Production operations responded by blocking in the 2" source water flush line to Slurry Tank. Investigation found the inspection cover on 2" check valve was leaking.	None. The area is approximately 300' from the pad edge.	The valve was replaced with a stronger type valve.	The area will be scraped up using hand tools and loader equipment.
20-Mar-01	Lube Oil	125	N	During routine pad rounds, the Pad Operator found an ongoing spill in the Injection compressor #1 building (IWAG#1). The rolling equipment hoist was moved and had displaced the manual oil fill valve on the Trabon Lube oil storage tank to 30-40% open. The day running tank had overfilled in the cabinet and ran out to the floor. The pad operator repositioned the rolling hoist and closed the valve.	None. All material was contained inside the building. No tundra or water was affected.	The valve handle has been removed. Incident will be communicated to all MPU Pad Operators.	Squeegees were used to push the material into the sump. The sump was removed with a vac truck. Residual contamination was removed with sorbent and rags.
17-Jun-01	Diesel	10	Y	The driver was adjusting the volume on his DJB Articulating Dump truck "trunk radio" located directly behind the right elbow in the rear of the cab. As the driver turned in his seat the truck tires caught the soft shoulder of the road and overturned the truck bed full of diesel contaminated gravel from a spill site onto the tundra.		Consult all drivers to stop their vehicles before making any adjustments that may divert their attention from their driving.	A super sucker and hand tools were used to remove the gravel from the tundra.
29-Jun-01	Diesel	2	Y	A crane was traveling down the spine road when it met a truck carrying a 300 bbl tank. The crane driver moved over to allow the truck to pass, and stopped about 16" from the edge of the road. The road failed under the crane, and it slid off the road and tipped over. The crane gantry landed on the Kuparuk sales oil line and the 120' boom landed on the same line in a different location. This event resulted in a recordable injury and a small spill of diesel, oil, and glycol from the overturned crane.		The Road and Pad Maintenance department has repaired the road. Peak has advised all drivers to maintain a safe distance between their vehicle and the edge of the road.	Contaminants were removed with a vac truck and sorbents. Affected gravel was removed with hand tools. The fluids were placed in a drum and the contaminants were skimmed off with sorbents.
	Hydraulic Fluid	0.5	Y				
	Motor Oil	0.5	Y				
27-Jan-02	Hydraulic Fluid	0 50	Y	A hydraulic line on loader pushing up ice chips failed, causing a spill on to the ice surface of a lake.	None. The contaminated area was cleaned up.	Do periodic equipment inspections daily.	Used hand tools to clean up the contaminated area.

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
3-Feb-02	Produced Water	75	N	An employee found a pig launcher door leaking. He contacted Environmental immediately and closed the launcher isolation valve to stop any further leakage. Environmental responded during Phase I weather conditions and estimated 5 gallons released into the snow. Weather conditions quickly turned to Phase III for approximately 2.5 days, not allowing for immediate clean up of release. When weather conditions subsided to Phase II, environmental was able to assess volume released as approximately 75 gal. Much of the released material was layered under blown snow and was not visible during initial inspection of the area. An interim agency report was faxed to ADEC notifying them of the change in volume released. Subsequent investigation revealed that the leaking seal was improperly treated and installed.	None. All of the contamination was contained on the gravel pad.	An additional step will be added to the pig launching demobilization. The launcher O-Ring will be inspected and the launcher will be pressure tested for integrity. The launcher isolation valve will be left in the closed position and the launcher area will be drained.	The area will be cleaned up using hand tools. Contaminated snow will be managed in tanks. Contaminated gravel will be managed in the contaminated gravel storage bins at MPU D-pad.
15-Mar-02	Crude Oil	2.5	Y	While bleeding off tubing from F-83i, gas mist venting off the top of the tank carried natural gas liquids mixed with crude oil onto the pad and surrounding area including on sea ice. Mist was not visible until daylight hours and was reported immediately by F-Pad day operator when found.	None. Material was contained on frozen gravel pad and frozen sea ice and snow. All material was removed prior to affecting water or tundra.	Pending further evaluation, specific procedural and equipment modifications will be made to existing Standard Operating Procedures and Vent Gas System Bleed Tanks.	Clean up actions included using hand tools such as shovels, brooms and snow storage hopper bins. A front end loader was used to remove the lightly contaminated snow from the affected sea ice and F-Pad frozen gravel surface. Approximately 550 cubic yards of contaminated snow was removed from the affected areas. All contaminated snow was moved to an area on the NW corner of F-Pad for short term storage.
8-Apr-02	Diesel	40	Y	Two vehicles were traveling in opposite directions when they encountered blowing snow from a snow blower. During the reduced visibility, the two vehicles entered the snow plume and collided with one another, damaging both vehicles and injuring one driver. A fuel tank was punctured during the crash and leaked diesel onto the roadway. Sorbent material was placed around the leak. Upon further investigation and removal of snow, it was found that diesel fuel had migrated off the roadway and onto the adjacent tundra. More snow was removed from the site in order to delineate the spill area.	Approximately 225 square feet of tundra was affected by the spilled diesel.		ACS and Peak Equipment Services responded to the spill with heavy equipment and hand tools to contain the spill. A hand pump was used to pump residual fuel into a 55 gallon drum. Hydraulic fluid, motor oil and propylene glycol (antifreeze) were spilled on the roadway and cleaned up with heavy equipment and hand tools. Snow and gravel was removed from the site using heavy equipment and hand tools. Verbal approval was given by ADEC (John Dixon) to use a propane torch to burn the grass/tundra areas that were contaminated with the diesel fuel in an effort to minimize environmental impact to the tundra surface.
	Hydraulic Fluid	1	Y				
	Motor Oil	1	Y				

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
6-Aug-02	Crude Oil	750	N	The overflow line from the sand slurry tank V-5417 discharged water/oil into the containment pit. X-ray operations were being conducted in Mod 54 and the level switches on V-5417 are of the nuclear source type (which are typically affected from x-ray). The tank level switch alarm was activated but was discounted due to presumed interference from x-ray activity.	None.	CFP Sand Slurry Operations procedures were reviewed and revised. Repair of versa valve on XV-5462 and adjustment of limit switch on rupture pin valve PZIO-5434.	A vacuum truck was dispatched and used to suck up crude oil from containment cell. Sorbents were used to clean the surface of the containment liner. Less than 1 cup of oil was found outside of containment and placed into a oily waste bag. A hot water pressure washer was used to clean the tank liner.
21-Sep-02	Crude Oil	5	Y	During a well servicing activity, a kill fluid was being circulated down hole at Well C-22a. The returned material was piped to a closed tank. A choke on the piping became temporarily plugged. When the plug was removed, a short surge of material entered the tank. This surge created a mist which left the tank through a vent and was blown by the wind to the gravel pad and adjacent tundra.	Approximately 30,000 square feet lightly contaminated tundra. Approximately 10,000 square feet of contaminated gravel pad was cleaned.	Under review. A spill review meeting will be held to determine preventative actions.	Heavy equipment was used to scrape contaminated gravel from surface of pad. Sorbents were used to clean the side of the tiger tank and nearby well house. Shovels and hand tools were used to remove contaminated snow from tundra surface. Contaminated snow was placed into hopper bins for temporary storage and transport to D-Pad to be melted and sent to MPU Clarifier water recycle. Contaminated gravel was sent to the Grind and Inject facility for disposal.
10-Mar-03	Produced Water	3	Y	While taking returns from pigging T-14 H2O header to portable tank, a leak developed in the chicsan tee hammer union, causing a produced water spill.	None. All contaminated material was removed from the spill site.	Purchase new style of o-ring inserts for the chicsans that have metal backing for extra strength.	Heavy equipment and hand tools were used to shovel and scrape the contaminated gravel pad. Shovels were used to remove the contaminated material on snow covered tundra.

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
18-Jul-03	Crude Oil	168	Y	During dewatering operations at the B pad reserve pit, the 400 bbl. tank that reserve pit water was being pumped into overflowed to the point that hydrocarbons floating on top flowed out of the tank roof vent and were blown outside the secondary containment berm onto the gravel pad and to the tundra by 15 mph winds that were gusting to 20-25 mph. Dewatering equipment inside the secondary containment was also contaminated with hydrocarbons. The primary cause of this spill was the operator's inattention to dewatering operations and not observing the tank level gauge indicator.	Minimal due to a diminimus quantity of oil lightly misting over tundra and ponds adjacent to the pad, an area approximately 100'x100'.	Review dewatering procedure MCD 99-031 with dewatering operations personnel prior to continuation of dewatering operations. While dewatering tanks are being filled from either reserve pits via trash pumps or vac trucks, dewatering operations personnel will not be allowed to leave "line of sight" of dewatering tanks or pumps unless they are relieved by trained dewatering operations personnel who are trained to monitor tank levels and pumping operations. Tank filling operations will be shut down and safed out if dewatering operations personnel are unavailable to monitor tank levels. No exceptions will be allowed. MCD 99-031 Annual Dewatering Procedure will be revised to reflect this requirement.	The SRT was activated and responded to the spill to initiate spill clean up actions. Heavy equipment was utilized to remove contaminated gravel from the pad. Sorbents were used to clean contaminated equipment and surrounding structures. A diminimus quantity of oil lightly misted over the adjacent tundra resulting in a very light sheen on ponded water. Sorbent boom was placed in the ponds to prevent migration of sheen from pond to pond. Written approval was issued by ADEC to use sorbent material to remove sheen from ponded water.
3-Nov-03	Diesel	90	N	Slickline crew working on well S-22 allowed bleed trailer to overflow and leak diesel on gravel pad. Established procedures for bleeding lubricator into bleed trailer not followed.	None. All contaminated material was promptly removed from the spill site.	Reinforce importance and requirement of following previously established procedures for bleeding wireline lubricator into bleed trailer. Further reinforce buddy system of more experienced workers checking work quality of lesser experienced workers.	A vacuum truck was used to remove fluid caught in secondary containment attached to the bleed trailer. Contaminated snow and gravel was removed from the site using a front end loader and hand tools.
26-Nov-03	Produced Water	120	N	High point bleed valve developed leak in valve stem spraying fine mist of produced water onto piping. Mist froze and created large icicle hanging from piping. icicle was knocked down into dumpster to remove falling ice hazard.	None. Spilled produced water was contained to the snow covered gravel and/or frozen to pipework.	Repair faulty fitting.	Contaminated snow and ice found on the gravel pad was chipped up and shoveled into a storage bin. Produced water found frozen on pipe arch was chipped off and placed in storage bin.
6-Dec-03	Produced Water	4830	N	Failure of the PU-0801 Turbine resulted in complete plant shut down. This had a direct affect on operation of Vessel 5417 and Pump 5432, causing high levels in V-5417 and release of produced water through PVIO-5434 into the containment pond. Additionally, the incident resulted in intermittent black smoke during facility depressurization and while restarting the facility.	None. All contents spilled were confined to containment pond.	The facility operations and maintenance departments will be working with the manufacturer of the turbine to determine the root cause of the malfunction that caused the plant shutdown.	Produced water spilled into containment was removed using a vacuum truck.
31-Dec-03	Hydraulic Fluid	130	N	While testing BOP's shut choke HCR valve hose failed losing 130 gallons oil in cellar.	None. All of the spilled material was caught in secondary containment.	Evaluate condition of all BOP hoses and replace as needed.	Skimmed out of cellar with air pump.

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
4-Dec-04	Produced Water	590	N	Well C-42 had been shut in for a pressure falloff. The well had been freeze protected and the injection header and s-riser to C-42 had heat trace and is not normally freeze protected. The S-Riser heat trace was working but the injection header froze, causing the pipe to burst. After energizing the heat trace on the header the frozen fluid thawed out and leaked out the ruptured line and into the reserve pit. Header was open to process system to keep any pressure from building up while waiting for heat trace to thaw line.	None. All contaminated material was contained on the gravel pad and inside the reserve pit.	Incident under investigation.	A spill clean up and disposal plan will be discussed with ADEC during site visit to Milne Point to inspect the spill site. Ultimately the contaminated material will be melted and sent to the MPU production facility for recycle.
16-Feb-05	Crude Oil Produced Water	84 1116	N	After finishing sand jet operations, personnel closed valves. A vac truck driver later notified the onsite personnel that the tank was overfilling. One of the downstream valves was found to be partially open. One of the upstream valves was found to be partially open. One of the upstream valves was found to be letting flow through in the closed position.	None. All of the affected area was in secondary containment.	Install new valves in the system and review the procedure with employees.	Hot water and a vacuum truck.
14-Mar-05	Produced Water	126	N	Booster Pump #2 inside Module 26 at C-Pad was found to have a seal leak between the electric motor and the pump during start up operations.	None. All produced water was contained inside the module on the floor.	Replace failed seal on booster pump.	Vacuum units, mops and hand tools were used to clean up spill from module floor.
22-Jul-05	Crude Oil	0 06	Y	While changing out a valve at the Tract 14 intersection, a cup of oil ran down the VSM and floated on the water in the ditch at the intersection.	None. All of the affected area was cleaned up immediately.		Used sorbent material to clean up the affected area.
18-Oct-05	Produced Water	90	N	During mid-summer the 07 & 08 turbine sump line heat trace and insulation was removed to do project work. The line remained in service throughout most the project as it is needed for turbine operation and is part of a larger collection system. On Oct 18, around noon, the heat trace was returned to service. Later that afternoon, the Area Operator noticed oil/water leaking from under the insulation jacket along the common header. The line was isolated and blinded. It appears the line had frozen over the last couple of weeks, and when the heat trace was returned to service the line thawed/split, leaking fluid onto the pad.	The spilled material was confined to the gravel pad beneath the elevated production facility. The contaminated materials will be removed from the site.		Free liquids will be vacuumed up and recycled through the production facility. Contaminated gravel will be removed with hand tools and supersucker (vacuum) truck and sent to GPB's Grind & Inject Facility for disposal. Oily waste and debris will be bagged and shipped off-site and incinerated.
30-Mar-06	Diesel	5	Y	Bus diesel fuel filter failed, resulting in a 5 gal. spill on ROW ice road.	Tundra damage in an area about 6 foot by 6 foot.	Maintenance procedures will be reviewed with employees in their safety meetings.	Area affected was cleaned up using hand tools and a bucket loader.
8-Feb-07	Produced Water	1050	N	At 10:15 PM on 2/8/07 at MPU C Pad, the produced water injection flow line began to leak following a freezing event from failed heat trace. The location of the line failure in the pipe was behind the C-17 well house in the pipe rack. The heat trace was written up on 10/19/2006 and C-19 was swapped to gas on 11/30/06. The dead leg of water pipe froze sometime after the well was swapped to gas injection. It remained frozen until the C-19 well was swapped back to water on 2/02/07. The heat trace was evaluated and verified to be out of service from the C-17 area to the C-19 well (150-170 ft). Repairs were made in the early evening of 2/8/2007. About 3 hours later the pipe was thawed enough to allow water to reach the first split section of the pipe. The pumps at the Pad went into a high flow rate condition and shut down on flow alarm High High. The Pad operator immediately recognized the situation to be a flow line failure and secured all the water to the Pad. The spill was reported via the proper channels.	None. No water or tundra was affected. Receiving environment is an active reserve pit.		Uncontaminated snow will be managed according to normal snow removal practices. Once the contaminated snow is reached, it will be removed using heavy equipment and hand tools and taken to a snow melter or storage bins for melting.
16-Feb-07	Hydraulic Fluid	0.42	Y	A loader operator had just finished loading a dump truck with snow for ice road work. After the dump truck left the area the operator noticed a dark spot on the ground. The operator repositioned the loader to cast the lights on the spot and saw that it appeared to be hydraulic oil. The operator immediately shut down the loader and placed containment under the unit and made notifications.	None. All of the affected area was clean up completely.		The area was cleaned up using a bucket loader and hand tools.

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
3-Mar-07	Produced Water	2500	N	Operations received a high level alarm in the control room from sand slurry vessel V-5317. Pump P-5432 automatically started and the discharge was open per process logic to pump the vessel level down. Several minutes later the control room received a high high alarm and requested area operator to investigate. As the area operator was responding, control room received a tank level not declining alarm and one minute later received an overflow alarm. Area operator found motor running but pump appeared to be running with reverse flow and tank was overflowing into containment. Pump P-5432 was shut down and isolated, tank overflow ceased. Pump P-5432 has a history of cavitation during start-up and has been under engineering review. A check valve between the pump and discharge valve was inspected and the cotter key and nut were loose. The failed check valve attributed to the process upset but root cause is believed to be excessive vibration from the pump over the last several months causing the check to rattle apart.	None. All fluids were contained in impermeable secondary containment.	Equipment repaired and placed back in to service.	Fluids were recovered via vacuum truck.
26-Mar-07	Lube Oil	0.84	Y	Pinhole in oil cooler on seismic equipment released 1 gallon to snow covered tundra. The spill was confined to a drip approximately 3740 linear feet in length.	None. All contaminated snow was recovered from snow covered tundra and lake ice.	PGS seismic crew instructed to perform more rigorous field inspections on equipment.	Contaminated snow cleaned up with hand tools.
31-Mar-07	Diesel	55	N	During an MIT, a leak developed in the production casing, resulting in a 55 gallon diesel spill into the cellar.	None. No tundra or water was affected.	Will place temporary cellar liners in mono-bore completions prior to future MITIAs to minimize gravel contamination in the event of a re-occurrence.	Contaminated gravel will be recovered via super sucker and disposed of at G&I.
8-Apr-07	Motor Oil	0.03	Y	A loose transmission filter leaked approximately 0.03 gallons of 0-30 weight oil to snow covered tundra. The transmission oil filter was dented, possibly by the filter wrench during installation, and developed a leak. The transmission filter is mounted near the wall of the dog house and when the seepage developed, a small amount of the oil dripped down the wall and escaped containment. A routine walk-around inspection detected the leak.	None. All of the affected area was cleaned up completely.	Inspect all filters on the vibrators for dents and leaks. Replace as necessary. Remind all mechanics to take care during filter installation and to replace any filters that have been dented or crushed.	Used hand tools to clean up the affected area. Spilled oil was immediately shoveled into one oily waste bag. The contaminated snow will be taken to camp and transferred to the appropriate SAA site.
9-Apr-07	Diesel	100	N	An inspection of the secondary containment of the F string generator found about twenty-seven inches of standing diesel fuel in the secondary containment of the double walled tank (approximately 100 gallons of diesel fuel). Spills to containment may have occurred during fueling operations and, on a couple of occasions, the fuel cap was not secured after the fueling operation was complete. Fuel spilled from the tank to containment during subsequent camp moves.	None. All fluids remained within secondary containment.		Containment to be drained into 55 gal drums using pump and duck pond.
9-Apr-07	Diesel	130	N	The return line in the diesel tank for the C string generator was broken which caused approximately 130 gal of diesel fuel to enter the secondary containment of the double walled tank. During a camp move 3/3/07 the return line in the diesel tank for the generator that supplies power to C string was broken. The result of the break was a leak of appx. 200 gallons of fuel to the secondary containment. The cause of the break was general wear and tear caused by vibration during the move. The first attempt to pump out the contents took place 3/3/07. The mechanics were lacking the proper gear to complete the pump out process. The stem pipe was replaced. There was fuel remaining in the containment. Appx 130 gals were removed 4/9.	None. All fluids remained within secondary containment.		Containment was drained into two 55 gal drums using pump and duck pond.
3-May-07	Diesel	80	N	The fuel hose on the discharge side of the electric fuel pump developed a crack due to vibration and cold.	None.	MPU is inspecting the hoses on other similar heaters.	Fluids were recovered via hand pumps.
6-May-07	Produced Water	56	N	The tubing line coming off a water injection pump failed from internal erosion.	None. All of the affected area was inside the building.	Under investigation.	Used hand tools to clean the affected area.

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
24-May-07	Lube Oil	0.0001	Y	Transmission oil leaked from a vehicle commingled with melting ice and water from the CFP pad causing a slight sheen to be carried off the pad during the spring break-up.	Minimal impact to tundra.	Vehicle sent for repairs.	Sorbent booms were utilized to recover sheen floating off pad. Contaminated snow and ice in the area in which the spill occurred was recovered using heavy equipment and hand tools.
23-Jun-07	Lube Oil	0.42	Y	Wells Support Rig truck 4028 was sent to Milne Point, J-Pad. When the driver was entering the pad he noticed the steering felt different. He parked on the edge of the pad, placed containment under the truck and opened the engine covers to check the power steering. He noticed power steering fluid leaking from the steering pump and called the base shop for a mechanic. When the mechanic arrived, he found a threaded plug had come loose. The mechanic fixed the plug, refilled the power steering reservoir. The mechanic asked the driver to turn the wheel, and upon doing so, the steering gear box over pressured and cracked. This resulted in a release of power steering fluid. Most of the release went into the containment under the truck; one quart of fluid went on the ground. A small mist of fluid went off the pad and into the tundra, resulting in a sheen on the water. Notifications were made and Milne Point SRT responded. This is classified as a spill because of the release to the tundra.	None. All affected areas were cleaned up immediately.	Vehicle was taken for repairs.	Contaminated gravel was recovered using hand tools and heavy equipment. Sheen on water was recovered using absorbent booms.
29-Jun-07	Motor Oil	0.001	Y	Summer trash clean-up crew found an oily absorbent on the tundra off of Milne Point Road. Absorbent pad had apparently blown out of a vehicle causing an oil sheen (approximately 3" in circumference) on tundra.	None. Affected area was cleaned up.	Discuss importance of properly securing/handling oily waste with personnel at HSE and ATP meetings.	Hand tools were utilized to scrape effected area.
2-Nov-07	Produced Water	75	N	While doing a jet wash transfer, a seal failed in the transfer pump.	None. All of the produced water was contained within the facility.	Under investigation.	Used a vacuum and sorbent to clean the affected area.
15-Jul-08	Diesel Hydraulic Fluid	0.42 0.84	Y Y	AES O & M was moving a crane (183-002) from A Pad to F Pad. Employee stated they tried to stay right of the roadway because of the traffic. Employee had a moment of dizziness, took a drink of water while the crane was still traveling down the road, and felt better. Employee stated that all of a sudden they felt the right front tire of crane start sinking into the soft soil at the right side of the roadway between L Pad and F Pad. Employee tried to get the right front tire back onto the roadway, but could tell the crane was going to continue to go off the road. When the crane got close to the bottom of the embankment, the top heavy crane rolled over on its right side, causing property damage, a spill of hydraulic fluid, diesel and glycol and a first aid injury.	Minimal. Slight amount of tundra damage that it is estimated to be 4 square feet.		Used hand tools, weed burner and heavy equipment to clean up the affected area.
21-Sep-08	Crude Oil Produced Water	0.125 0.84	Y	Employees were inserting coupons in the flow line. After removing the valve off the plug, there was some evidence of dirt and debris between the plug packing and the seal causing a drip. The plug was tightened to stop the drip (produced water), some escaped on to the tundra (pond) ~0.5 cup. SRT was notified and cleanup initiated immediately.	None. All of the affected area was cleaned up immediately.	Dirt and debris were cleaned and the plug tightened.	Used sorbent to clean the water. Used hand tools to clean up the affected gravel and tundra.
7-Nov-08	Produced Water	90	N	A water injection pump seal failure resulted in a spill of 90 gallons of produced water with a trace of crude in Module 54. The spill was totally contained within the module.	None. All of the product was contained in the module.	The pump seal was replaced.	Produced water was cleaned up with hand tools and recycled back into the facility.
12-Jan-09	Crude Oil Produced Water	4048 5712	N	There was a produced water/crude oil spill from the Sand Slurry vessel. It appears that an I/O (input/output) automation module failed, resulting in a communication failure (control logic failure), preventing the necessary pump and valves to respond as required. The tank overflowed into the secondary containment, which is designed to contain approx. 155 bbls of fluid. When the Control Room Operators saw the alarms, they expedited the area operators to investigate and manually close valves to isolate the Sand Slurry vessel process. The source was isolated in 15 to 25 minutes; however, during this time, the secondary containment filled and overflowed onto the ground and under module 54, covering an area of approx. 6000 square feet. The response team was activated immediately. They constructed a snow and gravel berm to contain the spill.	None. All the material was contained on the gravel pad.	Valves were manually closed to stop the release. The /O automation module was replaced and tested prior to the system being put back in service. A second level of protection (hardwired interlock) was added to remove power to all V-5417 inlet valves.	

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
10-Feb-09	Lube Oil	80	N	Power was lost to C-Pad and IWAG II shut down. A heater was delivered and installed in the building to keep the temperature of the building. Once power was restored to C-Pad the IWAG was started. The leak was discovered @ 20:00. the machine was shut down and enviro was called.	None. All of the oil was contained within the module.	Readjust control system.	Used warm water to clean the affected area.
27-Feb-09	Diesel	84	N	A 75 gallon day tank overflowed into a generator skid and into secondary containment due to an unattended fluid transfer at Texaco Pad. When the fueler noted the overflow, the fuel pump and transfer was shut down.	None. This release was totally contained within the skid and secondary containment under the skid.		All fluids and melted contaminated snow were recovered using a Vac Truck.
9-Apr-09	Produced Water	378	N	For the final clean-up of the V-5417 crude oil/produced water spill, timbers were removed from the north side of the containment to evaluate how far contamination had migrated beneath and behind the timber wall. After the timbers were removed and the liner examined, it was discovered that the liner was frozen to the ground. The decision was made to add approximately 9 inches of produced water in the containment area to melt the snow and thaw the liner. Prior to adding the produced water, the employees checked the wall without the timbers for integrity and it was frozen solid. 20 minutes later when the vac truck driver began to remove fluids the employees heard the wall collapse and observed the water escape out of the liner. In addition to melting the snow, the warmth of the produced water caused the frozen liner to become soft and pliable and lose its support properties.	None, all of the free fluid was vacuumed up immediately.	Require risk assessments for all spill clean-up activities and work impacting stationary secondary containment.	Free fluid was vacuumed up immediately. 100% of the affected area has been cleaned up using hand tools and equipment.
24-Apr-09	Motor Oil	0.84	Y	Employee was completing spring snow removal under central creek bridge with BP D-6 Cat Dozer number 56-5101. While pushing snow forward with the dozer, the employee noticed oil spray on snow. Employee immediately shut dozer off, and placed containment under the engine where the oil was leaking. Employee made appropriate notifications. It was determined by BP Environmental that there was less than 1 gallon of oil released. Upon further investigation by the MPU fleet shop, the spill was caused by an injector pump failure.	None. All spilled fluids were recovered.		All contaminated snow was recovered using shovels and hand tools.
9-Aug-09	Produced Water	0.84	Y	A small volume of produced water was noticed on the ground below the 8" produced water isolation valve entering E-Pad. The location of the valve is just at the edge of the pad. The produced fluid hit the gravel of the pad and into a small pond along the edge of the pad. The valve was in the closed position. The valve had just been closed for a pigging run. The blanket surrounding the valve was removed and there was evidence of a leak, but the valve was not leaking at that time. The valve needed to be reopened to return injection to the pad. No leak was noticed when opening or when the valve was in the full open position.	None. All spilled fluids were recovered.	Replace the valve.	Used sorbent material to clean up free material. Removed approx 2 cu ft of contaminated gravel with hand tools.
10-Oct-09	Produced Water	130	N	Bullseye sight glass broke inside mod 54, and produced water leaked onto module floor while sand jetting. Operator closed valve to isolate spill.	None.	Replace both bullseyes (sight glasses) with pipe spools.	Utilized pneumatic shop vac and squeegees to recover free standing fluid and placed back into production stream. Wiped up residuals w/ rags and placed into oily waste dumpster. Used mops and water w/ bucket for final cleanup.
28-Feb-10	Produced Water	120	N	Operator was making rounds and entered module 8004 on S-pad. Operator immediately noticed water on floor, found the leak, and shut a block valve to stop the leak. Operator called to report the leak.	None.	Replace faulty section of pipe. Pressure test and X-ray new pipe/weld. Will x-ray all similar pipe welds in the module. The pipe spool was replaced on 3/05/10.	Fluid was removed with a vacuum truck and residual fluid was mopped up with absorbent material.

APPENDIX C
MPU SPILL HISTORY TABLE
JANUARY 1994 THROUGH SEPTEMBER 2010

Date	Material	Gallons	Water / Tundra	Event Description	Environmental Impact	Preventative Action	Clean-Up Action
12-Apr-10	Diesel	147	N	Fueler found A Pad shop heater # 89-5514 with an overflow from its containment. Fueler notified A Pad mechanic crew who secured site and controlled spill. Shop foreman contacted MPU Environmental which responded and cleaned up small spill of diesel.	None. All contaminated material 100% recovered.	The containment area for A Pad's heater unit #89-5514 will be visually checked at the end of each shift when it is being run continually for emergency response purposes.	Environmental recovered 145.5 gallons from containment with transfer pump. All contaminated snow and gravel was recovered, using a loader, chipping bar and shovels.

APPENDIX D

OPA 90 ADDENDUM

U.S. Environmental Protection Agency

Spill Prevention, Control, and Countermeasures Plan

MILNE POINT UNIT SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PLAN

TABLE OF CONTENTS

SPCC PLAN FIVE-YEAR REVIEW	SPCC-iii
CROSS REFERENCE TO U.S. ENVIRONMENTAL PROTECTION AGENCY SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PLAN REQUIREMENTS	SPCC-1
CONFORMANCE TO 40 CFR 112.7, GENERAL REQUIREMENTS FOR SPCC PLANS	SPCC-11
General Conformance, 40 CFR 112.7(a)	SPCC-11
Potential Oil Discharges, 40 CFR 112.7(b)	SPCC-12
Oil Spill Containment, 40 CFR 112.7(c)	SPCC-12
Bulk Storage Containers Greater than 10,000 Gallons	SPCC-12
Bulk Storage Containers 55 Gallons to 10,000 Gallons	SPCC-13
Empty Bulk Storage Containers	SPCC-13
Totes and Drums	SPCC-13
Oil Transfer Areas	SPCC-13
Flow-Through Process Vessels	SPCC-14
Trailered Equipment ("Non-Mobile" Fleet)	SPCC-14
Tank Vehicles (Mobile Refuelers and Other Non-Transportation-Related Tank Trucks)	SPCC-14
Sumps	SPCC-15
Oil-Filled Equipment	SPCC-15
Oil Pipelines (Flowlines and Intra-Facility Gathering Lines)	SPCC-15
Spill Containment Impracticability, 40 CFR 112.7(d)	SPCC-15
Inspections, Tests, and Records, 40 CFR 112.7(e)	SPCC-15
Training, 40 CFR 112.7(f)	SPCC-16
Security (Excluding Oil Production Facilities), 40 CFR 112.7(g)	SPCC-16
Loading Racks, 40 CFR 112.7(h)	SPCC-17
Field-Constructed Aboveground Tank Repair, Modification or Change in Service, 40 CFR 112.7(i)	SPCC-17
Qualified Oil-Filled Equipment, 40 CFR 112.7(k)	SPCC-17
CONFORMANCE TO 40 CFR 112.8, REQUIREMENTS FOR ONSHORE FACILITIES (EXCLUDING PRODUCTION FACILITIES)	SPCC-17
General Requirements, 40 CFR 112.8(a)	SPCC-17
Facility Drainage, 40 CFR 112.8(b)	SPCC-17
Bulk Storage Containers, 40 CFR 112.8(c)	SPCC-17
Facility Transfer Operations, Pumping, and Facility Process, 40 CFR 112.8(d)	SPCC-19
CONFORMANCE TO 40 CFR 112.9, REQUIREMENTS FOR ONSHORE OIL PRODUCTION FACILITIES	SPCC-19
Drainage, 40 CFR 112.9(b)	SPCC-19
Bulk Storage Containers, 40 CFR 112.9(c)	SPCC-19
Facility Transfer Operations, 40 CFR 112.9(d)	SPCC-20
CONFORMANCE TO 40 CFR 112.10, REQUIREMENTS FOR ONSHORE DRILLING AND WORKOVER FACILITIES	SPCC-20
SPCC PLAN RECORD OF REVISIONS	SPCC-37

**MILNE POINT
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN
U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL, AND COUNTERMEASURE (SPCC) PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 112.10]**

SPCC PLAN FIVE-YEAR REVIEW

I have completed review and evaluation of the SPCC Plan for the Milne Point Unit, and will not amend the Plan to include more effective technology.

NAME	TITLE	DATE	SIGNATURE
Michael T. Bronson	Crisis Management Coordinator	March 25, 2007	

**MILNE POINT UNIT
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN**

**CROSS REFERENCE TO
U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PLAN
REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]**

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.7	General Requirements for Spill Prevention, Control and Countermeasure (SPCC) Plans	
112.7(a)(1)	Include a discussion of facility's conformance with the requirements listed in this section.	This section
112.7(a)(2)	(2) Comply with all applicable requirements listed in this part. Except as provided in §112.6, your Plan may deviate from the requirements in paragraphs (g), (h)(2) and (3), and (i) of this section and the requirements in subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.9(d)(3), 112.10(c), 112.12(c)(2), and 112.12(c)(11), where applicable to a specific facility, if you provide equivalent environmental protection by some other means of spill prevention, control, or countermeasure. Where your Plan does not conform to the applicable requirements in paragraphs (g), (h)(2), and (3), and (i) of this section, or the requirements of subparts B and C of this part, except the secondary containment requirements in paragraph (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11), you must state the reasons for nonconformance in your Plan and describe in detail alternate methods and how you will achieve equivalent environmental protection. If the Regional Administrator determines that the measures described in your Plan do not provide equivalent environmental protection, he may require that you amend your Plan, following the procedures in §112.4(d) and (e).	This section
112.7(a)(3)	(3) Describe in your Plan the physical layout of the facility and include a facility diagram, which must mark the location and contents of each fixed oil storage container and the storage area where mobile or portable containers are located. The facility diagram must identify the location of and mark as "exempt" underground tanks that are otherwise exempted from the requirements of this part under §112.1(d)(4). The facility diagram must also include all transfer stations and connecting pipes, including intra-facility gathering lines that are otherwise exempted from the requirements of this part under §112.1(d)(11). You must also address in your Plan:	This section; Volume 1, Sections 1.8 and 3.1.5.; Volume 2, Appendix B.
112.7(a)(3)(i)	(i) The type of oil in each fixed container and its storage capacity. For mobile or portable containers, either provide the type of oil and storage capacity for each container or provide an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities.	This section and Volume 2, Section 3.1.2; Table 3-1 and Appendix A.
112.7(a)(3)(ii)	Discharge prevention measures including procedure for routine handling of products (loading, unloading, and facility transfers, etc.).	Volume 2, Sections 2.1.1, 2.1.4 through 2.1.8, 2.3, 2.4, 2.5, 3.1.3, 4.7; Tables 2-8, 3-1, 4-5 and Appendix A.
112.7(a)(3)(iii)	Discharge or drainage controls such as secondary containment around containers and other structures, equipment, and procedures for the control of a discharge.	This section; Volume 1, Sections 1.6.4, 3.6.1, 3.6.3, 3.8, Tables 1-6 through 1-27; Volume 2, Section 2.1.5, 2.1.6, 2.1.9, 3.1.3, Table 3-1, and Appendix A.

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.7(a)(3)(iv)	Countermeasures for discharge discovery, response, and cleanup (both the facility's capability and those that might be required of a contractor).	This section; Volume 1, Part 1, Sections 3.3 through 3.9, Tables 1-1 through 1-28 and 3-3 through 3-8; Figures 1-1 and 1-2; Volume 2, Sections 2.1.9, 2.5, and 4.1
112.7(a)(3)(v)	Methods of disposal of recovered materials in accordance with applicable legal requirements.	Volume 1, Section 1.6.3
112.7(a)(3)(vi)	Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with whom you have an agreement for response, and all appropriate Federal, State and local agencies who must be contacted in case of a discharge as described in Section 112.1(b).	Volume1, Sections 1.1, and 1.2; Tables 1-1, 1-2, and 1-3
112.7(a)(4)	Unless you have submitted a response plan under Section 112.20, provide information and procedures in your Plan to enable a person reporting a discharge as described in Section 112.1(b) to relate information on the exact address or location and phone number of the facility; the date and time of the discharge, the type of material discharged; estimates of the total quantity discharged; estimates of the quantity discharged as described in Section 112.1(b); the source of the discharge; a description of all affected media; the cause of the discharge; any damages or injuries caused by the discharge; actions being used to stop, remove, and mitigate the effects of the discharge; whether an evacuation may be needed; and the names of individuals and/or organizations who have also been contacted.	Not applicable. The response plan has been submitted and approved.
112.7(a)(5)	Unless you have submitted a response plan under Section 112.20, organize portions of the Plan describing procedures you will use when a discharge occurs in a way that will make them readily usable in an emergency, and include appropriate supporting material as appendices.	This section
112.7(b)	Where experience indicates a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of a discharge), include in your Plan a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure.	This section; Volume 1 Section 1.6.4 and Part 5, Tables 1-6, 1-11, 1-16, and 1-21; Figures 1-4 through 1-7; Volume 2, Section 2.3 and 4.3
112.7(c)	(c) Provide appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in §112.1(b), except as provided in paragraph (k) of this section for qualified oil-filled operational equipment, and except as provided in §112.9(d)(3) for flowlines and intra-facility gathering lines at an oil production facility. The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank, will not escape the containment system before cleanup occurs. In determining the method, design, and capacity for secondary containment, you need only to address the typical failure mode, and the most likely quantity of oil that would be discharged. Secondary containment may be either active or passive in design. At a minimum, you must use one of the following prevention systems or its equivalent: (1) For onshore facilities: (i) Dikes, berms, or retaining walls sufficiently impervious to contain oil; (ii) Curbing or drip pans; (iii) Sumps and collection systems; (iv) Culverting, gutters, or other drainage systems; (v) Weirs, booms, or other barriers; (vi) Spill diversion ponds; (vii) Retention ponds; or (viii) Sorbent materials. (2) For offshore facilities: (i) Curbing or drip pans; or (ii) Sumps and collection systems.	This section; Volume 2, Sections 2.1.9, 2.5, 3.1.2, and 3.1.3; Tables 3-1 and Appendix A.

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.7(d)	(d) Provided your Plan is certified by a licensed Professional Engineer under §112.3(d), or, in the case of a qualified facility that meets the criteria in §112.3(g), the relevant sections of your Plan are certified by a licensed Professional Engineer under §112.6(d), if you determine that the installation of any of the structures or pieces of equipment listed in paragraphs (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11) to prevent a discharge as described in §112.1(b) from any onshore or offshore facility is not practicable, you must clearly explain in your Plan why such measures are not practicable; for bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; and, unless you have submitted a response plan under §112.20, provide in your Plan the following:	
112.7(d)(1)	(1) An oil spill contingency plan following the provisions of part 109 of this chapter.	ODPCP
112.7(d)(2)	A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.	Management Approval and Manpower Authorization Form, page i.
112.7(e)	Conduct inspections and tests required by this part in accordance with written procedures that you or the certifying engineer develop for the facility. You must keep these written procedures and a record of the inspections and tests, signed by the appropriate supervisor or inspector, with the SPCC Plan for a period of three years. Records of inspection and tests kept under usual and customary business practices will suffice for purposes of this paragraph.	This section and Volume 2, Sections 2.1.7 through 2.1.10, 2.5.3, 2.5.5, 2.5.6 and 2.5.7; Tables 2-3, 2-6, 3-1, and Appendix A
112.7(f)(1)	At a minimum, train your oil-handling personnel in the operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and the contents of the facility SPCC Plan.	This section and Volume 1, Section 3.9 Tables 3-6 and 3-7; and Volume 2, Section 2.1.1
112.7(f)(2)	Designate a person at each applicable facility who is accountable for discharge prevention and who reports to facility management.	This section
112.7(f)(3)	Schedule and conduct discharge prevention briefings for your oil-handling personnel at least once a year to assure adequate understanding of the SPCC Plan for that facility. Such briefings must highlight and describe known discharges, as described in Section 112.1(b), or failures, malfunctioning components, and any recently developed precautionary measures.	This section and Volume 2, Section 2.1.1
112.7(g) 112.7(a)(2)	Describe in your Plan (excluding oil production facilities) how you secure and control access to the oil handling, processing and storage areas; secure master flow and drain valves; prevent unauthorized access to starter controls on oil pumps; secure out-of-service and loading/unloading connections of oil pipelines; and address the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges.	This section and Volume 2, Section 2.1.4
112.7(g)(2)	(2) Ensure that the master flow and drain valves and any other valves permitting direct outward flow of the container's contents to the surface have adequate security measures so that they remain in the closed position when in non-operating or non-standby status.	This section and Volume 2, Sections 2.1.5; 2.1.8; and 2.1.10
112.7(g)(3)	(3) Lock the starter control on each oil pump in the "off" position and locate it at a site accessible only to authorized personnel when the pump is in a non-operating or non-standby status.	This section and Volume 2, Section 2.1.4
112.7(g)(4)	(4) Securely cap or blank-flange the loading/unloading connections of oil pipelines or facility piping when not in service or when in standby service for an extended time. This security practice also applies to piping that is emptied of liquid content either by draining or by inert gas pressure.	This section and Volume 2, Sections 2.1.5; 2.1.7 and 2.1.10
112.7(g)(5)	(5) Provide facility lighting commensurate with the type and location of the facility that will assist in the:	This section and Volume 2, Section 3.1.1

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.7(g)(5)(i)	(i) Discovery of discharges occurring during hours of darkness, both by operating personnel, if present, and by non-operating personnel (the general public, local police, etc.); and	This section and Volume 2, Section 3.1.1
112.7(g)(5)(ii)	(ii) Prevention of discharges occurring through acts of vandalism.	This section and Volume 2, Section 3.1.1
112.7(h)(1)	Where loading/unloading rack drainage does not flow into a catchment basin or treatment facility designed to handle discharges, use a quick drainage system for tank car or tank truck loading/unloading racks. You must design any containment system to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.	Not applicable. MPU does not have loading/unloading racks.
112.7(h)(2)	Provide an interlocked warning light or physical barrier system, warning signs, wheel chocks, or vehicle brake interlock system in the area adjacent to a loading/unloading rack to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines.	Not applicable. MPU does not have loading/unloading racks.
112.7(h)(3) 112.7(a)(2)	Prior to filling and departure of any tank car or tank truck, closely inspect for discharges the lowermost drain and all outlets of such vehicles, and if necessary, ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit OR provide equivalent method of environmental protection.	Not applicable. MPU does not have loading/unloading racks.
112.7(i) 112.7(a)(2)	If a field-constructed aboveground container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a discharge or failure due to brittle fracture, or has discharged due to brittle fracture or other catastrophe, evaluate the container for risk of discharge and take appropriate action OR state reasons for non-conformance and provide equivalent environmental protection.	This section
112.7(j)	In addition to the minimal prevention standards listed under this section, include in your Plan a complete discussion of conformance with the applicable requirements and other effective discharge prevention and containment procedures listed in this part or any applicable more stringent State rules, regulations, and guidelines.	Volume 2, Part 2
112.7(k)	The owner or operator of a facility with oil-filled operational equipment that meets the qualification criteria in paragraph 112.7(k)(1) of this sub-section may choose to implement for this oil-filled operational equipment the alternate requirements as described in paragraph 112.7(k)(2) of this sub-section in lieu of general secondary containment required in 112.7(c) of this section.	This section
112.7(k)(1)	The owner or operator of a facility that has had no single discharge as described in 112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons, or no two discharges as described in 112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons within any 12-month period in the three years prior to the SPCC Plan certification date, or since becoming subject to this part if the facility has been in operation for less than three years (other than oil discharges as described in 112.1(b) that are the result of natural disasters, acts of war, or terrorism).	This section
112.7(k)(2) 112.7(k)(2)(i) 112.7(k)(2)(ii)	If secondary containment is not provided for qualified oil-filled operational equipment pursuant to paragraph 112.7(c), the owner or operator of a facility with qualified oil-filled operational equipment must (i) establish and document the facility procedures for inspections or a monitoring program to detect equipment failure and/or a discharge; and (ii) unless you have submitted a response plan under Section 112.20, provide in your plan an oil spill contingency plan and (iii) a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.	This section
112.8	Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).	
112.8(a)	Meet the general requirements of the plan listed under Section 112.7, and the specific discharge prevention and containment procedures listed in this section.	This section

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.8(b)(1)	Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting to ensure no oil will be discharged.	This section and Volume 2, Section 2.1.9
112.8(b)(2)	Use valves of manual open-and-closed design for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, as provided in paragraphs 112.8(c)(3)(ii), (iii), and (iv).	Not applicable. Diked areas are emptied by vacuum trucks or sumps.
112.8(b)(3)	Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.	This section and Volume 2, Section 3.1.1
112.8(b)(4)	If facility drainage is not engineered as in paragraph 112.8(b)(3), equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.	This section
112.8(b)(5)	Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two "lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in Section 112.1(b) in case there is an equipment failure or human error at the facility.	Not applicable. Drainage waters are not treated.
112.8(c)(1)	Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.	This section; Volume 2, Section 2.1.8, and 3.1.2; Tables 3-1 and Appendix A.
112.8(c)(2)	Construct all bulk storage tank installations (except mobile refuelers and other non-transportation-related tank trucks) so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.	This section; Volume 1, Part 5; and Volume 2, Section 2.1.9, a; Tables 3-1 and Appendix A.
112.8(c)(3)	Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:	Not applicable. There are no storm drains or effluents from bypassed treatment systems.
112.8(c)(3)(i)	Normally keep the bypass valve sealed closed.	Not applicable. There are no drainage bypasses.
112.8(c)(3)(ii)	Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in Section 112.1(b).	This section
112.8(c)(3)(iii)	Open the bypass valve and reseal it following drainage under responsible supervision; and	Not applicable. There are no bypass valves.
112.8(c)(3)(iv)	Keep adequate records of such events, for example, any records required under permits issued in accordance with Sections 122.41(j)(2) and 122.41(m)(3) of this chapter.	Not applicable. No records required.
112.8(c)(4)	Protect any completely buried metallic storage tank installed on or after January 10, 1974, from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.	Not applicable. There are no completely buried tanks at this facility.

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.8(c)(5)	Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.	Not applicable. There are no partially buried tanks at this facility.
112.8(c)(6)	Test or inspect each aboveground container for integrity on a regular schedule, and whenever you make material repairs. You must determine, in accordance with industry standards, the appropriate qualifications for personnel performing tests and inspections, the frequency and type of testing and inspections, which take into account container size, configuration and design (such as containers that are: shop-built, field-erected, skid-mounted, elevated, equipped with a liner, double-walled or partially buried). Examples of these integrity tests include, but are not limited to: visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other systems of non-destructive testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this section.	This section; Volume 2, Sections 2.1.8 through 2.1.9, 2.5.2, and 2.5.7; Tables 2-6, 3-1, and Appendix A.
112.8(c)(7)	Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.	Not applicable. No internal heating coils operated in this manner at facilities regulated by this section.
112.8(c)(8)	Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:	This section, Volume 2, Sections 2.1.8, 2.5.5, and 4.7; Table 4-6
112.8(c)(8)(i) 112.7(a)(2)	High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. An audible air vent may suffice in smaller facilities.	Volume 2, Sections 2.1.8, 2.5.5, and 4.7; Table 4-6
112.8(c)(8)(ii)	High liquid level pump cutoff devices set to stop flow at a predetermined container content level.	Volume 2, Sections 2.1.8, 2.5.5, and 4.7; Table 4-6
112.8(c)(8)(iii)	Direct audible or code signal communication between the container gauger and the pumping station.	Volume 2, Sections 2.1.8, 2.5.5, and 4.7; Table 4-6
112.8(c)(8)(iv)	A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.	Volume 2, Sections 2.1.8, 2.5.5, and 4.7; Tables 4-6
112.8(c)(8)(v)	You must regularly test liquid level sensing devices to ensure proper operation.	This section and Volume 2, Section 2.1.8
112.8(c)(9)	Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in Section 112.1(b).	Not applicable. There are no effluent treatment facilities at this site.
112.8(c)(10)	Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.	This section
112.8(c)(11)	Position or locate mobile or portable oil storage containers to prevent a discharge as described in Section 112.1(b). Except for mobile refuelers and other non-transportation-related tank trucks, you must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.	This section and Volume 2, Section 2.1.9; Appendix B

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.8(d)(1)	Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in Part 280 of this chapter or a state program approved under Part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.	This section and Volume 2, Sections 2.1.10 and 4.8
112.8(d)(2)	Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.	This section and Volume 2, Section 2.1.10
112.8(d)(3)	Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.	This section and Volume 2, Section 2.1.10
112.8(d)(4)	Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.	Volume 2, Sections 2.1.7, 2.1.10, 2.5.2, 2.5.6, 2.5.7, and 2.5.9; Table 2-6
112.8(d)(5)	Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.	This section
112.9	Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil production facilities (excluding drilling workover facilities)	
112.9(a)	Meet the general requirements for the plan listed under 112.7, and the specific discharge prevention and containment procedures listed under this section.	This section
112.9(b)(1)	At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in Section 112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under Section 112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in Section 112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.	This section
112.9(b)(2)	Inspect field drainage systems, oil traps, sumps or skimmers for an accumulation of oil that may have resulted from a small discharge at regularly scheduled intervals.	This section
112.9(c)(1)	Not use a container for the storage of oil unless material and construction are compatible with the material stored and conditions of storage.	This section and Volume 2, Sections 2.1.8 and 3.1.2; Tables 3-1 and Appendix A
112.9(c)(2)	Except as provided in paragraph (c)(5) of this section for flow-through process vessels and paragraph (c)(6) of this section for produced water containers and any associated piping and appurtenances downstream from the container, construct all tank battery, separation and treating facility installations so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely contain drainage from undiked areas in a catchment basin or holding pond.	This section; and Volume 1, Part 5; and Volume 2, Section 2.1.9; Tables 3-1 and Appendix A
112.9(c)(3)	Except as described in paragraph (c)(5) of this section for flow-through process vessels and paragraph (c)(6) of this section for produced water containers and any associated piping and appurtenances downstream from the container, periodically and upon regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.	This section and Volume 2, Sections 2.1.8, 2.5.7, and 3.1.2; Tables 2-6, 3-1, and Appendix A

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.9(c)(4)	Engineer or update new and old tank battery installations in accordance with good engineering practice to prevent discharges. You must provide at least one of the following: (i) Container capacity adequate to assure container will not overflow if pumper/gauger is delayed in making regularly scheduled rounds, (ii) Overflow equalizing lines between containers so that full container can overflow into adjacent container, (iii) Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container, (iv) High level sensors to generate and transmit an alarm signal to the computer where facility is subject to computer production control system.	Not applicable. There are no tank batteries at MPU.
112.9(c)(5)	The owner or operator of a facility with flow-through process vessels may choose to implement the alternate requirements as described below in lieu of sized secondary containment required in paragraphs (c)(2) and (c)(3) of this section.	This section
112.9(c)(5)(i)	Periodically and on a regular schedule visually inspect and/or test flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge as described in Section 112.1(b).	This section
112.9(c)(5)(ii)	Take corrective action or make repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests or evidence of an oil discharge.	Volume 1, Section 1.1; Table 1-1
112.9(c)(5)(iii)	Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flow-through process vessels.	This section
112.9(c)(5)(iv)	If your facility discharges more than 1,000 U.S. gallons of oil in a single discharge as described in 112.1(b), or discharges more than 42 U.S. gallons in each of two discharges as described in 112.1(b) within any twelve-month period, from flow-through process vessels (excluding discharges that are the result of natural discharges, acts of war or terrorism) then you must, within six months from the time the facility becomes subject to this paragraph, ensure that all flow-through process vessels subject to this part comply with 112.9(c)(2) and (c)(3).	Not applicable. Discharges described have not occurred at MPU.
112.9(c)(6)(i)	A produced water container, and any associated piping and appurtenances downstream from the container, are exempt from the requirements of this part if a professional engineer certifies in accordance with 112.3(d)(1)(vi) that no discharge from the produced water container, including a complete loss of the capacity of the container, could cause a discharge in quantities that may be harmful, as described in Part 110 of this chapter. This determination for the container must be made in accordance with 112.1(d)(1)(i).	Not applicable. BP Exploration (Alaska) Inc. (BPXA) is not exercising this exemption.

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.9(c)(6)(ii)	For each container not exempted as described in paragraph (i), comply with 112.9(c)(1) and (c)(4); and 112.9(c)(2) and (c)(3), or: (A) Implement, on a regular schedule, a procedure for each produced water container that is designed to separate the free-phase oil that accumulates on the surface of the produced water. Include in the Plan a description of the procedures, frequency, amount of free-phase oil expected to be maintained inside the container, and a professional engineer certification in accordance with 112.3(d)(1)(vii). Maintain records of such events in accordance with 112.7(e). Records kept under usual and customary business practices will suffice for purposes of this paragraph. If this procedure is not implemented as described in the Plan, or no records are maintained, then you must comply with 112.9(c)(2) and (c)(3). (B) On a regular schedule, visually inspect and/or test the produced water container and associated piping for leaks, corrosion, or other conditions that could lead to a discharge as described in 112.1(b) in accordance with good engineering practice. (C) Take corrective action or make repairs to the produced water container and any associated piping as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge. (D) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with the produced water container. (E) If your facility discharges more than 1,000 U.S. gallons of oil in a single discharge as described in 112.1(b), or discharges 42 U.S. gallons of oil in each of two discharges as described in 112.1(b) within any twelve-month period from a produced water container subject to this subpart (excluding discharges that are the result of natural disasters, acts of war, or terrorism) then you must, within six months from the time the facility becomes subject to this paragraph, ensure that all produced water containers subject to this subpart comply with 112.9(c)(2) and (c)(3).	Not applicable. BPXA is not exercising this exemption.
112.9(d)(1)	Periodically, and upon a regular schedule, inspect aboveground valves and piping associated with transfer operations for general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.	This section and Volume 2, Sections 2.1.6, 2.1.7, 2.1.10, 2.5.3, 2.5.6 and 2.5.7; Table 2-6.
112.9(d)(2)	Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.	Not applicable. Brines are disposed of offsite.
112.9(d)(3)	For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with 112.7(c), unless you have submitted a response plan under 112.20, provide in your plan the following: (i) An oil spill contingency plan following the provisions of Part 109 of this chapter. (ii) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that might be harmful.	ODPCP Management Approval and Manpower Authorization Form
112.9(d)(4)	Prepare and implement a written program of flowline/intra-facility gathering line maintenance. The maintenance program must address your procedures to:	This section and Volume 2, Sections 2.1.10, 4.8, through 4.10
112.9(d)(4)(i)	Ensure that flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume and pressure, and other conditions expected in the operational environment.	Volume 2, Section 2.1.10

CROSS REFERENCE (CONT.)
TO U.S. ENVIRONMENTAL PROTECTION AGENCY
SPILL PREVENTION, CONTROL AND COUNTERMEASURE PLAN REQUIREMENTS
[40 CFR 112.7 THROUGH 40 CFR 112.10]

REGULATION SECTION	REGULATION	PLAN SECTION NUMBER
112.9(d)(4)(ii)	Visually inspect and/or test flowlines and intra-facility gathering lines and associated appurtenances on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in 112.1(b). For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with 112.7(c), the frequency and type of testing must allow for the implementation of a contingency plan as described under part 109 of this chapter.	This section and Volume 2, Section 2.1
112.9(d)(4)(iii)	Take corrective action or make repairs to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge.	This section and Volume 2, Sections 2.5.3 and 2.5.7
112.9(d)(4)(iv)	Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flowlines, or intra-facility gathering lines, and associated appurtenances.	This section; and Volume 1, Section 1.6.4, Tables 1-21 and 1-22; and Volume 2, Section 2.5.9;
112.10	Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities	
112.10(a)	Meet the general requirements listed under 112.7 and also meet the specific discharge prevention and containment procedures listed under this section.	This section
112.10(b)	Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in Section 112.1(b).	This section.
112.10(c)	Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.	This section and Volume 2, Sections 2.1.6 and 2.1.9
112.10(d)	Install blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.	This section.

MPU SPCC PLAN CONFORMANCE DISCUSSION

The Milne Point Unit (MPU) facility's conformance with the Spill Prevention, Control, and Countermeasure (SPCC) Plan and other applicable requirements as mandated by the Code of Federal Regulations (CFR) Title 40, Section 112.7(j), are discussed here, in this section's cross-reference table, and in the MPU Oil Discharge Prevention and Contingency Plan (ODPCP).

CONFORMANCE TO 40 CFR 112.7, GENERAL REQUIREMENTS FOR SPCC PLANS

General Conformance, 40 CFR 112.7(a)

MPU is a production facility and complies with the requirements in 40 CFR 112.3 through 112.10. The SPCC Plan covers regulated tanks, drums, vessels, and equipment with oil storage capacities of 55 gallons or greater located in MPU areas leased by BP Exploration (Alaska), Inc. (BPXA). The MPU is considered a single facility for SPCC purposes.

Regulation at 40 CFR 112.8 applies to regulated equipment at the MPU facility that is not directly related to crude oil production, treatment, or transport, such as: regulated equipment that supports the personal living quarters, life support facilities, power generation (e.g., diesel day tanks), the fire station, equipment and vehicle maintenance facilities, warehouses, waste disposal facilities, and fuel transfer areas.

Regulation at 40 CFR 112.9 applies to regulated containers, equipment and piping that is directly related to the production, extraction, recovery, lifting, stabilization, separation or treatment of oil, and associated storage or measurement. Examples include, but are not limited to, flowlines and gathering lines not otherwise regulated by the U.S. Department of Transportation (DOT); flow-through process vessels; bulk storage containers for crude oil; produced water, and drilling fluid storage, and hydraulic, dielectric, and lubrication oils used exclusively to support oil production operations.

Regulation at 40 CFR 112.10 applies to regulated equipment directly related to crude oil drilling and workover operations.

Contractors' SPCC-regulated equipment, which they own, rent, or lease, and bring onto BPXA leases, must be managed in accordance with their own (separate from BPXA) SPCC plan(s).

The MPU facility is described in ODPCP, Volume 2, Section 3.1, and facility diagrams are provided in ODPCP, Volume 2, Appendix B. As required by 40 CFR 112.7(a)(3), the following SPCC-regulated equipment is marked on the diagrams:

- Stationary aboveground bulk oil storage containers located outside a module
- Staging areas for portable oil tanks and equipment
- Drum and tote storage areas
- Oil-filled equipment located outside a module
- Oil transfer areas
- Oil piping

Regulated oil-filled equipment and bulk storage containers located within a module are not marked on the facility diagrams. This equipment is listed in the regulated equipment table at the end of the SPCC Plan with references to detailed diagrams where additional information can be found.

The location, contents, oil storage capacity, and a description of secondary containment for bulk oil storage containers with capacities greater than 10,000 gallons are presented in the ODPCP, Volume 2, Table 3-1 and Appendix A, which has been approved by the State of Alaska. Similar information is presented in the regulated equipment table at the end of the SPCC Plan for bulk oil storage containers with capacities of 55 to 10,000 gallons, drum and tote storage areas, oil-filled equipment with capacities of 55 gallons or greater, and flow-through process and pressure vessels with capacities of 55 gallons or greater.

There are no buried or partially buried bulk storage containers at MPU.

Countermeasures for discharge discovery, response, cleanup, and disposal are discussed in the ODPCP, which incorporates parts of the Alaska Clean Seas *Technical Manual*. Discharge reporting procedures and a facility contact list are presented in ODPCP Volume 1, Sections 1.1 and 1.2.

The facility has a Facility Response Plan approved by the U.S. Environmental Protection Agency (EPA) and a written management commitment for oil spill response resources. These documents are included in the ODPCP.

Potential Oil Discharges, 40 CFR 112.7(b)

Potential oil spills are described in ODPCP Volume 1, Sections 1.6.4, 4.3, and Part 5; and ODPCP, Volume 2, Section 2.3.

The trajectories of potential oil spills from major equipment failures are described in ODPCP Volume 1, Sections 1.6.4 and 3.2.1 and by way of surface drainage contours and directional arrows on facility diagrams located in ODPCP Volume 2, Appendix B.

Oil Spill Containment, 40 CFR 112.7(c)

Oil containers with capacities of 55 gallons or greater are provided with appropriate containment or diversionary structures capable of containing oil and constructed so discharge will not escape the containment system before cleanup occurs. Appropriate containment can be active or passive. Examples are: sealed modules or module floors with raised edges; diked concrete areas; built-in sump systems; vent collection containments; equipment with double walls or built-in containment; metal drip trays with raised edges; berms with impermeable liners; portable plastic liners, and sorbent boom or pads.

Regulated oil containers and their containments are inspected in accordance with the BPXA tank integrity management program.

Bulk Storage Containers Greater than 10,000 Gallons

In accordance with State of Alaska regulations, and in addition to EPA regulations, onshore oil (as defined by the ADEC) storage tanks with a capacity greater than 10,000 gallons have secondary containment of sufficient capacity to contain the volume of the largest container plus sufficient freeboard for precipitation. ADEC does not regulate: oil-filled equipment; flow-through process vessels; containers

under pressure or vacuum; containers with capacities of 10,000 gallons or less, or liquids defined by the EPA as oil that are not considered oil by ADEC's definition.

Bulk oil storage containers, and associated valves and piping, are tested if they are subjects of impracticability [40 CFR 112.7(d)]. BPXA has an EPA-approved Facility Response Plan and a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

Bulk Storage Containers 55 Gallons to 10,000 Gallons

Where it is practicable, containment or diversionary structures/equipment required by 40 CFR 112.7(c), 112.8(c)(2), and 112.9(c)(2) are provided for bulk oil storage containers with a capacity of 55 gallons or greater to prevent oil spills to tundra and water before cleanup occurs. Containment required by 40 CFR 112.7(c) need not be sized to the volume of the largest tank plus additional capacity; however, it must be appropriate and capable of containing a discharge before cleanup occurs.

For oil containers where secondary containment is not practicable, tank management practices like storing containers in designated on-pad storage areas; elevating containers on pallets or other structures, and locating containers at a distance from the pad edge, as well as periodic inspections by trained personnel, provide an alternate means to prevent a discharge. Personnel are required to visually inspect the container, valves, and piping prior to and following fluid transfers. Additionally, the containers undergo scheduled integrity inspections in accordance with 40 CFR 112.7(e) and the BPXA tank integrity management program.

Empty Bulk Storage Containers

Portable tanks that are temporarily not in use, empty, and stacked in designated storage areas on gravel pads do not pose a reasonable possibility of discharge to water/tundra.

Appropriate containment for portable oil tanks that are used to support production (e.g., regulated under §112.9) and temporarily not in use is provided by locating the containers in a designated area on a gravel pad, away from the pad edge, and behind a sign indicating the area is not to be used for storing oil. Additional environmental protection is provided by restricting public access and locating spill response resources nearby. The stored tanks remain subject to integrity inspections in accordance with the BPXA tank integrity management program.

Totes and Drums

Oil drums and totes are stored in designated drum and tote storage areas with containment sized for the volume of the largest drum or tote and sufficient freeboard for precipitation.

Oil Transfer Areas

Some oil transfer areas, including the transfer areas associated with Modules 54 and 61, have engineered secondary containment civil structures. Drip pans are used under hose connections, valves and vents during oil transfers in areas that do not have engineered containment structures.

Flow-Through Process Vessels

Flow-through process vessels have the primary function of processing, rather than storing, wellbore fluid. Treaters, separators, and slug catchers are examples of flow-through process vessels. Most of the flow-through process vessels at MPU have sized secondary containment. For those that do not, BPXA implements the alternative requirements of 112.9(c)(5).

Containment of at least “general” size is provided for flow-through process vessels by November 10, 2010.

Flow-through process vessels are visually inspected and tested periodically on a regular schedule. Corrective actions are taken as indicated by inspections or tests, or evidence of an oil discharge. Oil discharges are promptly removed and remediated.

Trailer Equipment (“Non-Mobile” Fleet)

BPXA’s “non-mobile” fleet is trailer-mounted equipment having onboard fuel storage that is not for the purpose of motive power, but to support the function of the equipment. The non-mobile fleet includes:

- Heaters
- Compressors
- Generators
- Light plants
- Pumps

Well service equipment (e.g., wire line, slick line, coiled tubing units)

- Bleed tanks and trailers

Fuel tanks on trailer equipment must have secondary containment, but the requirements vary depending on whether the equipment is used to directly support oil production. Non-production trailer equipment, including heaters, compressors, generators pumps and light plants, is regulated under 40 CFR 112.8 and required to have secondary containment under the fuel tank with a capacity greater than the tank. Generally, this size is not practicable (refer to the Impracticability Statement dated February 15, 2010 at the back of this document).

The secondary containment under fuel tanks of production-related trailer equipment (e.g., regulated under §112.9) must be sufficient to prevent a discharge to water, but do not necessarily have to be greater than the capacity of the tank. Well service equipment and bleed trailers are examples of this equipment.

Tank Vehicles (Mobile Refuelers and Other Non-Transportation-Related Tank Trucks)

The tanks of vacuum trucks containing oily liquids, mobile refuelers, lube oil trucks, tanker trucks carrying oil-based chemicals, and pickup or flatbed trucks with auxiliary-mounted oil containers are provided secondary containment when holding oil but not in use for transportation purposes (e.g., when parked overnight). The secondary containment does not have to be full-sized. BPXA’s intent of holding oil overnight in the tanks is to expedite delivery schedules from day-to-day, not to avoid having oil storage tanks.

Sumps

Floor drainage system sumps that contain oil as a consequence of small spills, drips, and leaks are part of the structure's secondary containment.

Oil-Filled Equipment

Oil-filled equipment is not subject to sized bulk storage container containment requirements. Examples of oil-filled equipment include: transformers, circuit breakers, hydraulic accumulators, lube and seal oil reservoirs, and heat exchangers.

BPXA meets the reportable discharge qualification criteria of 112.7(k)(1) at MPU and has documented procedures for inspections and monitoring to detect equipment failure or discharges. BPXA also has an oil spill contingency plan and a written commitment of manpower, equipment, and materials required to expeditiously control any quantity of oil discharged that may be harmful and, therefore, is eligible for the alternative requirements of 112.7(k).

Oil Pipelines (Flowlines and Intra-Facility Gathering Lines)

MPU's crude oil transmission pipeline transfers sales-quality crude oil from the MPU Central Facilities Pad to the Kuparuk Sales Pipeline. The crude oil transmission pipeline is regulated by the DOT and is not part of the SPCC-regulated facility. Flowlines and intra-facility gathering lines are regulated by the SPCC regulations.

Secondary containment and diversionary structures/equipment described in 40 CFR 112.7(c) generally are not provided for oil pipelines outside of oil container secondary containments or modules. Rather, they are managed under the requirements of 40 CFR 112.9(d)(3) and (d)(4). BPXA has an approved oil spill contingency plan and a written commitment of manpower, equipment and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

Flowlines and intra-facility gathering lines are operated, inspected, and maintained under comprehensive inspection and maintenance programs. The pipeline integrity management program is described in ODPCP, Volume 2, Section 2.1.10. Automated and visual leak detection systems are described in ODPCP, Volume 2, Sections 2.5.4 and 2.5.3.

Flowlines and gathering lines are built of materials compatible with the characteristics of the oil they contain. Corrective action is taken when inspection and monitoring procedures identify the need, and any accumulations of oil are promptly removed.

Spill Containment Impracticability, 40 CFR 112.7(d)

Secondary containment sized to the largest fuel tank plus freeboard for precipitation is not practicable for most non-production trailered equipment regulated under 40 CFR 112.8, including: heaters, compressors, generators pumps, and light plants. Refer to the Impracticability Statement dated February 15, 2010.

Inspections, Tests, and Records, 40 CFR 112.7(e)

SPCC-regulated containers, oil-filled equipment, and piping are inspected following written procedures in accordance with BPXA integrity management programs. Inspections of individual single-use drums and

totes are documented by the designated storage area rather than by the container's individual designation.

Written procedures for inspections of regulated equipment are kept electronically and are available to BPXA employees. Written inspection procedures for oil-filled electrical equipment are maintained at the facility.

Records of completed inspections are kept in accordance with usual and customary business procedures. Records of oil container inspections are kept electronically and in hard copy in files maintained by the Corrosion Inspection and Chemical (CIC) group at the Anchorage BPXA headquarters.

Oil-filled electrical equipment inspection completion records are maintained in the Computerized Maintenance Management System (CMMS) work order system.

Inspection results for facility piping and flowlines are kept by the CIC group in the Mechanical Integrity Management Information Repository (MIMIR) electronic database.

Signed records of inspections and tests are kept for at least three years and in accordance with BPXA integrity management programs.

Training, 40 CFR 112.7(f)

Oil-handling personnel with job duties directly involving inspection, maintenance, or operation of oil storage and transfer equipment are trained in the operation and maintenance of their equipment to prevent oil spills, as required by 40 CFR 112.7(f)(1). Oil-handling personnel do not include support staff and managers who do not operate oil equipment, although they may take the training.

BPXA employees and contractors that handle SPCC-regulated oil equipment also are trained in oil spill prevention procedures, relevant environmental regulations, and the contents of the SPCC Plan.

Oil-handling personnel are directly responsible for discharge prevention in their day-to-day activities. The Area Manager is accountable for spill prevention at the facility [40 CFR 112.7(f)(2)].

Oil-handling personnel are briefed at least once a year, as required by 40 CFR 112.7(f)(3). The briefings describe oil spills, malfunctioning equipment, and recently developed precautionary measures associated with oil spills. Additionally, bulletins or notices intended to brief personnel on safety or spill issues are displayed in conspicuous locations in the facility.

The SPCC regulations do not require documentation of spill prevention training, although documentation for BPXA employees is kept for five years in compliance with State regulations. Contractors maintain their own training records.

(b) (7)(F)



Loading Racks, 40 CFR 112.7(h)

MPU has no loading racks.

Field-Constructed Aboveground Tank Repair, Modification or Change in Service, 40 CFR 112.7(i)

If a field-constructed oil container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a spill or the risk of failure due to brittle fracture or other catastrophe, or the container has spilled oil, the container is evaluated per American Petroleum Institute (API) Standard 653, and appropriate action is taken as necessary.

Qualified Oil-Filled Equipment, 40 CFR 112.7(k)

Oil-filled equipment meets the qualification criteria found at 40 CFR 112.7(k)(1). Spill records show no oil spills to navigable water from transformers or other oil-filled equipment; therefore, the facility has chosen to implement the alternative requirements of 40 CFR 112.7(k)(2). The regulated equipment table at the end of Appendix A of the SPCC Plan lists transformers and other oil-filled equipment.

BPXA has established and documented inspection and monitoring procedures for oil-filled equipment as required by 40 CFR 112.7(k)(2)(i). BPXA also has an approved Facility Response Plan that complies with 40 CFR 112.20; an ODPCP as required by 40 CFR 112.7(k)(2)(ii)(A), and a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful, as required by 40 CFR 112.7(k)(2)(ii)(B).

CONFORMANCE TO 40 CFR 112.8, REQUIREMENTS FOR ONSHORE FACILITIES (EXCLUDING PRODUCTION FACILITIES)
General Requirements, 40 CFR 112.8(a)

The general requirements for the SPCC Plan listed under 40 CFR 112.7 are met at this facility.

Facility Drainage, 40 CFR 112.8(b)

Facility drainage systems are designed to control or preclude discharge from oil storage container areas. Water pumped from secondary containments to pads or tundra is first visually inspected and determined as uncontaminated. The de-watering and inspection are recorded on a Storm Water Discharge Checklist in accordance with the North Slope Storm Water Pollution Prevention Plan.

Bulk Storage Containers, 40 CFR 112.8(c)

The December 2008 and November 2009 amendments to 40 CFR 112 for the first time made it clear that regulated equipment and facilities not directly, uniquely, or exclusively related to oil production are regulated under the “non-production” rules of 40 CFR 112.8. BPXA provides full-sized secondary containment and overfill protection for non-production bulk storage containers by November 10, 2010, unless it is impracticable.

The materials used to construct bulk storage containers are compatible with the materials stored and the conditions of storage like temperature and pressure.

Bulk storage installations, except for mobile refuelers and other non-transportation-related tank trucks, are built with a means of secondary containment sized for the contents of the largest single container and

sufficient freeboard to contain precipitation where practicable. Diked areas are sufficiently impervious to contain discharged oil.

There are no partially buried or bunkered metallic tanks for the storage of oil at this facility.

Each aboveground container is tested for integrity on a regular schedule. Visual inspection is combined with another appropriate non-destructive shell testing method. Inspections of container supports and foundations are part of the inspection process, and the outside of containers are frequently inspected for signs of deterioration, discharges, and accumulations of oil inside diked areas.

There are no internal steam heating coils at the facility that are regulated under 40 CFR 112.8.

Non-production oil storage tanks are engineered or updated to prevent spills from overfilling, as follows:

- Single-wall stationary tanks >10,000 gallons have high liquid level alarms, or high level cutoff devices, or continuous liquid level indicators monitored by persons as required by 40 CFR 112.8(c)(8)(i), (ii) or (iv).
- Single-wall portable tanks >10,000 gallons have direct audible or code signal communication between the gauger and the pumper as required by 40 CFR 112.8(c)(8)(iii).
- Single-wall stationary and portable tanks <10,000 gallons meet 40 CFR 112.8(c)(8)(i), (ii), (iii) or (iv), respectively, with one of the following by November 10, 2010: high liquid level alarms, high liquid level shutoff devices (including automatic fuel-nozzle back-pressure shutoffs), gaugers and pumps for transfers, or continuous level indicators and visual monitoring.
- Double-wall portable tanks >10,000 gallons and without high level alarms or continuous level indicators have two persons to transfer and are equipped with catchments for overfills from fill ports or vents.
- A double-wall tank <10,000 gallons meets 40 CFR 112.8(c)8 with:
 1. Either an overfill alarm or two persons loading, and either an automatic flow restrictor or automatic shutoff, or
 2. A catchment for fill port and vent overfills, and either a high-level alarm, a cut-off, a monitored gauge or two persons loading.

A catchment may be built-in or it may be a ground liner.

There are no effluent treatment facilities at MPU.

Visible discharges that result in a loss of oil from the container, including but not limited to: leaking seams, gaskets, piping, pumps, valves, rivets, and bolts, are promptly corrected.

Mobile or portable oil storage containers are located to prevent discharges. With the exception of mobile refuelers and fuel tanks on trailered equipment that is covered by an Impracticability Statement (dated February 15, 2010), mobile and portable containers are provided with sized secondary containment sufficient to contain the contents of the container plus sufficient freeboard for precipitation where practicable.

Facility Transfer Operations, Pumping, and Facility Process, 40 CFR 112.8(d)

Buried piping that is installed or replaced on or after August 16, 2002, is provided with a protective wrapping and coating. The piping also is cathodically protected or otherwise satisfies the corrosion protection standards for piping in 40 CFR 280 or a state program approved under 40 CFR 281. If a section of buried line is exposed for any reason, it is carefully inspected for deterioration. If corrosion damage is found, then additional examination and corrective action is taken.

When transfer piping is not in service or is in standby service for an extended period of time, the terminal end is capped or blank-flanged.

Pipe supports are designed to minimize abrasion and corrosion and allow for expansion and contraction. Aboveground valves, piping, and appurtenances are regularly inspected. The inspections include assessment of the general condition of items, such as: flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, and metal surfaces.

Personnel receive driver safety training (e.g., North Slope Training Cooperative [NSTC] course) so they do not endanger aboveground piping or other oil-transfer operations.

CONFORMANCE TO 40 CFR 112.9, REQUIREMENTS FOR ONSHORE OIL PRODUCTION FACILITIES
Drainage, 40 CFR 112.9(b)

The general requirements for the SPCC Plan listed under 40 CFR 112.7 and the specific discharge prevention and containment procedures listed under this section are met at MPU.

Dike and containment drains are closed and sealed at all times. Draining of the areas is by sump or vacuum truck extraction.

In most instances, visual checks indicate the necessity for pumping of containment areas. Containments having automated sumps transfer fluids to a slop tank or tote for re-injection into the production stream. Drainage of secondary containments without sumps is by pump or vacuum truck. Fluids are inspected prior to dewatering and are disposed of according to written procedures documented in the North Slope Storm Water Pollution Prevention Plan.

Bulk Storage Containers, 40 CFR 112.9(c)

Bulk oil storage containers and flow-through process vessels are of materials and construction standards compatible with the stored material and the conditions of storage, as required by 40 CFR 112.9(c)(1).

Unless it is not practicable, stationary oil storage tanks at production facilities have secondary containment for the entire capacity of the largest single container plus sufficient freeboard to contain precipitation, as required by 112.9(c)(2).

Flow-through process vessels are managed under the alternative procedures allowed by 40 CFR 112.9(c)(5). The procedures are described in the Oil Spill Containment section (page 12) of this discussion.

Portable tanks less than 10,000 gallons have general secondary containment at the points of typical failure mode for the most likely spill volumes. Typical spill mode from portable oil tanks involves hose connections or overfills.

Produced water tanks less than 10,000 gallons have secondary containment for the most likely spill volumes.

Each bulk storage container supporting oil production is visually inspected on a periodic and regular basis in accordance with BPXA integrity management programs.

Regulation at 40 CFR 112.9(c)(4) is not applicable because there are no tank battery installations at MPU. BPXA defines tank batteries as stationary tanks that receive fluids directly from the well and are offloaded directly to tanker trucks.

Facility Transfer Operations, 40 CFR 112.9(d)

As required by 40 CFR 112.9(d)(1), valves and piping associated with oil transfer operations are regularly inspected according to written procedures.

Oil field brines are transported off the facility for disposal.

Flowlines are in a maintenance program, as required by 40 CFR 112.9(d)(3). The maintenance program is outlined in ODPCP, Volume2, Section 2.1.10.

The flowline/intra-facility gathering line maintenance program includes periodic and regular visual inspection and testing of valves, piping, and appurtenances for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in 40 CFR 112.1.

CONFORMANCE TO 40 CFR 112.10, REQUIREMENTS FOR ONSHORE DRILLING AND WORKOVER FACILITIES

Contract drillers operating on BPXA leases are required by BPXA to develop and implement their own SPCC plans specific to their rigs and ancillary equipment and tanks. Nevertheless, bulk oil containers supporting drilling and workover rigs and in secondary containment may undergo inspection at BPXA's discretion.

As required by 40 CFR 112.10(b), tanks are positioned away from the edges of pads to prevent oil spills to tundra and water bodies. As required by 40 CFR 112.10(c), catchment basins (e.g., lined secondary containment) are provided for these tanks, where practicable, to intercept and contain oil spills. Blowout prevention equipment is installed before drilling below casing and before well workovers.

Portable tanks less than 10,000 gallons have general secondary containment at the points of typical failure mode for the most likely spill volumes. Typical spill mode from portable oil tanks involves hose connections or overfills.

MPU SPCC-Regulated Equipment

(See ODCPC Appendix A for Oil Storage Tanks >10,000 gallons)

Location				Equipment Information							Secondary Containment Information	
Area	Facility	Module	Equipment ID	Description	Product Type	Nominal Design Capacity (gallons)	Production or Non-Production Service	Stationary or Portable	Overfill Protection Device	Leak Detection System	Description	Capacity (gallons)
Bulk Storage Containers (55 to 10,000 gallons)												
MPU	CFP	4	T-0107	Diesel Day Tank (Generator Holding Tank)	Diesel	2,000	Non-production	Stationary	Visual Observation; HLA	Visual Surveillance	Metal berm	4,174
MPU	CFP	4	T-0106A	Diesel Day Tank (Generator)	Diesel	120	Non-production	Stationary	Visual Observation; Level Gauge	LLA Visual Surveillance	Stainless steel box	126
MPU	CFP	4	T-0106B	Diesel Day Tank (Generator)	Diesel	120	Non-production	Stationary	Visual Observation; Level Gauge	LLA Visual Surveillance	Stainless steel box	126
MPU	CFP	47	T-4704	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4705	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4706	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4708	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4711	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4712	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4713	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4714	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4715	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4716	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	47	T-4717	Three Yard Hoppers (contaminated gravel/snow)	Oily Waste Solids (contaminated gravel/snow)	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	5,916
MPU	CFP	55	T-5505	Holding Tank	Synfilm 100	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Module	16,783
MPU	CFP	55	T-5506	Holding Tank	R&O 460	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Module	16,783
MPU	CFP	55	T-5507	Holding Tank	R&O 460	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Module	16,783
MPU	CFP	58	PU-5802-T1	Chemical Storage Tank	Emulsion Breaker REB-01319	516	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,048
MPU	CFP	58	PU-5802-T2	Chemical Storage Tank	Emulsion Breaker REB-01319	516	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,048
MPU	CFP	58	PU-5802-T3	Silicon Defoamer	Defoamer	2,000	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,048
MPU	CFP	58	T-5811	Chemical Storage Tank	Emulsion Breaker REB-01319	512	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,049
MPU	CFP	58	T-5812	Chemical Storage Tank	Emulsion Breaker VX8722	509	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,049
MPU	CFP	68	T-6801	Diesel Storage Tank	Diesel	2,780	Non-Production	Stationary	HLA, Visual Observation	Interstitial Level Alarm	Double-Walled Tank	>2,780
MPU	A Pad	A Pad	86-5202	Diesel Day Tank (Compressor)	Diesel	72	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Drip Tray	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	86-5701	Diesel Day Tank (Compressor)	Diesel	230	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Drip Tray	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	88-5512	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	88-5513	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	88-5514	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	88-5515	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	89-5505	Diesel Tank (Heater) w/Light Tower	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	88-5517	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	88-5518	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	89-5506	Diesel Tank (Heater) w/Light Tower	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Built in	Impracticability Statement (dated 2/15/2010)

MPU SPCC-Regulated Equipment

(See ODPCP Appendix A for Oil Storage Tanks >10,000 gallons)

[illegible]

MPU SPCC-Regulated Equipment

(See ODCPC Appendix A for Oil Storage Tanks >10,000 gallons)

Location				Equipment Information							Secondary Containment Information	
Area	Facility	Module	Equipment ID	Description	Product Type	Nominal Design Capacity (gallons)	Production or Non-Production Service	Stationary or Portable	Overfill Protection Device	Leak Detection System	Description	Capacity (gallons)
MPU	A Pad	A Pad	BLDT 1101	Bleed Trailer	Various	518	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	A Pad	BLDT 1102	Bleed Trailer	Various	518	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	A Pad	BLDT 1103	Bleed Trailer	Various	1,000	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	A Pad	BLDT 1109	Bleed Trailer	Various	500	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	A Pad	BLDT 1110	Bleed Trailer	Various	500	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	A Pad	BLDT 1111	Bleed Trailer	Various	1,000	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	A Pad	BLDT 1112	Bleed Trailer	Various	1,000	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	A Pad	BLDT 1113	Bleed Trailer	Various	1,000	Production	Portable	Visual Observation	Visual Surveillance	Drip Tray	General containment provided
MPU	A Pad	90 (Shop)	T-9002 / T1	Service Shop Tank 7 in1	Hydraulic Fluid	75	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Steel Floor Pan	1,500
MPU	A Pad	90 (Shop)	T-9002 / T2	Service Shop Tank 7 in 1	Used Oil	498	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Steel Floor Pan	1,500
MPU	A Pad	90 (Shop)	T-9002 / T3	Service Shop Tank 7 in 1	Glycol	150	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Steel Floor Pan	1,500
MPU	A Pad	90 (Shop)	T-9002 / T4	7 in 1 - Motor Oil Storage Tank	10w30 Motor Oil	299	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Steel Floor Pan	1,500
MPU	A Pad	90 (Shop)	T-9002 / T5	7 in 1 - Motor Oil Storage Tank	10W30 Motor Oil	150	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Steel Floor Pan	1,500
MPU	A Pad	90 (Shop)	T-9002 / T6	7 in 1 Motor Oil Tank	15W40 Motor Oil	150	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Steel Floor Pan	1,500
MPU	A Pad	90 (Shop)	T-9002 / T7	7 in 1 Gear Oil Tank	Gear Oil	75	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Steel Floor Pan	1,500
MPU	A Pad	90 (Shop)	T-9003	Diesel Tank (Heater)	Diesel	250	Non-production	Stationary	Visual Observation; Cut-off Nozzle	Visual Surveillance	Steel Floor Pan	280
MPU	A Pad	68-5601 Spooling Unit	T-1120	Diesel storage	Diesel	583	Non-production	Stationary	Manual Strapping; Cut-off Nozzle	Visual Surveillance	Trailer Floor	976
MPU	A Pad	68-5601 Spooling Unit	T-1121	Hydraulic fluid storage	Hydraulic Fluid	353	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Trailer Floor	976
MPU	A Pad	68-5601 Spooling Unit	80-5051	Diesel storage (generator)	Diesel	62	Non-production	Stationary	Visual Observation; Cut-off Nozzle	Visual Surveillance	Double-Walled Tank with Geomembrane Liner	>62
MPU	A Pad	Yard (Outside Centrlift)	T-9001	Diesel Day Tank	Diesel	500	Non-production	Stationary	Manual Strapping; Cut-off Nozzle	Visual Surveillance	Timber Berm with Geomembrane Liner	1,755
MPU	A Pad	Yard (Outside Tent)	T-9010	Diesel Tank	Diesel	2,780	Non-production	Stationary	HLA, Visual Observation	Interstitial Level Alarm	Double Walled	3,058
MPU	A Pad	Yard	T-9004	Storage Tank	Gasoline	5,000	Non-Production	Stationary	Visual Observation, Cut-off Nozzle	Visual Surveillance	Double Walled Tank with Geomembrane Lined Gravel Dike	Secondary tank capacity is 5389 gallons (Tertiary containment 1,192 gals)
MPU	A Pad	Yard	T-9016	Storage Tank	Gasoline	9,500	Non-Production	Stationary	Visual Observation, Cut-off Nozzle	Visual Surveillance	Double Walled Tank with Geomembrane Lined Gravel Dike	Secondary tank capacity is 9500 gallons (Tertiary containment 1,192 gals)
MPU	A Pad	A Pad	89-5519	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Drip Tray	Impracticability Statement (dated 2/15/2010)
MPU	A Pad	A Pad	89-5520	Diesel Tank (Heater)	Diesel	240	Non-Production	Portable	Visual Observation; Cut-off Nozzle	Visual Surveillance	Drip Tray	Impracticability Statement (dated 2/15/2010)
MPU	B Pad	20	T-2001/T1	Defoamer Storage Tank	Defoamer	200	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Module	9,324
MPU	B Pad	20	T-2001/T2	Emulsion Breaker Storage Tank	Emulsion Breaker	500	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Module	9,324
MPU	B Pad	B Pad	T-9172	Diesel Storage Tank	Diesel	9,297	Non-production	Portable	Sight glass / Visual Observation	Visual Surveillance	Lined Dike	11,400
MPU	C Pad	26 Generator Room	T-2603	Diesel Day Tank (Generator)	Diesel	160	Non-production	Stationary	CLI	CLI, Visual Surveillance	Module	798
MPU	C Pad	26 Diesel Loading Area	T-2601	Diesel Holding Tank	Diesel	6,462	Non-production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Berm with Spray-on Geomembrane Liner	37,724

MPU SPCC-Regulated Equipment

(See ODPSP Appendix A for Oil Storage Tanks >10,000 gallons)

Location				Equipment Information							Secondary Containment Information	
Area	Facility	Module	Equipment ID	Description	Product Type	Nominal Design Capacity (gallons)	Production or Non-Production Service	Stationary or Portable	Overfill Protection Device	Leak Detection System	Description	Capacity (gallons)
MPU	C Pad	26	PU-2601/T1	Emulsion breaker storage tank	Emulsion Breaker	200	Production	Stationary	CLI	LLA Visual Surveillance	Module	9,534
MPU	C Pad	26	PU-2601/T2	Emulsion breaker storage	Emulsion Breaker	500	Production	Stationary	CLI	LLA Visual Surveillance	Module	9,534
MPU	C Pad	26	PU-2601/T3	Defoamer storage tank	Defoamer	200	Production	Stationary	CLI	LLA Visual Surveillance	Module	9,534
MPU	C Pad	26	PU-2601/T4	Defoamer storage tank	Defoamer	200	Production	Stationary	CLI	LLA Visual Surveillance	Module	9,534
MPU	C Pad	28 IWAG #1	T-2610	Lube oil storage tote	Dectol 460	350	Production	Stationary	Visual Observation	Visual Surveillance	Module	4,326
MPU	C Pad	28 IWAG #1	T-2611	Crankcase oil storage	Lube Oil	350	Production	Stationary	Visual Observation	Visual Surveillance	Module	4,326
MPU	C Pad	28 IWAG #1	T-2612	Trabon system lube oil day tank	Lube Oil	110	Production	Stationary	Level Gauge	Visual Surveillance	Module	4,326
MPU	C Pad	28 IWAG #1	T-2613	Trabon system lube oil day tank	Lube Oil	110	Production	Stationary	Level Gauge	Visual Surveillance	Module	4,326
MPU	D Pad	Snowmelt Bin	T-2701	Contaminated Snowmelt	Misc Hydrocarbons	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	>500
MPU	D Pad	Snowmelt Bin	T-2703	Contaminated Snowmelt	Misc Hydrocarbons	500	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	>500
MPU	D Pad	Snowmelt Bin	T-4707	Contaminated Snowmelt	Misc Hydrocarbons	3,000	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	>3,000
MPU	D Pad	Snowmelt Bin	T-4709	Contaminated Snowmelt	Misc Hydrocarbons	3,000	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	>3,000
MPU	D Pad	Snowmelt Bin	T-4710	Contaminated Snowmelt	Misc Hydrocarbons	3,000	Non-production	Portable	Visual Observation	Visual Surveillance	Berm with geomembrane when holding oil	>3,000
MPU	E Pad	45 Test Separator	T-4502A	Defoamer storage tank	Defoamer	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,776
MPU	E Pad	45 Test Separator	T-4503A	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,776
MPU	E Pad	45 Test Separator	T-4503B	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,776
MPU	E Pad	45 Test Separator	T-4507	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,776
MPU	F Pad	3 Test Separator	T-2402A	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	751
MPU	F Pad	3 Test Separator	T-2403A	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	751
MPU	F Pad	3 Test Separator	T-2404A	Defoamer storage tank	Defoamer	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	751
MPU	F Pad	24 Exp Hdr Hyd Skid	PU-240-T1	Hydraulic Fluid Storage	Hydraulic Fluid	80	Production	Stationary	HLA, Visual Observation	Visual Surveillance	Module	640
MPU	H Pad	31 Test Separator	T-3102A	Defoamer storage tote	Defoamer	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	H Pad	31 Test Separator	T-3103A	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	H Pad	31 Test Separator	T-3103B	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	K Pad	44 Test Separator	T-4404	Emulsion breaker tank	Emulsion Breaker	400	Production	Stationary	Visual Observation	Visual Surveillance	Metal Liner, Module	738
MPU	K Pad	44 Test Separator	T-4405	Defoamer storage tank	Defoamer	400	Production	Stationary	Visual Observation	Visual Surveillance	Metal Liner, Module	738
MPU	L Pad	25 Test Separator	T-2502	Defoamer storage tank	Defoamer	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	L Pad	25 Test Separator	T-2503A	Emulsion breaker storage	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	L Pad	25 Test Separator	T-2503B	Emulsion breaker storage tote	Emulsion Breaker	400	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	L Pad	25 Test Separator	T-2507	Emulsion breaker storage	Emulsion Breaker	350	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	L Pad	25 Test Separator	T-2508	Emulsion breaker storage	Emulsion Breaker	350	Production	Stationary	Sight glass / Visual Observation	Visual Surveillance	Metal Liner, Module	1,642
MPU	S Pad	8005 Chem Injection Skid	T-8001	Emulsion breaker storage tank	Emulsion Breaker	764	Production	Stationary	HLA, Visual Observation	LLA Visual Surveillance	Module	468

MPU SPCC-Regulated Equipment

(See ODCPC Appendix A for Oil Storage Tanks >10,000 gallons)

Location				Equipment Information							Secondary Containment Information	
Area	Facility	Module	Equipment ID	Description	Product Type	Nominal Design Capacity (gallons)	Production or Non-Production Service	Stationary or Portable	Overfill Protection Device	Leak Detection System	Description	Capacity (gallons)
MPU	S Pad	Heavy Oil Facility	T-1104A	Defoamer storage tank	Defoamer	400	Production	Stationary	Sight glass / Visual Observation	LLA Visual Surveillance	Module	Double walled >400 gal.
MPU	S Pad	Heavy Oil Facility	T-1132	Sample Tap Flush Diesel Tank	Diesel	100	Non-production	Stationary	Visual Observation/Level Gauge	LLA Visual Surveillance	Module	Double walled >100 gal.
MPU	S Pad	Heavy Oil Facility	T-1133	Sample Tap Holding Tank	Diesel	100	Non-production	Stationary	Visual Observation/Level Gauge	LLA Visual Surveillance	Module	Double walled >100 gal.
MPU	S Pad	Heavy Oil Facility	GN-1101	Diesel day tank (Standby Generator)	Diesel	838	Non-production	Portable	Sight glass / Visual Observation	LLA Visual Surveillance	Drip Tray	800
Drum/Tote Storage Areas												
MPU	CFP	4 - LSF (E-Gen Room)	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 3-4 drums	Lube Oil	≥55		Portable	Visual observation	Visual Surveillance	Module Floor	>55
MPU	CFP	47	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 40-60 drums	Misc. Hydrocarbons / Chemicals	≥55		Portable	Visual observation	Visual Surveillance	Module Floor	5,916
MPU	CFP	Outside Mod 47	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 30 drums	Misc. Hydrocarbons / Chemicals	≥55		Portable	Visual observation	Visual Surveillance	Two Adjacent Areas - Timber Berm with Geomembrane Liner	1,428 5,916
MPU	CFP	57	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 6 drums	Miscellaneous Hydrocarbons	≥55		Portable	Visual observation	Visual Surveillance	Module Floor	6,178
MPU	CFP	Fire Station	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 6 drums	Used Oil / Misc. Hydrocarbons	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Drip Tray / Module	>55
MPU	CFP	Bulk Storage East of Mods 55/57/69	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 30 totes and 100 drums	Hydraulic Oil / Lube Oil / Chemicals	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Two Adjacent Areas - Timber Berm with Geomembrane Liner	1,488 5,500
MPU	A Pad	CH2MHILL Shop	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 2-6 drums	Used Diesel/Oil	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Shop Floor	>55
MPU	A Pad	Centrilift	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 3 drums	Miscellaneous Hydrocarbons	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Overpack drums	>55
MPU	B Pad	20	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 2-6 drums	Lube Oil	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	9,324
MPU	C Pad	26	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Miscellaneous Hydrocarbons	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	9,534
MPU	C Pad	26	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Royal Purple 22	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	9,534
MPU	C Pad	26	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Royal Purple 46	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	9,534
MPU	C Pad	28 IWAG #1	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	460 Hydroclear	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	4,326
MPU	C Pad	28 IWAG #1	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Pegasus Oil 710	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	4,326
MPU	C Pad	29 IWAG #2	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Miscellaneous Oil and Mobil Jet Oil	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	495
MPU	C Pad	29 IWAG #2	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	460 Hydroclear	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	495
MPU	C Pad	29 IWAG #2	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Pegasus Oil 710	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	495
MPU	D Pad	Drum Storage Area	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 24 drums and 12 Totes (400 gallons each)	Misc. Hydrocarbons / Chemicals	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Timber berm with geomembrane liner	3,725

MPU SPCC-Regulated Equipment

(See ODFPCP Appendix A for Oil Storage Tanks >10,000 gallons)

Location				Equipment Information							Secondary Containment Information	
Area	Facility	Module	Equipment ID	Description	Product Type	Nominal Design Capacity (gallons)	Production or Non-Production Service	Stationary or Portable	Overfill Protection Device	Leak Detection System	Description	Capacity (gallons)
MPU	D Pad	Drum Storage Area	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 6 Totes	Royal Purple Hythem/Demulsifier	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Timber berm with geomembrane liner	2,800
MPU	E Pad	Test Separator	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 2 drums	Misc. Hydrocarbons / Chemicals	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	1,776
MPU	F Pad	Expansion Header Hydraulic Skid	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Hydraulic Fluid	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	640
MPU	S Pad	8001/8004	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 3 drums	Production Fluids	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	>55
MPU	S Pad	8005	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Production Fluids	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	468
MPU	S Pad	8008	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Royal Purple Synfilm 46	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	>55
MPU	S Pad	8008	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Royal Purple Barrier Fluid 22	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	>55
MPU	S Pad	8008	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Royal Purple / Oil / Water	≥55	Non-Production	Portable	Visual observation	Visual Surveillance	Module Floor	>55
MPU	S Pad	Heavy Oil Facility Process Module 1101	N/A, storage drums are not assigned permanent equipment number/tag	Single drum	Pegasus 710	≥55	Non-Production	Portable	Visual observation	Visual surveillance	Module Floor	>55
Mobile Refuelers												
MPU	CFP	Mobile Refueler	32-5101	Mobile Refueler	Fuel	6,000	Non-Production	Portable (Mobile)	Visual observation	Visual Surveillance	Mod 61 Loading / Unloading Area (when not in use)	27,300
MPU	CFP	Mobile Refueler	32-5102	Mobile Refueler	Fuel	4,886	Non-Production	Portable (Mobile)	Visual observation	Visual Surveillance	Mod 61 Loading / Unloading Area (when not in use)	27,300
MPU	A Pad	Pick-up Truck	94-5005	Saddle Tank	Diesel	150	Non-Production	Portable	Visual observation	Visual Surveillance	Steel Liner	>150
MPU	CFP	Pick-up Truck 5050	T-1134	Saddle Tank	Gasoline	105	Non-Production	Portable	Visual observation	Visual Surveillance	Steel Liner	>105
MPU	A Pad	Pick-up Truck	94-5006	Saddle Tank	Diesel	150	Non-Production	Portable	Visual observation	Visual Surveillance	Steel Liner	>150
MPU	CFP	Mobile Refueler	32-5103	Mobile Refueler	Diesel	4,700	Non-Production	Portable (Mobile)	Visual observation	Visual Surveillance	Integral Containment/Module When Not In Use	
Oil-Filled Operational Equipment												
MPU	CFP - LSF	4	PU-0101A	Lube Oil Reservoir	Lube Oil	60	Non Production	Stationary	Visual Observation	Visual Surveillance	Module	>60
MPU	CFP - LSF	4	PU-0101B	Lube Oil Reservoir	Lube Oil	60	Non Production	Stationary	Visual Observation	Visual Surveillance	Module	>60
MPU	CFP - LSF	4	PU-0101C	Lube Oil Reservoir	Lube Oil	60	Non Production	Stationary	Visual Observation	Visual Surveillance	Module	>60
MPU	CFP - LSF	4	XFMR-0101	Transformer	Mineral Oil	514	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	652
MPU	CFP - LSF	4	XFMR-0102	Transformer	Mineral Oil	522	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	652
MPU	CFP	7	T-0701	Lube Oil Reservoir (TURBINE)	Lube Oil	120	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,241
MPU	CFP	7	T-0702	Hydraulic Fluid Storage	Hydraulic Fluid	80	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,251
MPU	CFP	7	T-0703	Lube Oil Reservoir (Generator)	Lube Oil	110	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,251
MPU	CFP	8	T-0801	Lube Oil Reservoir (TURBINE)	Lube Oil	120	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,241
MPU	CFP	8	T-0802	Hydraulic Fluid Storage	Hydraulic Fluid	80	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,251
MPU	CFP	8	T-0803	Lube Oil Reservoir (Generator)	Lube Oil	110	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,251
MPU	CFP	53	TFR-5310	Transformer	Mineral Oil	360	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	760
MPU	CFP	53	TR-5301	Transformer	Mineral Oil	514	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Concrete Liner	465
MPU	CFP	53	TR-5302	Transformer	Mineral Oil	514	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Concrete Liner	468
MPU	CFP	54	BD-5401	Transformer	Mineral Oil	514	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,120
MPU	CFP	54	BD-5402	Transformer	Mineral Oil	514	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,120
MPU	CFP	55	C-5501A C-5511A	Lube Oil Reservoir	Lube Oil	100	Production	Stationary	Visual Observation	Visual Surveillance	Module	16,783

MPU SPCC-Regulated Equipment

(See ODPSP Appendix A for Oil Storage Tanks >10,000 gallons)

Location				Equipment Information							Secondary Containment Information	
Area	Facility	Module	Equipment ID	Description	Product Type	Nominal Design Capacity (gallons)	Production or Non-Production Service	Stationary or Portable	Overfill Protection Device	Leak Detection System	Description	Capacity (gallons)
MPU	CFP	55	C-5501B C-5511B	Lube Oil Reservoir	Lube Oil	100	Production	Stationary	Visual Observation	Visual Surveillance	Module	16,783
MPU	CFP	55	C-5502A C-5503A C-5531A	Lube Oil Reservoir	Lube Oil	60	Production	Stationary	Visual Observation	Visual Surveillance	Module	16,783
MPU	CFP	55	C-5502B C-5503B C-5531B	Lube Oil Reservoir	Lube Oil	60	Production	Stationary	Visual Observation	Visual Surveillance	Module	16,783
MPU	CFP	56	BD-5601	Transformer	Mineral Oil	1,464	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,380
MPU	CFP	56	BD-5602	Transformer	Mineral Oil	1,464	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,380
MPU	CFP	56	BD-5603	Transformer	Mineral Oil	514	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	570
MPU	CFP	56	BD-5604	Transformer	Mineral Oil	514	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	570
MPU	CFP	56	TR-5605	Transformer	Mineral Oil	862	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	2,200
MPU	CFP	COLD STORAGE	NONE	Transformer	Mineral Oil	250	Non Production	Stationary	Visual Observation	Visual Surveillance	Timber Berm with Geomembrane Liner	4,185
MPU	CFP	COLD STORAGE	NONE	Transformer	Mineral Oil	250	Non Production	Stationary	Visual Observation	Visual Surveillance	Spill Pallet Berm Prefab/Spill Pallet Liner	13,776
MPU	CFP	COLD STORAGE	NONE	Transformer	Mineral Oil	250	Non Production	Stationary	Visual Observation	Visual Surveillance	Spill Pallet Berm Prefab/Spill Pallet Liner	13,776
MPU	A Pad	A Pad	XFMR-9004	Transformer	Mineral Oil	55	Non Production	Stationary	Visual Observation	Visual Surveillance	Timber Berm with Geomembrane Liner	1,052
MPU	A Pad	A Pad	XMFR-9011	Transformer	Mineral Oil	250	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	644
MPU	A Pad	A Pad	XMFR-9012A	Transformer	Mineral Oil	460	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	644
MPU	A Pad	A Pad	XMFR-9012B	Transformer	Mineral Oil	460	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	644
MPU	B Pad	20	VSDT-20XX	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	903
MPU	B Pad	20	XFMR-2002	Transformer	Mineral Oil	402	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	903
MPU	B Pad	20	TR-2001	Transformer	Mineral Oil	296	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	359
MPU	C Pad	26	TR-2601	Transformer	Mineral Oil	296	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	377
MPU	C Pad	26A	TR-2602	Transformer	Mineral Oil	122	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	643
MPU	C Pad	26A	TFR-2611	Transformer	Mineral Oil	55	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	632
MPU	C Pad	26A	TR-2610	Transformer	Mineral Oil	498	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-2641	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-26XX	Transformer	Mineral Oil	135	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-26XX-05	Transformer	Mineral Oil	135	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-26XX-08	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-26XX-9	Transformer	Mineral Oil	135	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	TR-2610	Transformer	Mineral Oil	498	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-2601	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-2613	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-2614	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-2624	Transformer	Mineral Oil	250	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-2643	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-26XX-03	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-26XX-04 SPARE	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	26A	VSDT-26XX-06	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,707
MPU	C Pad	29 IWAG #2	T-2911	Lube Oil Reservoir	Lube Oil	116	Production	Stationary	Visual Observation	Visual Surveillance	Module	495
MPU	C Pad	29 IWAG #2	T-2910	Lube Oil Reservoir	Lube Oil	70	Production	Stationary	Visual Observation	Visual Surveillance	Module	495
MPU	C Pad	29 IWAG #2	T-2907	Lube Oil Reservoir	Mobil Jet II Lube Oil	130	Production	Stationary	Visual Observation	Visual Surveillance	Module	495
MPU	C Pad	29 IWAG #2	T-2909	Lube Oil Drain	Used Oil	90	Production	Stationary	Visual Observation	Visual Surveillance	Module	495
MPU	D Pad	D Pad	TR-2701	Transformer	Mineral Oil	55	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	345
MPU	E Pad	E Pad	TR-4501	Transformer	Mineral Oil	55	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	684
MPU	E Pad	E Pad	TR-4504	Transformer	Mineral Oil	55	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	684
MPU	E Pad	E Pad	VSDT-4504	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	877
MPU	E Pad	E Pad	VSDT-4506	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	877
MPU	E Pad	E Pad	VSDT-4509	Transformer	Mineral Oil	250	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	877
MPU	E Pad	E Pad	VSDT-4510	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	877
MPU	E Pad	E Pad	VSDT-4511	Transformer	Mineral Oil	250	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	877
MPU	E Pad	E Pad	VSDT-4531	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	877
MPU	E Pad	E Pad	TR-4510	Transformer	Mineral Oil	55	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,530
MPU	E Pad	E Pad	VSDT-4514	Transformer	Mineral Oil	178	Non Production	Stationary	Visual Observation	Visual Surveillance	Metal Berm with Metal Liner	1,530

MPU SPCC-Regulated Equipment

(See ODPCP Appendix A for Oil Storage Tanks >10,000 gallons)

[illegible]

MPU SPCC-Regulated Equipment

(See ODPCP Appendix A for Oil Storage Tanks >10,000 gallons)

[illegible]

MPU SPCC-Regulated Equipment

(See ODPCP Appendix A for Oil Storage Tanks >10,000 gallons)

[illegible]

MPU SPCC-Regulated Equipment

(See ODPCP Appendix A for Oil Storage Tanks >10,000 gallons)

[illegible]

Flow-Through Process Vessels

MPU	CFP	53	V-5301	2nd Separator	Oil	23,500	Production	Stationary	Visual Observation	Visual Surveillance	Module	9,983
MPU	CFP	53	V-5303	3rd Separator	Oil	7,520	Production	Stationary	Visual Observation	Visual Surveillance	Module	9,983
MPU	CFP	53	V-5302	2nd Separator	Oil	10,904	Production	Stationary	Visual Observation	Visual Surveillance	Module	9,983
MPU	CFP	53	V-5304	Treater	Oil	12,636	Production	Stationary	Visual Observation	Visual Surveillance	Module	9,983
MPU	CFP	53A	V-5318	3rd Separator	Oil	13,160	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,636
MPU	CFP	53A	V-5317	Slugcatcher	Oil	67,964	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,636
MPU	CFP	53A	V-5319	Treater	Oil	29,376	Production	Stationary	Visual Observation	Visual Surveillance	Module	6,636
MPU	CFP	54	V-5424	Accumulator	Oil	91	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5423	Desander	Oil	158	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482

MPU SPCC-Regulated Equipment

(See ODPCC Appendix A for Oil Storage Tanks >10,000 gallons)

Location				Equipment Information							Secondary Containment Information	
Area	Facility	Module	Equipment ID	Description	Product Type	Nominal Design Capacity (gallons)	Production or Non-Production Service	Stationary or Portable	Overfill Protection Device	Leak Detection System	Description	Capacity (gallons)
MPU	CFP	54	V-5421	De-oiler	Oil	63	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5422	De-oiler	Oil	192	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5419	Desander	Oil	82	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5425	De-oiler	Oil	130	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5420	Accumulator	Oil	103	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5415	Sand Filter	Produced Water	158	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5416	Sand Filter	Produced Water	90	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5412	Water Injection Surge Drum	Produced Water	8,773	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5401	Produced Water Surge Tank	Produced Water	16,850	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5411	Source Water Separator	Produced Water	12,730	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5426	Separator	Oil	100	Production	Stationary	Visual Observation	Visual Surveillance	Module	13,482
MPU	CFP	54	V-5417	Slurry Tank	Sand Jet Slurry	3,500	Production	Stationary	Visual Observation	Visual Surveillance	Timber Berm Spray-on Geomembrane Liner	11,004
MPU	CFP	62	V-6201	Gas Scrubber Vessel	Hydrocarbons	11,894	Production	Stationary	Visual Observation	Visual Surveillance	Timber Berm with Spray-on Geomembrane Liner	3,950
MPU	CFP	62	V-6202	Scrubber Vent Vessel	Hydrocarbons	510	Production	Stationary	Visual Observation	Visual Surveillance	Timber Berm with Spray-on Geomembrane Liner	3,950
MPU	B Pad	20A	V-2001	Test Separator	Oil	1,128	Production	Stationary	Visual Observation	Visual Surveillance	Module	9,324
MPU	B Pad	20A	V-2002	Test Separator	Oil	1,128	Production	Stationary	Visual Observation	Visual Surveillance	Module	9,324
MPU	C Pad	26	V-2602	Test Separator	Oil	1,128	Production	Stationary	Visual Observation	Visual Surveillance	Module	9,534
MPU	E Pad	45	V-4501	Test Separator	Oil	275	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,776
MPU	F Pad	24	V-2401	Test Separator	Oil	188	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,230
MPU	H Pad	31	V-3102	Test Separator	Oil	397	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,642
MPU	K Pad	44	V-4401	Test Separator	Oil	261	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,201
MPU	L Pad	25	V-2501	Test Separator	Oil	397	Production	Stationary	Visual Observation	Visual Surveillance	Module	1,642
MPU	S Pad	Heavy Oil Facility	H-1101	Thermal Fluid Heater Skid	Royal Purple Hy-therm 707	126	Production	Stationary	Visual Observation	Visual Surveillance	Module	463
MPU	S Pad	Heavy Oil Facility	T-1105	Heat Medium Expansion Vessel	Royal Purple Hy-therm 707	300	Production	Stationary	Visual Observation	Visual Surveillance	Module	463
MPU	S Pad	Heavy Oil Facility	V-1108	Compressor Section Scrubber	Hydrocarbons	161	Production	Stationary	Visual Observation	Visual Surveillance	Module	2,738
MPU	S Pad	Heavy Oil Facility	V-1109	Flare Knockout Drum	Hydrocarbons	1,000	Production	Stationary	Visual Observation	Visual Surveillance	Module	2,738
MPU	S Pad	8006	V-8003	Test Separator	Oil	72	Production	Stationary	Visual Observation	Visual Surveillance	Module	340
MPU	S Pad	8009	V-8001-B	Separator	Oil	7,447	Production	Stationary	Visual Observation	Visual Surveillance	Module	17,682
MPU	S Pad	8009	V-8001-A	Inclined Separator	Oil	8,332	Production	Stationary	Visual Observation	Visual Surveillance	Module	17,682

Acronyms:CLI - Continuous Level Indicator
HLA - High-Level AlarmCFP - Central Facilities Pad
LLA - Low-Level AlarmIWAG - Injection Water Alternating Gas
MPU - Mine Point Unit

LSF - Life Support Facility

INSERT 2-PAGE MEMORANDUM TO M. BRONSON DATED FEB. 25, 2011 FROM ZACH ZALATEL
RE: TECHNICAL AMENDMENT VERIFICATION FINDINGS.

Memo



Date: February 25, 2011
To: Michael Bronson, Oil Spill Prevention Compliance Authority, BP Exploration (Alaska), Inc.
From: Zachary Zaletel, P.E.
Subject: Milne Point Unit SPCC Technical Amendment Verification Findings

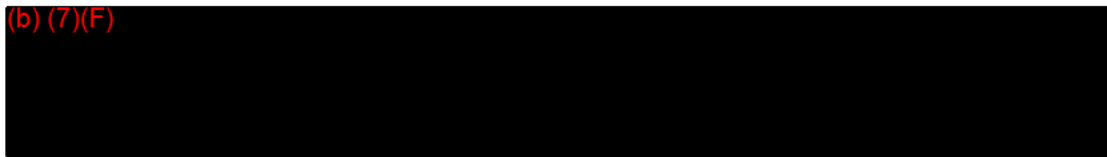
As a part of the BP Exploration (Alaska) Inc. (BPXA) Spill Prevention, Control and Countermeasures (SPCC) Technical Amendment Verification Project, Milne Point Unit (MPU) was visited on February 16, 2011 to confirm the status of changes to the list of U.S. Environmental Protection Agency (EPA) SPCC Plan & Alaska Department of Environmental Conservation (ADEC) regulated tanks and drums at the MPU facility and associated well pads. The MPU Environmental team facilitated inspection of the tanks and equipment identified by BPXA as being added, modified or removed since the last SPCC certification. The following tanks or vessels were inspected and found with the following specifics associated with/or require further action prior to certification of the equipment list:

(b) (7)(F)

A large rectangular area of the document has been redacted with a solid black box. The redaction code "(b) (7)(F)" is printed in red at the top left corner of this area.

The Gasoline Storage Tank (T-9004) for fueling has been relocated to A-Pad of MPU and was inspected and verified as being in its new location. The tank has a (b) (7)(F) [redacted] and is clearly labeled for easy identification. The secondary containment for T-9004 is a gravel dike with a geo-membrane liner; the exact capacity of the secondary containment could not be determined due to the amount of snow preventing accurate measurement of the containment; this volume will need to be recorded during the summer season. The location of T-9004 is not reflected on the current A-Pad map; a copy of the current version of the map has been included with redlines highlighting the location of the tank with respect to the other buildings on pad.

(b) (7)(F)

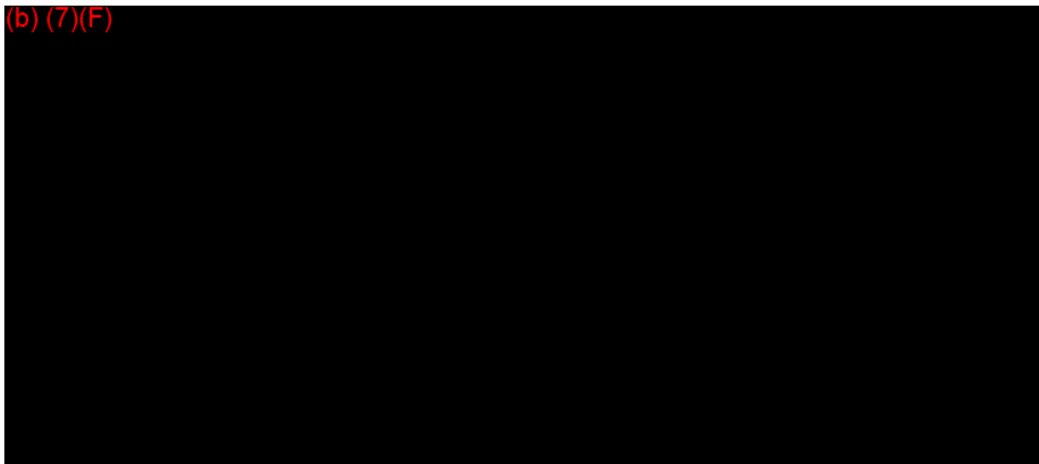
A large rectangular area of the document has been redacted with a solid black box. The redaction code "(b) (7)(F)" is printed in red at the top left corner of this area.

The large Diesel Storage Tank (T-9172), located on B-Pad, was inspected to confirm that the changes from the last SPCC inspection were completed. T-9172 has proper on-site labeling, the correct tank capacity has been determined and noted on the SPCC equipment list and the correct location of T-9172 and its secondary containment are marked correctly on the B-Pad map for the MPU.

Memo

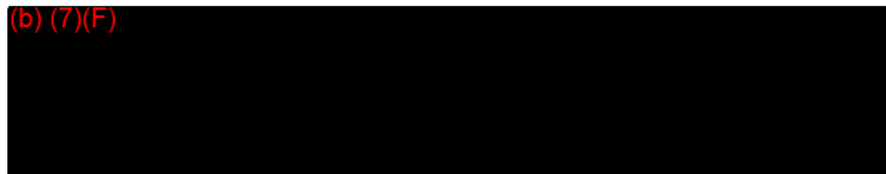


(b) (7)(F)



The Heavy Oil Facility, located on S-Pad, was inspected and verified as it has been recently constructed and will be commissioned soon. The facility and its associated equipment are labeled on some S-Pad location maps and not on others. A redlined and labeled copy of a S-Pad map is included with this memo to ensure that the proper locations of each of the equipment is updated to the most current version of the map; this map is also being sent to cartography to ensure.

(b) (7)(F)



A Mobile Fuel Truck (32-5103) has been added to the MPU fleet of SPCC regulated mobile equipment. The fuel truck has a nominal capacity of (b) (7)(F) and will be based out of Central Facility as per the MPU Environmental Advisor. The mobile fuel truck has integral secondary containment built into the tank; however it is also stored in a lined module when not in use. This is a new addition to the SPCC regulated equipment list.

INSERT 2-PAGE CERTIFICATION MEMO FROM ZACH ZALATEL DATED FEB. 16-18, 2011

Facility Name: Milne Point Unit
VERIFICATION DATE OF THE SPCC REGULATED EQUIPMENT LIST.

Facility Owner: BP Exploration Alaska, Inc.

Facility Location: North Slope Borough, Alaska

Date of Inspection: February 16-18, 2010

As a part of a semi-annual update to the Milne Point Unit (MPU) Spill Prevention, Control and Countermeasures (SPCC) Plan to reflect changes at the facilities and pads, an inspection was conducted to review changes to equipment on the MPU SPCC Regulated Equipment List. The purpose of the review is to ensure the documented equipment changes are accurately described in the list; these include equipment secondary containment (as feasible and applicable), overfill protection equipment or procedures and that the equipment is in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Table 1; any equipment whose removal was verified during this inspection has been excluded from this table.

Table 1. Equipment inspected as a part of the February 2011 MPU Equipment List Update Technical Amendment

Facility	Module or Location	Equipment Name	Tank or Equipment #
MPU	A Pad/Mobile	Mobile Refueler	32-5103
MPU	B Pad	Diesel Storage Tank	T-9172
MPU	S Pad	Emulsion Breaker Tank	T-1198
MPU	S Pad	Defoamer Storage Tank	T-1104A
MPU	S Pad	Sample Tap Flush Diesel Tank	T-1132
MPU	S Pad	Sample Tap Holding Tank	T-1133
MPU	S Pad	Diesel Day Tank (Generator)	GN-1101
MPU	S Pad	Transformer	XMFR-1101
MPU	S Pad	Thermal Fluid Heater Skid	H-1101
MPU	S Pad	Heat Medium Expansion Vessel	T-1105
MPU	S Pad	Compressor Section Scrubber	V-1108
MPU	S Pad	Flare Knockout Drum	V-1109

I hereby certify the following:

- (i) That I am familiar with the requirements of 40 C.F.R. 112;
- (ii) That I or my agent has visited and examined the facility;
- (iii) That the technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part;
- (iv) That procedures for required inspections and testing have been established; and
- (v) That the information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature: _____

Date of Certification: _____

Professional Engineer's Stamp: _____



STATE OF ALASKA
 49TH
 2/21/2010
 SIMON J. DAWSON
 CE 6396
 REGISTERED PROFESSIONAL ENGINEER

PROFESSIONAL ENGINEER SPCC CERTIFICATION OF

~~SPCC PLAN TECHNICAL AMENDMENT~~
 INSERT 3-PAGE TECHNICAL AMENDMENT DATED APRIL 23, 2010 CERTIFIED BY ZACH ZALATEL.

Non-Mobile Equipment Fleet

I hereby certify that I or my agent has examined secondary containment for non-stationary regulated tanks in the BPXA non-mobile equipment fleet and I am familiar with the provisions of 40 CFR Part 112.

I certify that full-size secondary containment is impracticable for fuel tanks on the trailered equipment known as the BPXA "non-mobile fleet." The list of equipment covered by the impracticability statement is attached.

Modification of the listed equipment to provide full-sized secondary containment is impractical based on one or more of the reasons below.

1. Installing additional containment could interfere with the functionality (portability) of the equipment (lowering road clearance, or reducing tire clearance).
2. Additional containment on manufactured equipment could change center of gravity of trailered equipment, causing possible tipping hazards or increased or decreased tongue loads.
3. Major modifications to equipment could void the manufacturer's warranty.
4. Additional modification to base frame could impact electrical and fuel line routing or the support structure for tank or engine.
5. Additional underside plating would reduce natural ventilation for engine cooling.
6. Additional plating would reduce access to portions of equipment for repairs and annual maintenance and tank inspections.
7. Currently, full-sized secondary containment on trailered equipment is not commercially available.

The trailered fleet is highly mobile and typically at one location from a few hours to several days. Providing full-sized containment during the short time the equipment is at one location is impracticable for the reasons specified below.

- The equipment often is used at a facility or on a well pad with simultaneous operations and considerable space constraints.
- The risk to personnel safety while constructing and operating near temporary secondary containments is considerable. Safety issues include slips, trips, falls, crushing injuries and wind-related incidents.
- The materials used to construct temporary secondary containments are meant for long-term, stationary use, not for frequent construction and dismantling.
- Temporary containments would increase snow drifting around structures and equipment.

- Temporary containments typically require mobile equipment to be backed in. As most vehicle accidents occur during backing, there would be an increased risk of personnel injury and the possibility of damaging equipment and associated fuel tanks.
- Snow removal work would be restricted by temporary secondary containments, creating additional possible vehicle/equipment impact hazards.

BPXA will minimize the risk of an oil spill from trailered equipment by following the steps outlined below.

- The integrity of built-in drip pans is checked during preventative maintenance.
- For non-motive fuel tanks without a built-in sealed drip pan, "duck pond" containment liners are placed under the tanks during use and storage.
- On rare occasions, equipment from the non-mobile fleet (e.g., a generator set) may be in a location longer than the typical hours to days. As a best management practice, BPXA requires equipment that is holding oil and positioned at one location for more than 180 days¹ to be provided full-sized secondary containment (110% of the tank capacity).


Signature

2-15-2010
Date

Name	Tony SlatonBarker
Company	BPXA
Address	900 E. Benson, Anchorage, Alaska, 99519
Alaska Registration No.	CE 10259



Stamp in Space Above

¹ "Temporary" structures are buildings, tents and other structures intended to remain in place for a period of no more than 180 days, as defined by the International Business Code (Section 3103) and International Fire Code/National Fire Protection Association (Section 3.3.254).

Covered Equipment

Generators

- AK Detroit Diesel 60kW
- Caterpillar 100kW
- Delco 100kW
- Emerson 315kW
- Emerson 995kW
- Ingersoll-Rand 30kW
- Ingersoll-Rand 62kW
- Ingersoll-Rand 65kW
- International 60kW
- John Deere 60kW
- Kato 650kW
- Magnum MMG80 65kW
- Baylor (1985) 160kW

Pumps

- Equipment Source Triplex
- Tritan Triplex

Heaters

- Equipment Source 600k - 999k BTU
- Equipment Source 600k BTU
- Equipment Source 700k BTU
- Equipment Source 1.2MM BTU
- Equipment Source 1.5MM BTU
- Tioga 20k BTU
- Tioga 600k BTU
- Tioga 900k BTU
- Tioga 1.2MM BTU

Compressors

- Ingersoll-Rand 600 CFM
- Ingersoll-Rand 1100 CFM
- Ingersoll-Rand 1300 CFM
- Ingersoll-Rand HP3100WCU
- Joy 1300 CFM

Light Towers

- Allmand Brothers
- Ingersoll-Rand
- Maxi-Lite

THIS PAGE INTENTIONALLY LEFT BLANK

Facility Name: Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: April 23, 2010

INSERT 3-PAGE TECHNICAL AMENDMENT CERTIFICATION FOR NON-MOBILE EQUIPMENT FLEET DATED 2/15/2010 CERTIFIED BY TONY SLATON-BARKER.

As a part of a semi-annual update to the Milne Point Unit (MPU) Spill Prevention, Control and Countermeasures (SPCC) Plan to reflect changes at the facility, an inspection was conducted to review changes to equipment on the MPU Regulated Equipment List. The purpose of the review is to ensure the documented equipment changes are accurately described, have secondary containment (as feasible and applicable), have overfill protection equipment or procedures and are in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Table 1.

Table 1. Equipment inspected as a part of the April 2010 MPU Equipment List Update Technical Amendment

Facility	Pad	Module or Location	Tank or Equipment #
MPU	CFP	4 (LSF)	T-0107
MPU	CFP	4 (LSF)	T-0106A
MPU	CFP	4 (LSF)	T-0106B
MPU	CFP	On pad near Module 47	T-4704
MPU	CFP	On pad near Module 47	T-4705
MPU	CFP	On pad near Module 47	T-4706
MPU	CFP	On pad near Module 47	T-4708
MPU	CFP	On pad near Module 47	T-4711
MPU	CFP	On pad near Module 47	T-4712
MPU	CFP	On pad near Module 47	T-4713
MPU	CFP	On pad near Module 47	T-4714
MPU	CFP	On pad near Module 47	T-4715
MPU	CFP	On pad near Module 47	T-4716
MPU	CFP	On pad near Module 47	T-4717
MPU	CFP	CFP	68-5629
MPU	A-Pad	A-Pad	86-5202
MPU	A-Pad	A-Pad	86-5701
MPU	A-Pad	A-Pad	88-5502
MPU	A-Pad	A-Pad	88-5503
MPU	A-Pad	A-Pad	88-5504
MPU	A-Pad	A-Pad	88-5505
MPU	A-Pad	A-Pad	88-5506
MPU	A-Pad	A-Pad	88-5507
MPU	A-Pad	A-Pad	88-5508
MPU	A-Pad	A-Pad	88-5509
MPU	A-Pad	A-Pad	88-5510
MPU	A-Pad	A-Pad	88-5511
MPU	A-Pad	A-Pad	88-5512
MPU	A-Pad	A-Pad	88-5513

Facility	Pad	Module or Location	Tank or Equipment #
MPU	A-Pad	A-Pad	88-5514
MPU	A-Pad	A-Pad	88-5515
MPU	A-Pad	A-Pad	89-5505 (replaces 88-5516)
MPU	A-Pad	A-Pad	88-5517
MPU	A-Pad	A-Pad	88-5518
MPU	A-Pad	A-Pad	89-5506 (replaces 88-5519)
MPU	A-Pad	A-Pad	88-5520
MPU	A-Pad	A-Pad	88-5521
MPU	A-Pad	A-Pad	88-5522
MPU	A-Pad	A-Pad	88-5523
MPU	A-Pad	A-Pad	89-5507 (replaces 88-5524)
MPU	A-Pad	A-Pad	88-5525
MPU	A-Pad	A-Pad	88-5526
MPU	A-Pad	A-Pad	88-5527
MPU	A-Pad	A-Pad	88-5528
MPU	A-Pad	A-Pad	88-5529
MPU	A-Pad	A-Pad	88-5530
MPU	A-Pad	A-Pad	89-5508 (replaces 88-5531)
MPU	A-Pad	A-Pad	89-5509 (replaces 88-5532)
MPU	A-Pad	A-Pad	89-5510 (replaces 88-5533)
MPU	A-Pad	A-Pad	89-5511 (replaces 88-5534)
MPU	A-Pad	A-Pad	89-5512 (replaces 88-5535)
MPU	A-Pad	A-Pad	89-5513 (replaces 88-5536)
MPU	A-Pad	A-Pad	89-5514 (replaces 88-5537)
MPU	A-Pad	A-Pad	89-5515 (replaces 88-5538)
MPU	A-Pad	A-Pad	89-5516 (replaces 88-5539)
MPU	A-Pad	A-Pad	89-5517 (replaces 88-5540)
MPU	A-Pad	A-Pad	89-5518 (replaces 88-5541)
MPU	A-Pad	A-Pad	89-5501
MPU	A-Pad	A-Pad	89-5502
MPU	A-Pad	A-Pad	89-5503
MPU	A-Pad	A-Pad	89-5504
MPU	A-Pad	A-Pad	88-5542
MPU	A-Pad	A-Pad	80-5053
MPU	A-Pad	A-Pad	68-5627
MPU	A-Pad	A-Pad	90-5501
MPU	A-Pad	A-Pad	90-5502
MPU	A-Pad	A-Pad	90-5803

Facility	Pad	Module or Location	Tank or Equipment #
MPU	A-Pad	90	T-9002/T4
MPU	A-Pad	90	T-9002/T5
MPU	A-Pad	90	T-9002/T6
MPU	A-Pad	90	T-9002/T7
MPU	A-Pad	90	T-9003
MPU	A-Pad	68-5601 (Spooling Unit)	T-1120
MPU	A-Pad	68-5601 (Spooling Unit)	T-1121
MPU	A-Pad	68-5601 (Spooling Unit)	80-5051
MPU	A-Pad	Yard	T-9001
MPU	B-Pad	B-Pad	T-9172
MPU	C-Pad	C-Pad Module 26 Diesel Loading Area	T-2601
MPU	J-Pad	J-Pad	V-3304 (Removed from service)

I hereby certify the following:

- (i) That I am familiar with the requirements of 40 C.F.R. 112;
- (ii) That I or my agent has visited and examined the facility;
- (iii) That the technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part;
- (iv) That procedures for required inspections and testing have been established; and
- (v) That the information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature:

Zachary John Ziskind

Date of Certification:

14-June-2010

Professional Engineer's Stamp:



THIS PAGE INTENTIONALLY LEFT BLANK

Facility Name: Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: June 28, 2011

As a part of a semi-annual update to the Milne Point Unit (MPU) Spill Prevention, Control and Countermeasures (SPCC) Plan to reflect changes at the facility, an inspection was conducted to review changes to equipment on the MPU Regulated Equipment List. The purpose of the review is to ensure the documented equipment changes are accurately described in the list; these include equipment secondary containment (as feasible and applicable), overfill protection equipment or procedures and that the equipment is in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Table 1.

Table 1. Equipment inspected as a part of the 2nd Quarter 2011 MPU Equipment List Update Technical Amendment

Facility	Module or Location	Master Equipment List #	Tank or Equipment Name
MPU	G Pad Module 3010	T-3071	Chemical Storage Tank
MPU	H-Pad Module 1105	T-1130	Chemical Storage Tank
MPU	I-Pad Module 1106	T-1131	Chemical Storage Tank
MPU	S-Pad Heavy Oil Facility	T-1198	Emulsion Breaker Tank

I hereby certify the following:

- (i) That I am familiar with the requirements of 40 C.F.R. 112;
- (ii) That I have or my agent has visited and examined the facility;
- (iii) That the technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part;
- (iv) That procedures for required inspections and testing have been established; and
- (v) That the information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature:

Zechariah John Zolofel

Date of Certification:

06/29/11

Professional Engineer's Stamp:



THIS PAGE INTENTIONALLY LEFT BLANK

Facility Name: Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: October 13, 2011

As a part of a quarterly update to the Milne Point Unit (MPU) Spill Prevention, Control, and Countermeasures (SPCC) Plan to reflect changes at the facility, an inspection was conducted to review changes to equipment on the MPU Regulated Equipment List. The review ensures the documented equipment changes are accurately described in the list. The equipment changes include equipment secondary containment (i.e., feasible and applicable), overfill protection equipment or procedures, and verification of the equipment being included in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Table 1.

Table 1. Equipment Inspected as a Part of the 3rd Quarter 2011 MPU Equipment List Update Technical Amendment

Facility	Module or Location	Equipment No.	Equipment Name
MPU	CFP	68-5629	Diesel Tank (for Emergency Response Trailer Generator)
MPU	A Pad	89-5519	Diesel Tank (Heater)
MPU	A Pad	89-5520	Diesel Tank (Heater)
MPU	A Pad	BLDT-1104	Bleed Trailer
MPU	A Pad	BLDT-1105	Bleed Trailer
MPU	C Pad, Module 26 (Generator Room)	T-2603	Diesel Day Tank (Generator)
MPU	S Pad, Modules 8001/8004	NA, storage drums are not assigned permanent equipment number/tag	Drum Storage Area (Approximately 3 drums of Production Fluids)
MPU	S Pad, outside Heavy Oil Facility	NA, storage drums are not assigned permanent equipment number/tag	Drum Storage Area (Approximately 6 totes)
MPU	S Pad, Heavy Oil Facility, Process Module 1101	NA, storage drums are not assigned permanent equipment number/tag	Drum Storage Area (Approximately 1 drum Pegasus 710)
MPU	A Pad, Yard	T-9004	Gasoline Storage Tank
MPU	B Pad	T-9172	Diesel Storage Tank
MPU	G Pad, Module 3040	T-3074	Chemical Storage Tank (Corrosion Inhibitor)
MPU	H Pad, Module 1105	T-1130	Chemical Storage Tank (Corrosion Inhibitor)
MPU	I Pad, Module 1106	T-1134	Chemical Storage Tank (Corrosion Inhibitor)
MPU	S Pad, Module 8005 (Chemical Injection Skid)	T-8004	Chemical Storage Tank (Emulsion Breaker)
MPU	S Pad, Module 8005 (Chemical Injection Skid)	T-8003	Chemical Storage Tank (Scale Inhibitor)
MPU	CFP, Fuel Loading/ Offloading Area	NA, storage drums are not assigned permanent equipment number/tag	Approximately 15 drums (Fuel Conditioner)
MPU	D Pad, Drum Storage Area	NA, storage drums are not assigned permanent equipment number/tag	Approximately 6 totes (Royal Purple)
MPU	S Pad, Heavy Oil Facility	XFRM-1101	Transformer (Mineral Oil)

I hereby certify the following statements:

- (i) I am familiar with the requirements of 40 CFR 112.
- (ii) I have or my agent has visited and examined the facility.
- (iii) The technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and with the requirements of this part.
- (iv) Procedures for required inspections and testing have been established.
- (v) The information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature: _____

Date of Certification: _____

Professional Engineer's Stamp:



Facility Name: Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: December 5–8, 2011

As a part of a quarterly update to the Milne Point Unit (MPU) Spill Prevention, Control, and Countermeasures (SPCC) Plan to reflect changes at the facility, an inspection was conducted to review changes to equipment on the MPU Regulated Equipment List. The review ensures the documented equipment changes are accurately described in the list. The equipment changes include equipment secondary containment (i.e., feasible and applicable), overfill protection equipment or procedures, and verification of the equipment being included in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Table 1.

Table 1. Equipment Inspected as a Part of the 4th Quarter 2011 MPU Equipment List Update Technical Amendment

Facility	Module or Location	Equipment No.	Equipment Name
MPU	S-Pad	T-8003	8005 Chem Injection Skid

I hereby certify the following statements:

- (i) I am familiar with the requirements of 40 CFR 112.
- (ii) I have or my agent has visited and examined the facility.
- (iii) The technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and with the requirements of this part.
- (iv) Procedures for required inspections and testing have been established.
- (v) The information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature:

Zachary J. Zolot

Date of Certification:

12/20/2011

Professional Engineer's Stamp:



THIS PAGE INTENTIONALLY LEFT BLANK

Facility Name: Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: December 5–8, 2011

As a part of a quarterly update to the Milne Point Unit (MPU) Oil Discharge Prevention and Contingency Plan (ODPCP) to reflect changes at the facility, an inspection was conducted to verify and update the equipment in Tables 3-1 and Appendix A. The purpose of the review is to confirm that the equipment is accurately described, has secondary containment (as feasible and applicable), and has overfill protection equipment or procedures. Equipment verified as a part of this technical amendment is included in Table 3-1, 'Milne Point Unit Regulated Stationary Oil Storage Tanks Greater than 10,000 Gallons, and 'ADEC-Regulated Portable, Shop-Fabricated Storage Tank Data for Tanks Greater than 10,000 gallons on BPXA Leases' located in Appendix A of the MPU Oil Discharge Prevention and Contingency Plan, as of Revision 1, dated January 2012.

Equipment verified as part of this technical amendment is listed in Table 1.

Table 1. Equipment Inspected as a Part of the 4th Quarter 2011 MPU Equipment List Update Technical Amendment

Facility	Module or Location	Equipment No.	Equipment Name
MPU	S Pad	T-1102	Separator Tank - vertical, cylindrical, single-wall with cone-down bottom
MPU	S Pad	T-1128	Separator Tank - vertical, cylindrical, single-wall with cone-down bottom

I hereby certify the following statements:

- (i) I am familiar with the requirements of 40 CFR 112.
- (ii) I have or my agent has visited and examined the facility.
- (iii) The technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and with the requirements of this part.
- (iv) Procedures for required inspections and testing have been established.
- (v) The information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature: _____

Date of Certification: _____

Professional Engineer's Stamp: _____



STATE OF ALASKA
49TH
Zachary John Zolotek
EC-12143
6/27/2012
REGISTERED PROFESSIONAL ENGINEER

Facility Name: Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: May 21, 2012

As part of a quarterly update to the Milne Point Unit (MPU) Spill Prevention, Control, and Countermeasures (SPCC) Plan to reflect changes at the facility, an inspection was conducted to review changes to equipment on the MPU Regulated Equipment List. The review ensures the documented equipment changes are accurately described in the list. The equipment changes include secondary containment (i.e., feasible and applicable), overfill protection equipment or procedures, and verification of the equipment being included in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Table 1.

Table 1. Equipment inspected as a part of the 2nd Quarter 2012 MPU Equipment List Update Technical Amendment

Facility	Module or Location	Equipment No.	Equipment Name
Modified or Added to Regulated Equipment List			
MPU	58	T-5812	Chemical Storage Tank
MPU	A Pad	BLDT 1111	Bleed Trailer
MPU	A Pad	BLDT 1112	Bleed Trailer
MPU	A Pad	BLDT 1113	Bleed Trailer
MPU	A Pad	XMFR-9012B	Transformer
Removed from Regulated Equipment List			
MPU	A Pad	88-5507	Diesel Tank (Heater)
MPU	A Pad	88-5508	Diesel Tank (Heater)
MPU	A Pad	88-5509	Diesel Tank (Heater)
MPU	A Pad	88-5510	Diesel Tank (Generator)
MPU	A Pad	88-5511	Diesel Tank (Heater)
MPU	A Pad	BLDT 1104	Bleed Trailer
MPU	A Pad	BLDT 1105	Bleed Trailer
MPU	CFP	Drum Storage located in Fuel Loading/Unloading Area	Approximately 15 drums in the Drum Storage Area
MPU	B Pad Module 20	V-2002	Test Separator
MPU	B Pad Module 20A	V-2001A	Production Monitoring Separator
MPU	D Pad	T-2704	Diesel Storage Tank
MPU	G Pad Module 3010	T-3071	Chemical Storage Tank
MPU	H Pad Module 1105	T-1130	Chemical Storage Tank
MPU	I Pad Module 1106	T-1131	Chemical Storage Tank

I hereby certify the following statements:

- (i) I am familiar with the requirements of 40 CFR 112.
- (ii) I have or my agent has visited and examined the facility.

- (iii) The technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and with the requirements of this part.
- (iv) Procedures for required inspections and testing have been established.
- (v) The information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature:

Zachary John Zolatel

Date of Certification:

6/11/2012

Professional Engineer's Stamp:



Facility Name: Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: December 18-19, 2012

As part of a quarterly update to the Milne Point Unit (MPU) Spill Prevention, Control, and Countermeasures (SPCC) Plan to reflect changes at the facility, an inspection was conducted to review changes to equipment on the MPU Regulated Equipment List. The review ensures the documented equipment changes are accurately described in the list. The equipment changes include secondary containment (i.e., feasible and applicable), overfill protection equipment or procedures, and verification of the equipment being included in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Table 1.

Table 1. Inspected as a part of the 3rd & 4th Quarters 2012 MPU Equipment List Update Technical Amendment

Facility	Module or Location	Equipment No.	Equipment Name
Modified or Added to Regulated Equipment List			
MPU	A Pad	T-9016	Gasoline Storage Tank
MPU	D Pad	N/A	Drum Storage Area
MPU	Skid 4	XFMR-0102	Transformer
MPU	Skid 20	VSDT-20XX	Transformer
MPU	Skid 20	XFMR-2002	Transformer
MPU	Skid 26A	TR-2610	Transformer
MPU	L Pad	TR-2510	Transformer
Removed from Regulated Equipment List			
MPU	L Pad	TR-2510	Transformer (replaced with new)
MPU	D Pad	T-2704	Diesel Storage Tank (Removed)
MPU	A Pad	88-5502	Diesel Tank (Heater) (Removed)
MPU	A Pad	88-5503	Diesel Tank (Heater) (Removed)
MPU	A Pad	88-5504	Diesel Tank (Heater) (Removed)
MPU	A Pad	88-5505	Diesel Tank (Heater) (Removed)
MPU	A Pad	88-5506	Diesel Tank (Heater) (Removed)

I hereby certify the following statements:

- (i) I am familiar with the requirements of 40 CFR 112.

- (ii) I have or my agent has visited and examined the facility.
- (iii) The technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and with the requirements of this part.
- (iv) Procedures for required inspections and testing have been established.
- (v) The information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature: _____

Date of Certification: _____

Professional Engineer's Stamp:



Facility Name: Greater Prudhoe Bay Unit and Milne Point Unit
Facility Owner: BP Exploration Alaska, Inc.
Facility Location: North Slope Borough, Alaska
Date of Inspection: May 2013

As part of a quarterly update to the Greater Prudhoe Bay (GPB) and Milne Point (MP) Units Spill Prevention, Control, and Countermeasures (SPCC) Plans to reflect changes at the facilities, an inspection was conducted to review changes to equipment on the GPB and MPU Regulated Equipment Lists.

The May 2013 inspections were conducted to ensure the documented equipment changes are accurately described in the lists. The equipment changes include secondary containment (i.e., feasible and applicable), overfill protection equipment or procedures, and verification of the equipment being included in a regular inspection program. Equipment verified as a part of this technical amendment is listed in Tables 1 and 2. Details of equipment use, secondary containment volumes, and the like, are found in Volume 2 of the GPB and MPU Oil Discharge Prevention and Contingency Plans (ODPCP), starting on pg. SPCC-21.

Table 1. Equipment Inspected as part of the 1st Quarter 2013 GPB Equipment List Update Technical Amendment

ADDED OR MODIFIED ON THE REGULATED EQUIPMENT LIST				
Facility	Module or Location	Equipment No.	Equipment Name	Secondary Containment Description
EOA	DSM	90864 TNK02	Storage Tank	Active Containment
EOA	DSM	90864 TNK02	Storage Tank	Active Containment
EOA	DSM	94-769	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-770	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-771	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-772	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-773	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-774	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-775	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-782	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-783	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-784	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-785	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	94-786	Stainless Steel Portable Trailer	IC, Active Containment
EOA	DSM	B-61	Horizontal Single Wall, Trailer Mounted Tank	IC/BDL
EOA	DSM	O-34	Storage Tank	BDL
EOA	DSM	O-35	Storage Tank	BDL
Equip Svc	Equip Svc	68-903	Emergency Shower Trailer Generator	IC
Equip Svc	Equip Svc	68-904	Emergency Shower Trailer Generator	IC
Equip Svc	Equip Svc	68-905	Emergency Shower Trailer Generator	IC
Equip Svc	Equip Svc	80-030	Generator - 10 KW	DW
Equip Svc	Equip Svc	80-343	Generator - 36 KW	IC
Equip Svc	Equip Svc	80-344	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-345	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-346	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-347	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-348	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-349	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-350	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-351	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-352	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	80-353	Generator - 36 KW Trailer Mounted	IC
Equip Svc	Equip Svc	86-513	Compressor - 675 CFM 175 PSI	IC/Drip sheet

Table 1. Equipment Inspected as part of the 1st Quarter 2013 GPB Equipment List Update Technical Amendment
(Continued)

ADDED OR MODIFIED ON THE REGULATED EQUIPMENT LIST (Continued)				
Facility	Module or Location	Equipment No.	Equipment Name	Secondary Containment Description
Equip Svc	Equip Svc	89-600	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-601	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-602	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-603	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-604	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-605	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-606	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-607	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-608	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-609	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-610	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-611	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-612	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-613	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-614	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-615	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-616	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-617	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-618	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-619	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-620	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-621	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-622	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-623	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-624	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-625	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-626	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-627	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-628	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-629	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-630	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-631	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-632	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-633	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-634	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-635	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-636	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-637	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-638	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-639	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-640	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-641	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-642	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-643	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-644	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-645	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-646	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-647	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-648	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-649	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-650	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-651	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-652	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-653	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-654	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-655	Heater 700K BTU w/Light Tower	IC

Table 1. Equipment Inspected as part of the 1st Quarter 2013 GPB Equipment List Update Technical Amendment (Continued)

ADDED OR MODIFIED ON THE REGULATED EQUIPMENT LIST (Continued)				
Facility	Module or Location	Equipment No.	Equipment Name	Secondary Containment Description
Equip Svc	Equip Svc	89-656	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-657	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-658	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	89-659	Heater 700K BTU w/Light Tower	IC
Equip Svc	Equip Svc	90-896	1500 GPM Fire Water Pump (Trailer)	BDL
Equip Svc	Equip Svc	90-897	1500 GPM Fire Water Pump (Trailer)	BDL
Equip Svc	Equip Svc	94-800	Lube Bay Diesel Tank	MFS
PBOC Fleet Shop	Equip Svc	94-801	Lube Bay OW30 Storage Tank	MFS
PBOC Fleet Shop	Equip Svc	94-802	Lube Bay 75W90 Storage Tank	MFS
PBOC Fleet Shop	Equip Svc	94-803	Lube Bay 15W40 Storage Tank	MFS
PBOC Fleet Shop	Equip Svc	94-804	Lube Bay Used Oil Storage Tank	MFS
PBOC Fleet Shop	Equip Svc	94-805	Shop Fluid Recovery Filter Unit	MFS
PBOC Fleet Shop	Equip Svc	94-806	Shop Used Oil Recovery Unit	MFS
Equip Svc	Equip Svc	94-818	Waste Oil Holding Tank	BDL
Equip Svc	Equip Svc	94-819	Waste Oil Holding Tank	MFS
Equip Svc	Equip Svc	94-820	Waste Oil Holding Tank	MFS
Equip Svc	Equip Svc	98-400	Envirovac 28 ft Trailer (Diesel Generator)	BDL

Table 2. Equipment Inspected as part of the 1st Quarter 2013 MPU Equipment List Update Technical Amendment

ADDED OR MODIFIED ON THE REGULATED EQUIPMENT LIST				
Facility	Module or Location	Equipment No.	Equipment Name	Secondary Containment Description
D Pad	Drum Storage Area	N/A, storage drums are not assigned permanent equipment number/tag	Approximately 24 drums and 12 totes (400 gals each)	Timber berm with geomembrane liner

I hereby certify the following statements:

- (i) I am familiar with the requirements of 40 CFR 112.
- (ii) I have or my agent has visited and examined the facility.
- (iii) The technical amendment has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and with the requirements of this part.
- (iv) Procedures for required inspections and testing have been established.
- (v) The information and procedures for the vessels listed in the technical amendment are correct and adequate for the facility.

Signature: _____

Julie Hoffman

Date of Certification: _____

06.14.13

Professional Engineer's Stamp: _____



THIS PAGE INTENTIONALLY LEFT BLANK