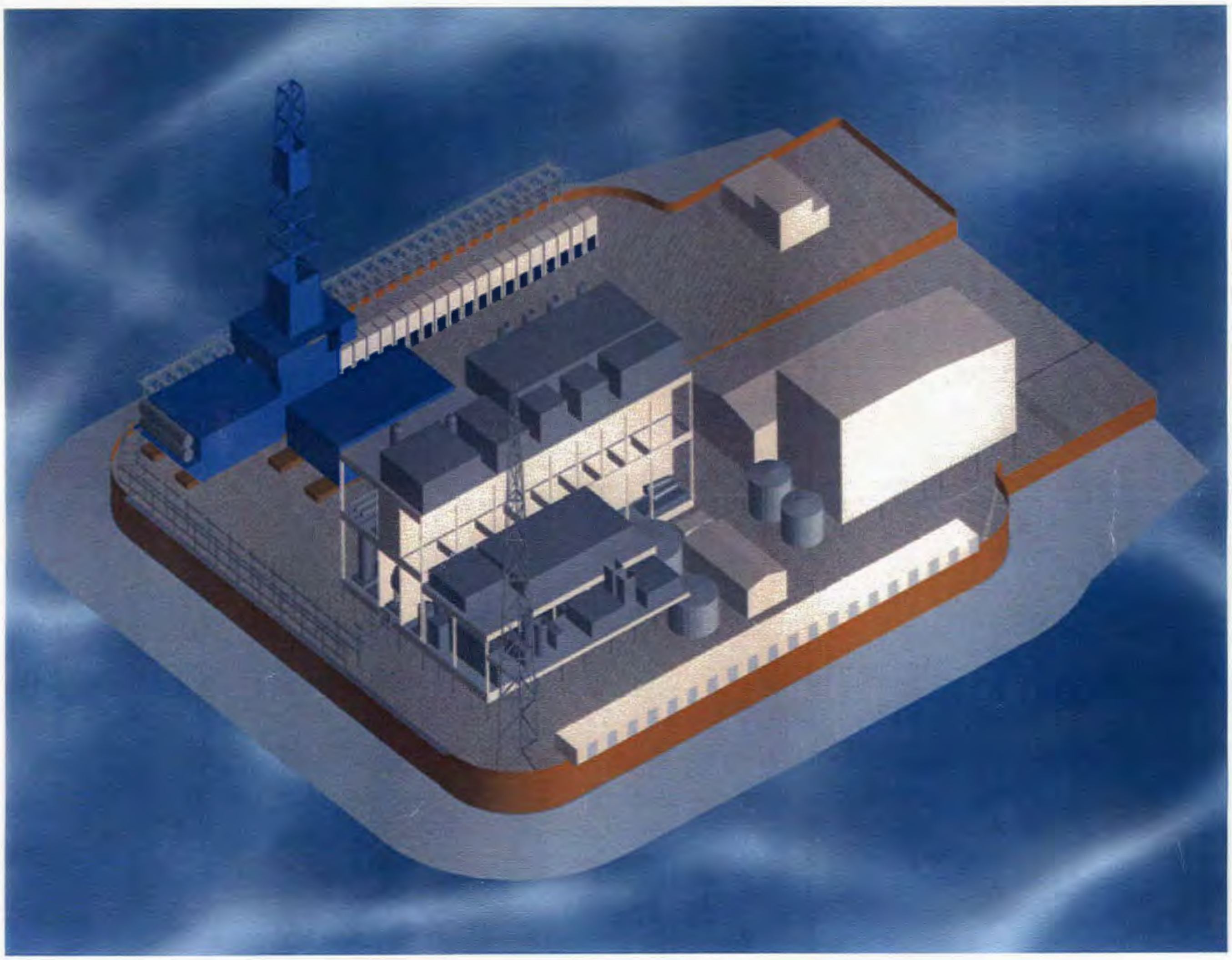
NORTHSTAR DEVELOPMENT PROJECT



FINAL PROJECT DESCRIPTION

DEPARTMENT OF THE ARMY
U.S. ARMY ENGINEER DISTRICT, ALASKA
P.O. BOX 898
ANCHORAGE, ALASKA 99506-0898

REPLY TO ATTENTION OF:

OCTOBER 14 1999

Paul
Rec'd 10/29/99
copy to FO

Regulatory Branch
North Section
O-950372

Mr. Glenn Gray
State Pipeline Coordinators Office
Division of Governmental Coordination
c/o P.O. Box 110030
Juneau, Alaska 99811-0030

Dear Mr. Gray:

This is in response to a request from BP Exploration (Alaska), Incorporated, dated August 19, 1999, concerning a modification of Department of the Army permit number N-950372, Beaufort Sea 441. That permit was issued to BP Exploration on May 3, 1999, for development of the Northstar Project.

BP Exploration presently requests that authorization be granted for the following changes in the development plan. Details are included on the enclosed plans dated February, July, and September 1999.

1) Relocation of the center of the reconstructed Seal Island 150 feet to the southwest due to movement of the remnant island (see revised coordinates on Figures 2 and 3).

2) An increase in the fill volume for the reconstructed Seal Island from 724,000 cy to 750,000 cy due to continued erosion of the remnant island.

3) Relocation of the excess trench spoils disposal zones (see revised Figure 7) to:

		Latitude	Longitude
Zone 1	NE corner	70° 26′ 29.49″	148° 41′ 49.23″
	NW corner	70° 26′ 28.46″	148° 43′ 08.44″
	SW corner	70° 26′ 16.66″	148° 43′ 07.06″
	SE corner	70° 26′ 17.70″	148° 41′ 47.87″
Zone 2	NE corner	70° 29′ 19.33″	148° 41′ 44.39″
	NW corner	70° 29′ 19.26″	148° 41′ 50.27″
	SW corner	70° 26′ 17.94″	148° 41′ 29.33″
	SE corner	70° 26′ 18.02″	148° 41′ 23.46″

4) Relocation of the compressor pad from the CCP to 1.25 miles west along the pipeline access road between the CCP and C-pad. The proposed site is adjacent to an existing caribou crossing (see revised Figures 15 and 16). Fill volume for this pad would be increased over the previously authorized compressor pad from 2,700 cy to 7,500 cy, and the total new footprint from 0.3 acres to 0.8 acres, including the reshaped caribou crossing.

5) Relocation of ice roads, proposed primary water source, material staging area, and temporary spoils placement sites, and addition of ice dumping areas, as shown on the figure titled "Northstar: Pipeline and Island Construction Ice Roads" (replaces figure 2.1-6 in Project Description).

6) Expansion of the landfall pad from 70' x 135' to 110' x 175' (see revised Figure 12) which would increase the total footprint from 0.2 acres to 0.4 acres, and increase the fill volume from 2,100 cy to 3,211 cy. The additional area is for a larger helicopter landing pad to accommodate a Bell 212 helicopter.

7) Additional excavation and placement of thaw stable fill below the pipelines at the shore crossing would result in placement of 7,274 cy of thaw stable gravel and 682 cy of native fill, increases from 700 cy and 100 cy, respectively. The depth of excavation and fill below the pipelines between the shoreline and the valve pad would be increased to 8 feet and gravel backfill would be placed below the pipelines in the seabed out to 400 feet from the shoreline (see revised Figure 13). A bentonite plug would be placed within the trench to prevent seawater from impregnating the shoreward section of trench (see revised Figures 13 and 13a).

8) Changes in the Mining and Rehabilition Plan for the Northstar minesite as shown in revised Figures 18, 19, and 21. The changes are to avoid great depths in the northeast corner and to possibly excavate deeper in the other portion of the pit. The boundaries of the mining area would not change, however a bench may be created at -20 in the northeast corner.

9) The area for temporary windrows of spoil material adjacent to the ice slot from excavation of the pipeline trench in bottomfast ice would be extended to the 8 foot isobath on the outside of the barrier islands (see Figure 7a). Previously it was planned for this material to be stored in disposal Zone 1 or Zone 2.

10) Relocation of the gravel reload area from the shore side of Egg Island to the ocean side of Egg Island (see Figure titled "Northstar: Pipeline and Island Construction Ice Roads"). The selected site is shallow enough that the sea ice would be grounded.

11) Addition of three simultaneous tests of the submersible soil agitator pump system at locations (see Figure D) along the offshore pipeline trench:

At test section "A", up to 500 feet of undisturbed seafloor would be excavated to a depth of 5 feet to test the operation of the system; excavated slurry would be deposited adjacent to and behind the soil agitator sled, within the ultimate pipeline trench footprint (Figure A).

At test section "B", up to 500 feet of previously excavated trench (excavation by backhoe bucket) would perform cleanout of the trench (Figure B), depositing slurry material adjacent to the trench in the area identified on Figure E; up to 3.41 acres of seabed could be covered by the sidecast slurry.

At test section "C", up to 500 feet of undisturbed seafloor would be excavated by pipe-jetting with the soil agitator pump system to test its use for adjusting the trench bottom after the pipe is placed (Figure C). The system would also be used to transport the excavated material back into the trench.

Additional changes of which we have been advised, but are not authorized by the DA permit include:

12) Inclusion of the ball mill within the drill rig, therefore its removal from the island dock area (see revised Figures 2 and 3).

13) Removal of the pipeline expansion cofferdam from the construction plan and thus from Figures 2 and 11.

14) Addition of an option to drive VSMs at the Putuligayuk River crossing rather than drilling holes for installation of VSMs.

We are also requesting comments on the Geotechnical Investigation report distributed to the agencies by BP Exploration on September 22, 1999.

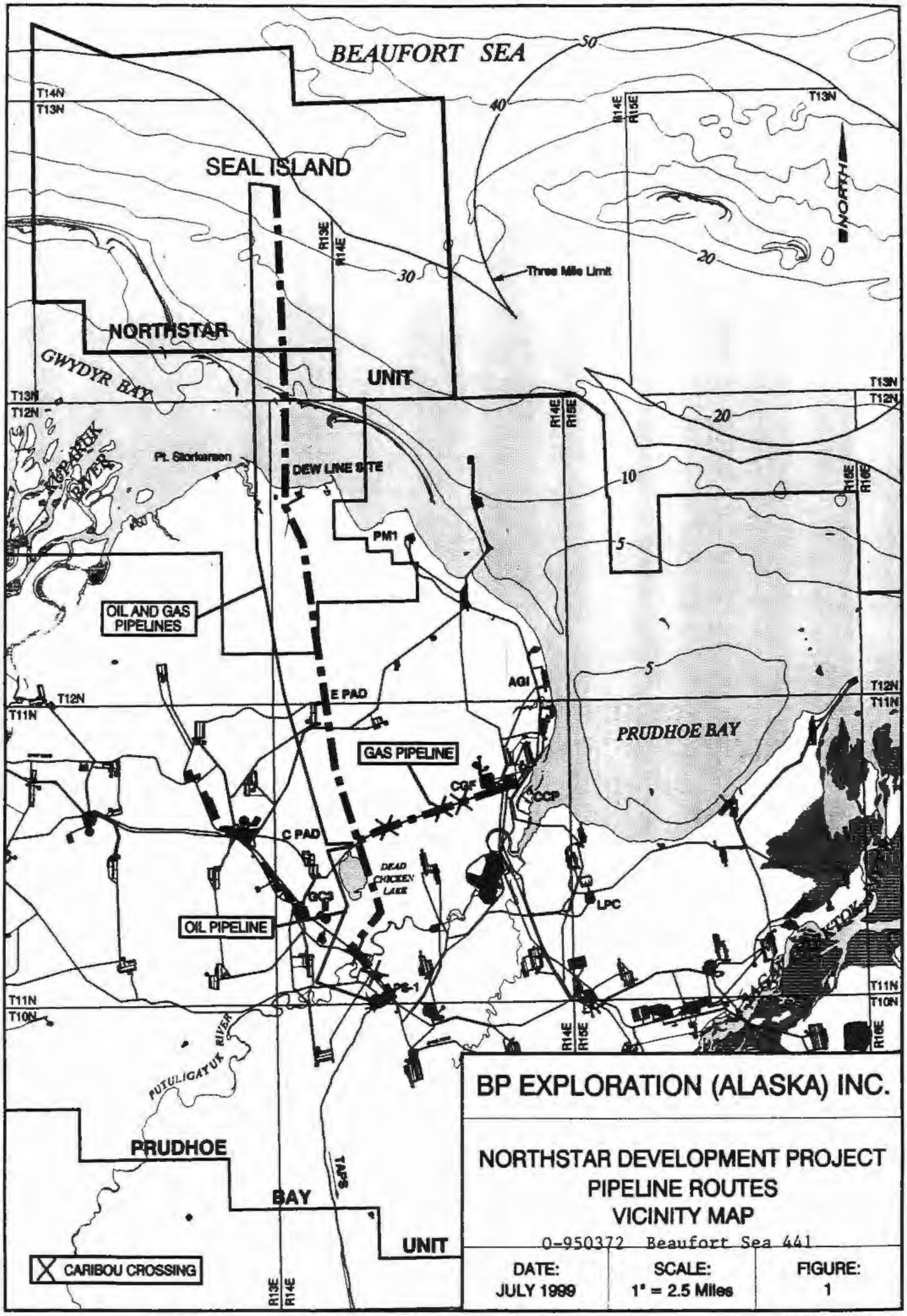
This office has determined that the modifications as proposed are not significant enough to warrant a full public interest review. Your comments concerning the matter must be received within 15 days of the date of this letter. If no comments are received, it will be presumed that your agency has no substantive objections to the authorization of the modification as proposed. Please contact me at (907) 753-2716, toll-free from in Alaska at (800) 478-2712, or by FAX at (907) 753-5567, should you have any questions concerning this proposal.

Sincerely,

Terry A. Carpenter

Terry A. Carpenter
Project Manager

Enclosures



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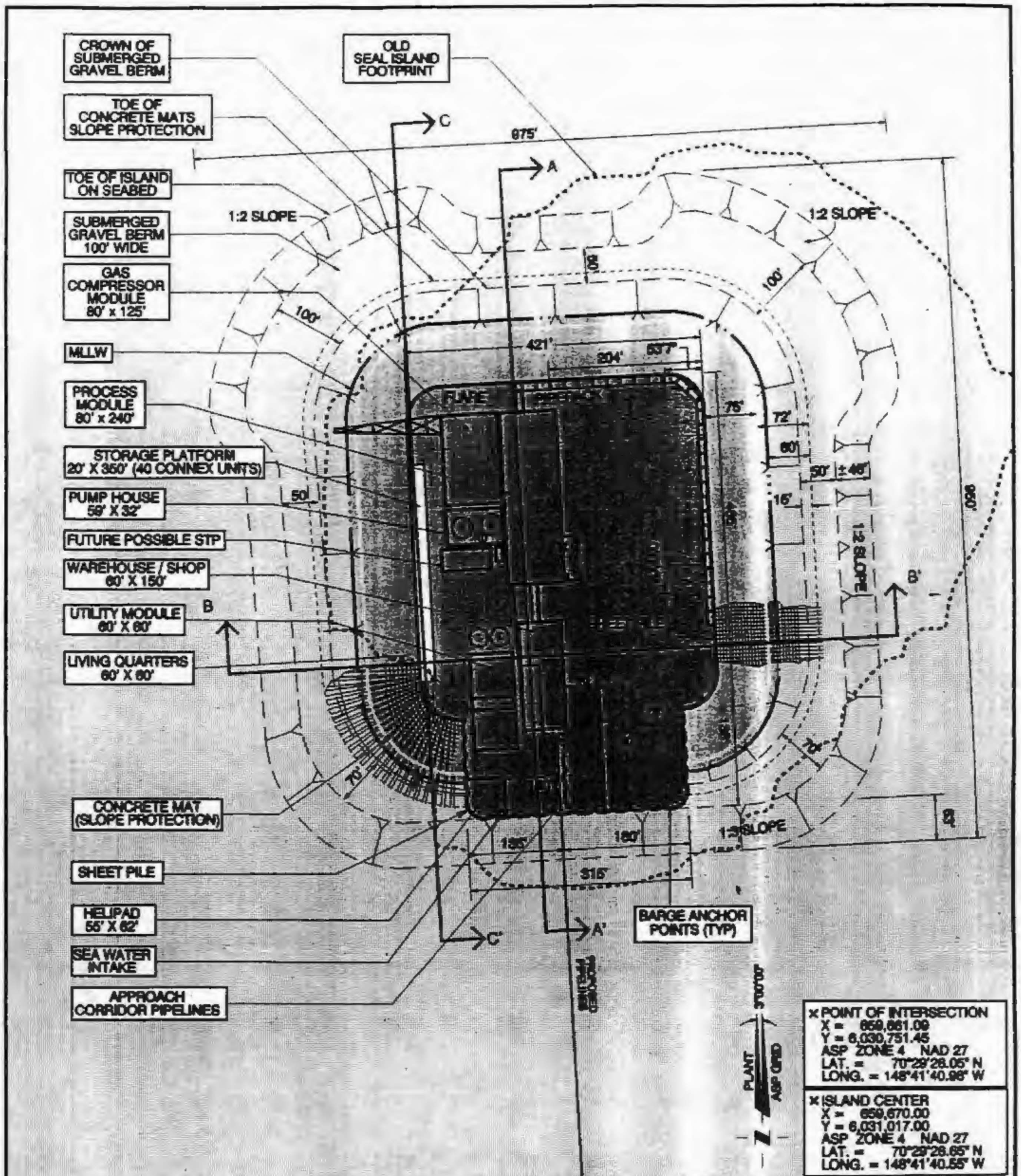


SEABOTTOM FOOTPRINT OF NEW ISLAND =	18.1 ACRES
ISLAND WORKING SURFACE =	5.4 ACRES
ISLAND SURFACE ABOVE MLLW =	8.7 ACRES
ISLAND SURFACE BELOW MLLW =	9.4 ACRES

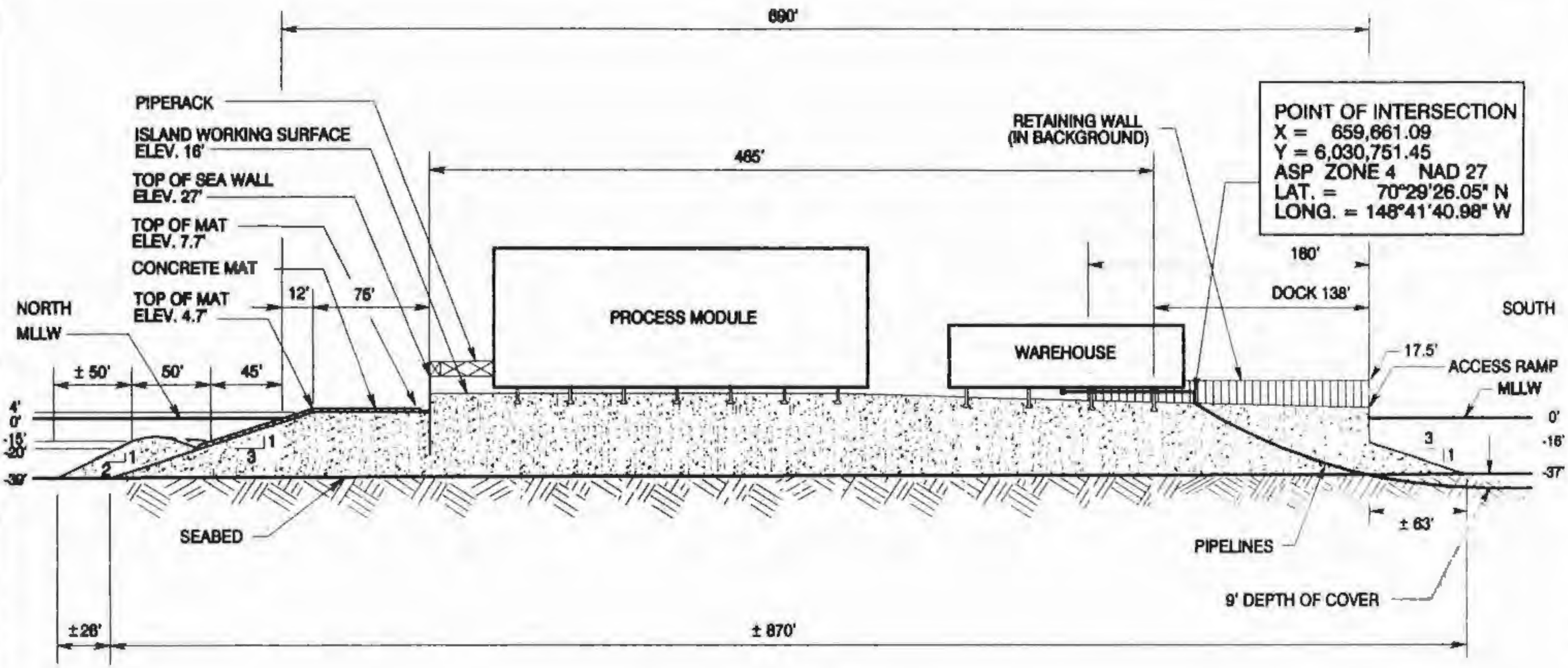
BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND GENERAL ARRANGEMENT
PLAN VIEW

0-950372 Beaufort Sea 441

DATE:	SCALE:	FIGURE:
JULY 1999	NOT TO SCALE	2

nsv799.dgn



SIDE VIEW A-A'

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
SIDE VIEW

0-950372 Beaufort Sea 441
S

DATE:	SCALE:	FIGURE:
JULY 1999	N/A	3

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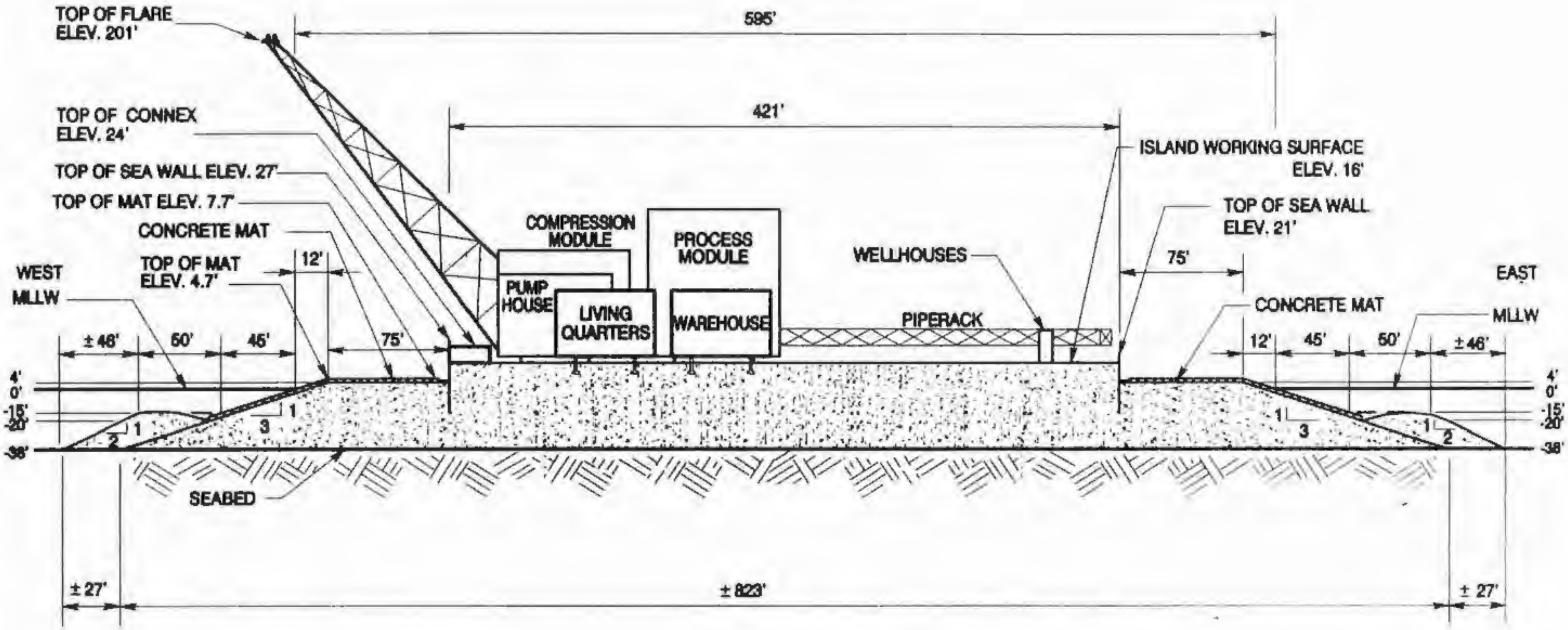
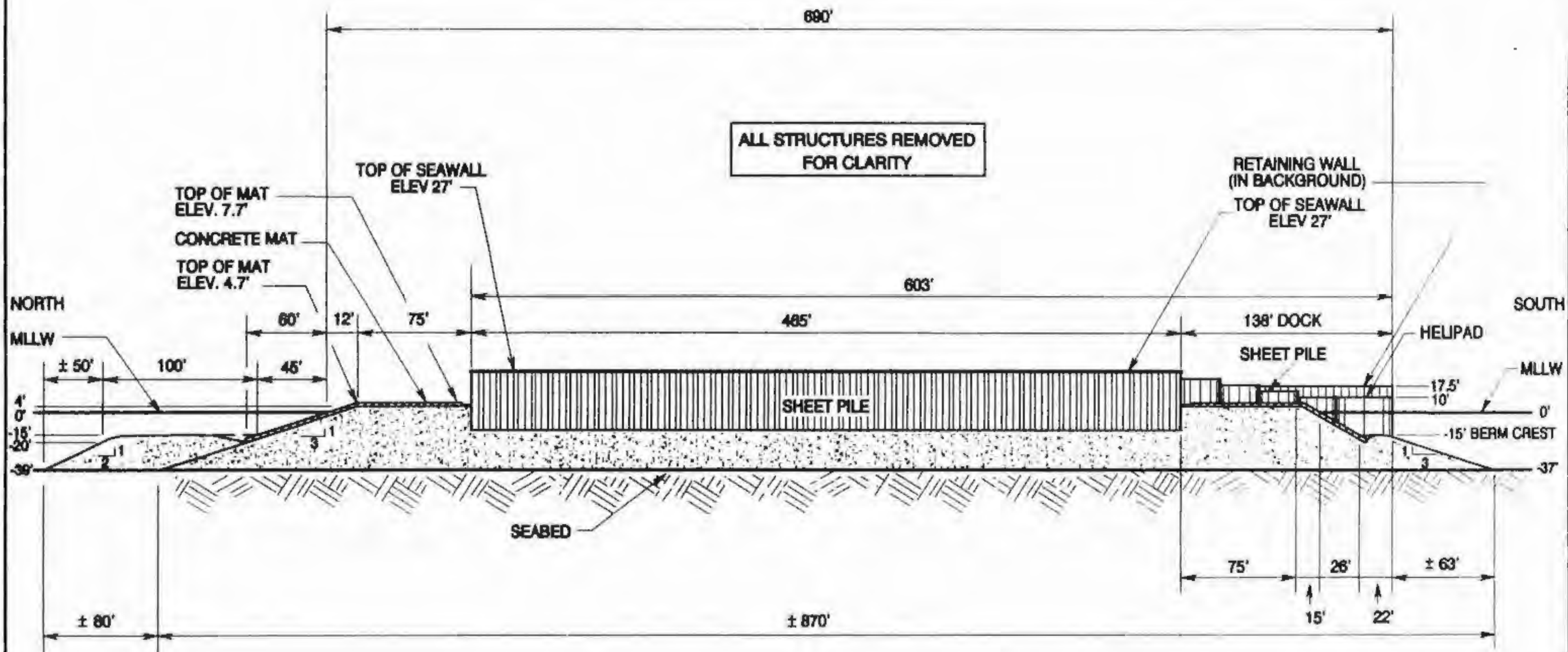


SIDE VIEW B-B'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAL ISLAND SIDE VIEW 0-950372 Beaufort Sea 441		
DATE: JULY 1999	SCALE: N/A	FIGURE: 4

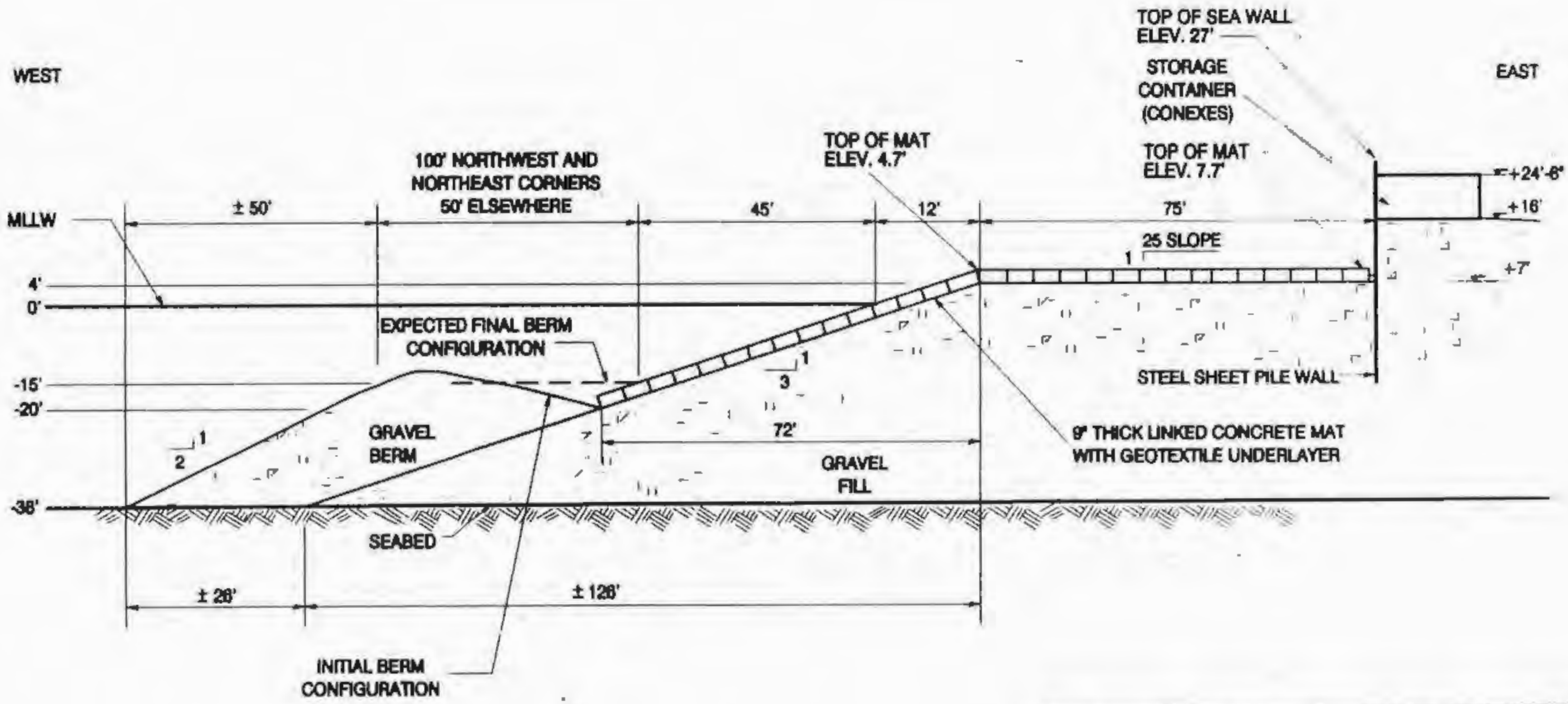
nsv799.dgn



SIDE VIEW C-C'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAL ISLAND SIDE VIEW 0-950372 Beaufort Sea 441		
DATE: JULY 1999	SCALE: N/A	FIGURE: 5

nsv799.dgn



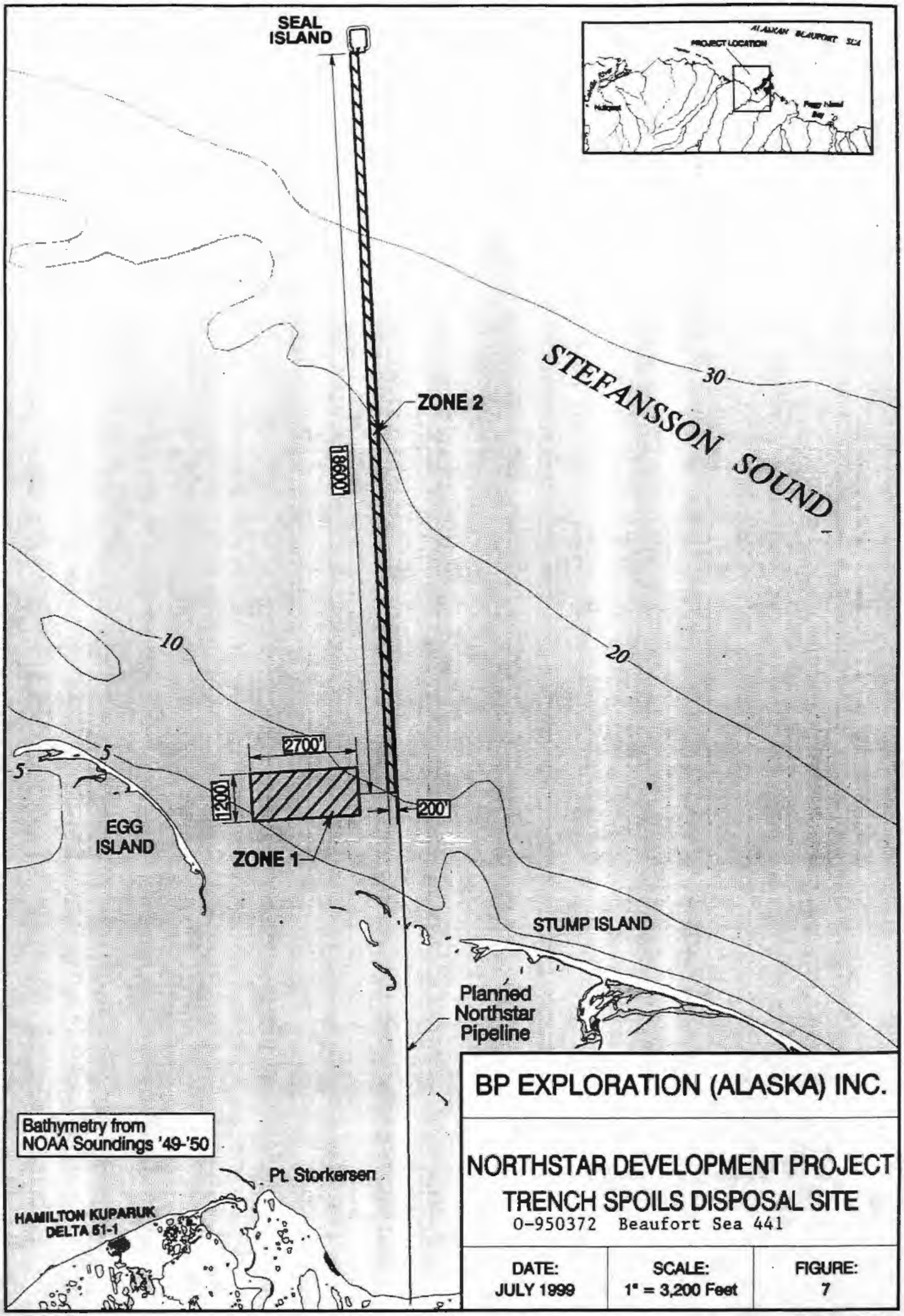
BP EXPLORATION (ALASKA) INC.

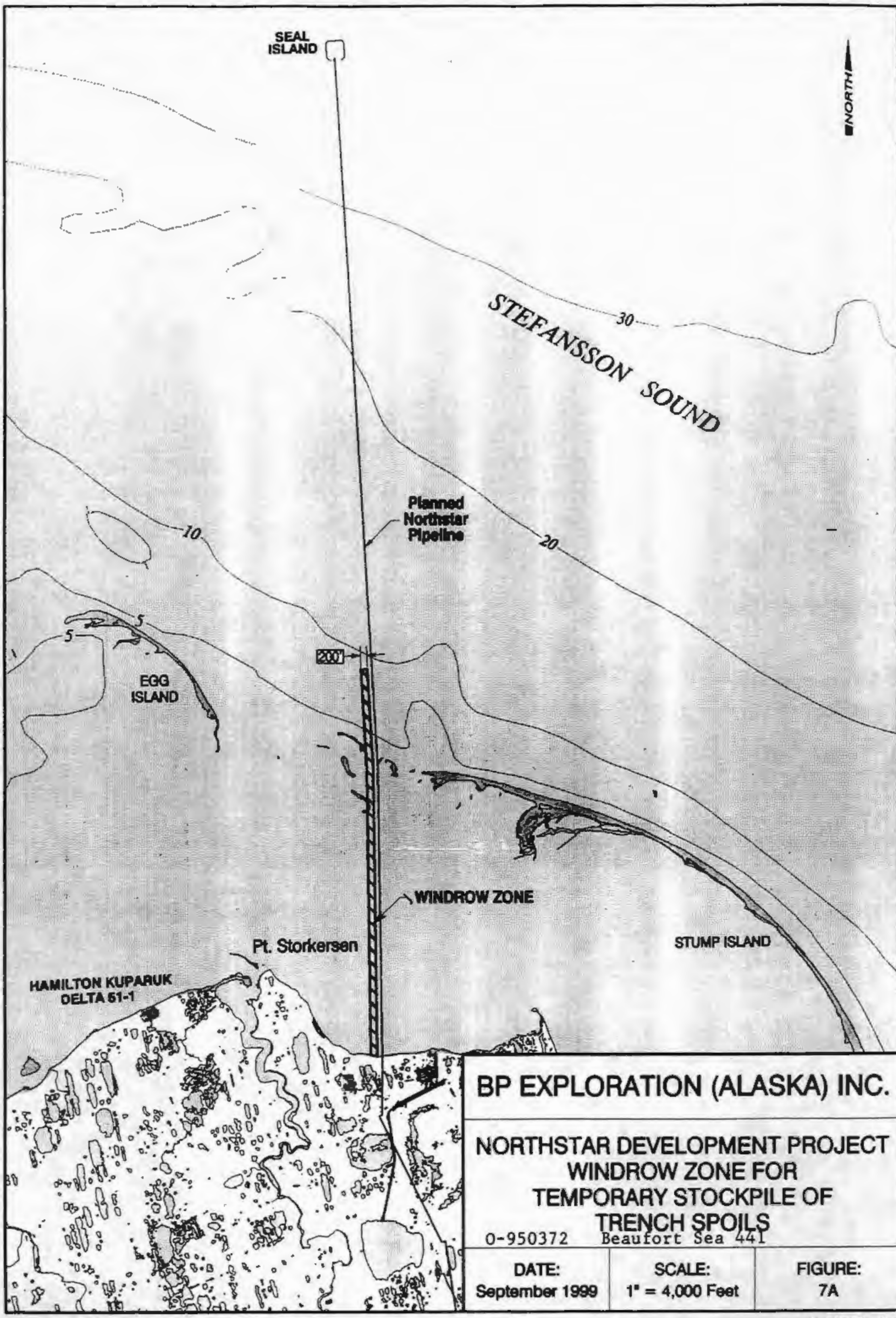
NORTHSTAR DEVELOPMENT PROJECT
ISLAND SLOPE PROTECTION
SIDE VIEW

0-950372 Beaufort Sea 441

DATE: JULY 1999	SCALE: N/A	FIGURE: 6

nsv799.dgn


SEAL ISLAND
PROJECT LOCATION
STEFANSSON SOUND
30
ZONE 2
18600'
10
20
2700'
5
5
1200'
200'
EGG ISLAND
ZONE 1
STUMP ISLAND
Planned Northstar Pipeline
Bathymetry from NOAA Soundings '49-'50
Pt. Storkersen
HAMILTON KUPARUK DELTA 51-1
BP EXPLORATION (ALASKA) INC.
NORTHSTAR DEVELOPMENT PROJECT
TRENCH SPOILS DISPOSAL SITE
0-950372 Beaufort Sea 441
DATE: JULY 1999
SCALE: 1" = 3,200 Feet
FIGURE: 7



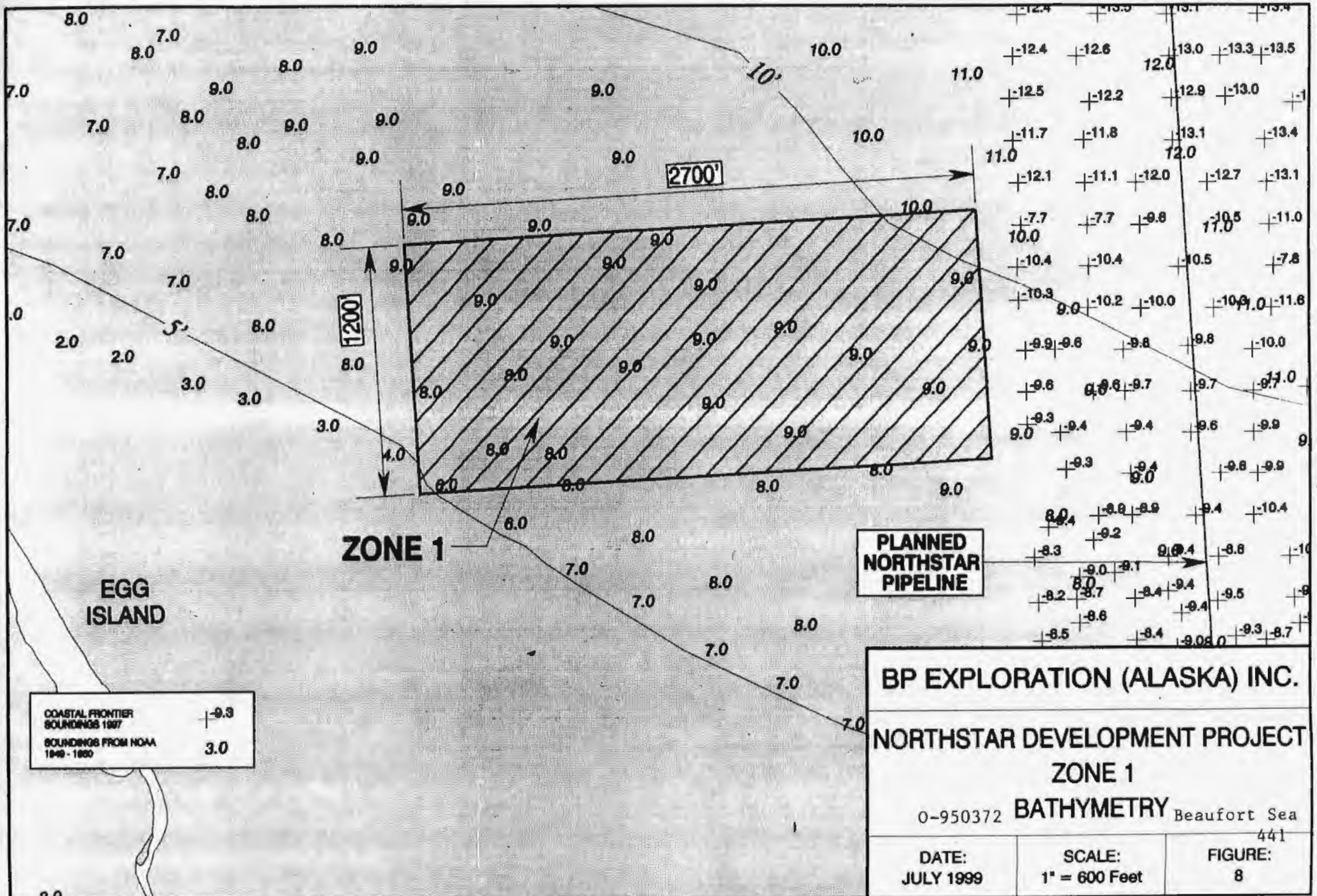
BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT WINDROW ZONE FOR TEMPORARY STOCKPILE OF TRENCH SPOILS

0-950372 Beaufort Sea 441

DATE:	SCALE:	FIGURE:
September 1999	1" = 4,000 Feet	7A

bs13570a.dgn



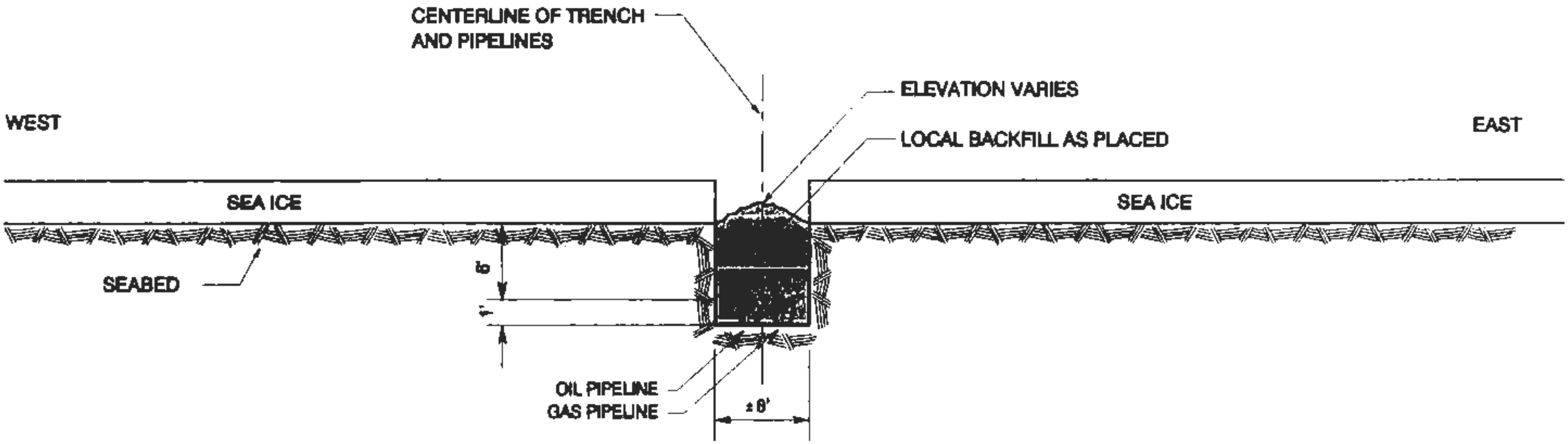
BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
ZONE 1
0-950372 BATHYMETRY Beaufort Sea

441

DATE:	SCALE:	FIGURE:
JULY 1999	1" = 600 Feet	8

bs13702a.dgn



NOTES:

1. PIPELINES DEPTH OF COVER IS 6 FEET.
2. TRENCH SIDE SLOPES ARE VARIABLE, DEPENDING ON SOIL CONDITIONS. VERTICAL TRENCH SIDES ARE SHOWN.
3. PIPELINES WILL BE INSTALLED AS A BUNDLE. FOR SIMPLICITY, INDIVIDUAL PIPELINES ARE SHOWN.

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT TYPICAL PIPELINES CROSS-SECTION SOUTH OF BARRIER ISLANDS 0-950372 Beaufort Sea 441		
DATE: JULY 1999	SCALE: N/A	FIGURE: 9

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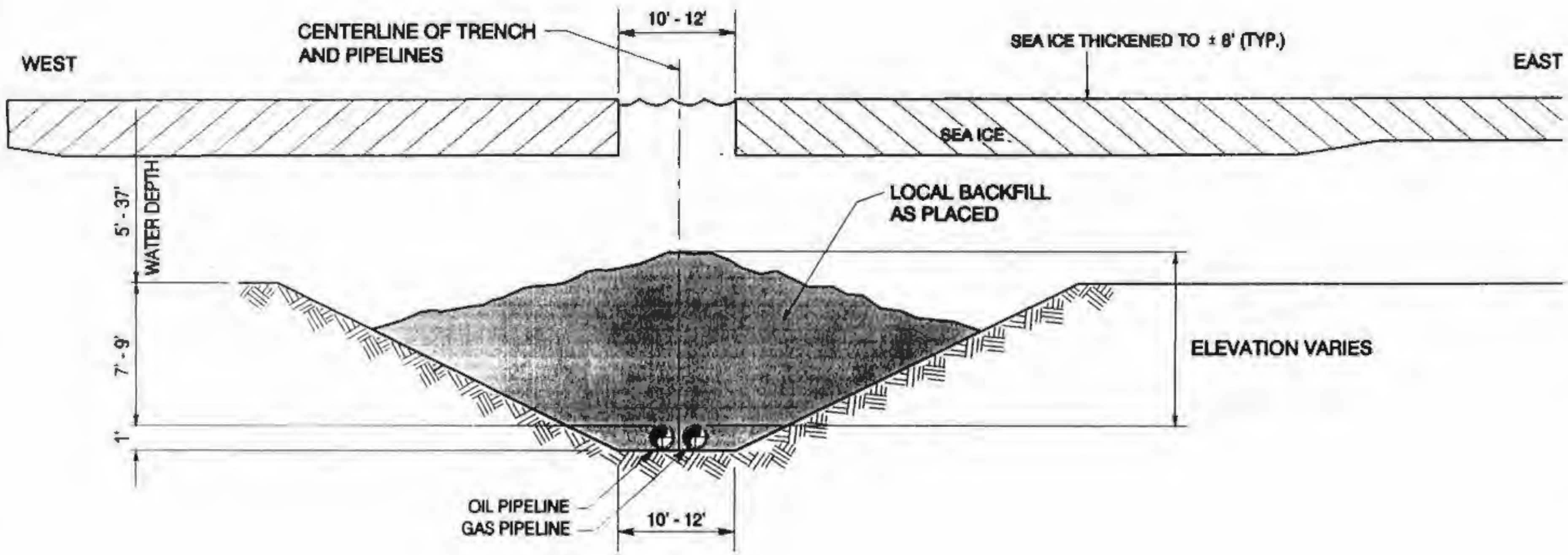


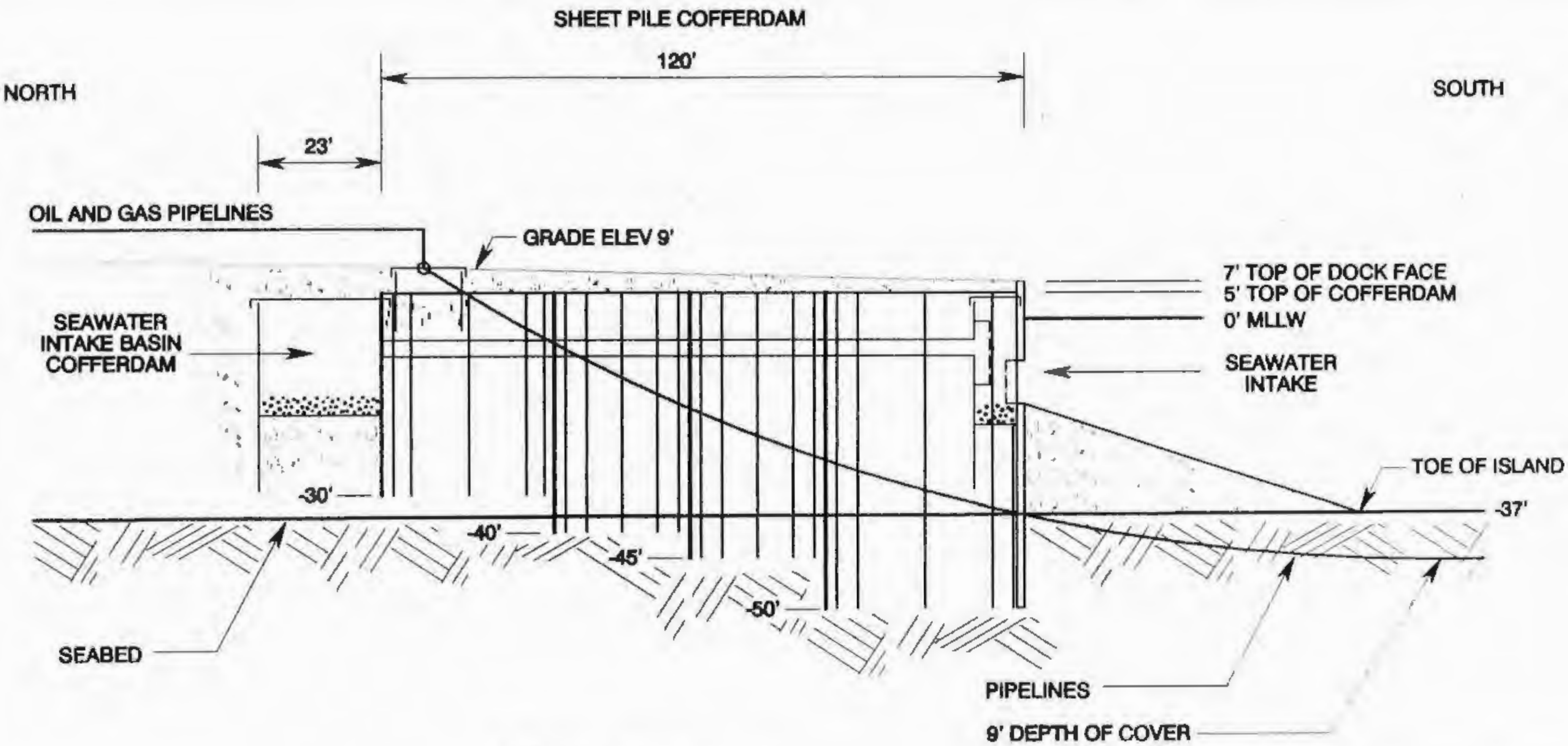
NOTES:

1. PIPELINES DEPTH OF COVER IS 7-9 FEET.
2. TRENCH SIDE SLOPES ARE VARIABLE, DEPENDING ON SOIL CONDITIONS. SLOPES SHOWN ARE 1V : 2H.
3. PIPELINES WILL BE INSTALLED AS A BUNDLE. FOR SIMPLICITY, INDIVIDUAL PIPELINES ARE SHOWN.
4. THICKENED ICE SUFFICIENT IN THICKNESS TO SUPPORT HEAVY EQUIPMENT TRAFFIC.

O-950372 Beaufort Sea 441

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT TYPICAL PIPELINES CROSS-SECTION NORTH OF BARRIER ISLANDS		
DATE: JULY 1999	SCALE: N/A	FIGURE: 10

nsv799.dgn



SIDE VIEW A - A'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAL ISLAND PIPELINE APPROACH COFFERDAM SIDE VIEW		
DATE: JULY 1999	SCALE: N/A	FIGURE: 11

0-950372 Beaufort Sea 441

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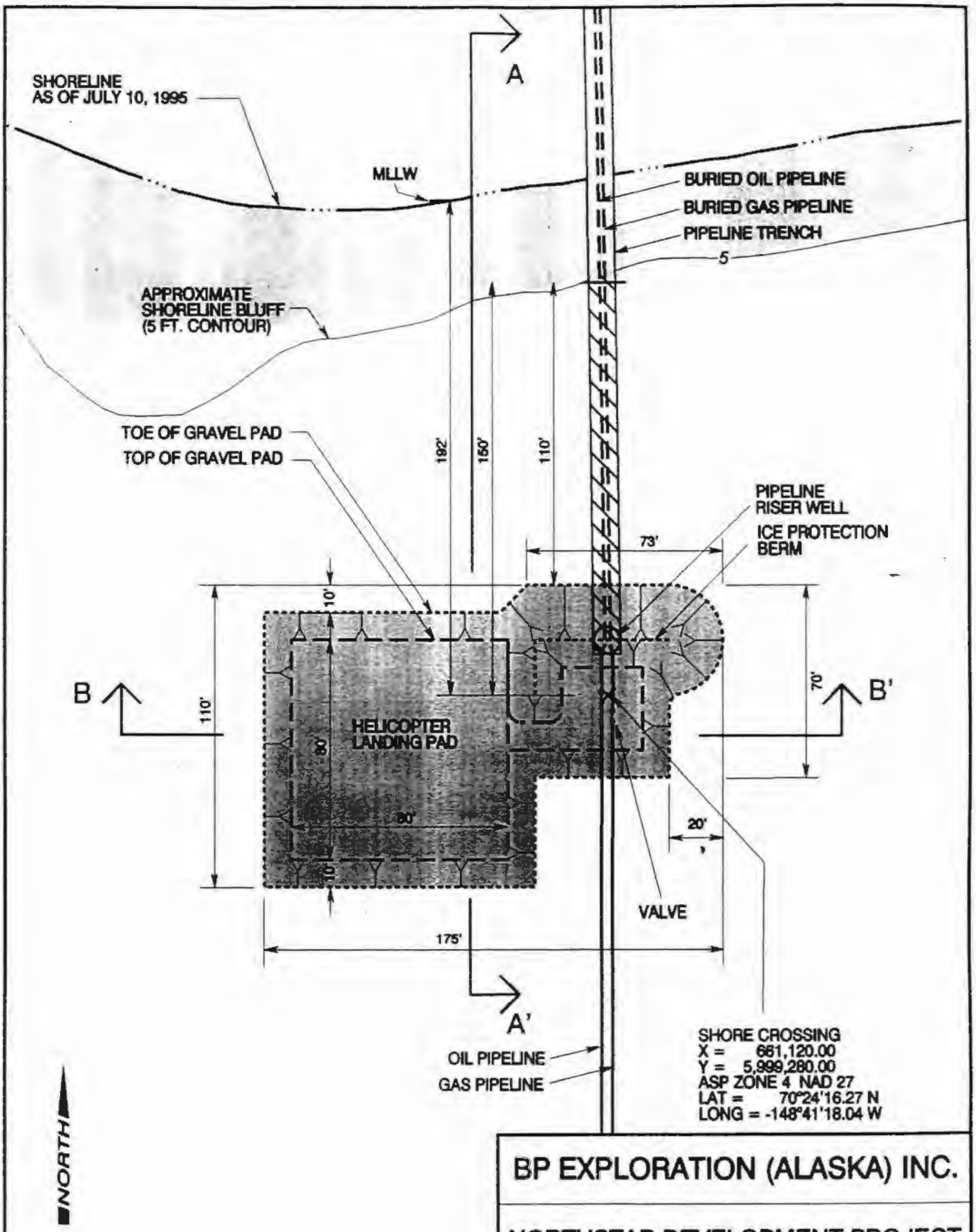
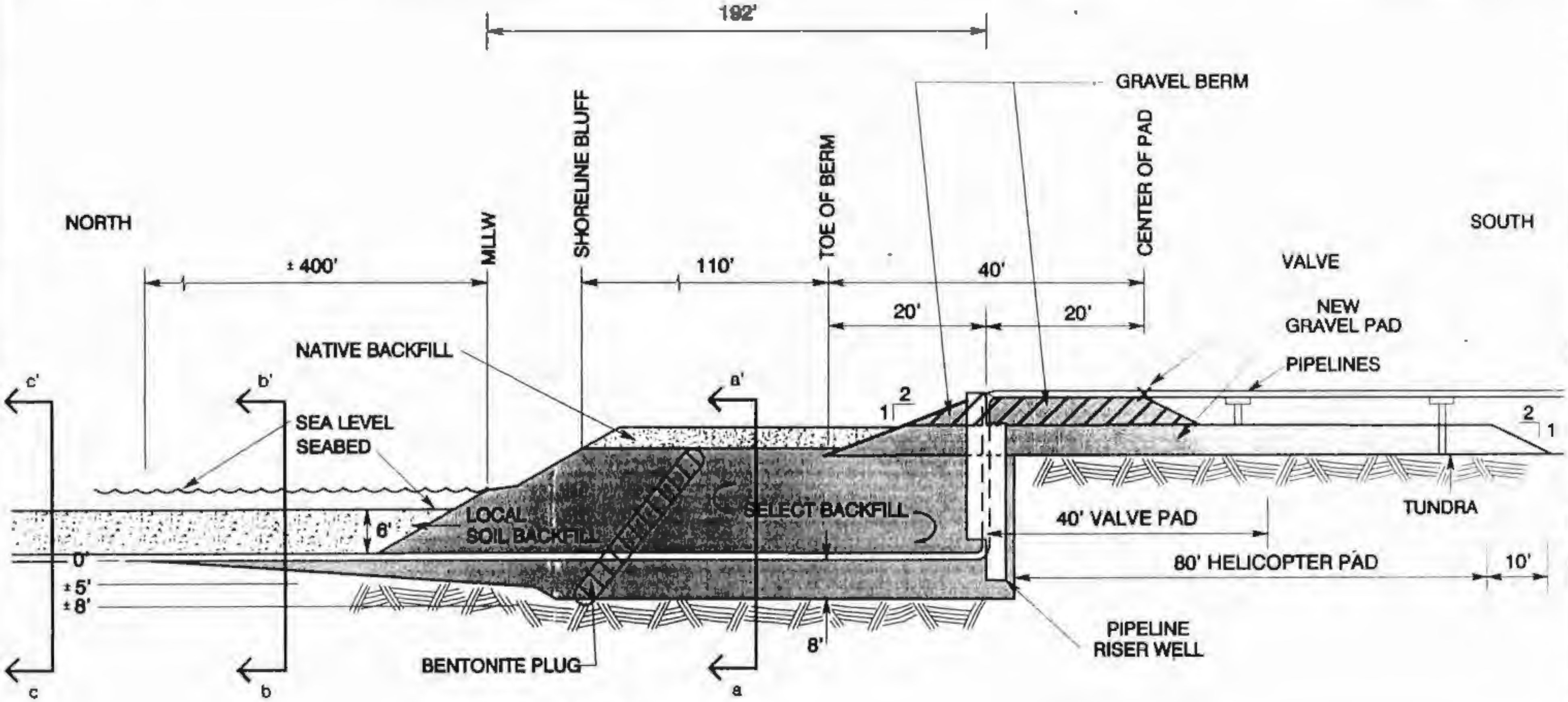


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
LANDFALL VALVE PAD
LAYOUT

DATE:	SCALE:	FIGURE:
JULY 1999	1" = 50'	12

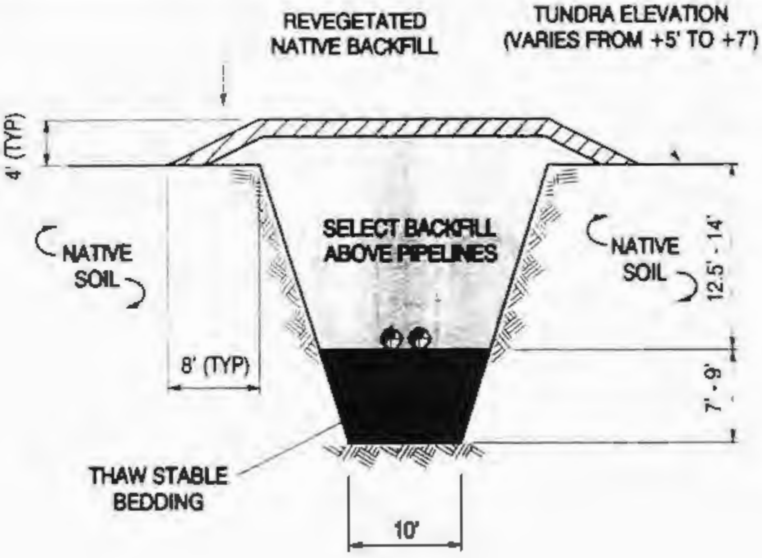
nsvn799.dgn



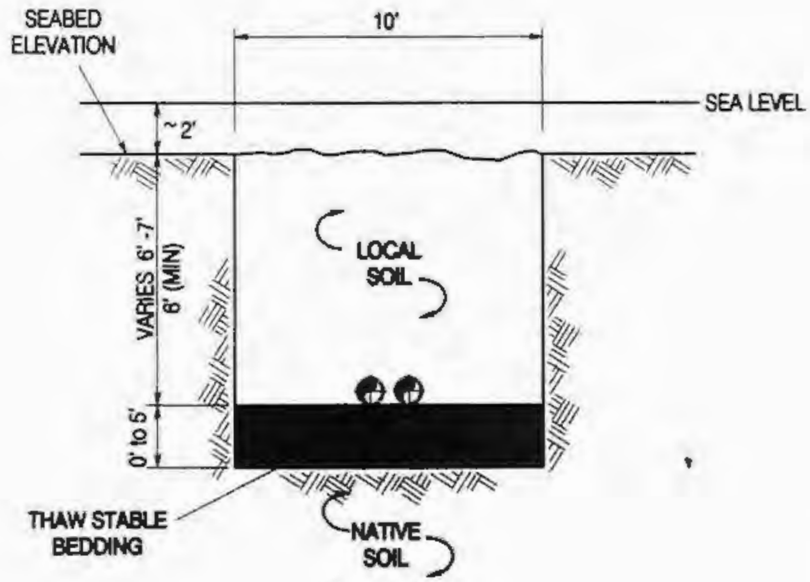
SIDE VIEW A-A'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT LANDFALL VALVE PAD SIDE VIEW		
DATE: JULY 1999	SCALE: NOT TO SCALE	FIGURE: 13

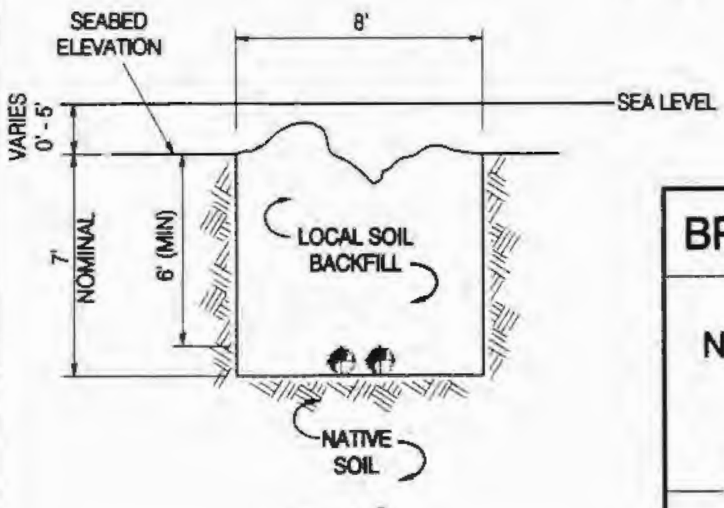
1



a-a'

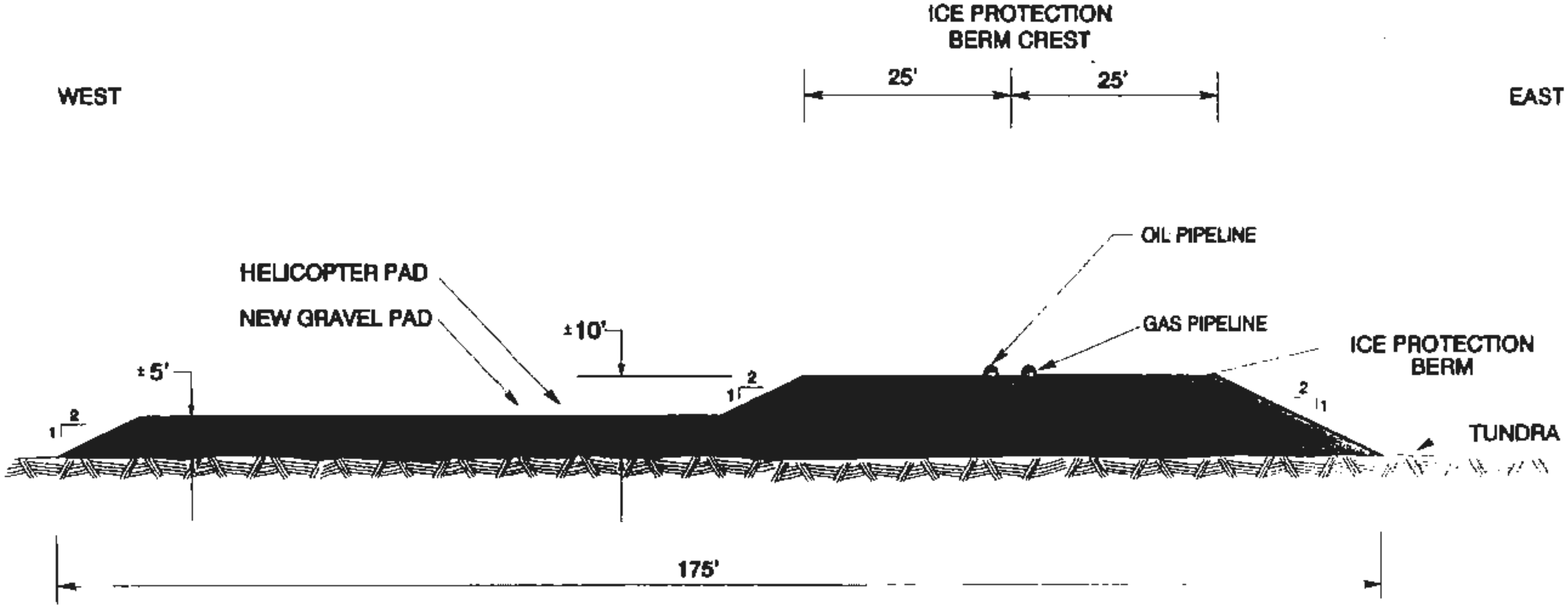


b-b'



c-c'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT TYPICAL TRENCH PROFILES 0-950372 Beaufort Sea 441		
DATE: JULY 1999	SCALE: NOT TO SCALE	FIGURE: 13a



SIDE VIEW B-B'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT LANDFALL VALVE PAD SIDE VIEW		
DATE: JULY 1999	SCALE: NOT TO SCALE	FIGURE: 14

0-950372 Beaufort Sea 441

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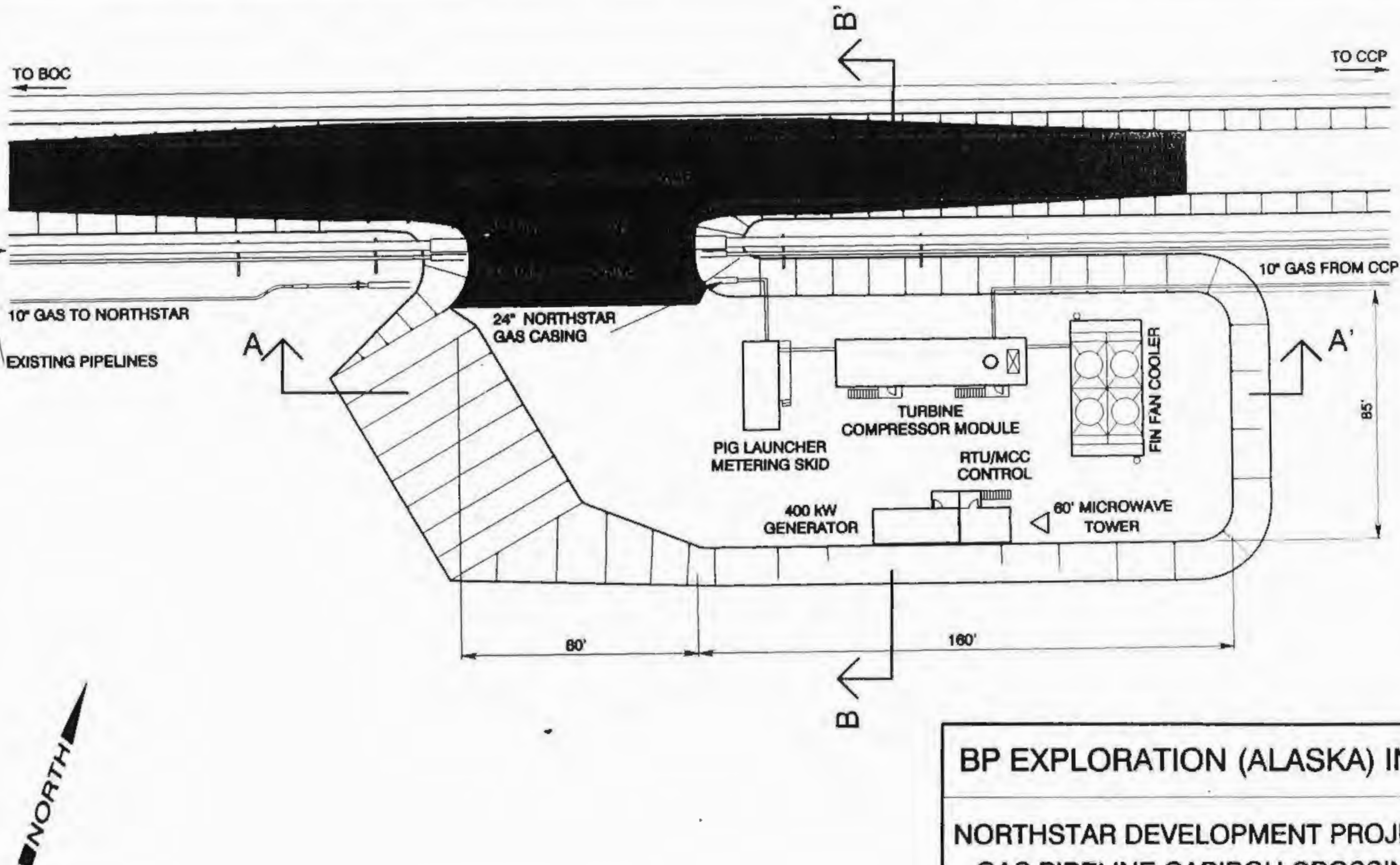
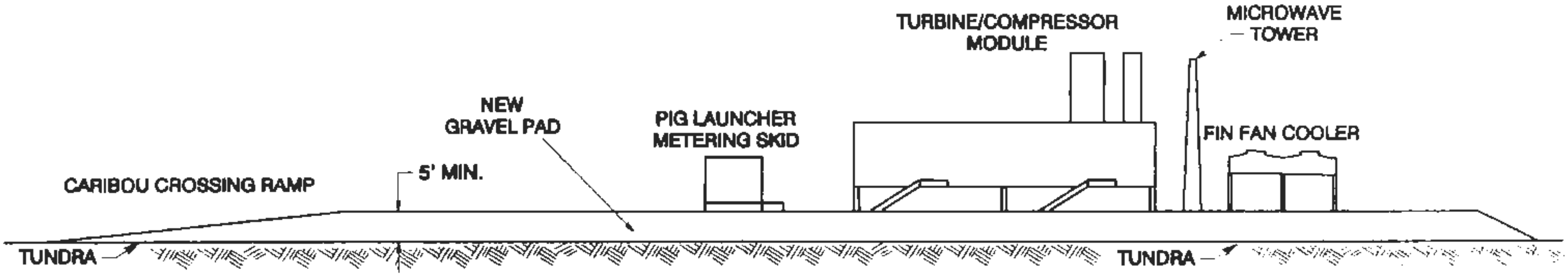


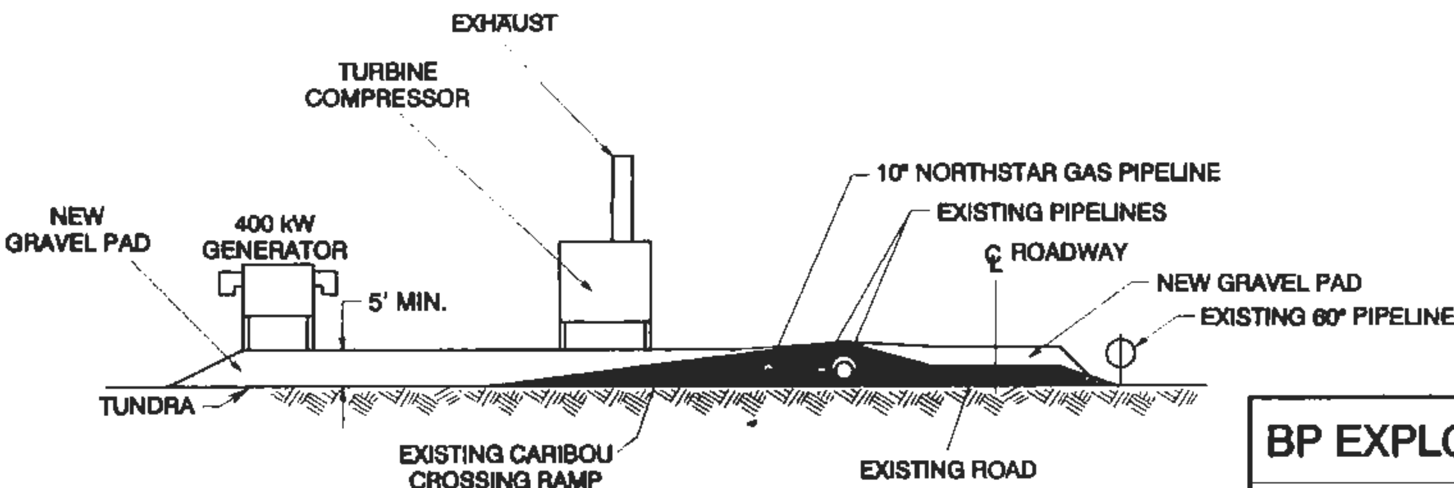
BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
GAS PIPELINE CARIBOU CROSSING
GENERAL ARRANGEMENT

DATE:	SCALE:	FIGURE:
JULY 1999	1' = 50'	15



SIDE VIEW A-A'

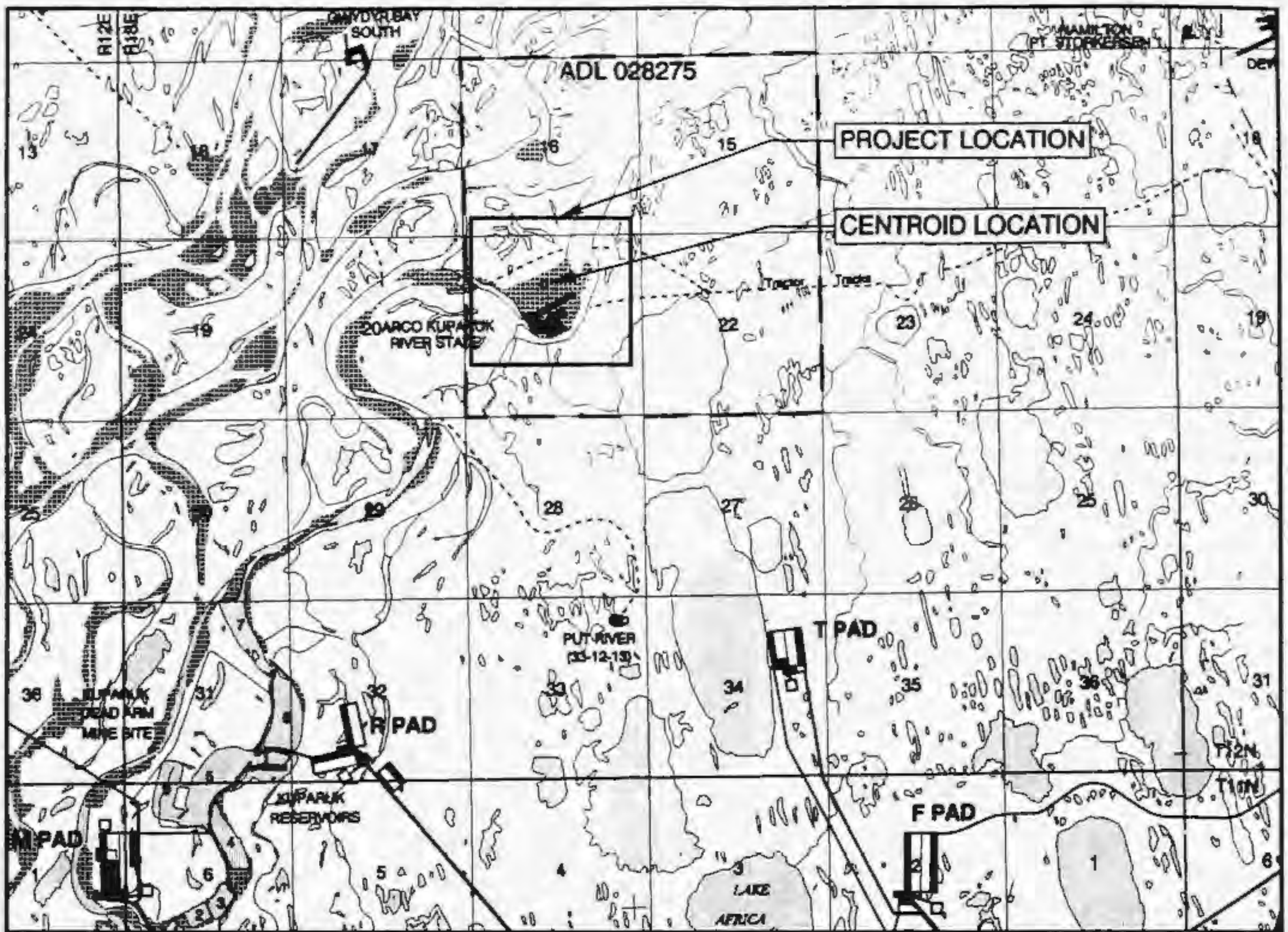


SIDE VIEW B-B'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT GAS PIPELINE CARIBOU CROSSING SIDE VIEWS		
DATE: JULY 1999	SCALE: NOT TO SCALE	FIGURE: 16

0-950372 Beaufort Sea 441

nsv799.dgn



This map is based on U.S.G.S. quad Beechy Point (B-4) and on the Unit Operator's Facility Maps.

NORTH

PROJECT LOCATION:

CENTROID FOR NORTHSTAR MINE SITE

LAT. = 70° 22' 58.85" NORTH
LONG. = 148° 51' 12.11" WEST

X = 641,000.00 FEET EAST
Y = 5,991,000.00 FEET NORTH
ALASKA STATE PLANE ZONE 4, NAD 27

SEC. 21, T12N, R13E, UMIAT M.

ADL # 028275

DATUM: MEAN SEA LEVEL

PURPOSE: MINE SITE DEVELOPMENT

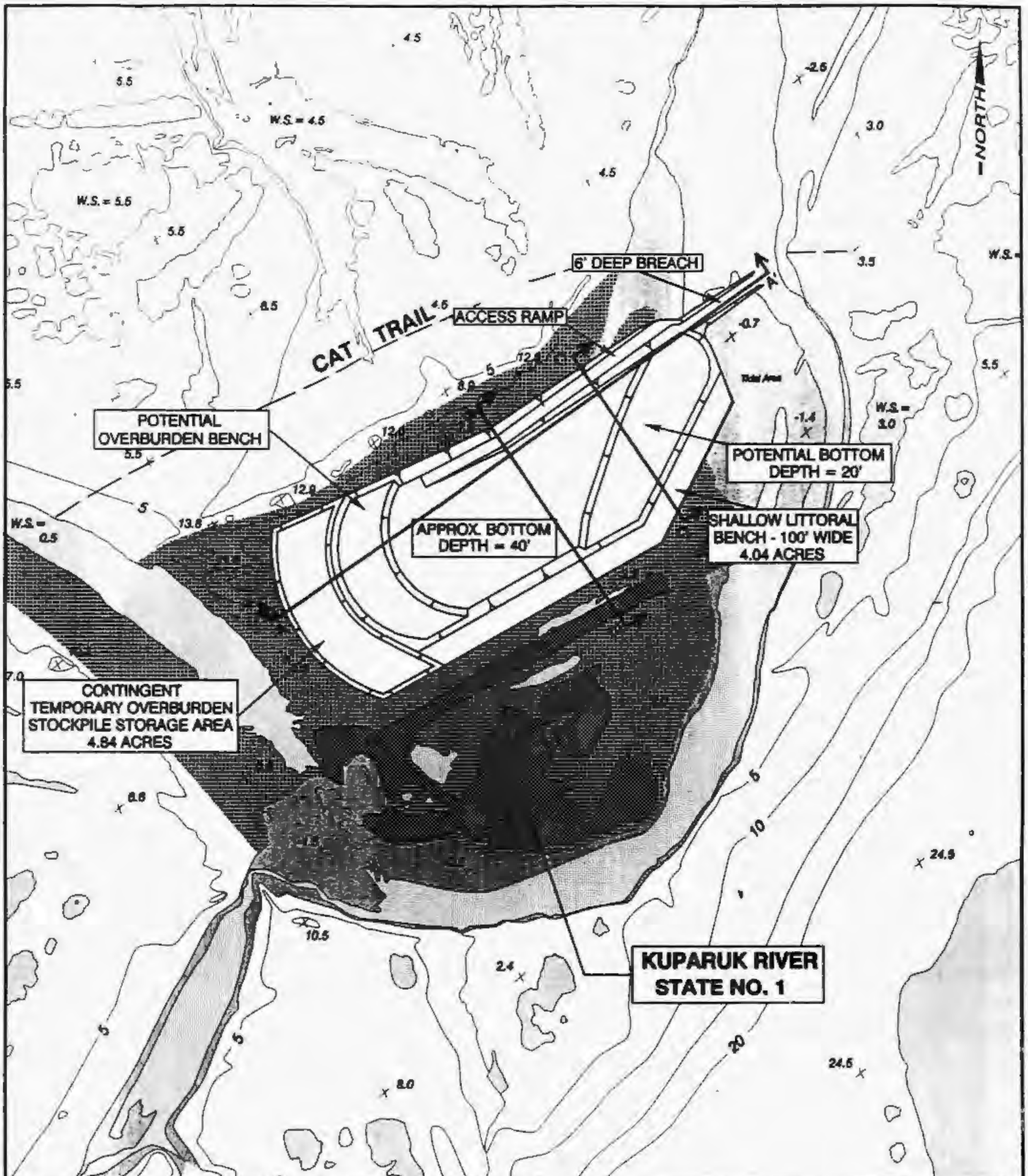
ADJACENT PROPERTY OWNER:
STATE OF ALASKA

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
VICINITY MAP

DATE:	SCALE:	FIGURE:
JULY 1999	1" = 1 MILE	17

gn13115.dgn



Mapped from photography of July 10, 1973, updated from 1995 photography. This map meets National Map Standards AT 1" = 500'. Horizontal datum NAD 1927 based on USC&GS monumentation, coordinate system Alaska State Plane Zone 4. Vertical datum mean sea level established by observation at East Dock in 1968 by F.M. Lindsey and Associates. Prepared by AeroMap US Inc. of Anchorage, AK for BP Exploration (Alaska) Inc.

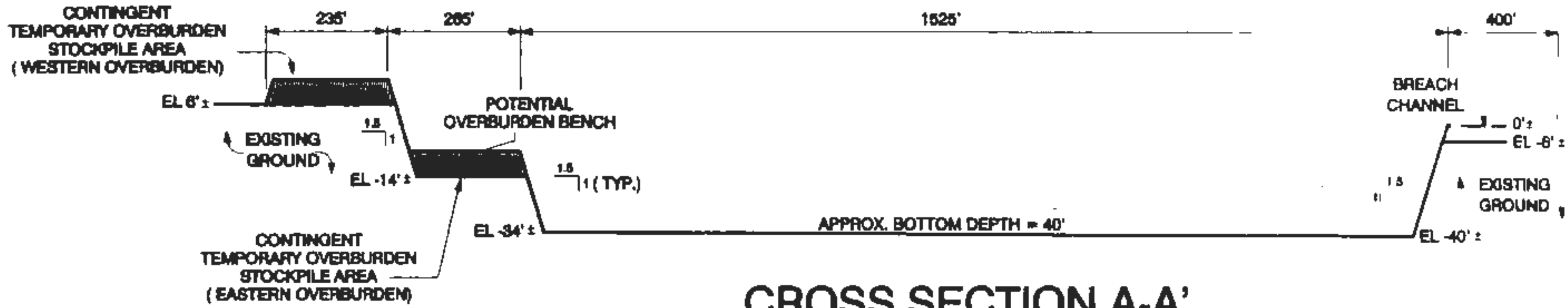
BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
MINE DEVELOPMENT PLAN VIEW

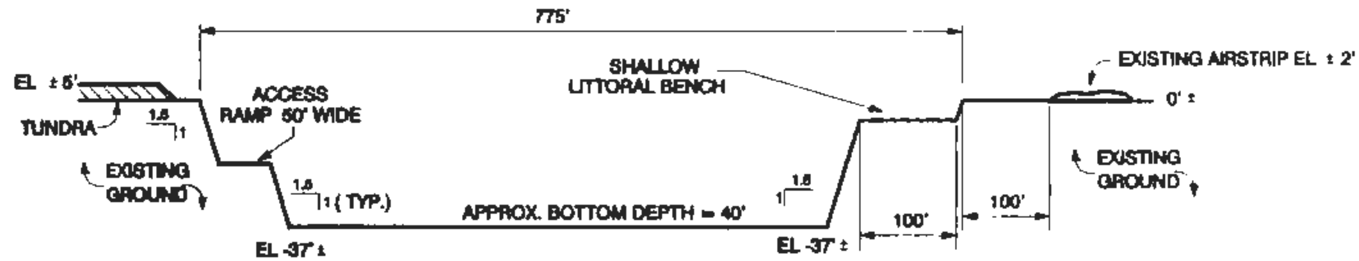
	POTENTIAL MINE AREA - ACRES
PROPOSED MINE AREA	35.59 ACRES
EXCAVATION AREA	30.75 ACRES
TEMPORARY STOCKPILE	4.84 ACRES
AREA OF LITTORAL BENCH	4.04 ACRES
GRAVEL (TO DEPTH -40')	1,286,000 CY

DATE:	SCALE:	FIGURE:
February 1999	1" = 600'	18

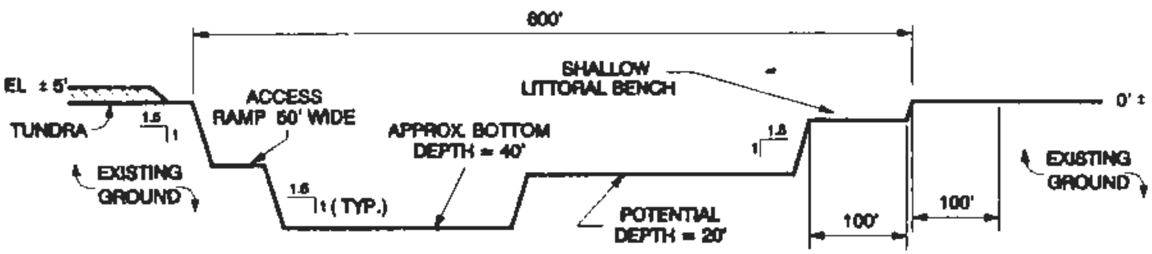
gp13117.dgn



CROSS SECTION A-A'



CROSS SECTION B-B'



CROSS SECTION C-C'

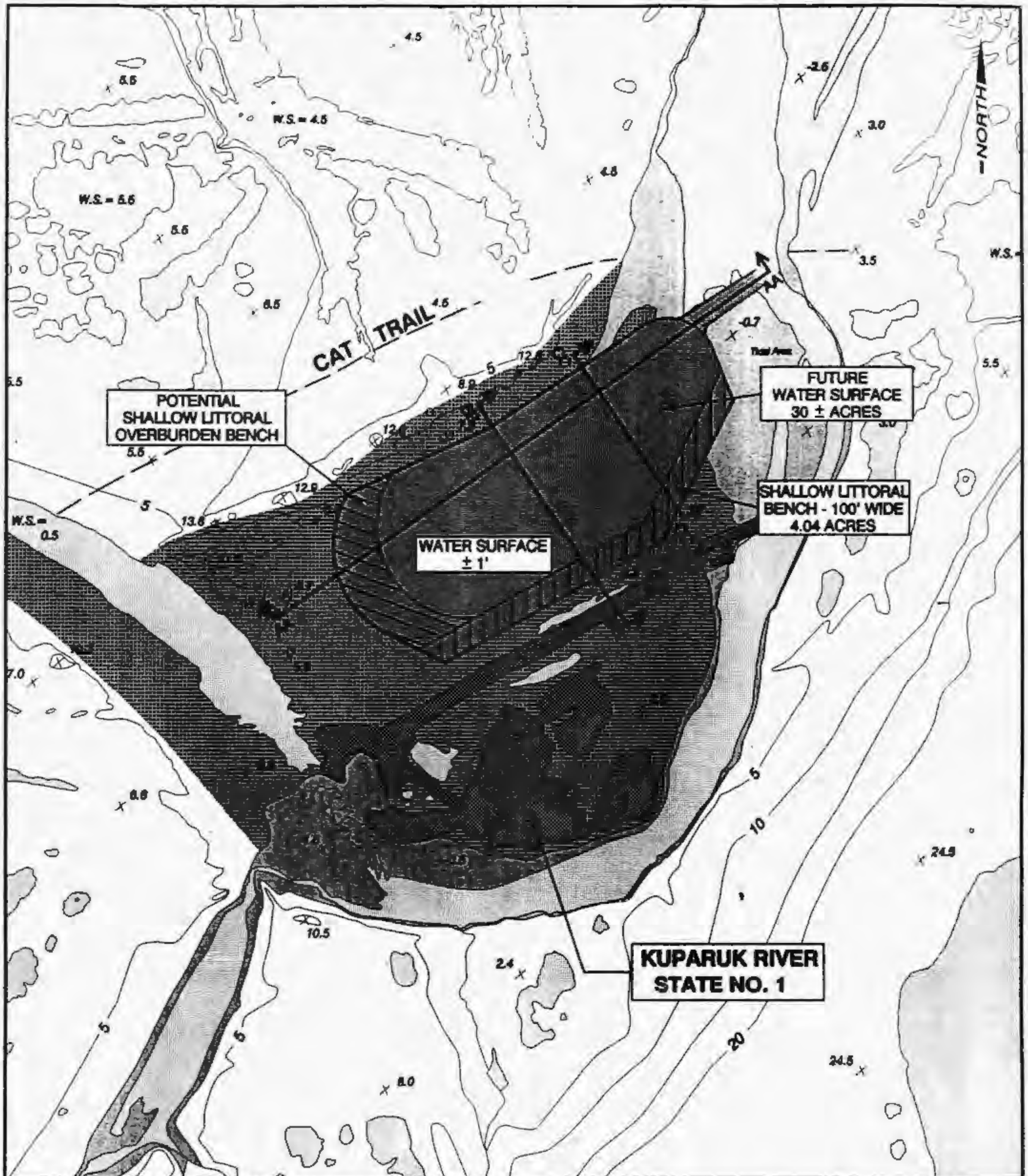
0-950372 Beaufort Sea 441

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
MINE DEVELOPMENT CROSS SECTIONS

DATE:	SCALE:	FIGURE:
February 1999	NOT TO SCALE	19

gp13117.dgn



Mapped from photography of July 10, 1973, updated from 1995 photography. This map meets National Map Standards AT 1" = 500'. Horizontal datum NAD 1927 based on USC&GS monumentation, coordinate system Alaska State Plane Zone 4. Vertical datum mean sea level established by observation at East Dock in 1968 by F.M. Lindsey and Associates. Prepared by AeroMap US Inc. of Anchorage, AK for BP Exploration (Alaska) Inc.

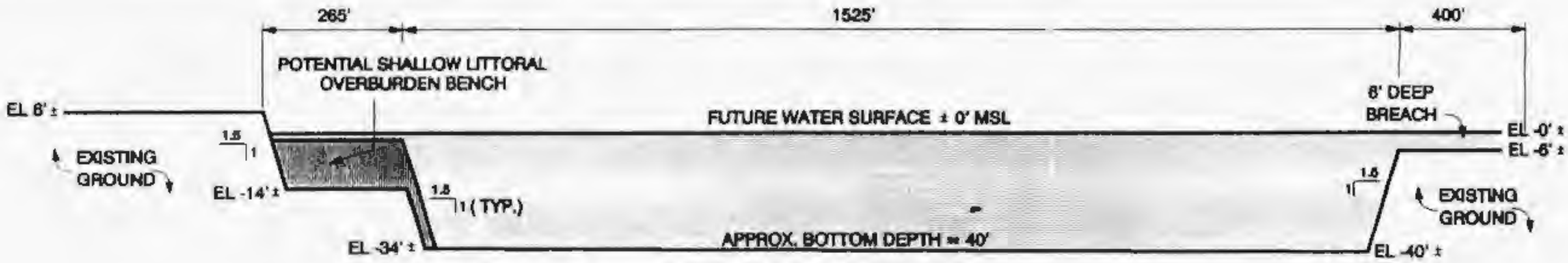
BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
CONCEPTUAL PLAN VIEW

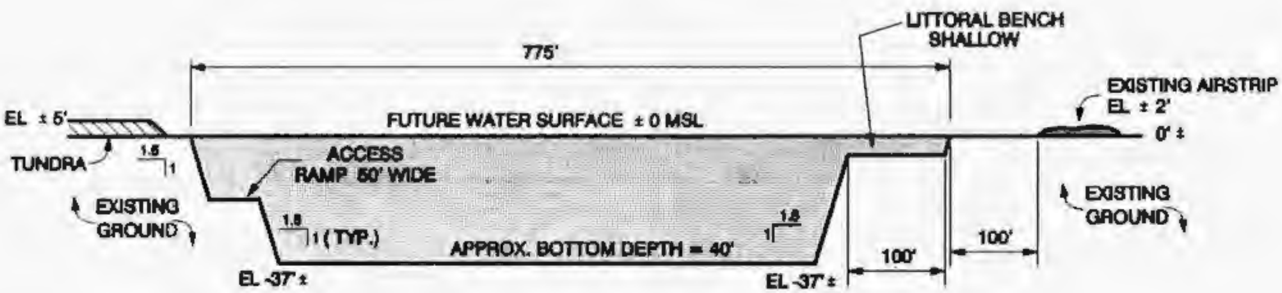
DATE:	SCALE:	FIGURE:
February 1999	1" = 600'	20

0-950372 Beaufort Sea 441

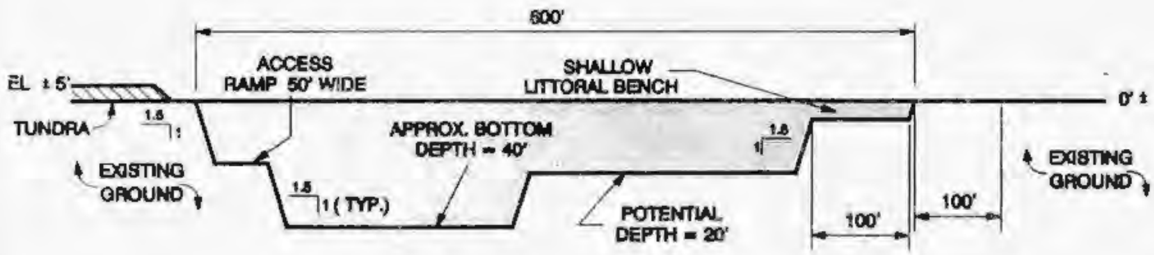
gp13118.dgn



CROSS SECTION AA-AA'



CROSS SECTION BB-BB'



CROSS SECTION CC-CC'

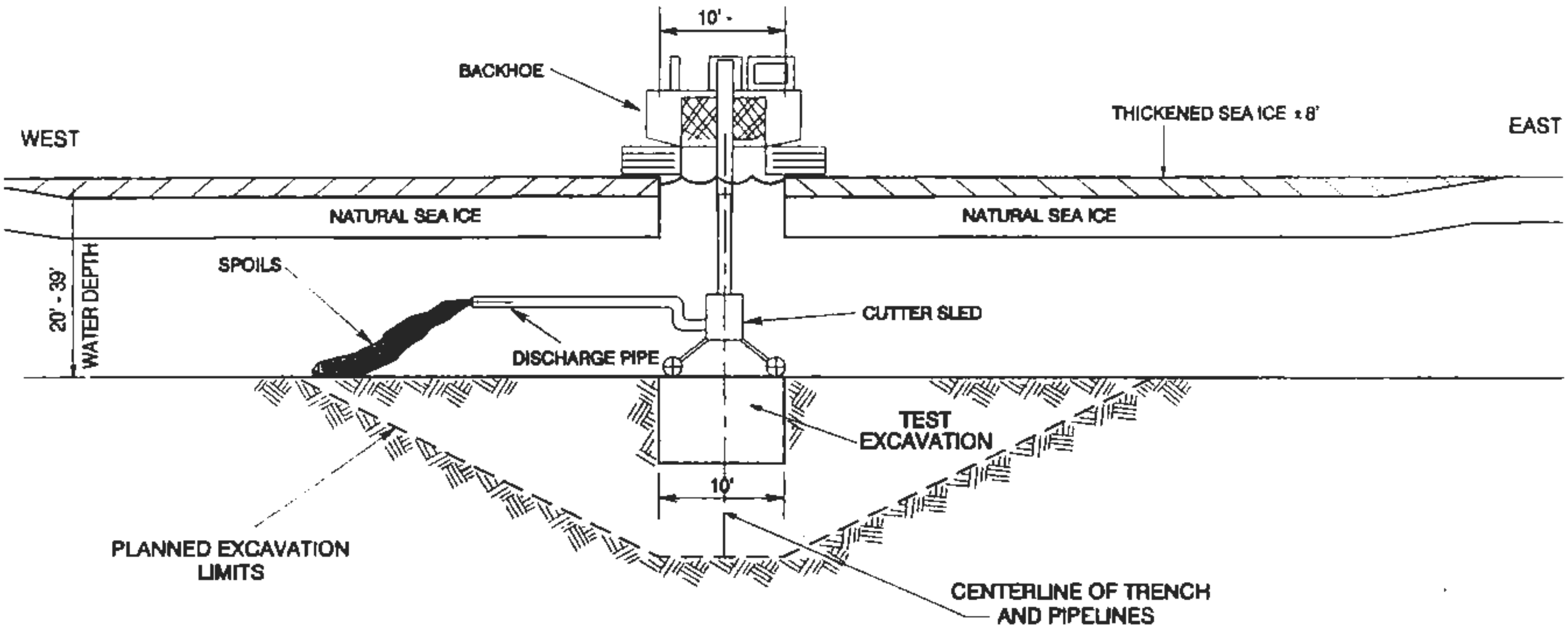
0-950372 Beaufort Sea 441

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
CONCEPTUAL PLAN CROSS SECTIONS

DATE:	SCALE:	FIGURE:
February 1999	NOT TO SCALE	21

GP13118.dgn



BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT TEST SECTION A		
DATE: JULY 1999	SCALE: N/A	FIGURE: A

O-950372 Beaufort Sea 441

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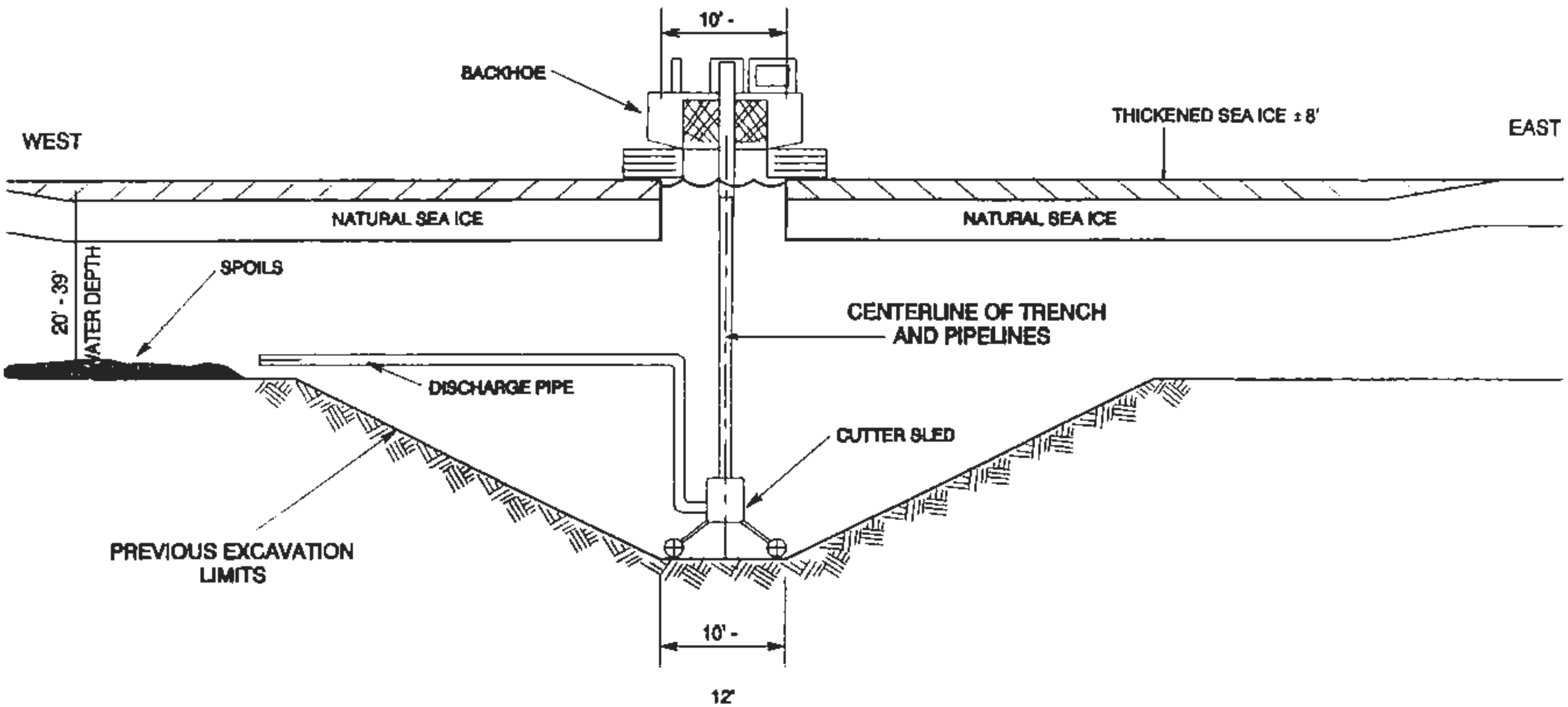
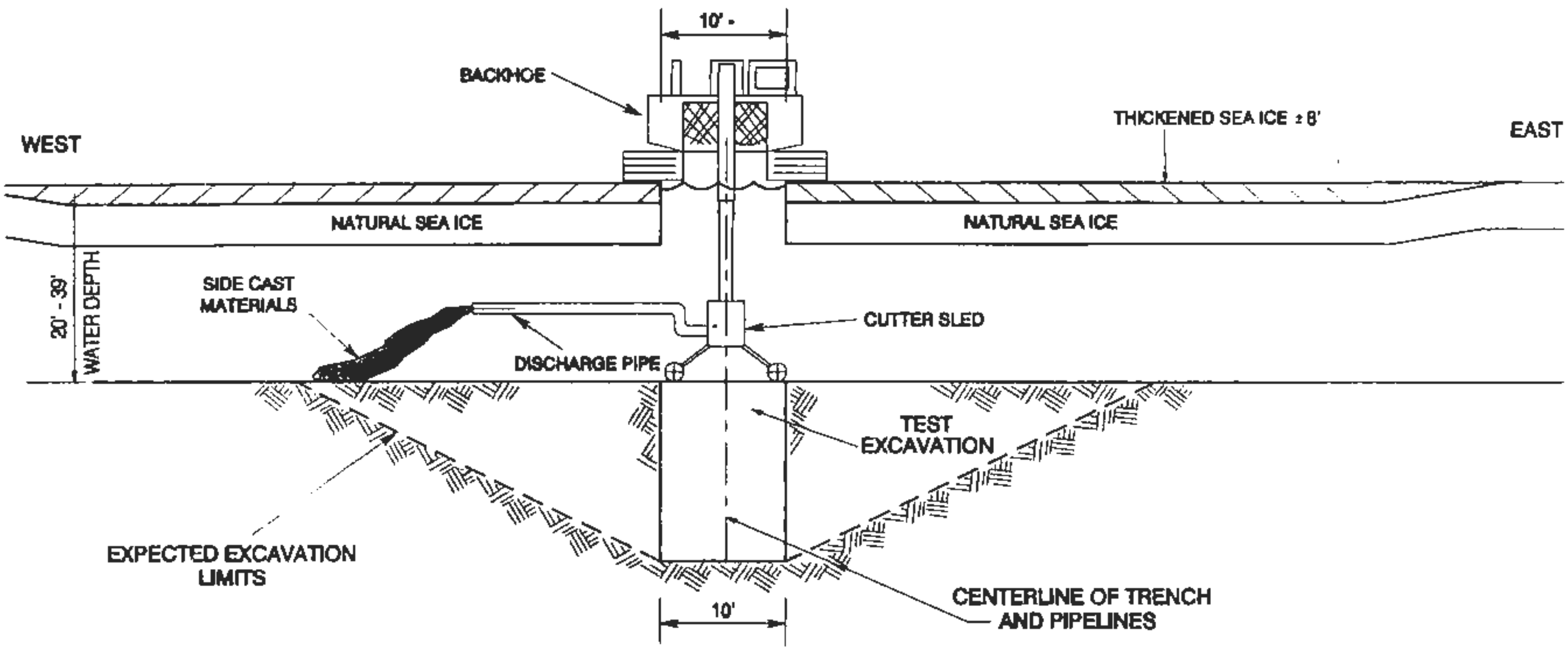


BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT TEST SECTION B CLEAN-OUT TEST		
DATE: JULY 1999	SCALE: N/A	FIGURE: B

0-950372 Beaufort Sea 441

ns799.dgn



0-950372 Beaufort Sea 441

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
TEST SECTION C

DATE: JULY 1999	SCALE: N/A	FIGURE: C

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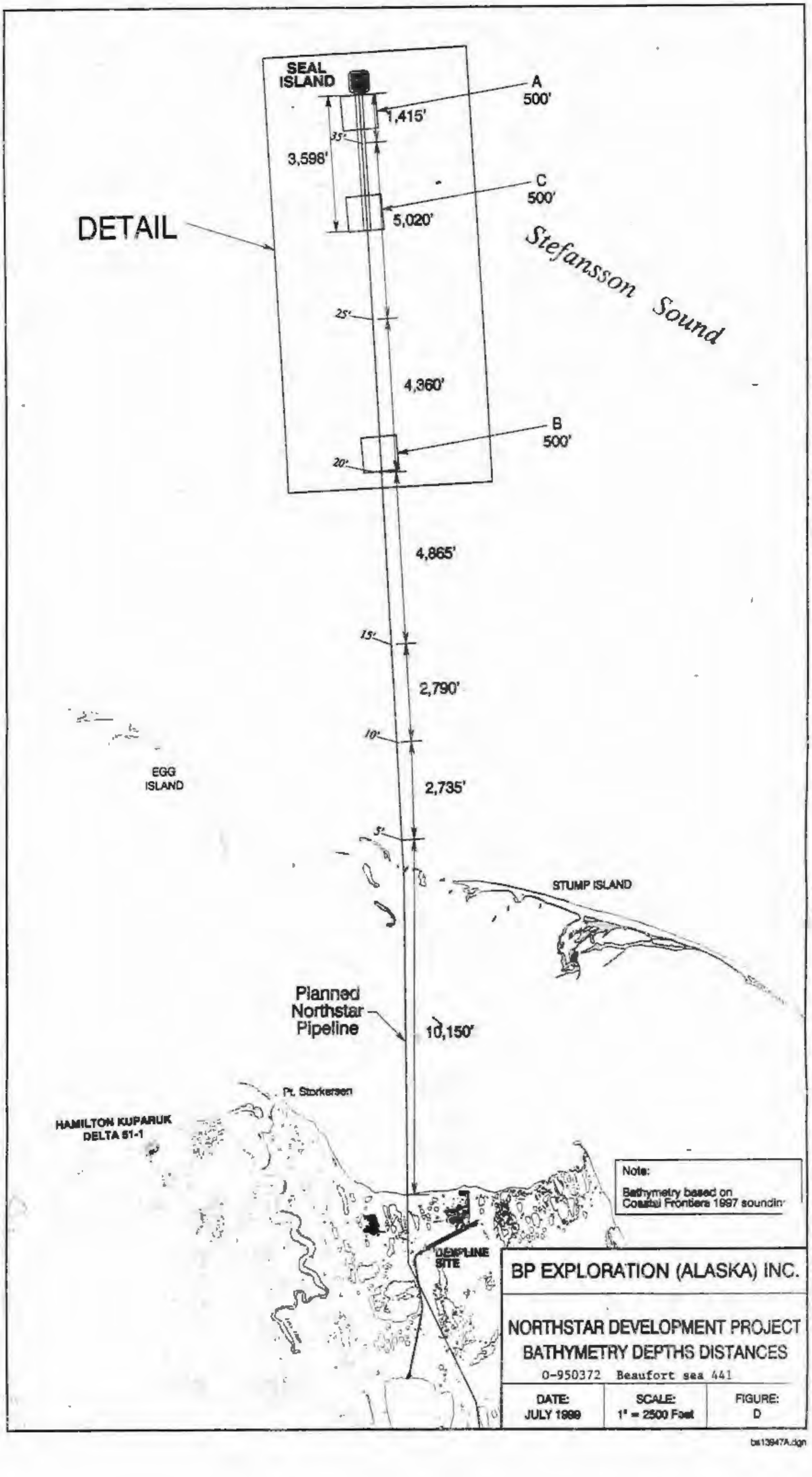

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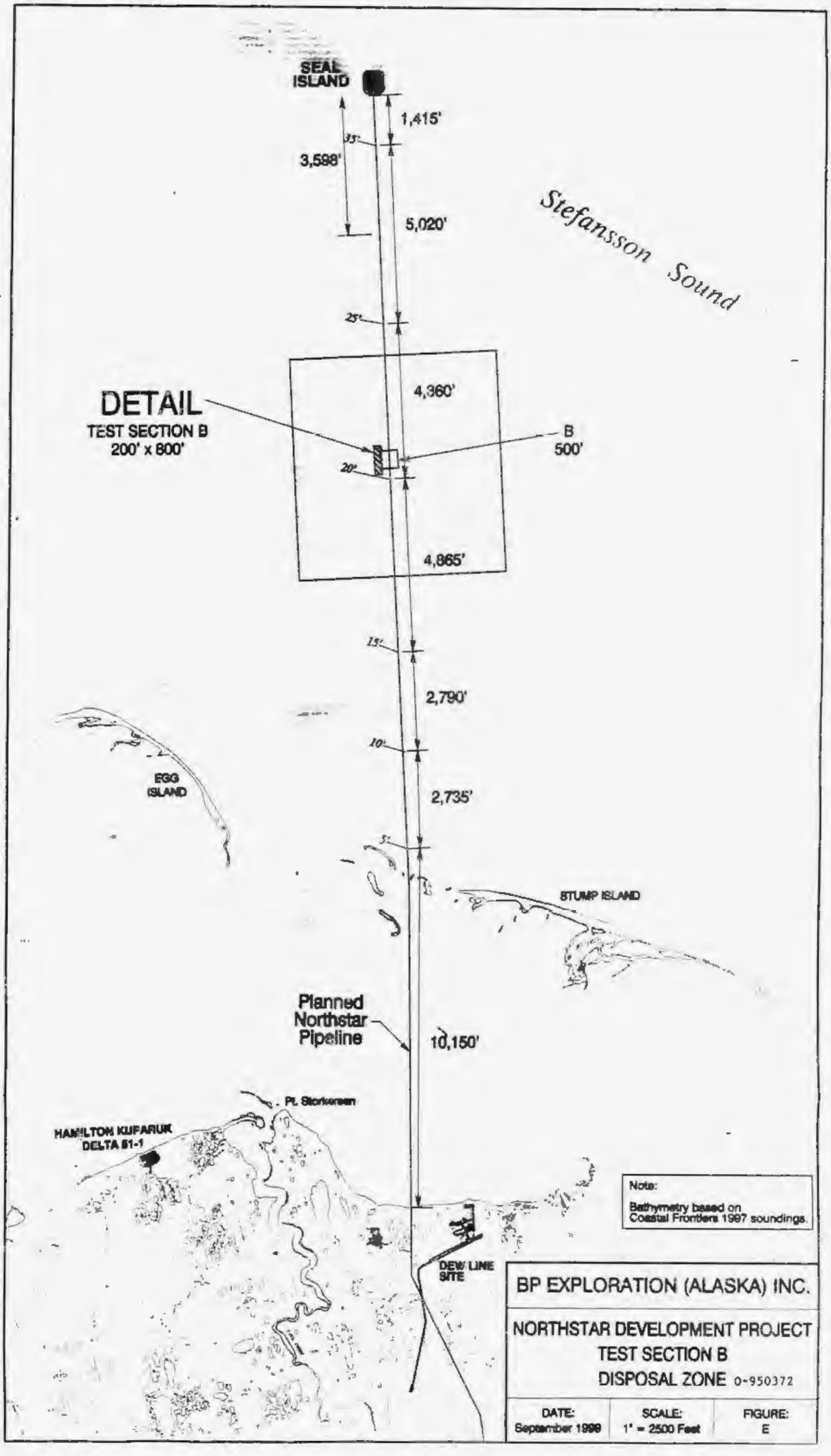
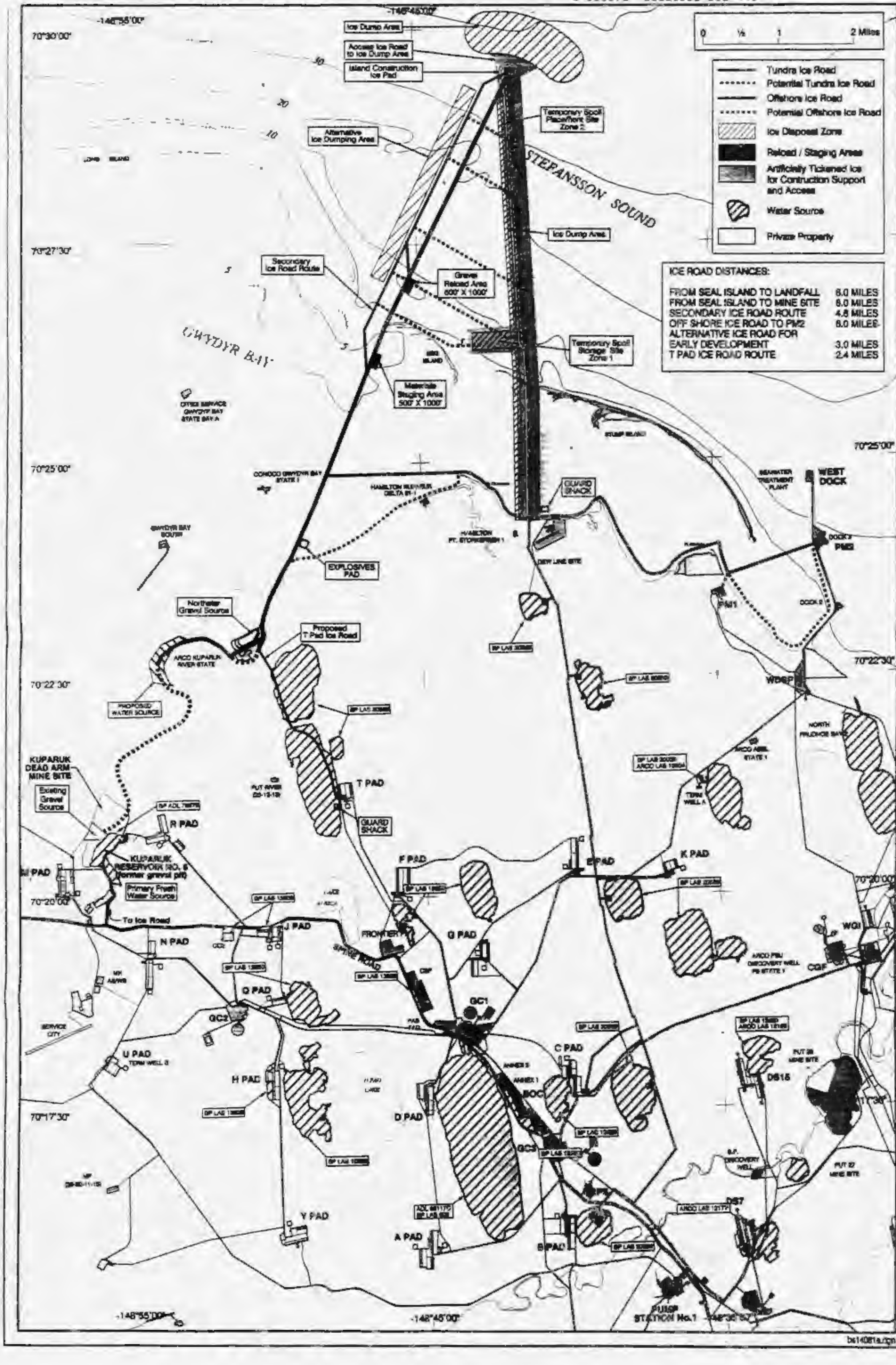

SEAL ISLAND
1,415'
35'
3,598'
5,020'
Stefansson Sound
25'
DETAIL
TEST SECTION B
200' x 800'
4,360'
B
500'
20'
4,865'
15'
2,790'
10'
EGG ISLAND
2,735'
5'
STUMP ISLAND
Planned Northstar Pipeline
10,150'
Pt. Storkersen
HAMILTON KUPARUK DELTA 51-1
Note:
Bathymetry based on Coastal Frontiers 1997 soundings.
DEW LINE SITE
BP EXPLORATION (ALASKA) INC.
NORTHSTAR DEVELOPMENT PROJECT
TEST SECTION B
DISPOSAL ZONE 0-950372
DATE: September 1999
SCALE: 1" = 2500 Feet
FIGURE: E

NORTHSTAR: PIPELINE AND ISLAND CONSTRUCTION ICE ROADS

0-950372 Beaufort Sea 441



CHANGES MADE

BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

March 13, 1998

Ms. Terry Carpenter
Regulatory Branch
U.S. Army Corp. of Engineers
P.O. Box 898
Anchorage, Alaska, 99506-0898

<u>Northstar Development Project</u>
<u>Northstar Final Project Description, Rev. 1; March 27, 1997</u>
<u>Transmittal of Update Modification Packet dated March 13, 1998</u>

Dear Ms. Carpenter:

BP Exploration (Alaska) Inc. (BPXA) hereby transmits the subject Modification Packet to update your copy of the Northstar Final Project Description.

Included in this packet are updates to the NPDES permit application that are being sent to Mr. Robert Robichaud at EPA, Region 10. Changes to the NPDES application involve modifications to the design of the deck drainage sumps (Outfalls 003 and 004), Construction Dewatering (Outfall 005) and the associated Construction Dewatering BMP plan. These changes were made at the direction of Mr. Ted Rockwell, of the local EPA office.

The deck drainage system has been significantly enlarged due to the use of Barter Island precipitation data that we believe is not representative of the precipitation to be expected at Seal Island. However, in agreement with Mr. Rockwell and Mr. Mike Lidgard, EPA Region 10, we have reserved the right to redesign and reduce the size of the sumps when more representative precipitation data becomes available.

A brief description of these modifications follows:

Deck Drainage Sumps

- Significantly increased the capacity of the north and south deck drainage sumps. Added a high level alarm and a high high level alarm. Added a stilling well with a viewing hatch. Added an overflow wier and an underflow wier. Added a low point sump within the sump and redesigned the overflow line configurations.

Construction Dewatering

- Added language to indicate our intent to conduct the construction dewatering activity in accordance with NPDES permit stipulations.
- Added language to define where the ditch plug will be placed during installation of below grade outfall lines 001 and 006.

Air Emissions

- Updated Section 3.3.2 to reflect latest modelling results.

A more specific, page-by-page listing of document modifications entitled, "Specific Changes by Page, Figure, and Table" is included with the modification packet.

The success of this update process requires that you begin with the December 5, 1997 version of the Final Project Description, which is the latest modification.

Please contact Tom Barnes at (907) 564-5154 if you have questions.

Sincerely,

Peter T. Hanley, Permitting Supervisor
Environmental & Regulatory Affairs, Alaska

PTH/jag

Enclosure: Northstar Final Project Description, Modification Packet dated 3/13/98.

Distribution- All registered holders of the Northstar Final Project Description

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION
REVISION 1, March 27, 1997

Modification March 13,1998

Please replace the following referenced items with the attached updated pages:

Page Numbers
2.1-9
3.3-7,8

Figure Number
2.1-16

Appendix A
Tab: EPA National Pollutant Discharge Elimination System

Page ii	Revision Log
Page 6	Exhibit XI-2
Page 7	Exhibit XI-3
Page 31 thru 33	Exhibit 10
Page 34	Exhibit 11
Page 38	Exhibit 12
Attachment 7, Page 3	Construction Dewatering BMP
Page 44	Exhibit 15

Please sign to indicate receipt of the above replacement pages and an understanding of the instructions. Then return signed page to:

Tom Barnes
BP Exploration (Alaska), Inc.
P.O. Box 196612 MB11-6
Anchorage, Alaska 99519-6612

If you have any questions, please contact Tom Barnes at (907) 564-5154.

Name ____________________ Date ____________

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION UPDATE
March 13, 1998

SPECIFIC CHANGES BY PAGE, FIGURE AND TABLE

Page	
2.1-9	Updated section to reflect current sump design.
3.3-7,8	Updated section to reflect latest modelling results.

Figure Number	
2.1-16	Revised to show current sump designs.

Appendix A,	NPDES Permit Application
Page ii	Updated Revision Log.
Page 6	Exhibit XI-2 revised to show current sump dimensions.
Page 7	Exhibit XI-3 revised to show current sump design.
Page 31 thru 33	Exhibit 10 language revised to address current sump design and operational philosophy.
Page 34	Exhibit 11 deck drainage sources updated to reflect Barter Island precipitation rates.
Page 38	Exhibit 12 revised to indicate compliance with NPDES permit stipulations.
Attachment 7, Page 3	Construction Dewatering BMP revised to state where ditch plug will be installed.
Page 44	Exhibit 15 revised to show correct destination of coarse strainer backwash wastes.

LIST OF MODIFICATIONS

DATE	PAGE	MODIFICATION
May 9, 1997	see update instructions	Deletion of cooling water from the project description
July 25, 1997	see update instructions	General modifications to text, tables and figures
Oct. 28, 1997	see update instructions	Modified to bring into agreement with updated NPDES permit application.
Dec. 5, 1997	See update instructions	General revision to bring all documents (Final Project Description, NPDES Application, and Mixing Zone Application) up-to-date and consistent with one another. Also increased stack heights, changed flare configuration, added compressor facilities at CCP.
Mar.13, 1998	See update instructions	Enhanced deck drainage sump design, modified construction dewatering language, updated air emissions section, NPDES permit application revised.

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION
REVISION 1, March 27, 1997

Modification December 5, 1997

Please remove the following pages, tables and figures and replace with the attached replacement pages:

<u>Page Numbers</u>

2.2-1	3.3-3 thru 3.3-8
2.3-1	3.5-1 thru 3.5-4
2.4-5 thru 2.4-13	3.6-1 thru 3.6-4
2.5-1	

<u>Table Number</u>

2.4-2	3.3-3
2.5-1	3.5-1

<u>Figure Number</u>

2.1-2	2.4-11
2.1-4	2.4-13
2.1-6	2.4-14
2.1-14	2.4-19
2.1-16	2.4-20
	2.4-21

<u>Appendix A</u>

Tab: EPA National Pollutant Discharge Elimination System,
Replace entire section

Please sign to indicate receipt of the above replacement pages and an understanding of the instructions. Then return signed page to:

Tom Barnes
BP Exploration (Alaska), Inc.
P.O. Box 196612 MB11-6
Anchorage, Alaska 99519-6612

If you have any questions, please contact Tom Barnes at (907) 564-5154.

Kris Tuttall for
Raymond R. Emerson 12/16/97
Name Date

Distribution Copy #049

LIST OF MODIFICATIONS

DATE	PAGE	MODIFICATION
May 9, 1997	see update instructions	Deletion of cooling water from the project description
July 25, 1997	see update instructions	General modifications to text, tables and figures
Dec. 5, 1997	See update instructions	General revision to bring all documents (Final Project Description, NPDES Application, and Mixing Zone Application) up-to-date and consistent with one another. Also increased stack heights, changed flare configuration, added compressor facilities at CCP.

Distribution No.: 049

Assigned to: RAY EMERSON

NORTHSTAR DEVELOPMENT PROJECT

FINAL PROJECT DESCRIPTION

Revision 1
March 27, 1997

Northstar Project Management Team
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, Alaska 99519-6612

BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

March 27, 1997

Ms. Terry Carpenter
Regulatory Branch
U. S. Army Corps of Engineers
P. O. Box 898
Anchorage, Alaska 99506-0898

Northstar Development Project
Transmittal of Final Project Description (Rev. 1)

Dear Ms. Carpenter:

BP Exploration (Alaska) Inc. (BPXA) hereby submits the Northstar Development Project Final Project Description (FPD), Rev. 1. This document, which is essentially identical to the original FPD submitted to the Northstar EIS Team on December 20,1996, was produced at the request of the EIS Team as a means of clarifying certain aspects of the Northstar Development Project.

This document includes the incorporation of BPXA responses to EIS Team and State agency comments to the December 20, 1996 FPD. Responses to the EIS Team comments were submitted to your office on February 11, 1997. In addition, as requested by the EIS Team, this document includes, as Appendix A, applications for Federal and North Slope Borough permits/authorizations. Because the applications for the Minerals Management Service (MMS) Development and Production Plan, and the North Slope Borough Rezoning and Master Plan are essentially customized versions of this document, they are not appended in their entirety to this document. Rather, an explanatory page has been included in the appropriate agency section of Appendix A explaining what authorization is being sought and when the application will be submitted. A listing of State permits required to construct and operate Northstar is included as Appendix B.

In addition to incorporating the responses to the EIS Team and State agencies into this document, BPXA has taken the opportunity to further enhance this document by inclusion of the following:

- information on a two-season construction schedule alternative without specific dates; and
- additional information on BPXA's revised NPDES permit application submitted to EPA on February 4, 1997, including BPXA's March 24, 1997 responses to EPA's completeness review.

Please note that the provision of information related to the two-season construction alternative reflects BPXA's desire to preserve flexibility in the construction phase resulting from uncertainties related to the Northstar lease litigation, as well as uncertainties related to EIS completion and related permit issuance. Subject to satisfactory completion of the EIS on a timely basis, it is BPXA's intention to proceed with construction of the island in the winter of 1998.

The Northstar Final Project Description, Rev. 1, is being issued in a three-ring binder format as a "controlled document", with each copy being assigned a unique control number for ease of use and documentation purposes.

BPXA has worked closely with the EIS Team, consistent with the provisions of our agreement, to respond to all requests and comments on the content and format of the Final Project Description. We request your confirmation that this Final Project Description, Rev. 1, meets the needs of the Corps as a complete Section 404/10/103 application, as well as meeting the needs of the other EIS Team members' regulatory requirements.

If you have any questions, please contact me at (907) 564-5202 or Tom Barnes at (907) 564-5154.

Sincerely

Peter T. Hanley
Supervisor Permitting,
Environmental and Regulatory Affairs, Alaska

Enclosure (1)

cc: w/ enclosure
Ted Rockwell, EPA, Anchorage
Paul Lowry, MMS
Tom Lohman, NSB, Anchorage
Jeanne Hanson, NMFS
Kate Moiteret, USFWS, Fairbanks
Gary Hayward, Dames & Moore, Anchorage

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION
REVISION 1, March 27, 1997

Modification May 9, 1997

Please remove the following pages and sections and replace with the attached replacement pages:

Page Numbers

List of Modifications (errata sheet)	3.1-2
T-3	Section 3.3 (pages 3.3-1 through 3.3-8)
1.2-3	3.5-1
2.1-1	3.5-2
2.1-8	3.5-4
2.2-2	3.6-4
2.4-8 through 2.4-13	Section 6.1 (pages 6.1-1 through 6.1-4)

Table Number

3.5-1

Figure Number

2.1-2	2.4-9
2.1-3	2.4-10 (DELETED)
2.1-13	2.4-11
2.1-15	2.4-12 (DELETED)
2.4-8	

If you have any questions, please contact Tom Barnes at (907) 564-5154.

BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

July 29, 1997

To: Distribution List R. Emerson

Final Project Description, Rev.1
Northstar Development Project
Transmittal of Minor Modifications Replacement Pages, dated 7/25/97

Dear Ms. Carpenter:

BP Exploration (Alaska) Inc. (BPXA) is enclosing minor modifications and clarifications to the Final Project Description, Rev.1 for the Northstar Development Project. These refinements are a result of ongoing questions and comments from the EIS Team and in response to constructability issues which have been identified.

A brief description of these refinements follows:

1. Widen working surface of island 11 feet in an east-west direction:

As a result of island constructability reviews, a technical problem arose involving the connection of the linked concrete mat slope protection to the sheet pile wall and the open cell sheet pile which is being used for the dock on the south end of the island. Due to the geometry involved there were two basic options which would solve the technical problem: a) widen the working surface of the island by 11 feet, or, b) narrow the width of the dock face on the south side of the island by 11 feet. In trying to assess option b) above, it became readily apparent that shrinking the width of the dock face would have adverse impacts on module movement on to the island, and would negatively impact materials movement for re-supply of tubulars and other consumables for the drilling rig operations.

With the problems encountered with shrinking the dock dimensions, the project worked to minimize the impacts of widening the working surface of the island. The widening of the island by 11 feet can be accomplished without increasing the footprint of the island at the mud line. The total gravel necessary to rebuild Seal Island is still estimated to be approximately 750,000 cubic yards. (See replacement figures 2.1-2, 2.1-4, and 2.1-11, dated 7/25/97)

2. <u>Raise western sheet pile wall to uniform 27-foot height</u>:

Because of previous space constraints, it was necessary to position the conexs to overhang the concrete mat on the west side of the island by 4 feet. The conexs served as a seawall adjacent to the sheet pile wall. With the proposed island widening, there no longer is a space constraint and therefore the sheet pile wall can now extend along the west side of the island at a uniform height of 27 feet. (See replacement figures 2.1-4 and 2.1-11, dated 7/22/97)

3. <u>Adjust location and height of conexs</u>:

With the slight widening of the island there is no longer a space constraint on the west side of the island. Therefore, the conexs can be relocated 4 feet towards the east to set directly behind the raised sheet pile wall. In addition, the conexs will be set directly onto the gravel island surface rather than be placed on footings. The result of this relocation is that a previous 4-foot overhang above the concrete mat is eliminated, as well as a 3-foot space under the conexs. Concerns that man-made habitat (the space under the conex storage containers) for polar bears, foxes, and other arctic animals are eliminated by this proposed modification. (See replacement figures 2.1-4 and 2.1-11, dated 7/22/97).

4. <u>General replacement of foundation pilings to spread footings</u>:

A gravel soil boring program was conducted on Seal Island in March and April, 1997 to verify the properties of the existing Seal Island gravel. The results of the investigation yielded that the existing gravel has the following properties:

- high density, low ice content
- high quality sand and gravel - low amount of fines
- high load bearing capacity
  (5,000 #/ft^2 - long term, 10,000 #/ft^2 - short term)
- low potential for differential settlement

An additional field trip was made to the North Slope in late June, 1997 to view winter placed gravel at F Pad at Milne Point. The gravel that had been placed during the winter of 1996 had the same characteristics as the Seal Island gravel above.

As a result of these investigations, the project is comfortable that a spread footing design will provide a stable foundation design for the Northstar facilities. The foundation system will be very similar to that in use since 1986 for the Endicott Development. The Endicott design has had no substantial problems with the spread footing foundation system since its initial installation. (See replacement figures 2.1-4 and new figure 2.1-12a, dated 7/22/97. Also see figures 5.3-1 and 5.3-2, dated 7/21/97)

5. Relocation of Seawater Intake and Marine Outfalls 001 and 006

The seawater intake has been relocated approximately 85 feet west of it's original location, (see revised figures 2.1-13 and 2.4-11, dated 7/22/97 and figure 2.4-8, dated 7/23/97). The reason for the relocation is based on constructability reviews and risk assessment. The seawater intake was previously located in the sheet pile cell and the same corridor as the oil and gas pipelines. The opening in the sheet pile for the seawater intake is approximately 8' by 5' at -16'MLLW and there is a 36" diameter pipe at -8' MLLW that carries the intake water to the cofferdam. Because the seawater intake is installed as part of the island construction, relocating the intake eliminates the risk of damaging the intake piping when the pipelines are brought to the island the following year in the two year construction scenario. It also removes the intake from the ramp area and will eliminate potential damage caused by moving the process modules and drilling rig onto the island.

The relocation of the seawater intake has caused Effluent Outfall lines 001 and 006 to be relocated to the east. This new location now separates Outfall 001 and 006 from the seawater intake by approximately 140' (see figures 2.1-15 and 2.4-11, dated 7/22/97).

6. Disposal well nomenclature:

Figure 3.6-1 has been modified to correct disposal well numbering to be consistent within the Project Description document.

7. Effluent Wastewater Characteristics, Table 3.5-1:
This table has been updated to reflect NPDES permit application revisions in response to ongoing dialogue with the EPA .

The attachment to this letter consists of the errata sheet listing the report modification, an update instruction sheet identifying the replacement pages, and the individual pages, figures and tables to replace. The modification date (July 25, 1997) will be located in the lower left hand corner of each replacement page.

If you have any other questions, please contact me at (907) 564-5202 or Tom Barnes of my staff at (907) 564-5154.

Sincerely,

Peter T. Hanley, Permitting Supervisor
Environmental & Regulatory Affairs, Alaska

PTH/jag

Enclosure (1)
cc: see Controlled Distributions List 3 attached

Northstar Project

Final Project Description (Rev. 1) - Controlled Document Distribution

Control Number	Name	Group	Location	Control Number	Name	Group	Location
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2	Mike Skitmore	BPXA	ANC	44	Peter Gadd	CFC	Chwth, CA
3	Ian Livett	BPXA	ANC	45	George Valiuis	MMS	Hndn, VA
4	Peter Hanley	BPXA	ANC	46	Richard Pomeroy	MMS	ANC
5	Wayne Gum	BPXA	HOU	47	Jeff Walker	MMS	ANC
6	Gary Campbell	BPXA	ANC	48	Bob Broek	MMS	ANC
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14	Ted Rockwell	EPA	ANC	56	Joseph Gross	BPXA	ANC
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16	Tom Lohman	NSB	ANC	58			
17	~~Kate Moiteret~~ Eric Taylor	USFWS	FAI	59			
18	Gary Hayward	Dames & Moore	ANC	60			
19	Molly Birnbaum	DGC	ANC	61	Betty Haire	BPXA	ANC
20	Glenn Gray	DGC	JNU	62			
21	Bruce Webb	DNR/DOG	ANC	63			
22	Nancy Welch	DNR/DL	FAI	64			
23	Al Ott	ADFG	FAI	65			
24	Brad Fristoe	ADEC	FAI	66			
25	Jack Kerin	DNR/DMWM	FAI	67			
26	Cindi Godsey	ADEC	ANC	68			
27	Judy Kitagawa	ADEC	VAL	69			
28	Robert Watkins	ADEC	ANC	70			
29	Luke Franklin	Gateway	ANC	71			
30	Larry Foster	D & M	ANC	72			
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33	Mike Foster	D & M	ANC	75			
34	Art LeMaster	Veco	ANC				
35	Richard Siira	BPXA	ANC				
36	Craig Heywood	Fluor Danial	ANC				
37	Richard Goff	BPXA	HOU				
38	Doug Rainwater	BPXA	ANC				
39	Jim Gilroy	BPXA	ANC				
40	Sam Foster	Intec	HOU				
41	Greg Swank	SPCO	ANC				
42	Craig Miller	VEI	ANC				

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION
REVISION 1, March 27, 1997

Modification July 25, 1997

Please remove the following pages, tables and figures and replace with the attached replacement pages:

Page Numbers

✓T-3 ✓3.3-8
✓1.2-1 ✓3.5-2
✓2.1-1 ✓3.6-1
✓2.1-7 ✓3.6-3
✓2.1-8 ✓5.2-1
✓2.1-9 ✓5.2-2
~~2.3-1~~

Table Number

✓3.1-1 ✓3.5-1

Figure Number

✓2.1-2 2.1-15
2.1-3 2.4-8
2.1-4 2.4-11
2.1-5 2.4-14
2.1-11 3.6-1
2.1-12a (New) 5.3-1
2.1-13 5.3-2

Appendix A
Tab: U.S. Army Corps of Engineers Permit
Replace single page

DID NOT RECEIVE (CONTACTED BPXA)

Please sign to indicate receipt of the above replacement pages and an understanding of the instructions. Then return signed page to:
Tom Barnes
BP Exploration (Alaska), Inc.
P.O. Box 196612 MB11-6
Anchorage, Alaska 99519-6612

If you have any questions, please contact Tom Barnes at (907) 564-5154.

checked

Paul L. Lowry
Name

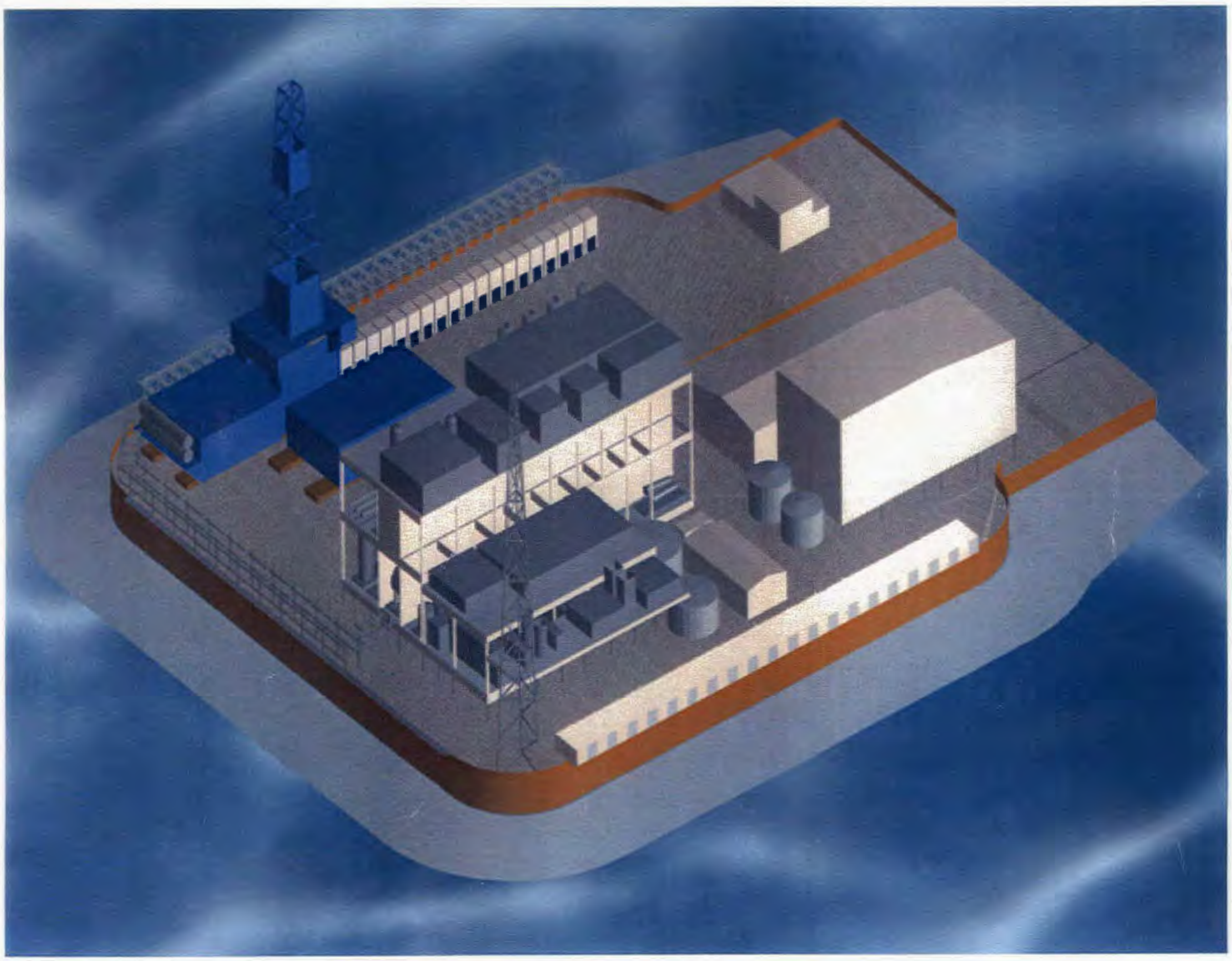
9/3/97
Date

Distribution copy #049

LIST OF MODIFICATIONS

DATE	PAGE	MODIFICATION
May 9, 1997	see update instructions	Deletion of cooling water from the project description
July 25, 1997	see update instructions	General modifications to text, tables and figures

NORTHSTAR DEVELOPMENT PROJECT



FINAL PROJECT DESCRIPTION

Revision 1
March 27, 1997

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

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APPENDICES

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- U.S. Army Corps of Engineers Permit (Sect. 404/10/103)
- USFWS: IHA and LOA
- NMFS: IHA and LOA
- Mineral Management Service: Development and Production Plan
- North Slope Borough Rezone Request and Master Plan

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NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

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INTRODUCTION

NORTHSTAR DEVELOPMENT PROJECT FINAL PROJECT DESCRIPTION

1. INTRODUCTION

1.1 PURPOSE

This document is the *Northstar Development Project, Final Project Description, Revision 1* for the BP Exploration (Alaska) Inc. (BPXA) Northstar Project. It was first issued December 20, 1996, and has been updated and revised to provide clarification in response to State and Federal agency questions and comments.

The development of this project description has evolved from engineering, economic, and environmental evaluations conducted as part of the Conceptual, Preliminary, and Detailed Engineering phases of project planning. Conceptual Engineering, which included a thorough evaluation of alternatives, was completed in February 1996 and the results of that work were presented in the *Conceptual Engineering Report*. The *Proposed Action Plan, Revision 0*, dated June 3, 1996, presented the selected alternative. BPXA's *Project Description* resulted from work conducted during Preliminary Engineering, which was completed in September 1996.

1.2 PROJECT DESCRIPTION SUMMARY

The Northstar oil field is located about 6 miles offshore of the Point McIntyre/Point Storkersen area in the central Alaska Beaufort Sea. BPXA plans to develop the reservoir beginning with construction of a gravel island during the winter following receipt of the necessary agency approvals. The Northstar recoverable reserves consist of a current estimate of 145 million barrels of oil. Initial production is planned for the first quarter of the year following sealift of the major production facilities.

The main facilities required for Northstar include a gravel island work surface for drilling and oil production, drilling equipment and processing facilities and associated transportation system (two pipelines). A personnel camp and supporting infrastructure will also be required on the island.

Table 1.2-1 is a summary of the fill and excavation quantities planned for the Northstar project. Tables 1.2-2 and 1.2-3 are a summary of the major activities planned during the construction phase of the Northstar project, indicating the quantities and timing of the main resource movements planned in the Prudhoe Bay area. The estimated average monthly manpower forecast and associated housing needs are shown in Tables 1.2-4 and 1.2-5.

1.2.1 Island

The island will be built at the location of the existing man-made Seal Island. Additional gravel will be hauled during the winter season to create an island work surface of approximately 465 feet by 421 feet. A sheet pile wall, concrete-block slope protection system and facilities' foundations will be installed, thus completing the island construction phase.

A new gravel source will be opened near the mouth of the Kuparuk River. Transportation of materials and personnel will be via an ice road, usable from early January until breakup. The work on the island, once the gravel is placed, will involve installing spread footing foundations and sheet pile for the island perimeter which will be completed by August 15. The other activities will involve placement of the island slope protection, which consists of linked concrete mats. These materials will be transported by ice road in late winter or by barge from West Dock during the open water season.

Manpower employed will average approximately 60 during island construction, with approximately 100 employed during peak construction. Housing for the island construction crews will be onshore in the Deadhorse service area, with transportation to and from the project site by ice road during the winter and helicopter during breakup and open water.

1.2.2 Process Facilities

The process facilities will separate water and gas from the crude oil produced at Northstar. Two primary modules, a process module and a compressor module, will be built at the Port of Anchorage to accommodate the processing needs. The process module will be built in two sections. Each section will be approximately 120 feet long and 80 feet wide. The compressor module will measure approximately 125 feet long and 80 feet wide. They will be loaded on ocean-going barges and shipped to Seal Island from Anchorage in July to arrive early in the open water season in mid-August.

Installation and hook-up of the modules on the island will occur between August and November. The first oil production into the facility will occur in the first quarter of the following year.

The bulk of the materials required for final installation will travel with the modules on the barge. Construction equipment will also travel to the island on barges from West Dock.

Module fabrication in Anchorage will employ an average of 250 individuals over approximately 18 months. Module installation on the island will require approximately 120 people at the peak in late August after arrival of the sealift.

1.2.3 Pipelines

Two pipelines are planned for the Northstar project. The crude oil sales line will be a 10-inch line running from the island to a tie-in at Pump Station 1 (PS-1). A 10-inch gas line to supply gas to the island will begin at the Prudhoe Bay Unit (PBU) Central Compressor Plant (CCP).

The offshore portion will be six miles in length and will be constructed during the winter between December and April. The crude oil sales and supply gas pipelines will be buried together in a common trench and backfilled. The trenching will be done from thickened ice using excavation and other construction equipment.

The onshore pipeline construction will start in January and be completed in May. Ice roads will be built to access the pipeline routes during construction. The onshore oil and gas pipelines will be about eleven and ten miles long respectively and will be constructed using above ground vertical support members (VSM).

Materials for the pipeline will be transported via truck from Anchorage or Fairbanks during the summer prior to winter construction. Manpower will be approximately 160 during pipeline construction, peaking at 285. As with island construction, these people will be housed onshore in existing facilities.

1.2.4 Drilling

Twenty-three wells will be drilled initially. One is a Class I disposal well for non-hazardous and Resource Conservation and Recovery Act (RCRA) exempt waste generated by drilling and camp activities, 15 are oil producers, and seven wells are for gas injection into the reservoir for the gas cycling depletion plan.

For a single season island construction schedule an existing drill rig from Prudhoe Bay modified for the Northstar project will be transported via barge during September and set up on the island. Drilling will commence in late September using fuel gas provided by the gas pipeline. A barge will be used to transport a four month supply of drilling consumables during September to provide sufficient quantities until an ice road is again built the following January. For a two season island construction schedule, the rig and drilling consumables will be mobilized by ice road in March of the second full winter construction season with drilling operations commencing in early May when fuel gas is available from the gas pipeline. For both schedules the initial phase of development drilling will be completed approximately 21 months later.

A significant portion of the non-hazardous and RCRA exempt waste material generated on the island will be from the camp and drilling activities, and this waste will be injected into the Class I injection well. A grind and inject facility will dispose of drilling cuttings and fluids plus camp waste.

There will be a period of three months (August through October for single season option and March through May for two season option) when the island camp facilities will be occupied prior to the completion of the disposal well for waste disposal. A National Pollutant Discharge Elimination System (NPDES) permit will be required for disposal of treated camp sewage until the Class I well is available. A copy of the NPDES Permit Application has been included in Appendix A of this report.

The drilling crew will average approximately 50 persons and will be housed on the island in the permanent camp facilities for both single season and 2 season schedules.

1.2.5 Island Infrastructure

A combination drilling/operations permanent camp, designed to accommodate 75 people on a long-term basis, will be installed on the island. The 75 people include 20 to 25 core operations staff and a 50-man drilling crew. Emergency power generation, fire water, potable water and sewage treatment facilities will be provided for the camp and island. The sea water intake system is built into the dock face and provides sea water to an intake sump located under the warehouse. Tankage for diesel fuel and potable water storage is provided, and a helipad is located near the dock.

The camp facilities will be built in two modules. One module will be the quarters; the other will contain some of the utility support equipment mentioned above. The warehouse/shop will house the sea water intake sump, and pumps. The camp and utility modules will be fabricated in Anchorage and transported to the island by barge arriving in mid-August.

During installation and hook-up of the facilities, the total island manpower is forecast to peak at approximately 140 people. To accommodate construction manpower needs, additional bunks will be made available in the permanent camp, increasing the sleeping capacity on a temporary basis. Additional consumables for catering support will be stored on site in conex storage containers.

TABLE 1.2-1
NORTHSTAR GRAVEL FILL AND EXCAVATION

ACTION	REQUIREMENTS	CUBIC YARDS	ACRES AFFECTED
Mine Site (Kuparuk River Delta)	Pit excavation (note 1)	700,000	35
	Overburden Stockpile	N/A	N/A
	Subtotal	700,000	35
Island Construction	Existing gravel (note 2)	450,000	17-20
	Place new gravel	700,000	5± (note 3)
	Subtotal	1,150,000	22-25
Pipeline Construction (Offshore)	Seabed excavated (trench)	270,000	21
	Spoil placement back into trench	270,000	N/A
	Subtotal	270,000	21
Pipeline Construction (Onshore)	Valve pad at Pt. Storkersen landfall	1,800	0.20
	Place select backfill in onshore trench	700	0.02
	Place native backfill on top of select fill	100	N/A
	Valve/pig launcher pad south of CCP	1,500	0.20
	Subtotal	4,100	0.42
Total, Placed Quantities Only		974,100	78.4-81.4

Notes:
1. Overburden material pushed back into pit at abandonment.
2. The existing Seal Island is continuously eroding, thereby expanding its seabed footprint and making it impossible to predict exact quantities available at time of construction.
3. Usable gravel within the proposed footprint will be incorporated into the project. Gravel outside the toe of the proposed footprint will not.

TABLE 1.2-2 MAJOR ACTIVITIES RESOURCE IMPACTS - PRUDHOE BAY AREA (SINGLE SEASON)

PROJECT ACTIVITY	PERIOD FROM	PERIOD THROUGH	ESTIMATED MANPOWER RANGE	TRANSPORTED ITEMS	TRANPORTATION METHOD (see note 1) (by number of round trips) BUS	BARGE	BOAT	HELICOPTER	TRUCK	COMMENTS
ISLAND										
Manufacture Concrete Mats	June (Year 1)	September (Year 1)	20 - 40	Personnel Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	December (Year 1)	April (Year 2)	30 - 50	Personnel Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies. Ice roads construction will occur annually to support drilling and operations.
Island Construction	February (Year 2)	April (Year 2)	90 - 100	Personnel Gravel and Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies, Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 CY's of gravel per day from mine site to Seal Island.
Install Island Piling	April (Year 2)	June (Year 2)	50 - 60	Personnel Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize Personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	June (Year 2)	August (Year 2)	50 - 60	Personnel Concrete Blocks, Filter Fabric, and Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily. Barge supplies in July to August timeframe from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge. Boat for personnel during bad weather
PIPELINES										
Install Road and Caribou Crossings	July (Year 1)	September (Year 1)	20 - 30	Personnel Casing Materials, Structural Steel, and Heavy Equipment	100				64	Mobilize personnel via bus to and from the job site. Insulation board, misc. materials, etc. will require 2 to 4 truck trips. Casing pipe will require 10 to 20 truck trips. Sidebooms, dozers, cranes, front end loaders, super sucker, backhoe, etc. will require 10 to 40 truck trips.
Install Offshore Pipelines	December (Year 1)	April (Year 2)	65 - 145	Personnel Pipe, Structural Steel, Hydro Test Media, Fittings, Heavy Equipment, and Consumables	650				254	Mobilize personnel via bus to and from the job site. Pipe 10" X 66,000 LF, hauled from the pipe yard to the job site requiring 80 to 130 truck trips. Spacers, banding, and anodes will require 10 to 20 truck trips. Glycol for hydro testing requires 12 to 20 truck trips. Valves, flanges, bend, etc will require 2 to 4 truck trips. Sidebooms, dozers, light plants, heaters, cranes, front end loaders, etc. require 35 to 50 truck trips. FBE powder, welding rod, skids, spare parts, spill supplies, etc. will require 20 to 30 truck trips.
Install Onshore Pipelines	January (Year 2)	May (Year 2)	60 - 150	Personnel Pipe, Structural Steel, Hydro Test Media, Fittings, Heavy Equipment, and Consumables	900				820	Mobilize personnel via bus to and from the job site. Pipe 10" X 123,000 LF hauled from the pipe yard to the ROW requireing 100 to 160 truck trips. VSM's, saddles, slides, guides, and anchors will require 180 to 230 truck trips. Glycol for hydro testing requires 30 to 60 truck trips. Valves, flanges, bend, etc. will require 10 to 30 truck trips. Sidebooms, dozers, light plants, heaters, cranes, front end loaders, etc. require 120 to 240 truck trips. Insulation foam, welding rod, skids, spare parts, spill supplies, slurry, etc. will require 80 to 100 truck trips.

Note:

1. Transportation methods reflect maximum total estimated round trips during noted period

TABLE 1.2-2 MAJOR ACTIVITIES RESOURCE IMPACTS - PRUDHOE BAY AREA (SINGLE SEASON)

PROJECT ACTIVITY	PERIOD		ESTIMATED MANPOWER RANGE	TRANSPORTED ITEMS	TRANPORTATION METHOD (see note 1) (by number of round trips)					COMMENTS
	FROM	THROUGH			BUS	BARGE	BOAT	HELICOPTER	TRUCK	
MODULE INSTALLATION										
Infrastructure Installation	August (Year 2)	September (Year 2)	40 - 50	Personnel Heavy equipment (cranes, loaders, mod transporters), Modules (20), Consumables/tools (6 conexes, 8' x 8' x 20'), Construction Materials (4 conexes), Fuel / start up materials	90	5	50	900		Mobilize personnel via bus, then boat or helicopter, to job site daily. 300 ton crane (1), loaders (2), hyd. crane (2), module transport trailers (16' wide x 400' long) will require 2 local barge trips. Utility / camp, diesel / water tank, flare (3 pieces), piperacks (15) require 1 barge trip from Anchorage.
Process Facilities Installation	August (Year 2)	November (Year 2)	50 - 120	Personnel Modules (7), Fuel / startup fluids	240	2	20	480		Mobilize personnel via bus, then boat or helicopter, to job site daily. Same heavy equipment as used for Infrastructure installation. Process (2), Compressor, Tank (2), Pumphouse, Warehouse will require 2 barge's from Anchorage.
DRILLING										
Drilling Mobilization	September (Year 2)	September (Year 2)	20 - 25	Personnel Drill rig, Drilling tubulars and bulks		21		30		Assume 1 helicopter trip per day for drilling personnel. Drill rig and associated service buildings require 5 to 6 local barge trips. Approx. 4 months supply of tubulars, cement, mud, wellheads, Xmas trees, etc. will require 15 to 16 local barge trips.
Drilling Resupply	February (Year 3)	April (Year 3)	50	Personnel Drilling tubulars and bulks					200	Personnel already housed on Island. Approx. 4 months supply of tubulars, cement, mud, wellheads, Xmas trees, etc. will require 150 to 200 truck trips. Subsequent bi-annual resupply (Feb to April by Ice road, Aug to Sept by Barge).

Note:

1. Transportation methods reflect maximum total estimated round trips during noted period

TABLE 1.2-3 MAJOR ACTIVITIES RESOURCE IMPACTS - PRUDHOE BAY AREA (TWO SEASON)

PROJECT ACTIVITY	PERIOD		ESTIMATED MANPOWER RANGE	TRANSPORTED ITEMS	TRANPORTATION METHOD (see note 1) (by number of round trips)					COMMENTS
	FROM	THROUGH			BUS	BARGE	BOAT	HELICOPTER	TRUCK	
ISLAND										
Manufacture Concrete Mats	June (Year 1)	September (Year 1)	20 - 40	Personnel Cement, Aggregate, and Supplies	120				250	Mobilize personnel via bus locally in Deadhorse daily. Local trucking from Deadhorse yard to block plant with aggregate and water. Haul Road trucking from Fairbanks and Anchorage with permanent materials.
Ice Road Construction	December (Year 1)	April (Year 2)	30 - 50	Personnel Heavy Equipment	150				125	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies. Ice roads construction will occur annually to support drilling and operations.
Island Construction	February (Year 2)	April (Year 2)	90 - 100	Personnel Gravel and Heavy Equipment	300				30,500	Mobilize personnel via bus from Deadhorse to job site daily. Local trucking from Deadhorse yard to job site with equipment and supplies. Haul Road trucking from Fairbanks and Anchorage with permanent materials. Haul approximately 15,000 CY's of gravel per day from mine site to Seal Island.
Install Island Piling	April (Year 2)	June (Year 2)	50 - 60	Personnel Sheet Pile, Foundation Piles, Concrete Footings				360	75	Mobilize Personnel via helicopter from Deadhorse to job site daily. Truck supplies from Anchorage/Fairbanks to North Slope via Haul Road, then to Seal Island by ice road.
Install Island Slope Protection	June (Year 2)	August (Year 2)	50 - 60	Personnel Concrete Blocks, Filter Fabric, and Hardware		45	10	440	175	Mobilize personnel via helicopter from Deadhorse to job site daily. Barge supplies in July to August timeframe from West Dock to Seal Island. Truck fuel and supplies to West Dock for shipment by barge. Boat for personnel during bad weather
PIPELINES										
Install Road and Caribou Crossings	July (Year 2)	September (Year 2)	20 - 30	Personnel Casing Materials, Structural Steel, and Heavy Equipment	100				64	Mobilize personnel via bus to and from the job site. Insulation board, misc. materials, etc. will require 2 to 4 truck trips. Casing pipe will require 10 to 20 truck trips. Sidebooms, dozers, cranes, front end loaders, super sucker, backhoe, etc. will require 10 to 40 truck trips.
Install Offshore Pipelines	December (Year 2)	April (Year 3)	65 - 145	Personnel Pipe, Structural Steel, Hydro Test Media, Fittings, Heavy Equipment, and Consumables	650				254	Mobilize personnel via bus to and from the job site. Pipe 10" X 66,000 LF. hauled from the pipe yard to the job site requiring 80 to 130 truck trips. Spacers, banding, and anodes will require 10 to 20 truck trips. Glycol for hydro testing requires 12 to 20 truck trips. Valves, flanges, bend, etc will require 2 to 4 truck trips. Sidebooms, dozers, light plants, heaters, cranes, front end loaders, etc. require 35 to 50 truck trips. FBE powder, welding rod, skids, spare parts, spill supplies, etc. will require 20 to 30 truck trips.
Install Onshore Pipelines	January (Year 3)	May (Year 3)	60 - 150	Personnel Pipe, Structural Steel, Hydro Test Media, Fittings, Heavy Equipment, and Consumables	900				820	Mobilize personnel via bus to and from the job site. Pipe 10" X 123,000 LF hauled from the pipe yard to the ROW requireing 100 to 160 truck trips. VSM's, saddles, slides, guides, and anchors will require 180 to 230 truck trips. Glycol for hydro testing requires 30 to 60 truck trips. Valves, flanges, bend, etc. will require 10 to 30 truck trips. Sidebooms, dozers, light plants, heaters, cranes, front end loaders, etc. require 120 to 240 truck trips. Insulation foam, welding rod, skids, spare parts, spill supplies, slurry, etc. will require 80 to 100 truck trips.

Note:

1. Transportation methods reflect maximum total estimated round trips during noted period

TABLE 1.2-5 ESTIMATED MONTHLY AVERAGE MANPOWER FORECAST
TWO SEASON CONSTRUCTION PROGRAM

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

Notes:

The living quarters and utilities modules are sealifted to the island, installed and operational by October.

These numbers reflect the estimated average manpower per month.

CONSTRUCTION PHASE

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

2. CONSTRUCTION PHASE

2.1 ISLAND

2.1.1 Introduction

The Northstar Development Project is a stand-alone, self-contained, offshore drilling and production facility located on a gravel island which will include all support infrastructure and necessary facilities. This island will be built over the existing Seal exploration island, the location of which is shown on Figure 2.1-1.

2.1.2 Structure

A plan of Seal Island is shown in Figure 2.1-2. Figures 2.1-3, 2.1-4 and 2.1-5 provide details of various side elevation views. The datum utilized in this document for all calculations and measurements of elevations and depths is in feet as referenced to Mean Lower Low Water (MLLW). The island work-surface dimeusions will be approximately 465 feet by 421 feet to accommodate drilling, processing, and life-support needs. The slope armor design of the island incorporates a steel sheet pile perimeter wall to surround the work surface completely. On the west side of the island where storms are most intense, the wall will rise to an elevation of +27 MLLW. On the east side of the island, the wall will rise to an elevation of +21 MLLW. The island dimensions at MLLW are 690 feet (north-south direction) by 595 feet (east-west direction). The nominal work surface elevation on the island is +16 MLLW. An open-cell type sheet pile dock is planned on the south. The dock area whose dimensions are approximately 315 feet by 138 feet consists of several integral parts: helipad (SW corner), dock (central) and ball mill (SE corner). The cofferdam constructed for the approach of the pipelines will be located in the central section of the dock. The width of this central section is dictated by the need to move several very wide loads over the dock (production modules and drill rig). The ball mill area is elevated to +16 MLLW and will allow a crane to offload barges from this location.

A submerged gravel berm having a crown width of approximately 50 feet will be placed around the west, north, and east sides of the island. On the northwest and northeast corners, the berm will have a width of approximately 100 feet (Fig. 2.1-2). The crown of the submerged berm at approximately -15 MLLW will cause premature breaking of incoming waves, thus reducing the force of large waves against the concrete mat and sheet pile wall, and minimizing wave overtopping. The primary purpose of this submerged berm will be to prevent thick multi-year ice floes and ridge features from contacting the concrete mat slope armor. Because of its -15 MLLW elevation, the submerged berm will experience erosive forces only during major storm events. Periodic maintenance and replenishment of the submerged berm will be undertaken as needed. The footprint of the island on the seabed, including the protective berm measures 950 feet (north-south direction) by 975 feet (east-west direction).

Since the island will be built over the existing Seal Island, it is anticipated that approximately 400,000 to 500,000 cubic yards of gravel currently at that location can be used. Only gravel within the new island footprint will be incorporated into the island. To complete the island, the balance of the gravel will be quarried onshore at the Northstar mine site and transported to the island site over an ice road during the winter construction season. Island construction is discussed in Section 2.1.4.

Based on knowledge gained through the successful use of concrete mats in the past, designs have been formulated to incorporate mats on the island. The mat damage caused by multi-year ice at the existing Northstar Exploration Island has been noted, and design improvements have been made for long-term use of mats (Table 2.1-1). Extensive wave-model testing has been performed for the proposed design.

2.1.3 Physical Environment - Island Design Criteria

The *Northstar Development Project, Conceptual Engineering Report* dated February 1996 was the source used for the following physical environment information.

2.1.3.1 Oceanography

Table 2.1-2 provides a summary of the oceanographic data on currents, sea-level fluctuations, and waves affecting the design of offshore structures in the Northstar project area.

Ocean Currents

For a storm-generated sustained wind speed of 60 knots (101 ft/sec, 69 mph), the surface current would be about 4 knots (6.7 ft/sec, 4.6 mph).

Water Level Fluctuations

A storm surge value of +6 MLLW has been selected for design purposes at shore. Farther offshore, the effect of storm surge diminishes. The selected design storm surge condition at the offsbore production island site having a water depth of 39 feet is +4 MLLW.

Ocean Waves

Table 2.1-3 presents the extreme wave events developed for the proposed site of the Northstar Development Island based on a numerical hindcast model performed by Offshore and Coastal Technologies, Inc. (1996).

2.1.3.2 Geotechnical Considerations

Three geologic units make up the foundation soils. Table 2.1-4 summarizes the foundation soil properties.

2.1.3.3 Ice Physical Environment and Conditions

Table 2.1-5 provides a summary of the average (typical) and design (extreme) ice parameters.

2.1.3.4 Global Ice Loads

The island will be in contact with uniformly thick first-year ice potentially up to seven feet thick, rafted and ridged first-year ice, multi-year ice floes, and multi-year ice ridges. Various combinations of ice feature interactions have been considered to determine the combinations leading to the governing design loads used to assess the global stability of the island.

2.1.4 Island Construction Techniques

2.1.4.1 Ice Road Construction

The civil portion of the project is scheduled for a double shift, seven days per week operation. The schedule will be adjusted in accordance with the ambient air temperature and prevailing weather conditions. The crews will be housed in the Prudhoe Bay area and bused to their work sites.

The current plan is to build an ice road from either the West Dock or the drill site Point McIntyre No. 1 (PM-1) to the Northstar mine site, and from the mine site to Seal Island. Fresh water sources will include already permitted sources.

Gravel hauling and placement will be conducted during winter using ice roads. The existing Prudhoe Bay road network will be used to deliver goods and equipment to the launching point of the ice road. Figure 2.1-6 provides an overall plan view of the ice roads and gravel haul routes. The ice roads will be constructed starting in early December and should be completed and ready for heavy traffic by mid-February. Following construction, the roads will be maintained using graders with snow wings and snow blowers until ice-road travel is no longer possible, typically in mid-May.

An over tundra ice road is expected to be constructed for site access purposes several hundred feet from PM-1 to the coastline. The route from the shoreline to the new mine site may also require intermittent tundra ice roads. Initially, snow will be cleared utilizing tracked equipment and front-end loaders with snow drags to the required 60-foot road width minimum. A thin layer of snow will be left in place for the first lift of the new ice road. When the snow has been leveled and spread/compacted between the tundra hummocks onshore, one half of the roadway will be saturated with fresh water and allowed to re-freeze. When this approximately 30-foot-wide section is frozen, the adjacent 30 foot roadway will be saturated and allowed to re-freeze. Subsequent flooding will be at a lesser rate of application until the required thickness has been achieved.

The offshore ice roads will be cleared and maintained free of snow to allow more rapid freezing as soon as the natural ice will support the snow removal equipment. Reflective delineators will be provided and placed along the roadways. The roads will be cleared to a width of approximately 300 feet, and the snow tapered out, eliminating berms that create drifting prior to starting the flooding operation to thicken the ice.

Pump units will flood the routes with sea water available at each hole. Once the entire length of sea-ice roads is completed, tankers will haul fresh water to cap and finish the roads. Construction of the ice roads will take approximately 45 days.

Where the ice is floating, pumping units will be used to flood the surface of the ice with approximately three inch layers of sea water. In areas where ridges and depressions prevent easy access for heavy equipment, the sea ice will be cleared to the bare ice surface and fresh water will be hauled to level the surface. Once an area is flooded, it will be allowed to freeze, and the process will be repeated once competent ice is created. Work will continue until a stable ice bridge is formed, creating an area wide enough for two-lane traffic to travel safely. The bridge will be competent enough to support the heaviest loads expected to be hauled to Seal Island.

The ramp from the shoreline to the sea ice will be constructed with lifts of snow and water. The initial lifts of water will be hauled with small tanker trucks. The ramps through the major drainage areas will be constructed with a saturated snow and water mix and allowed to freeze solid prior to placement of additional lifts.

2.1.4.2 Pit Development

The gravel to be used for island construction will be obtained from a new mine site to be developed near the mouth of the Kuparuk River. A geotechnical coring program conducted in 1996 confirmed the suitability of the site as a gravel source. Details of the proposed site, both in plan and in elevation, are provided in Section 7.

The mine site has been selected based on the following considerations:

- Nearest gravel source to Seal Island;
- Least haul distance for gravel to the island;
- Least ice road construction length;
- No vegetation to remove; and
- No impact to tundra (gravel bar in riverbed).

Gravel mining will be conducted in accordance with the mining plan described in Section 7.3 of this document. Section 7.6 discusses the possible alternatives considered.

The snow and ice layers will be ripped, removed, and stockpiled adjacent to the new Northstar mine site. Conventional earth-moving equipment, front-end loaders, and trucks, will be used to clear and remove the snow and ice from the pit area. The bulk of the available gravel is covered by two to three feet of waste material. Gravel will be extracted to the -40-foot elevation.

After the snow and waste material are removed from the pit surface, blasting operations will begin. Pit preparations will take approximately one month before commencement of gravel-placement activities.

Under a one year construction schedule, all gravel, including that for the island, valve pads and pipe approach to the Point Storkersen land fall, will be obtained from the Northstar mine site. The pit will be mined on a one-time basis during the winter prior to island construction and will serve as the primary source of construction material for the island. The exception would likely be the use of gravel from either the Put 23 Oxbow mine site or the Kuparuk Deadarm mine site for the placement of the oil and gas pipelines within existing caribou and road crossings during the summer along the existing oil and gas pipeline road system.

Under the two year construction schedule, only gravel for the island will be obtained from the Northstar mine site, since the Northstar mine site will be flooded at breakup and therefore will not be available for future use. Gravel for the two valve pads and the Point Storkersen pipe approach will be obtained from either the Put 23 Oxbow mine site or the Kuparuk Deadarm mine site. Again, the exception to this would be the possible placement of the oil and gas pipelines within existing caribou and road crossings in the summer prior to pipeline construction using gravel from either the Put 23 Oxbow mine site or the Kuparuk Deadarm mine site.

2.1.4.3 Gravel Haul and Placement

The snow and ice will be cleared to a point 10 feet outside the toes of the island slopes Utilizing established centerline reference points and slope stakes the ice rubble ring that accumulates in late fall will be ripped and removed with tracked equipment to allow 360-degree access to the island. Prior to placing gravel, the surface ice will be cut and removed.

Using large-volume haul units, gravel will be transported from the mine site to a reload area on the shore side of Egg Island. This area is identified on Figure 2.1-6. The scale of the map does not allow for easily identifying the separation of the temporary stockpile location from the islands. The exact location of this site will be delineated prior to commencing the gravel haul activities and will be such that it avoids alteration of wildlife habitats during gravel transport and potential off-road activity.

Ice thickness will be surveyed to find a grounded section of ice. Approximately 50,000 cubic yards will be stored at the site at any time; this will allow for approximately three days of surge capacity. The reload area is a surge pile with material being dumped and loaded at similar rates. From this location, the gravel will be reloaded into lighter end-dumps for hauling to Seal Island. The end-dumps will deposit their loads on the existing Seal Island surface; dozers will then spread the dumped load out ahead of the existing fill. Graders and compactors will shape the fill. In addition to the vibratory compactors, truck traffic on Seal Island will be routed over the fill to assist in attaining the best possible winter compaction possible.

Signs will be posted along the haul routes and portable lights will be placed at intersections. Unauthorized traffic will be kept off the haul routes. A series of reflective signs, fiberglass road markers, and flashing arrow boards will alert traffic of the haul route.

All gravel required for the island and sub-sea berm will be placed during the initial hauling process. Fine grading and shaping of the slopes will take place in later months, just prior to slope protection installation. The berm will not be fine-graded but wave and ice action will tend to level the crown over time.

2.1.5 Sheet Piling

The working surface of the island will be surrounded on all four sides by sheet piling. A typical cross-section through the sheet piles is shown in Figure 2.1-7. On the north, east, and west faces of the island, it is planned to drive sheet piles into the island gravel so that their top elevation will vary between +19 and +27 MLLW as shown in Figures 2.1-3, 2.1-4 and 2.1-5. The sheet pile wall is designed to carry the loads of the gravel and water behind it, and surface loads placed on top of the gravel with a magnitude of 600 pounds per square foot (psf) of area.

Open-cell sheet pile construction will be used on the south side of the island for the dock area. The top elevation of the sheet piles along a section of the dock face will be +7 MLLW to allow docking of barges and roll off of loads onto the island. The water depth at the base of the dock will be -16 MLLW.

The sheet pile sections will be hauled by truck from Anchorage via the Parks and Dalton Highways to Deadhorse, and then over an ice road to the island. The sheet pile wall will be installed in the spring, before the bench is shaped and the concrete mats are placed.

On the west side of the island, up to 40 conex storage containers will be placed behind the sheet pile wall which has a height of +27 MLLW. The 20 feet long and 8½ feet high conex units will rest on the gravel surface. Placing conex units directly on the gravel surface will eliminate creation of sheltered areas where wildlife, such as polar bears, could approach or remain near the Northstar facilities undetected.. This is depicted in Figures 2.1-4, 2.1-5 and 2.1-11.

2.1.6 Slope Protection System

Linked concrete-mat armor will be used for the Northstar Development Project. These blocks will be approximately four feet by four feet by nine inches thick with one inch integral spacers. A 3½ inch straight chamfer is planned. The blocks will be both square (approximately 9,500 total) and corner trapezoids (approximately 5,800 total). While the square blocks are approximately 48 inches square (exclusive of the one inch spacer), there are 36 individual trapezoidal block sizes of various dimensions. Figures 2.1-8, 2.1-9 and 2.1-10 provide details of the arrangement of typical mats, a typical concrete block and the mat linkages.

A block plant will be set up in a Deadhorse yard for fabrication of these blocks. Cement and required additives will be trucked from Anchorage. The concrete aggregates will be mined in the Put 23 mine site on the North Slope. Water will be obtained from permitted sources shown in Figure 2.1-6. The blocks will be stored outside until they are transported to Seal Island via ice road or barge.

The island slopes will be fine-graded and shaped. The bench cross-section of Figure 2.1-11 shows the sub-sea side slope of 1 vertical to 3 horizontal. The final shaping will be closely followed by filter fabric and block installation. On this figure, the dashed line indicates the expected final gravel berm configuration which would result from wave and ice action. The top of the berm is expected to be flat, following initial wave and ice action.

Prior to concrete mat placement, a highly permeable polyester fabric, which terminates at the level of -20 MLLW, will be placed on the gravel island side slopes to prevent erosion of the fines from the island slope.

The individual mat elements will be linked together for placement by cranes. Each block is connected to the adjoining blocks with a series of shackles and chains. The entire island will be armored in a single open-water season.

Cranes will be utilized for setting of concrete mats below the water surface. Divers will be utilized to connect adjoining mat sections. The concrete armor will be connected to the sheet pile wall with shackles and chain linked to steel angle iron welded to the base of the sheet pile wall (see Figure 2.1-7). Blocks which are damaged during the construction phase will be hauled back to shore for disposal in an approved disposal site.

2.1.7 Main Facility Foundations

The heaviest loads to be supported on the island, excluding the drilling rig which provides its own foundation through the substructure, are the process module, followed by the gas compression module and the accommodation and warehouse modules. They will be supported on spread footings placed in the gravel.

A typical module foundation spread footing is shown in Figure 2.1-12a. When the modules are installed, an extension from the module structural base will result in the modules being elevated above the island surface.

Should there be any settlement in the gravel, provisions for leveling and alignment of all modules and facilities will be achieved by using a hydraulic jacking system.

2.1.8 Water Intake Facilities

Water will be required on the island for domestic use and for drilling. Sea water will also provide fire-fighting capability. Intake facilities will be installed below water at the dock face of the island (see Figure 2.1-13). The intake will be capable of withstanding impact from rubble ice and will be configured to limit the flow velocity to acceptable levels.

Sea water intake requirements are approximately 62,000 BWPD.

2.1.9 Deck Drainage

Deck drainage runoff will be managed as required in the Northstar Unit Development, NPDES Permit. Except for permitted NPDES discharges associated with the Northstar facility, no process streams will be discharged.

Runoff from the Northstar facility will normally be limited to the period from May to September, with the greatest volume of runoff being composed of snowmelt. Uncontaminated snow may be pushed off the edge of the island, where it will gradually melt into the Beaufort Sea at breakup. Uncontaminated snow is defined as having no discoloration or petroleum/chemical odor. Contaminated snow will be collected for melting and injection in the UIC Class I disposal well, or if necessary, transported off-site for proper disposal at a permitted facility.

Surface drainage of snowmelt and other runoff will be managed by a gravity drainage and catchment system. The surface of the island will be graded so that all runoff will collect in two sumps; the north sump will be situated in the northwest corner of the island and the south sump will be located on the dock immediately east of the helideck, The island surface will be contoured such that approximately 31% of the island work surface will drain to the south deck drainage sump while the remaining 69% of the work surface will drain to the north deck drainage sump.

The drainage sumps consist of buried fabricated steel boxes as depicted on figure 2.1-16. The sumps are sized for a 2 hour retention based on a predicted 10 year storm event using Barter Island precipitation data. Each sump will have a dedicated drain line and shutoff valve for operator initiated drainage of impounded, uncontaminated water from the sump to the ocean. Each sump will have an overflow wier at the inlet end for sediment containment and an underflow wier located at the outlet end to capture and prevent oily discharges. In addition, each sump will be equipped with a slotted stilling well that will allow viewing from above of the undisturbed liquid surface for the detection of the presence of an oil sheen.

Each sump will have two level switches installed and configured such that an alarm will sound at both the main control room and in the security office if the sump level reaches either of the predetermined levels as indicated on Figure 2.1-16.

2.1.10 Color Scheme for Northstar Structures

The color scheme for exterior structures on the island is shown in Table 2.1-6. The sheet pile perimeter wall will be untreated steel with a rust colored scale. Module walls, buildings and conex storage containers will be painted beige, and exposed module steel will be painted gray. The concrete mat will be natural concrete color.

TABLE 2.1-1
CONCRETE MAT DESIGN IMPROVEMENTS FOR APPLICATION TO THE NORTHSTAR DEVELOPMENT

SLOPE ARMOR DESIGN PARAMETER	NORTHSTAR EXPLORATION ISLAND (Constructed 1985, Abandoned 1994)	NORTHSTAR DEVELOPMENT ISLAND (SEAL ISLAND)	IMPROVEMENTS OBTAINED
Slope Profile	1V:3H	• Compound slope: Lower slope (1V:3H), waterline bench (1V:25H), • Submerged berm • Vertical sheet pile surrounding work surface	• Lower wave forces and run-up • Lower ice forces • Physical ice-floe barrier • Safety buffer
Concrete Mix, Rebar Design	Fines in aggregate, galvanized rebar	• Optimized use of aggregates available • Improved concrete mix design • Improved rebar design	• Improved elasticity • Improved durability • Improved concrete/rebar adhesion
Mat Underlayer	Non-woven polyester fabric (poor permeability and strength)	• Highly permeable, durable woven polyester fabric	• Reduced wave uplift • Reduced sub-grade displacement
Block Profile	2-inch top chamfer	• 3 1/2-inch top chamfer	• Reduced ice plucking
Mat Anchors	Timber deadmen buried in island fill	• Linked directly to steel sheet pile wall	• Stronger anchor • Improved maintenance
Mat Linkage	3/4 inch shackles (defective), 5/8 inch chain	• Stronger shackles and chain to accommodate installation loads	• Increased strength to resist ice loads and long-term fatigue

TABLE 2.1-2
SUMMARY OCEANOGRAPHIC DESIGN CRITERIA

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

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

TABLE 2.1-3
EXTREME WAVE PREDICTION
BASED ON BEAUFORT SEA HINDCAST STUDY
SEAL ISLAND SITE

RETURN EVENT (Years)	WESTERLY STORM		EASTERLY STORM	
	H_S (Feet)	T_{PEAK} (Seconds)	H_S (Feet)	T_{PEAK} (Seconds)
1	7.1	6.8	7.6	7.0
5	8.3	7.8	8.3	7.5
10	10.8	8.3	9.7	7.8
25	14.6	5.1	11.1	9.9
50	18.4	9.9	11.8	10.7
100	19.9	10.9	12.8	12.3

TABLE 2.1-4
SUMMARY SOIL PROPERTIES AT SEAL ISLAND

SOIL	DESCRIPTION	DEPTH (FEET)	SHEAR STRENGTH (PSF)	DRY DENSITY (PCF)	MOISTURE CONTENT (PERCENT)
Type I	Silty clay (CL) and silty sand (SM); small amount sandy silt (ML) Very stiff to hard; low plasticity Sands and silts dense to very dense	0 to 8	800	97 (average)	27 (average)
Type II	Silty sand (SM or SP-SM) and sandy gravel (GP) Dense to very dense	8 to 20		119 (average)	
Type III	Sandy gravel (GP) and gravel (GP or GW) Dense to very dense	20+		120	

TABLE 2.1-5
DESIGN BASIS ICE ENVIRONMENT CRITERIA FOR NORTHSTAR

ICE CONDITION OR PARAMETER	AVERAGE OR TYPICAL VALUES	DESIGN OR EXTREME VALUES
Ice Type	First-Year Ice	Multi-year ice
Ice Zone	Landfast Ice	Summer multi-year invasions Freeze-up multi-year invasions
Ice Season		
• Freeze-up	October 7	3rd week in September to the 4th week in October
• Breakup	July 4	4th week in June to the 2nd week in July
• First Open Water	mid-July	
• Ice Season Duration	290 ± 8 days	
• Total Open Water	75 ± 10 days	
• Season Duration	Almost every summer	
• Summer Ice Invasion	—	2-3 times during summer
Max. Sheet Ice Thickness	6 feet	7.5 feet
Multi-Year Ice Parameters		
• Presence	1 in 2 years during summer 1 in 3 to 4 yr during freeze-up	
• Multi-Year Ice Concentration	0.5 to 1.0 tenth	2 to 3 tenths
• Floe Diameter	1,000 to 1,500 feet	4,000 to 5,000 feet
• Floe Thickness		
- Nearshore floes	23 to 26 feet	Water-depth-limited
- Pack floes	13 to 17 feet	30 to 33 feet
• Keel Depth	30 to 33 feet	Water-depth-limited
• Ice Crushing Pressure	100 to 175 psi	200-250 psi
Ice Speed (20 to 40 ft of water)		
• Summer	0.2 to 0.4 knots	3 to 4 knots
• Freeze-up	0.3 to 0.6 knots	3 to 4 knots

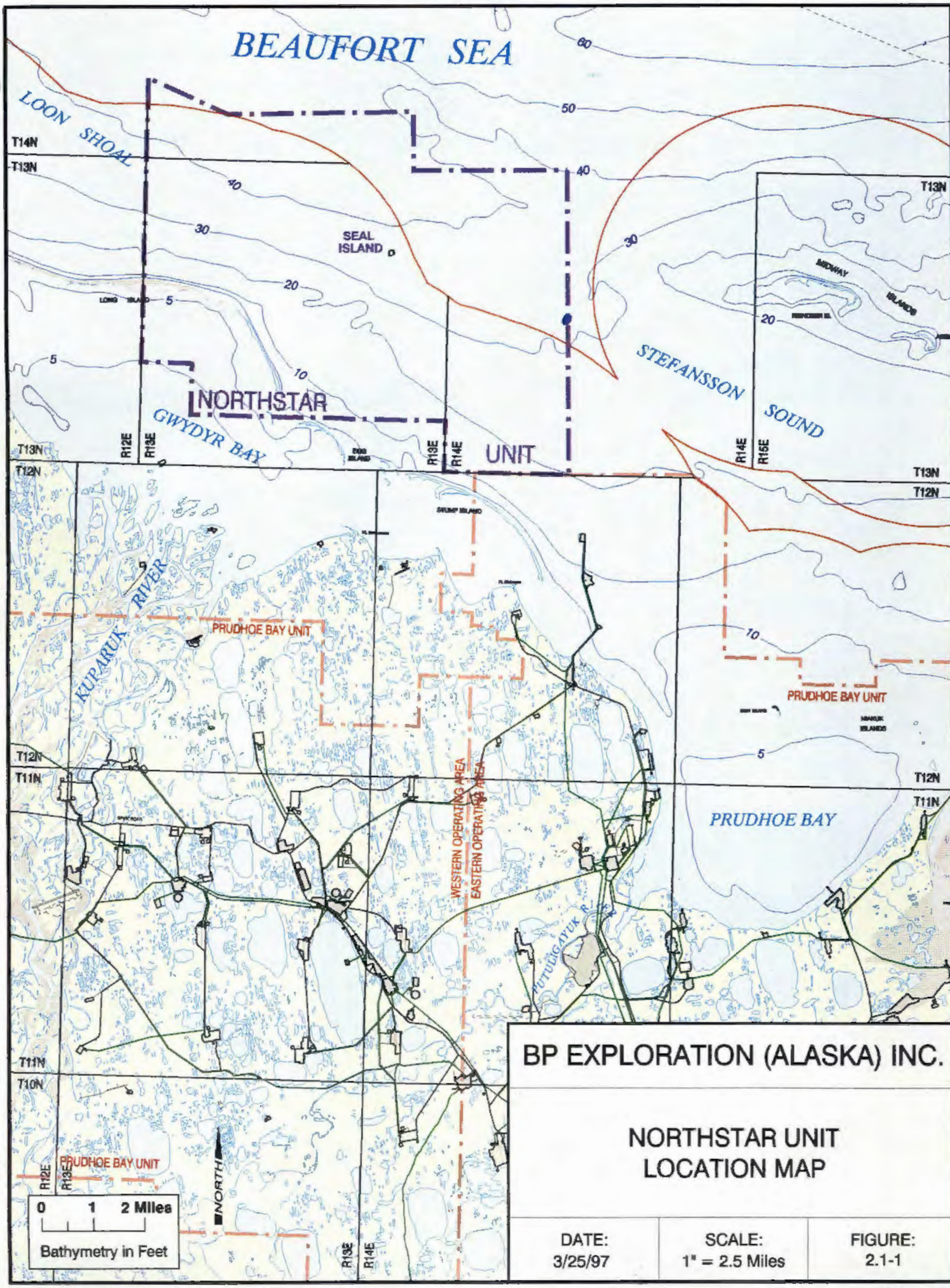
TABLE 2.1-5 (CONT'D)
DESIGN BASIS ICE ENVIRONMENT CRITERIA FOR NORTHSTAR

ICE CONDITION OR PARAMETER	AVERAGE OR TYPICAL VALUES	DESIGN OR EXTREME VALUES (EXTRAPOLATED)
Ice Gouges/Strudel Scours		
• Gouge Depths		
- Simpson Lagoon	<1 foot*	<2 feet
- 0- to 16-foot Water Depth	<1 foot*	<3.5 feet
- 16- to 39-foot Water Depth	<2 feet*	<3.5 feet
• Strudel Scours		
- Depth	<4 feet	15 to 20 feet
- Width	<50 feet	90 to 110 feet in diameter
- Population	40 to 50 per year	75 to 100 per year
- Density	5 to 10 per square mile	20 to 25 per square mile

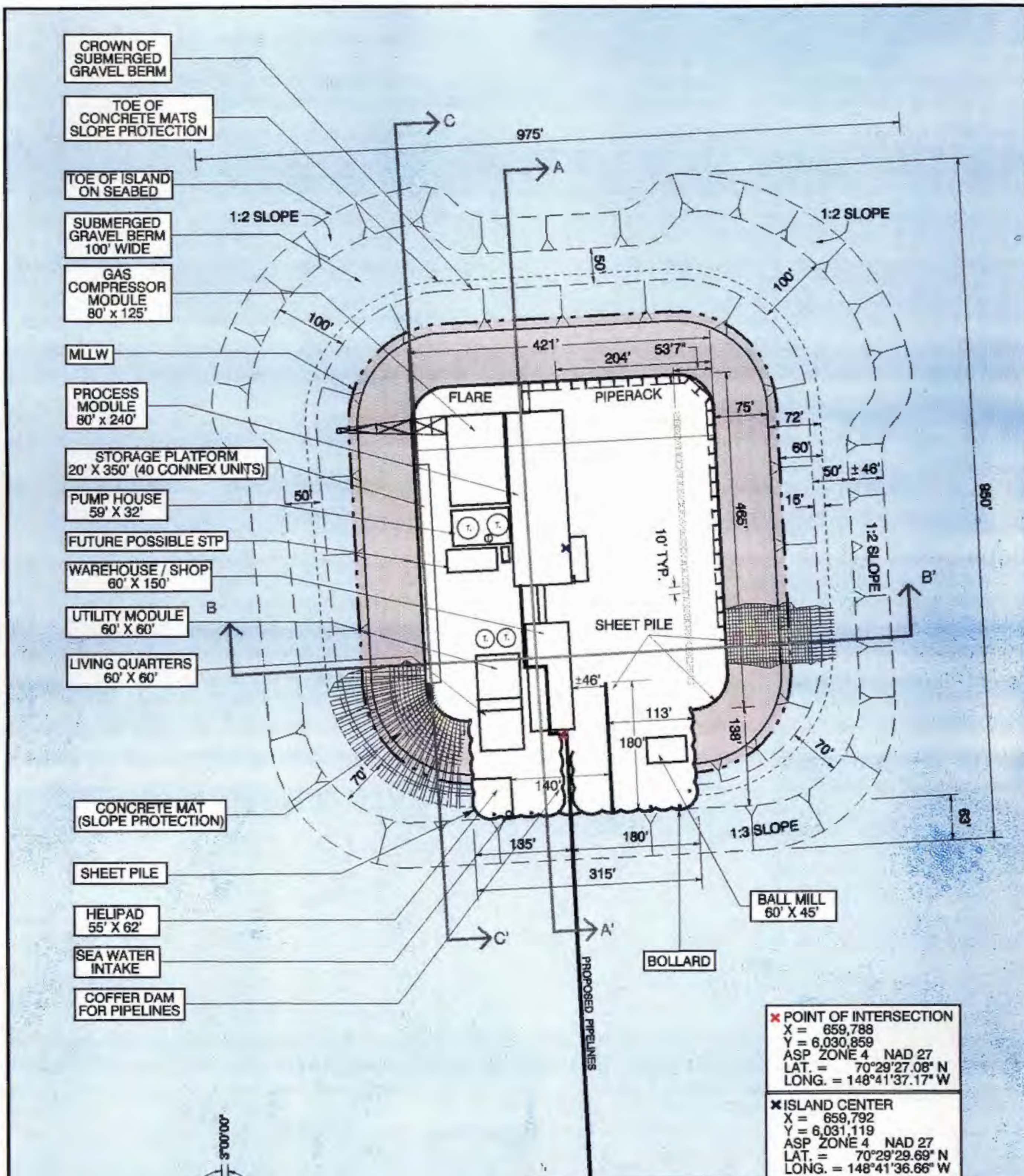
* Based on pipeline route surveys conducted in the Seal Island region during the summers of 1985 (Harding-Lawson 1985) and 1995 (Coastal Frontiers 1996).

TABLE 2.1-6
COLOR SCHEME FOR NORTHSTAR STRUCTURES

STRUCTURE	COLOR
PIPE RACK	GRAY
INSULATED EXTERIOR PIPING	ALUMINUM
NON-INSULATED EXTERIOR PIPING	GRAY
DRILL RIG AND SERVICES BLDG	BLUE
BALL MILL	BEIGE
PROCESS MODULE ENCLOSURE	BEIGE
PROCESS MODULE AREAS	GRAY
GAS COMPRESSOR ENCLOSURES	BEIGE
GAS COMPRESSION MODULE AREAS	GRAY
PROCESS TANK PLATFORM	GRAY
PRODUCED WATER TANK	ALUMINUM
SLOP OIL TANK	ALUMINUM
PUMP HOUSE	BEIGE
POSSIBLE SEA WATER TREATMENT MODULES	BEIGE
WAREHOUSE	BEIGE
ELEVATED WALKWAYS	BEIGE
UTILITY TANK PLATFORM	GRAY
POTABLE WATER TANK	ALUMINUM
DIESEL TANK	ALUMINUM
UTILITIES MODULE	BEIGE
LIVING QUARTERS	BEIGE
CONEX STORAGE CONTAINERS	BEIGE
FOUNDATION STUB COLUMNS	GRAY
STAIRS & LANDINGS	GRAY
SHEET PILE	BARE STEEL
FLARE TOWER	GRAY
UNPAINTED CONCRETE MAT SLOPE ARMOR	NATURAL CONCRETE


BEAUFORT SEA
LOON SHOAL
SEAL ISLAND
NORTHSTAR
UNIT
GWYDYR BAY
STEFANSSON SOUND
KUPARUK RIVER
PRUDHOE BAY UNIT
WESTERN OPERATING AREA
EASTERN OPERATING AREA
PRUDHOE BAY
T14N
T13N
T12N
T11N
T10N
R12E
R13E
R14E
R15E
60
50
40
30
20
10
5
0 1 2 Miles
Bathymetry in Feet
NORTH
BP EXPLORATION (ALASKA) INC.
NORTHSTAR UNIT
LOCATION MAP
DATE:
3/25/97
SCALE:
1" = 2.5 Miles
FIGURE:
2.1-1

bs13114.dgn



PLANT
ASP GRID
3°00'00"

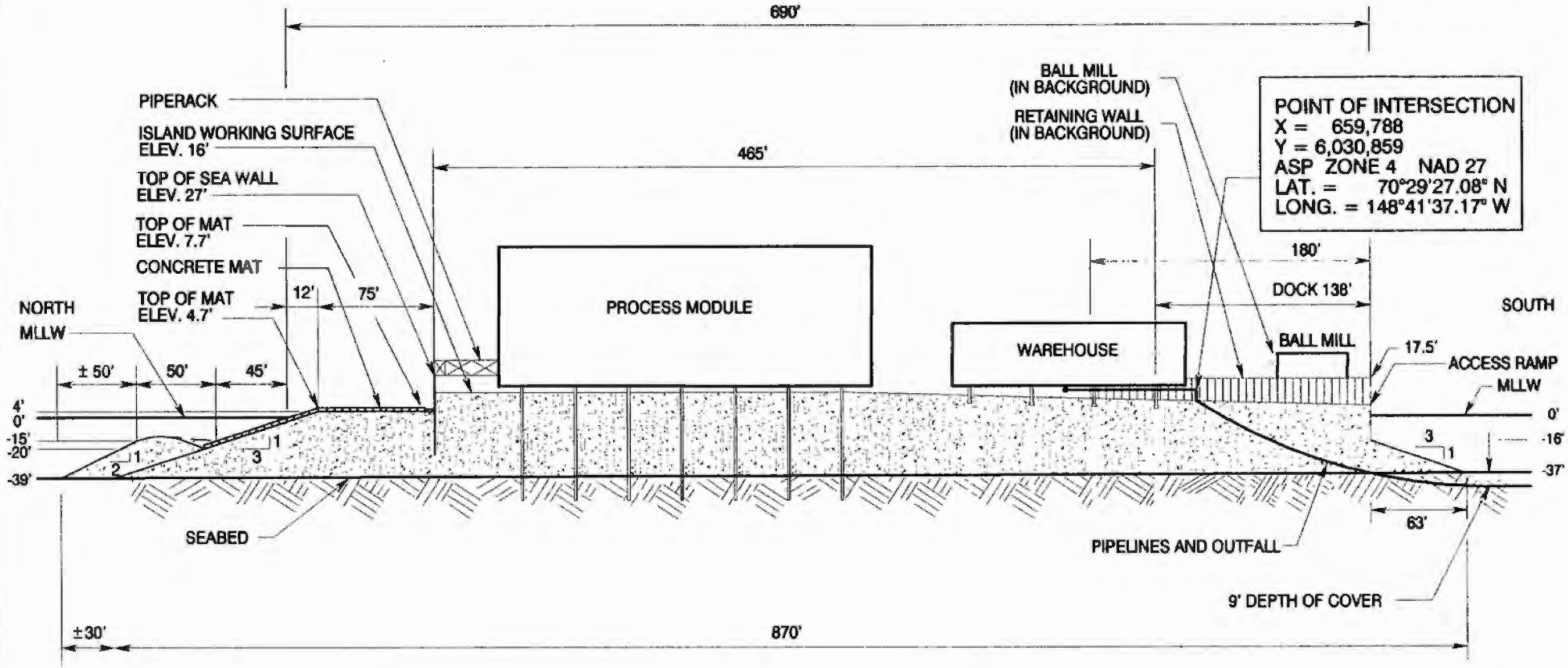
ISLAND SEABOTTOM FOOTPRINT =	18.1 ACRES
ISLAND WORKING SURFACE =	5.4 ACRES
ISLAND SURFACE ABOVE MLLW =	8.7 ACRES
ISLAND SURFACE BELOW MLLW =	9.4 ACRES

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND AND PIPELINE APPROACH
PLAN VIEW

DATE:	SCALE:	FIGURE:
NOV. 1997	NOT TO SCALE	2.1-2

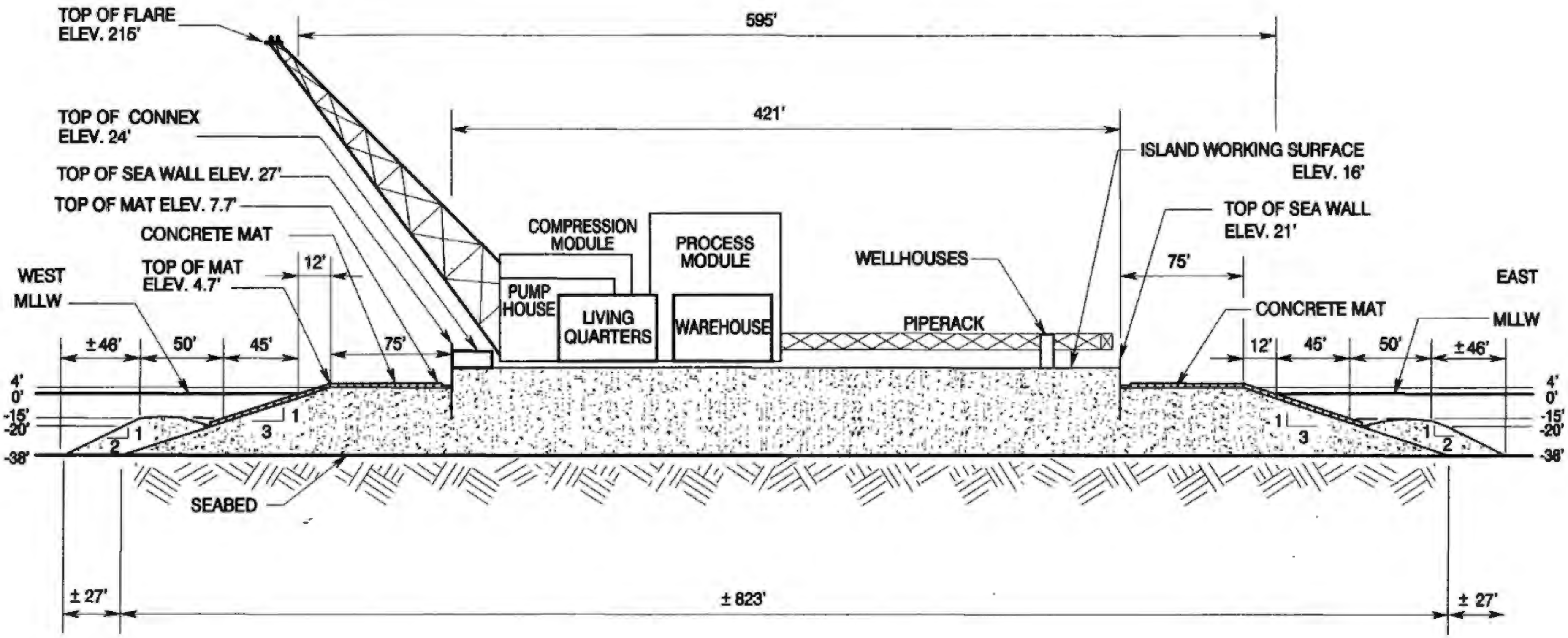
nsv1197.dgn



SIDE VIEW A-A'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAL ISLAND SIDE VIEW		
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.1-3

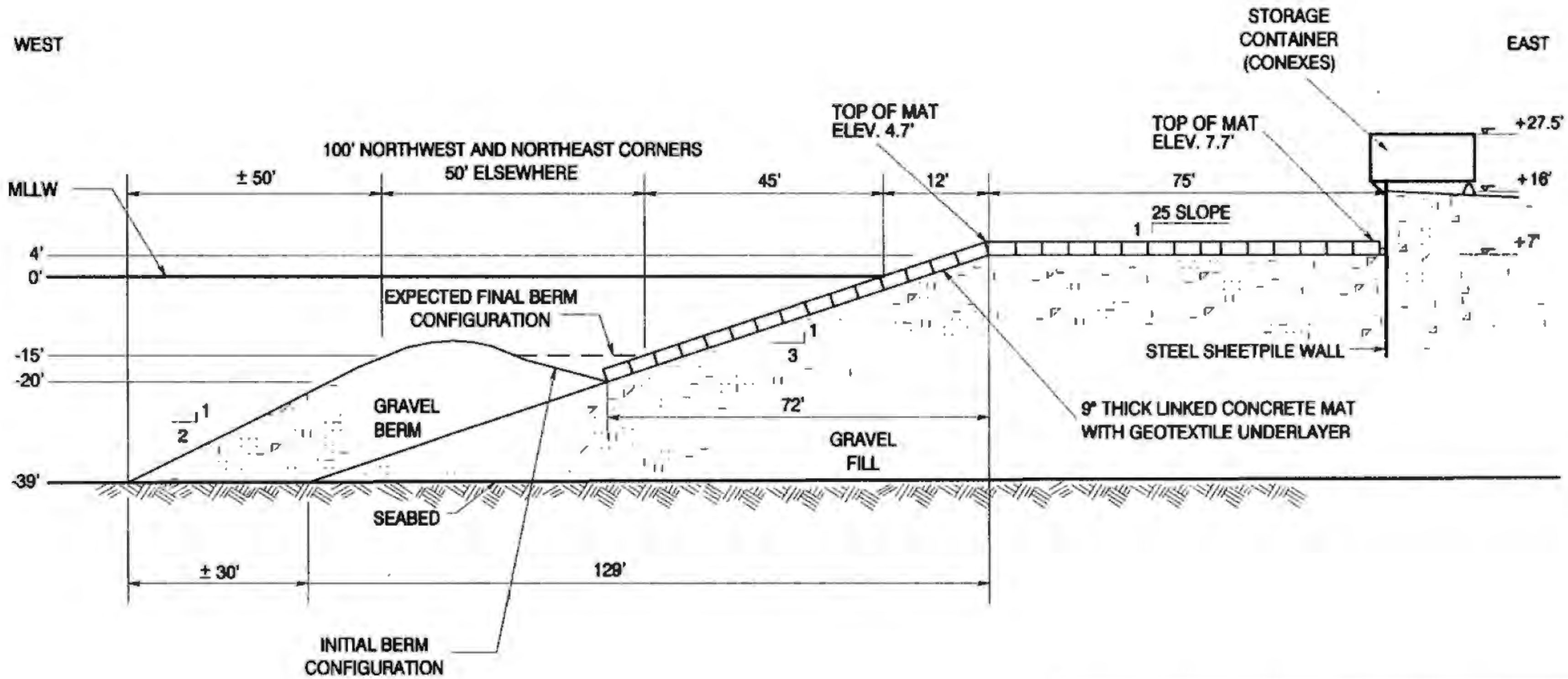
ncv297.dgn



SIDE VIEW B-B'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAL ISLAND SIDE VIEW		
DATE: NOV. 1997	SCALE: N/A	FIGURE: 2.1-4

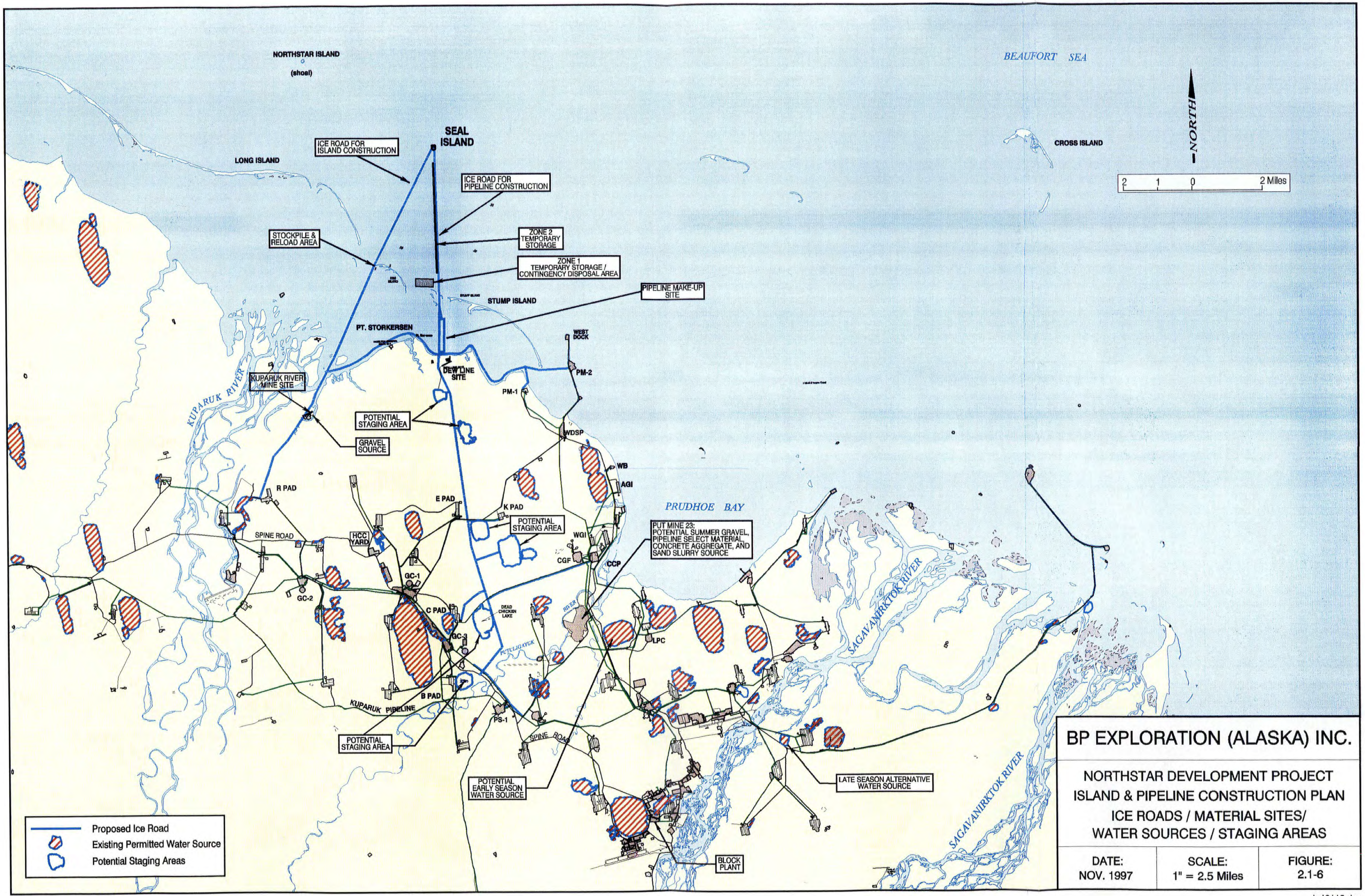
nsv1197.dgn



BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
ISLAND SLOPE PROTECTION
SIDE VIEW

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.1-11


BEAUFORT SEA
NORTHSTAR ISLAND
(shoal)
SEAL ISLAND
LONG ISLAND
CROSS ISLAND
NORTH
2 1 0 2 Miles
ICE ROAD FOR ISLAND CONSTRUCTION
ICE ROAD FOR PIPELINE CONSTRUCTION
STOCKPILE & RELOAD AREA
ZONE 2 TEMPORARY STORAGE
ZONE 1 TEMPORARY STORAGE / CONTINGENCY DISPOSAL AREA
STUMP ISLAND
PIPELINE MAKE-UP SITE
PT. STORKERSEN
WEST DOCK
DEW LINE SITE
PM-2
PM-1
KUPARUK RIVER MINE SITE
KUPARUK RIVER
POTENTIAL STAGING AREA
GRAVEL SOURCE
WDSP
WB
AGI
PRUDHOE BAY
R PAD
E PAD
K PAD
POTENTIAL STAGING AREA
SPINE ROAD
HCC YARD
WGI
CGF
CCP
PUT MINE 23: POTENTIAL SUMMER GRAVEL, PIPELINE SELECT MATERIAL, CONCRETE AGGREGATE, AND SAND SLURRY SOURCE
GC-1
GC-2
C PAD
GC-3
DEAD CHICKEN LAKE
PUTULIGAYUK
LPC
SAGAVANIRKTOK RIVER
KUPARUK PIPELINE
B PAD
PS-1
SPINE ROAD
POTENTIAL STAGING AREA
POTENTIAL EARLY SEASON WATER SOURCE
LATE SEASON ALTERNATIVE WATER SOURCE
BLOCK PLANT
SAGAVANIRKTOK RIVER
Proposed Ice Road
Existing Permitted Water Source
Potential Staging Areas
BP EXPLORATION (ALASKA) INC.
NORTHSTAR DEVELOPMENT PROJECT
ISLAND & PIPELINE CONSTRUCTION PLAN
ICE ROADS / MATERIAL SITES/
WATER SOURCES / STAGING AREAS
DATE: NOV. 1997
SCALE: 1" = 2.5 Miles
FIGURE: 2.1-6

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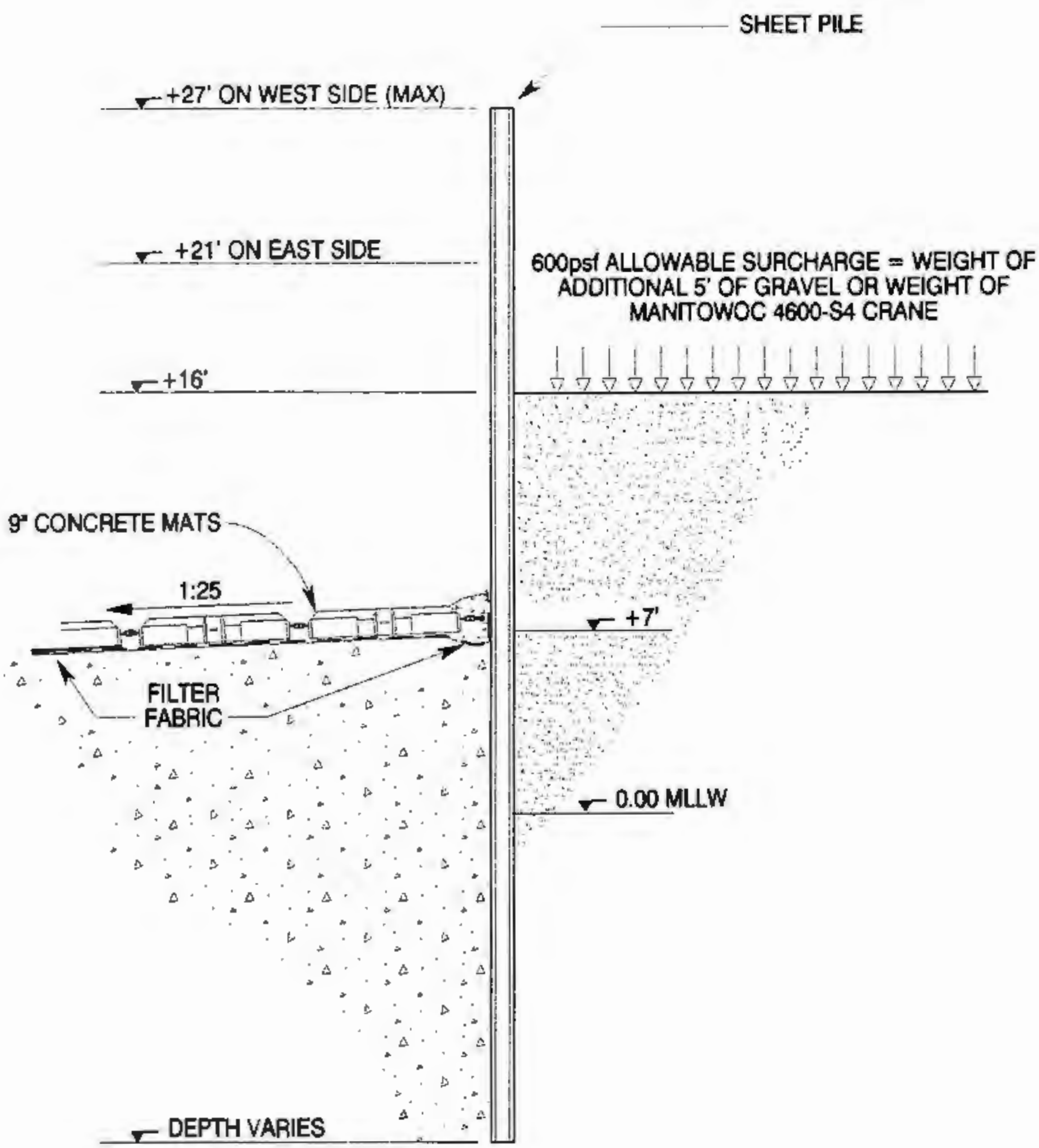

SIDE DETAIL

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT ISLAND SHEET PILE DETAIL		
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.1-7

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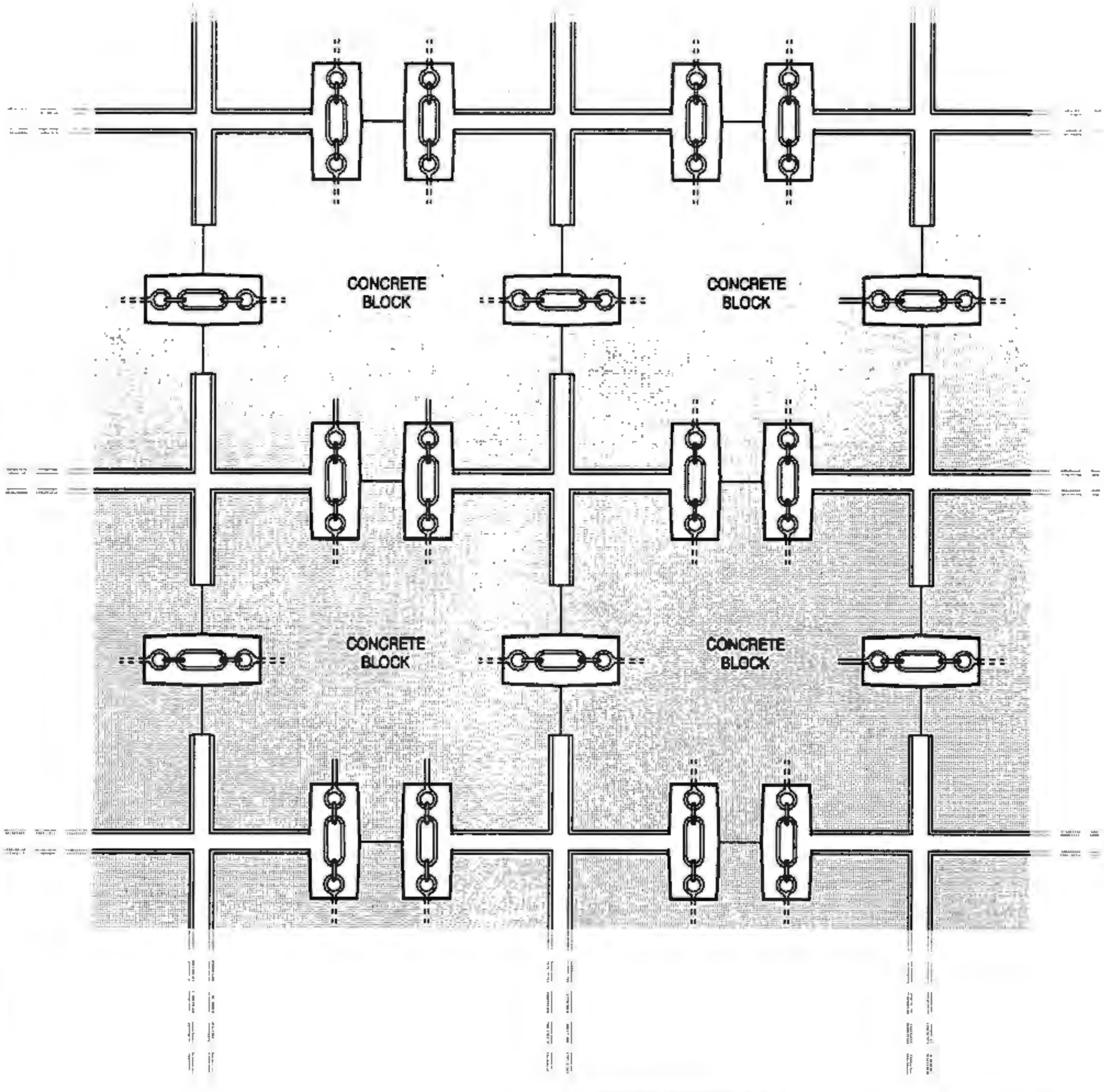
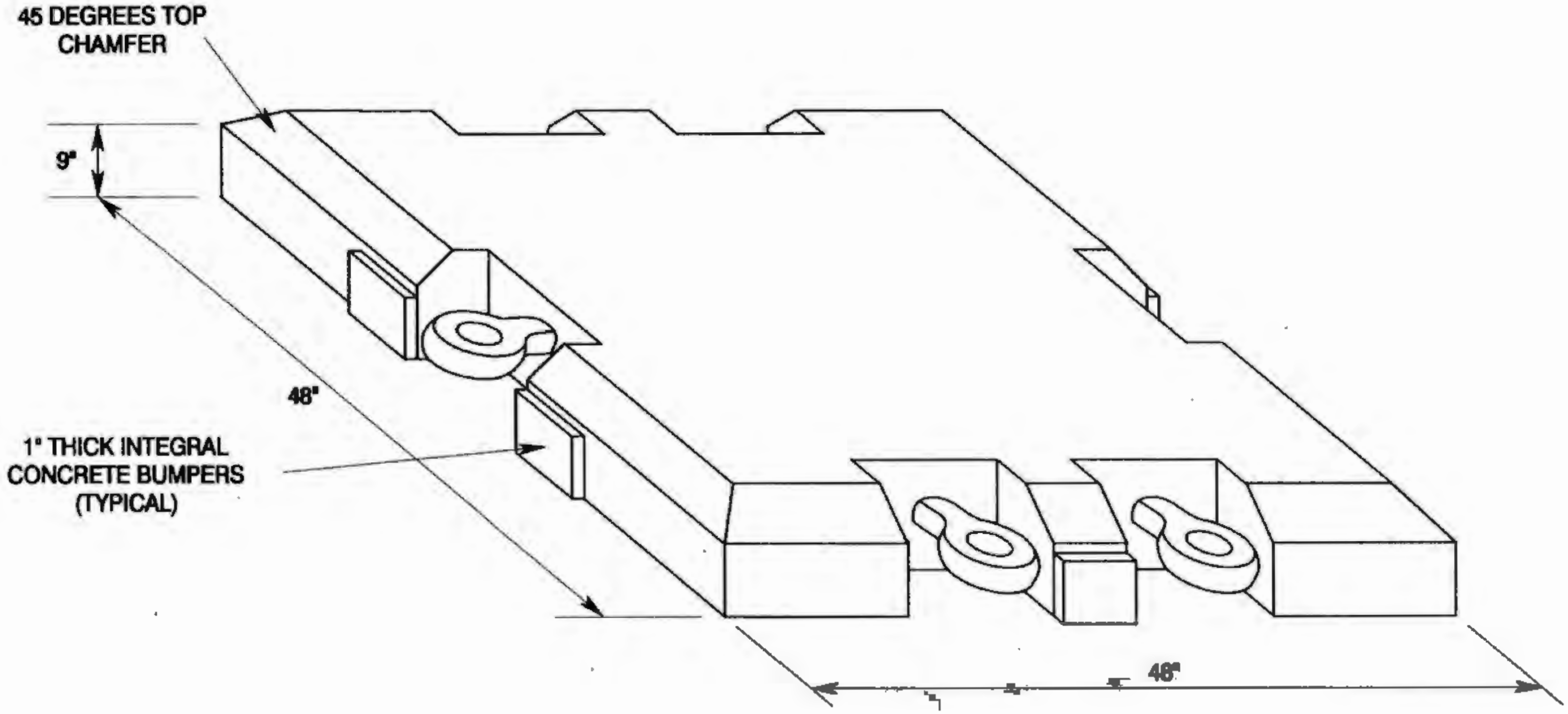


BP EXPLORATION (ALASKA) INC.

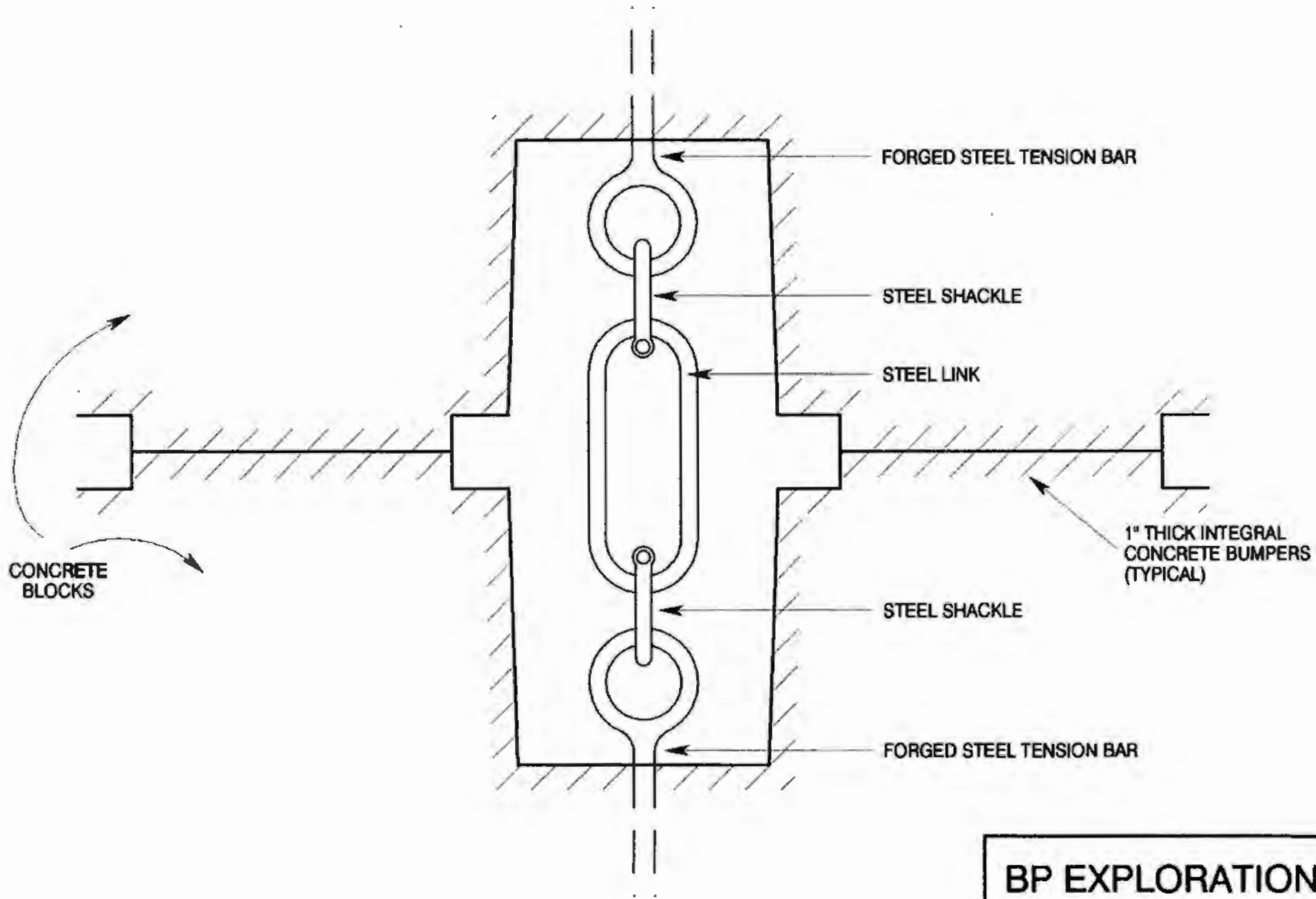
NORTHSTAR DEVELOPMENT PROJECT
ISLAND SLOPE PROTECTION
CONCRETE MAT
LAYOUT

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.1-8

nsv297.dgn



BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT ISLAND SLOPE PROTECTION CONCRETE BLOCK		
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.1-9



BP EXPLORATION (ALASKA) INC.		
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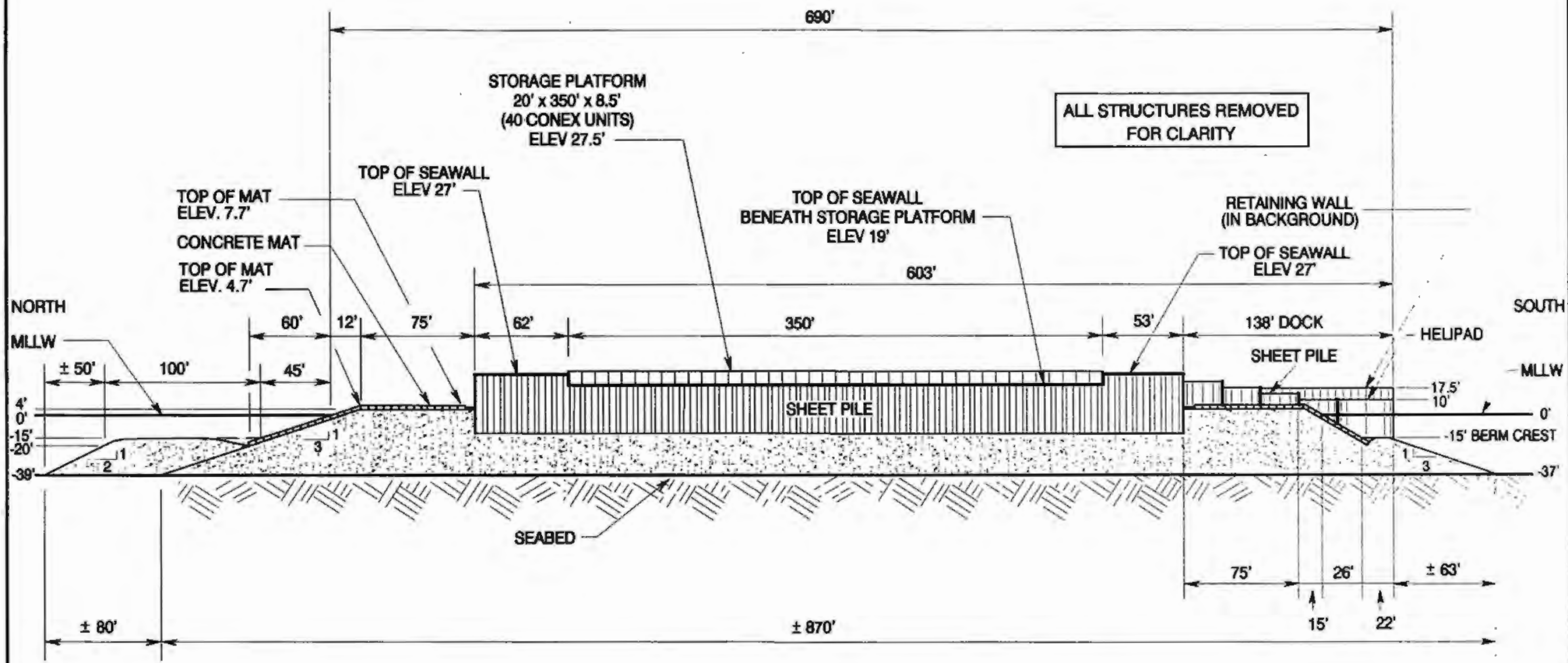
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.1-10

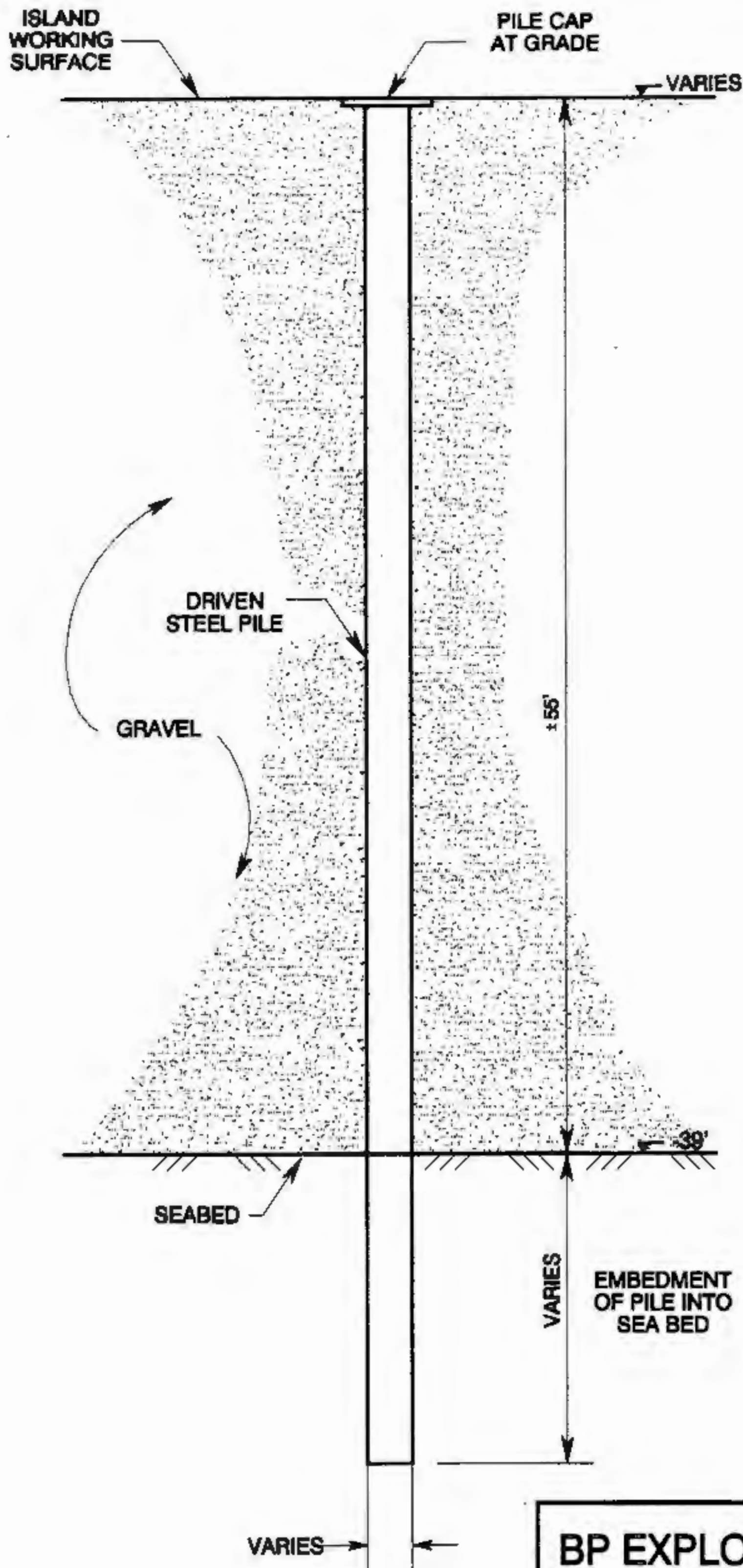


SIDE VIEW C-C'

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
SIDE VIEW

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.1-5

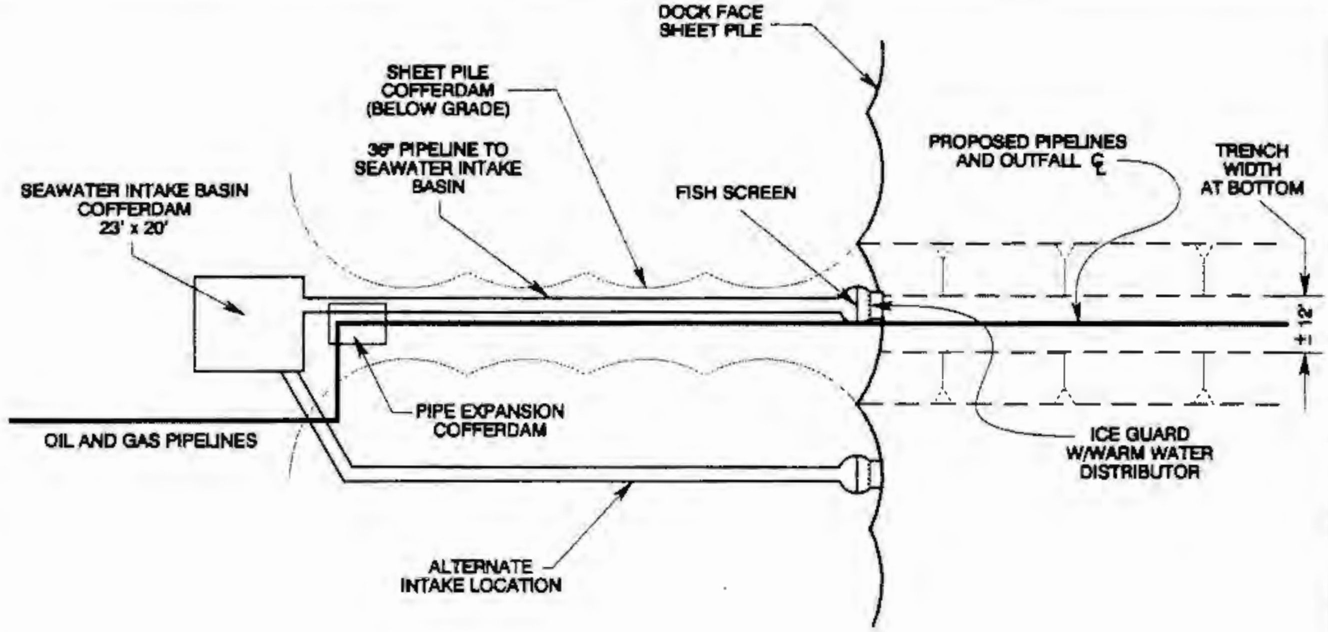


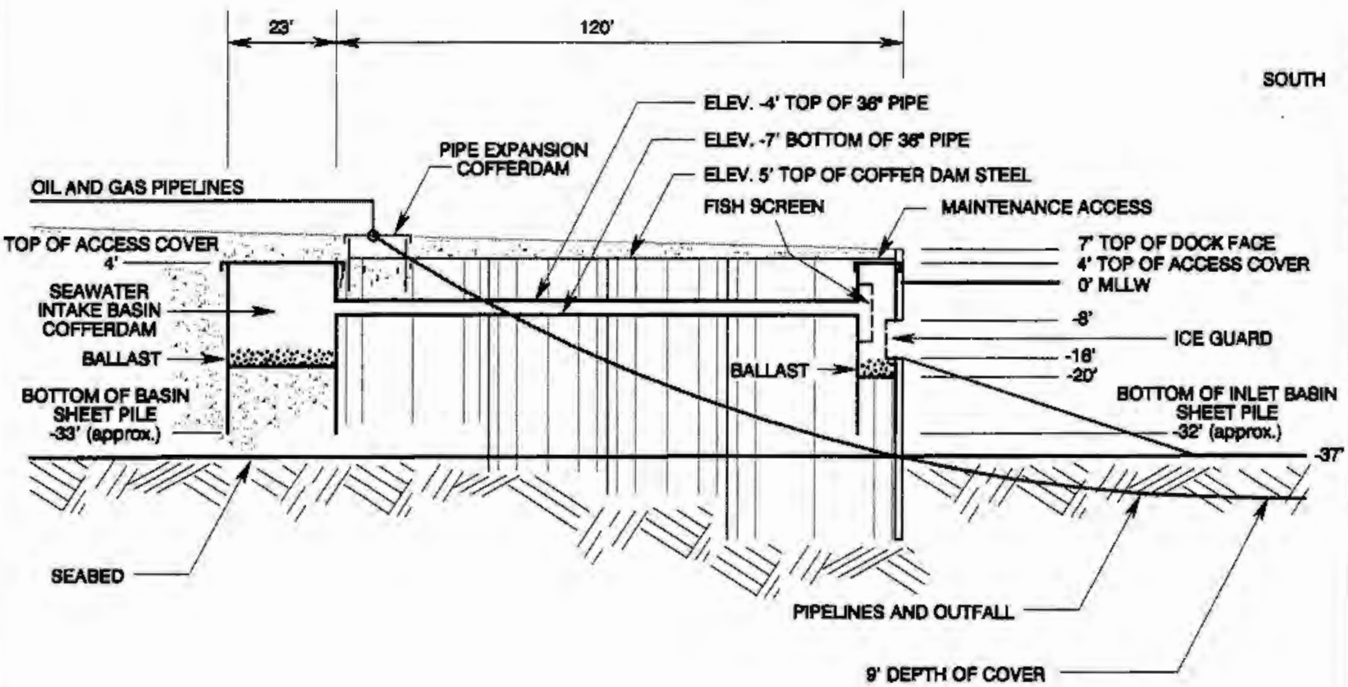
BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
ISLAND DESIGN FOUNDATION PILE
SIDE ELEVATION

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.1-12

nsv297.dgn



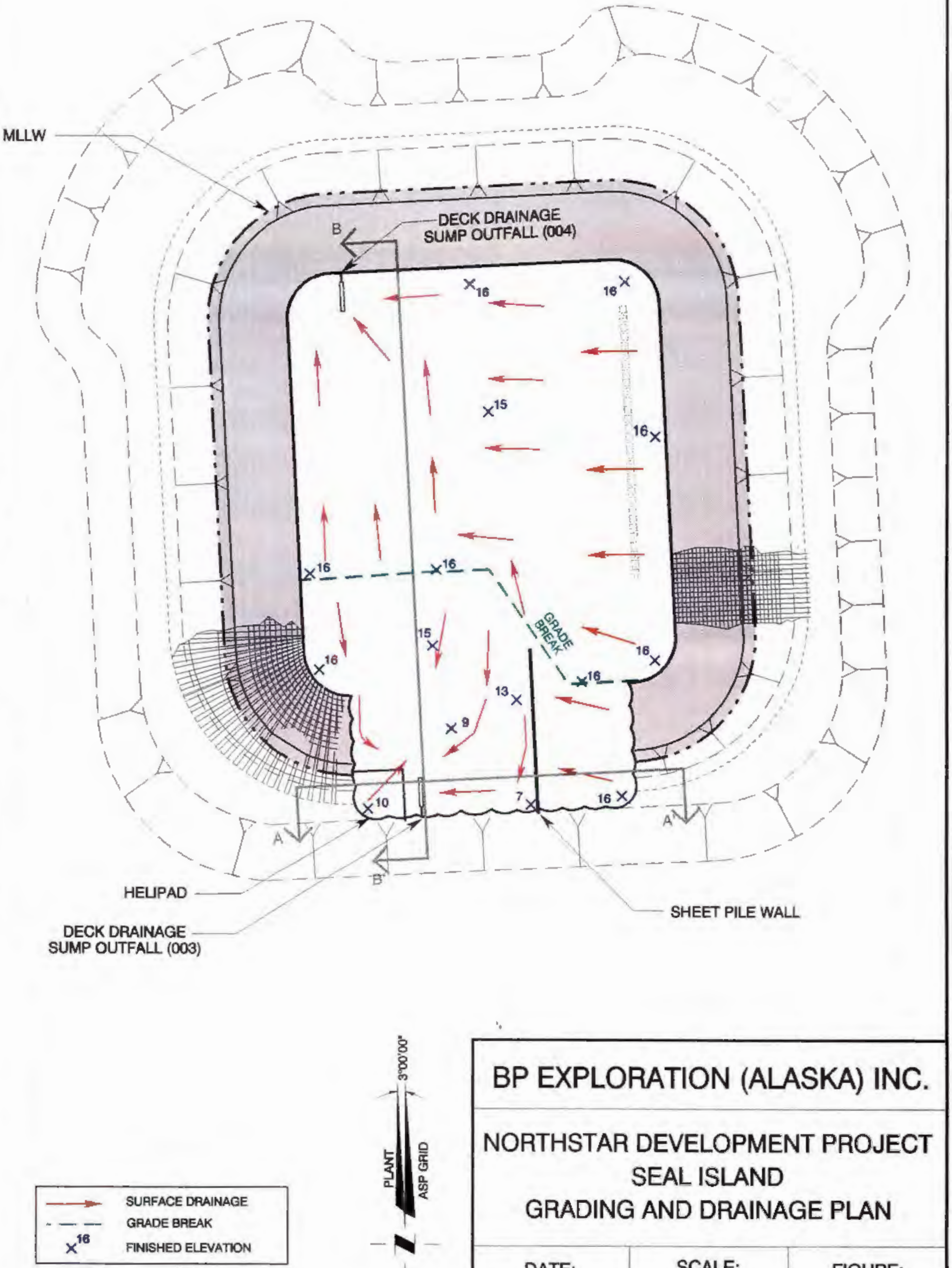


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAWATER INTAKE
PLAN AND ELEVATION VIEWS

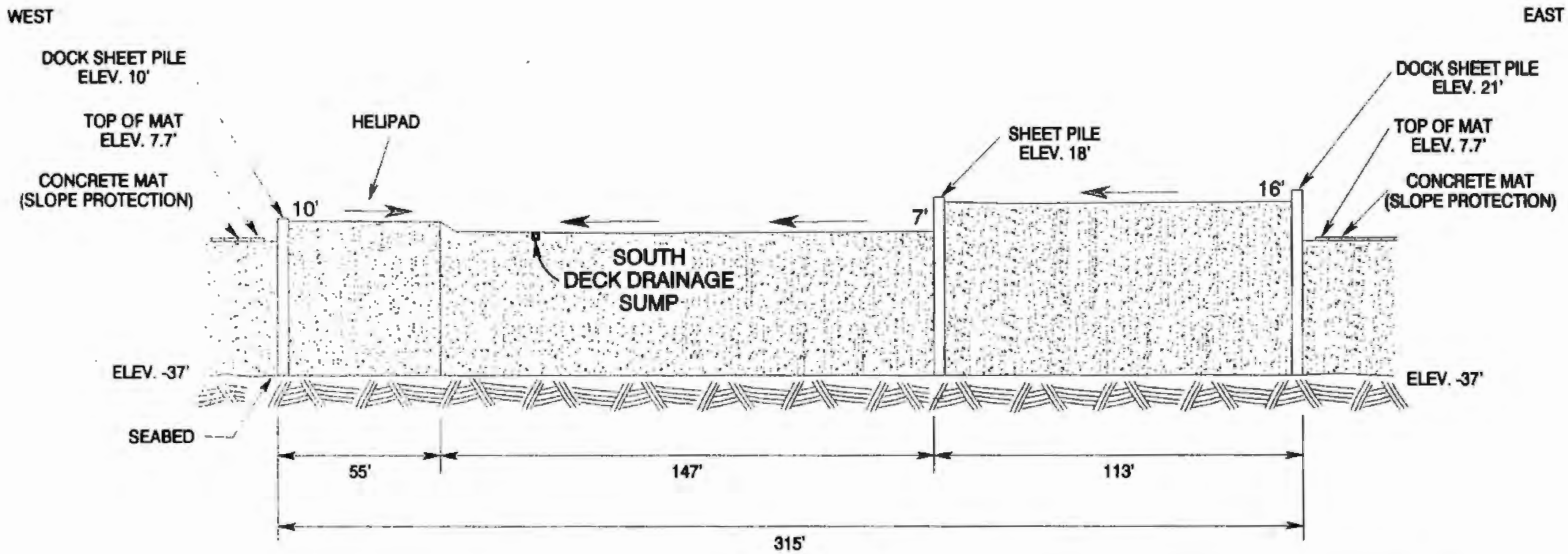
DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.1-13

nsv297.dgn



BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAL ISLAND GRADING AND DRAINAGE PLAN		
DATE: NOV. 1997	SCALE: NOT TO SCALE	FIGURE: 2.1-14

nsv1197.dgn



SIDE VIEW A-A'

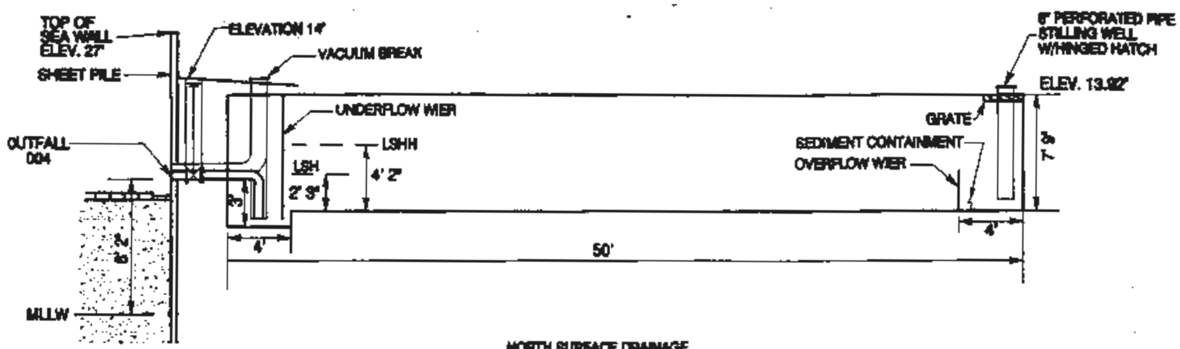
SURFACE DRAINAGE

BP EXPLORATION (ALASKA) INC.

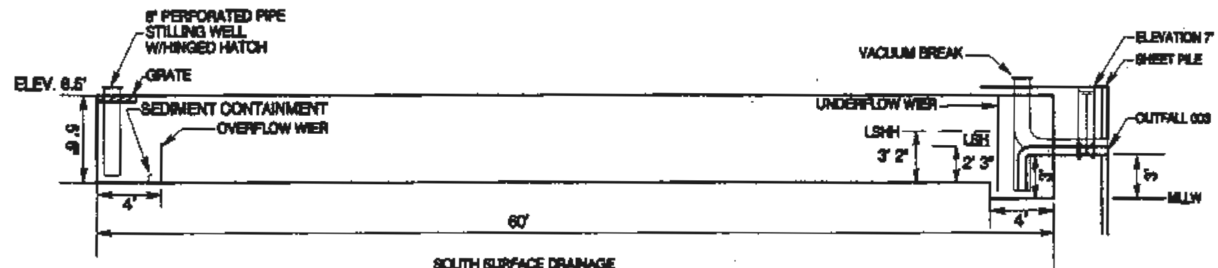
NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
GRADING AND DRAINAGE
SIDE VIEW

DATE:	SCALE:	FIGURE:
3/25/97	NOT TO SCALE	2.1-15

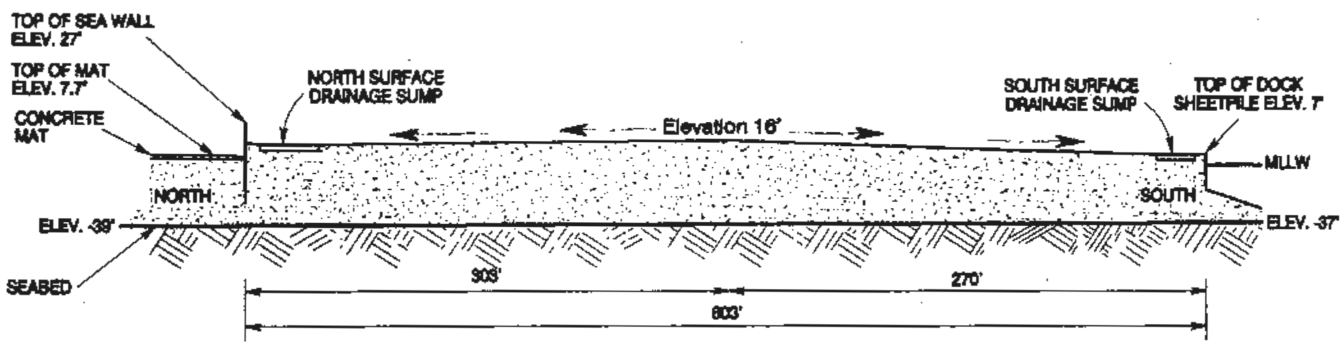
nsv297.dgn



NORTH SURFACE DRAINAGE
SUMP FOR OUTFALL 004



SOUTH SURFACE DRAINAGE
SUMP FOR OUTFALL 003



SURFACE DRAINAGE

SOURCE:
BPXA'S FINAL PROJECT DESCRIPTION
(BPXA, 1997 : FIG. 2.1-15 #1659)

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
GRADING AND DRAINAGE
SIDE VIEW

DATE:	SCALE:	FIGURE:
March 1998	NOT TO SCALE	2.1-16

bs13734.dgn

2.2 FACILITIES FABRICATION

2.2.1 Introduction

The Northstar Development Project is composed of infrastructure and crude oil processing facilities. The infrastructure facilities are designed to perform the functions of lodgings, life support, logistics, waste management and drilling support. The crude oil processing facilities will include the process and compressor modules.

2.2.2 Module Descriptions

2.2.2.1 Process Module

The process module is the primary crude processing facility. It will perform oil-water-gas separation. This module consists of a steel structure with approximate dimensions of 240 feet long by 80 feet wide by 90 feet tall. The main exhaust stacks (four each) will extend to a height of approximately 130 feet. The process module will be built in two sections with a total weight of approximately 6,000 tons. A significant percentage of the equipment will be installed outside on the module frame.

2.2.2.2 Compressor Module

This module provides five stages of compression for gas re-injection into the reservoir to maintain reservoir pressure during oil production. The steel structure, which will weigh approximately 2,500 tons, has approximate dimensions of 125 feet long by 80 feet wide by 55 feet high. The compressor exhaust stacks will extend to a height of approximately 130 feet.

2.2.2.3 Permanent Quarters

The permanent quarters module will be approximately 60 feet long by 60 feet wide by 40 feet high and will accommodate (house and feed) 75 personnel.

2.2.2.4 Utility Module

This facility includes the potable water system, emergency power generation and wastewater management and will be approximately 60 feet wide by 60 feet long by 35 feet high. The potable water system will be capable of producing up to 14,400 gal/day (343 bbl/day). Emergency power generation is sized to generate 2.46 megawatts of power. The wastewater management facility handles 9,360 gal/day (223 bbl/day) of sewage effluent and up to 5,040 gpd of fresh water washdown water (which is injected directly into the disposal well).

This support facility will also include two modularized tanks (one potable water tank and one diesel storage, 2,100 and 2,800 bbl capacity, respectively).

2.2.2.5 Warehouse/ Shop Facility

This module will be approximately 150 feet long by 60 feet wide by 35 feet high. The warehouse will serve several functions, including heated storage and vehicle and equipment maintenance.

2.2.2.6 Pipe Rack

The pipe rack is a fabricated steel assembly supporting the following piping: production, gas injection, production test, firewater and waste injection headers; and sea water, potable water, firewater, diesel, fuel gas, and mud and cuttings piping. In addition, the pipe rack supports electrical and instrumentation cables.

2.2.2.7 Flare

The flare is comprised of a 215 foot high cantilevered support tower.

2.2.3 Fabrication: General Plan

The modules will be assembled at the Port of Anchorage, on the North Star Stevedores' property (no relation to this Northstar Development Project). This is private property and will require some improvements prior to construction. A sheet pile dock facility exists that has the capability for loading the modules onto a barge. Some minor modifications are needed to allow longitudinal loading of the modules. Fabrication will begin early enough to support a July sealift. The modules will be loaded on sea-going barges for an ocean tow to Seal Island. Arrival at the island is scheduled for approximately August 15. Permits for the module assembly and site preparation have been acquired.

2.2.4 Port Improvements

Prior to construction of the modules, a temporary office/break area will be erected. Underground utilities (electric, gas, water, and phone) will be installed.

2.2.5 Module Fabrication

Fabrication of the modules will begin in March in Anchorage and will be completed in June of the following year. Manpower peaks at approximately 350. The average manpower during most of the construction effort is 250. A predominantly Alaskan workforce is planned.

Major construction equipment includes two 300-ton cranes and three 45-ton hydraulic cranes.

2.2.6 Transportation

The modules will be transported to Seal Island via ocean-going barges. The modules will be on-loaded and offloaded using a multi-rubber-tired vehicle capable of transporting as much as 5500 tons

2.3 FACILITIES INSTALLATION

2.3.1 Introduction

Facilities installation begins with offloading and setting the modules onto Seal Island. After the modules are in place, connections to the island infrastructure (primarily piping and electrical connections) will be made. Installation will continue through functional checkout of the equipment and startup of the facilities.

2.3.2 Pre-Sealift Preparation

Prior to the arrival of the barges, preparation work on the island will be necessary. Pile shim plates, rig mats and steel plates for module transport will be set, and construction equipment and supplies will be mobilized.

2.3.2.1 Construction Manpower

During installation and hook-up of the modules, the construction installation manpower is forecast to peak at approximately 120 people. This will occur in late August while the modular facilities are being offloaded and set up. To accommodate the construction manpower needs, additional bunks will be installed in the permanent camp increasing the sleeping capacity on a temporary basis. The potable water, sewage and kitchen facilities in the permanent camp are adequate to meet this peak.

2.3.2.2 Material Staging

Module setting support materials will be staged on the island surface prior to sealift arrival. These materials consist of rig mats and steel plate for transporting the modules over the island gravel.

2.3.2.3 Equipment Staging

Construction equipment for module installation will be transported to Seal Island in late July via a support barge from the Prudhoe Bay area.

Diesel fuel for the construction equipment will come from Prudhoe and will be transferred to the permanent facilities diesel storage tank on the island.

2.3.2.4 Pad Preparation

The module transport path from the dock to the final location will be graded and compacted prior to placing rig mats and one-inch steel plate.

2.3.3 Module Setting

After the barges have arrived, the modules will be unloaded and set in their final positions. Upon completion of module setting, module interconnecting activity will be conducted. The interconnecting tasks will include piping, structural, electrical and instrumentation connections.

2.3.4 Functional Checkout

The final functional checkout (FCO) effort for the facilities will begin after the facilities interconnect activities have been completed. FCO is the process of documenting that all systems work as designed. Upon completion of the FCO activities, the facilities will be ready for turnover to Operations.

2.3.5 Startup

First oil startup will occur once drilling has completed the required three or four wells (one disposal, one gas injector and one or two producers). This should occur early in the first quarter of the year following installation of the process facilities.

2.3.6 Demobilization

All major tools and equipment related to construction and installation will be removed from the island upon completion.

2.4 PIPELINES

2.4.1 Introduction

Two pipelines are part of the Northstar Development Project:

1) One 10-inch pipeline from Seal Island to PS-1 to transport sales quality oil that meets delivery specifications for the Trans Alaska Pipeline.

2) One 10-inch pipeline from the Prudhoe Bay Unit (PBU) Central Compressor Plant (CCP) to Seal Island to transport high-pressure natural gas to fuel the drilling rig and assist in the management of the reservoir.

2.4.2 Pipeline Routes

The offshore oil pipeline departs the island and runs south in a subsea trench, making landfall just west of the Distant Early Warning (DEW) Line Site near Point Storkersen. The oil pipeline continues due south along a new pipeline right-of-way running northeast of Dead Chicken Lake in the PBU until it intersects a segment of existing pipeline facilities routed between the Gathering Center 3 (GC-3) and PS-1 on the north side of the Spine Road.

The gas pipeline travels west from the CCP to a point where it intersects the alignment of the oil pipeline northeast of Dead Chicken Lake turning north to the Point Storkersen valve pad, where it then runs offshore in the same trench as the sales oil pipeline to Seal Island.

Figure 2.4-1 shows details of the pipeline routes. Table 2.4-1 provides details of the lengths of the various pipelines routes, and of the proposed and available facilities.

2.4.3 Design Criteria

The significant design aspects of the Northstar pipelines are described below. More detailed design information is available in a series of technical notes submitted by BPXA to the Joint Pipeline Office of the Department of Natural Resources in support of BPXA's pipeline right-of-way lease application.

2.4.3.1 Pipeline Description

The pipeline descriptions are summarized in Table 2.4-2.

2.4.3.2 Pipeline Coatings

In order to provide protection against corrosion of the exterior wall of the pipe, the offshore segment of the pipelines will be provided with a coating of Fusion Bonded Epoxy (FBE).

A cathodic protection system will be employed on the offshore segment of the pipelines to account for the presence of any possible defects or breakdowns in the coating. This system consists of anodes which will be attached to the pipelines at predetermined distances during the process of lowering the lines into the excavated trench.

The onshore oil and gas pipelines will be insulated to control heat loss.

2.4.3.3 Pipeline Protection and Support

The offshore pipelines are placed in a trench to protect them from the combined effects of ice and strudel scour and coastline dynamics, and will be backfilled after their installation. Within 2,000 to 3,000 feet of the island, a deeper trench (ten feet) will be excavated to provide about nine feet of cover over the pipeline. From this point to the barrier islands the trench depth will be eight feet deep, with about seven feet of cover. Inside the barrier islands, the trench depth is seven feet, providing approximately six feet of cover. The trench backfill will be the excavated spoils.

With the exception of the shore approach segment, the onshore pipelines are built above ground supported on VSMs. The design includes the use of new VSMs along the entire length of the onshore segments of the pipelines. Use of existing space on selected segments has been researched. This space is reserved for future expansion by the owners and is not available to the Northstar project.

2.4.3.4 Operations

To ensure safe operations, the pipeline system includes state-of-the-art leak detection instrumentation interconnected to the process facilities controls via a Supervisory Control and Data Acquisition (SCADA) system. The pipelines will be capable of accommodating inspection pigs to obtain information to provide early warning of potential leak points or pipeline deformation. The inspection pig launchers and receivers are located at the terminus of each pipeline. Systematic pig runs will allow operators to monitor trends which can help forecast maintenance work.

Valve stations are included at each terminus and at the shore crossing. These facilities will allow for the isolation of sections of the pipeline(s) for maintenance and/or repairs. Additionally, the oil pipeline across the Putuligayuk River will include a manual valve on both sides of the river.

2.4.4 Schedule

Preparatory work, such as road and caribou crossings, and other construction activities will be performed in the summer. The remainder of the construction activities will take place in winter between December and May.

A summer pipeline work option has been removed from consideration. In the event that adverse weather, ice conditions or other factors preclude installation or completion on the Northstar pipeline in winter, these activities would be conducted the following winter season. No summer season pipeline installation or completion is planned as a contingency.

2.4.5 Offshore Pipeline Construction

Construction of the offshore segment of the pipelines includes construction of ice roads, thickening of the sea ice to form a bearing surface and making ice slots by cutting and removing ice blocks, excavation of an offshore trench into which the pipelines are lowered, and backfilling of the trench.

2.4.5.1 String Fabrication

The speed at which the pipe laying activities proceed is determined by the pace of trench excavation. In order to make the most effective use of the available time and also to minimize the risks associated with delays in the excavation work, pipe strings will be fabricated and towed to the required location for lowering into the excavated trench over the surface of the ice.

The strings will be fabricated on the sea ice close to the shore approach at Point Storkersen, where a site measuring approximately 5,000 feet by 750 feet will be prepared. As shown in Figure 2.1-6, this site is situated immediately east of the proposed pipeline trench, and extends northward for approximately one mile as measured from a point approximately 1,000 feet seaward of the shoreline. The site will be situated within the construction right-of-way. The ice slot and pipeline trench will be located at the western edge of the string fabrication pad.

The string fabrication pad will be located in shallow water near the shore line and the ice will be generally bottom fast by the time construction activities begin. If required to enhance the safety of the operations, the ice will be made bottom fast by pumping water on the ice surface where needed.

The ice surface will be leveled by ~~of~~ tracked equipment and graders to produce a level surface where joints of line pipe can be welded to form strings. Where required for purposes such as safety, prevention of snowdrift formation, and containment of spills, snow berms may be constructed.

This ice pad will be used to store line pipe and completed pipeline strings which will be up to approximately 5,000 feet long. Upon completion of each string, and prior to its tow to the required offshore location, it may be subjected to a hydrostatic test. The test medium, which would be composed of water and glycol, would be circulated from string to string as the work progresses.

Hydrotest fluids will be transported to the job site by tank trucks and transferred through hoses via a fill pump into the pipeline segment to be tested. Portable containment (drip pans with absorbent liners) will be placed under each fitting and connection. Continuous monitoring will be effected whenever transfers are in progress. Should an unconfined leak occur, the fluid will be scooped with shovels, along with any snow it has contacted, and placed in plastic bags for delivery to existing snow-melt and waste disposal facilities in the PBU area. Upon completion of testing, the fluids will be returned to the vendor, or transported to the contractor's permanent tanks for storage and reuse, or injected into approved wells.

Containment of debris from dispersal by the wind will be performed by implementing housekeeping routines that result in the absence from the jobsite of trash and other light weight construction material. Covered dumpsters will be provided at any location where they would be required. Constant policing of the site will be done by the work crews and by personnel specifically assigned that responsibility.

The string fabrication activities will be performed from January to March.

2.4.5.2 Ice Road Construction and Ice Thickening

Ice roads will be prepared and maintained along the pipeline routes and will be the main means of access to the construction area. The ice roads will be built within an approximately 200-foot-wide ice platform where pipeline construction will take place. Additionally, ice roads will be built south of Stump Island and run from PM-1 and PM-2 to a location near the string fabrication area. These roads will provide an alternative means of access to the construction site, and will permit construction of the onshore pipeline facilities on two fronts (from Point Storkersen and from the vicinity of E Pad).

The ice road and construction area extending between the shore approach near Point Storkersen and near the western-most point of Stump Island will be built atop ice that will be bottom-fast. The ice may need to be thickened to ensure that it is bottom-fast, to permit safe transit of construction equipment. Water obtained from approved sources would be applied to the ice until the required thickness has been achieved.

The construction platform and ice road segment between the tip of Stump Island and Seal Island will be built on floating ice which will be artificially thickened. It is estimated that the ice can be thickened at the rate of three inches per day. With reference to Figures 2.4-2 and 2.4-3, the ice will be thickened for a width of approximately 200 feet to permit the transit and operation of the construction spreads. The total width of the proposed construction Right-of-Way is 1,500 feet. Figure 2.1-6 shows details of the proposed fresh water sources, as well as the ice roads and pads that are planned to be built. Construction of the ice roads and thickening of the ice will take place between December and February.

2.4.5.3 Construction Activities

Pipeline construction activities will take place on an ice platform which, where required, has been thickened to provide support to the construction equipment. Figures 2.4-2 and 2.4-3 provide a general view of the various activities undertaken in the construction of the offshore segment of the pipelines. The sequence of activities follows.

Ice Cutting and Slotting

A slot will be cut in the ice using ice trenchers. The slot will be five to six feet wide in the segment south of the barrier islands (nearshore zone) and 10 to 12 feet wide in the segment north of the barrier islands (intermediate and deep zones) (Figures 2.4-4 and 2.4-5). The ice will be cut into six-foot by six-foot blocks and removed using backhoes. The blocks will be moved by front-end loaders to locations away from the work site to prevent excessive deflections of the ice in the working areas.

These activities will be performed between the first half of February and the end of March.

Trenching

In the nearshore zone, a trench nominally seven feet deep (six feet of cover over the pipeline) and six feet wide will be excavated. In the intermediate and deep zones, a trench nominally eight feet deep and 10 feet deep, respectively (seven and nine feet of cover over the pipe) and 10 feet wide at its bottom width will be excavated (Figures 2.4-4 and 2.4-5). The excavation will be performed using backhoes. The backhoes required for the deep-region trenching will be fitted with an extended-reach boom to allow excavating in 40 feet of water.

Excavation of the offshore trench will be conducted in such a way that the total excavation volume is removed in one pass. If a second pass is needed to sweep and clean the ditch, this would be performed just prior to the installation of the pipelines.

The planned construction method anticipates a continuous process of trenching, pipelaying and backfilling. Beginning in February, three trenching crews will be mobilized simultaneously. Crew 1 will start at the shoreline and trench the area of bottom fast ice to a point immediately outside the barrier islands corresponding to the 10' isobath as shown on Figure 2.1-6. Crew 1 will take approximately two weeks to complete the excavation of this portion of the trench and will progress at an estimated rate of approximately 50 feet per hour for 20 hours per day. The excavation will yield approximately 4 cubic yards per foot of trench. Crew 1 will store the excavated materials in windrows alongside the trench.

Crew 2 will start trenching operations at the barrier islands and proceed seaward to a point midway between the barrier islands and Seal Island. Crew 3 will start trenching operations at the midpoint and continue until the trench reaches Seal Island. Crew 2 and 3, working on floating ice, will progress at an estimated rate of approximately 30 and 10 ft/hr respectively. Excavation in this area will yield approximately 11 cubic yards per foot of trench.

There are two cases in the current plan for temporary storage of excavated materials from the area of floating ice (Crews 2 & 3). In the base case, the excavated materials from the first two weeks of trenching will be hauled to the Zone 1 area for storage. The preferred alternative is to store the materials in windrows alongside the trench in the area shown as Zone 2. The decision on the location for temporary storage (Zone 1 or 2) will be dependent on the loading capacity and deflection characteristics of the ice as determined by on-site measurements at the commencement of operations.

The first section of pipeline will be placed after Crew 1 completes the trench excavation up to the barrier islands, approximately two weeks after trenching begins. Backfilling of the trench will occur immediately after pipeline placement using excavated materials stored alongside the trench. Excess spoils (approx. 5,000 cu. yd.) will be collected and hauled to Zone 1. The next section of pipeline will be welded to the first section, lowered into place and backfilled with material freshly excavated from the ongoing trenching operations of Crews 2 and 3 and materials from temporary storage at Zone 1.

In the nearshore zone, where it is expected that the trench excavation will be conducted in dry seabed, traditional surveying will be conducted to verify that the desired trench depth has been achieved. In the intermediate and deep zones, where the water will rise near the surface of the ice slot, acoustical and mechanical surveying equipment will be utilized to determine that the desired trench depth has been achieved. The records, together with the results of the bathymetric survey performed in the summer of 1996, will serve as the basis for the as-built records of the construction activities.

The trenching activities will be performed between the first half of February and the end of March. Backhoes, front-end loaders and other earth-moving equipment will constitute the main items of equipment to excavate and backfill the trench. Underwater survey equipment will be used to determine the configuration of the seabed at regular intervals. Land survey equipment and techniques will be employed to provide horizontal control.

Pipeline Installation

Pipeline installation will follow immediately behind the trenching spread. Tracked equipment will tow one string of each of the pipelines to the side of the trench, where tie-in welds to the previous strings will be made and non-destructive testing (NDT) performed. The welds will then be coated, the cathodic protection anodes attached to the pipelines, and the pipelines strapped together to form a bundle. Sidebooms will be used to lower the bundle through the slot and into the trench.

The work will require tracked equipment or front end loaders to move the pipeline strings from the make-up area, as well as sidebooms and bulldozers to facilitate the tie-in of strings and lowering to the seabed.

The pipe laying activities at the shore and island approaches are described separately.

Backfilling the Trench

The trench spoils will be transported back from the windrows or from their temporary storage site and will be placed in the trench (Figures 2.4-6 and 2.4-7). Backfilling of the trench in the segment between the shore and the barrier islands will be performed by having earth moving equipment, such as front-end loaders or bulldozers, push the spoils deposited alongside the ice slot into the trench.

The pipeline construction plan calls for all spoils to be placed back into the pipeline trench. This includes transporting the spoils from the temporary storage site back over the ice and replace them into the trench. See Figures 2.4-6 and 2.4-7.

Certain circumstances, such as timing variations between the trenching and backfill operations, installation schedule delays or unfavorable weather, may prevent transportation of the temporarily stored spoils back to the open trench section, resulting in sections of the trench not being fully backfilled.

Spoils Storage and Disposal Zones

As depicted on Figure 2.1-6, Zone 1 represents an area 1200' x 2700' in water depths greater than -5 ft. MLLW immediately outside the barrier islands. This defined area will be used for three purposes. First, it serves as the designated disposal site for approximately 5,000 cubic yards of spoils that will remain after the near shore trench inside the lagoon has been backfilled. These excess spoils result from pipeline displacement and natural swell of the excavated materials. Second, it serves as the temporary storage location of all materials excavated from the area of floating ice during the first two weeks of trenching operations (estimated at 60,000 cu. yds.). Third, as a contingency, it is the disposal location of the 65,000 cu. yds. of materials temporarily stored there if the weather or ice conditions dictate the abandonment of operations prior to completion. Zone 1 has been sized to be approximately twice the size required to store up to 65,000 cu. yds. at an average depth of one foot. This size has been chosen to facilitate the efficient placement and spreading of spoils.

Zone 2 is a 200 ft. wide section, 16,600 ft. long within the pipeline construction right-of-way extending northward from the barrier islands to a point 2,000 ft. south of Seal Island. Zone 2 is in an area of floating ice and water depths of -10 to -30 ft. It is an alternate storage area and contingent disposal location for stockpiled excavated materials.

There are two cases in the current plan for temporary storage of excavated materials from the area of floating ice (Crews 2 & 3). In the base case, the excavated materials from the first two weeks of trenching will be hauled to the Zone 1 area for storage. The preferred alternative is to store the materials in windrows alongside the trench in the area shown as Zone 2. The decision on the location for temporary storage (Zone 1 or 2) will be dependant on the loading capacity and deflection characteristics of the ice as determined by on-site measurements at the commencement of operations.

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Contingency Disposal

It is possible that unforeseen conditions such as drifting ice, opening leads, impending premature breakup, etc. could develop which would threaten the safe and successful completion of the trenching and pipelaying operations. Under these conditions, a decision to abandon the operation for the protection of life and equipment may be required. The stored materials will be spread and levelled in preparation for permanent disposal. Materials stored near the trench inside the barrier islands will be pushed into the trench and/or hauled to Zone 1. Materials already stored in Zone 1 will be spread and levelled to an average height of 1 foot with no single geologic feature higher than 2 feet in any 100‘ by 100’ area. Materials stored in Zone 2 will be spread and levelled to a height not to exceed 3 feet.

Testing the Pipelines

Once the pipelines have been installed, they will be pressure tested with a glycol/water mix to satisfy applicable regulations and codes. To reduce the volume of fluid required, the pipelines will be tested one after the other by transferring the testing fluid from one to another. Hydrostatic test fluids shall either be stored for future work, injected into an approved disposal well, or sent back to the supplier for recycling. It is possible that all or part of these options will be employed.

The activities will be performed in April prior to sealift of major facilities that summer.

2.4.5.4 Seal Island Approach

The pipeline approach to Seal Island requires a transition from the island crown at +16 MLLW elevation to the bottom of the trench at -47 MLLW elevation. This transition will be made concurrently with the trenching operation and will be performed under wet conditions.

Figure 2.4-8 provides a plan view of the position of the pipelines with regard to the island. Figure 2.4-9 provides a cross-sectional profile of the installed pipelines.

2.4.5.5 Marine Outfall (NPDES Outfall 001)

Marine outfall (001) exits on the south side of the island through the dock face at an elevation of approximately -16 MLLW. The actual exit is through a two inch diameter nozzle that is recessed in the steel sheet pile dock. This is shown in Figure 2.4-11. This outfall discharges and diffuses a minimum of 21,600 gpd to a maximum of 49,020 gpd. The maximum expected temperature rise due to the process is 6.7°C above ambient in the winter and 6.0°C above ambient in the summer. The component streams that contribute to this outfall are listed in Table 3.5-1 as Seawater Flush (outfall 001a), Desalination (outfall 001b) and Wastewater (outfall 001c). Except during facility startup and during periods when the disposal well may not be available, all treated wastewater will be injected into the disposal well.

2.4.5.6 Shore Approach

In this area, the pipelines transition from the bottom of the submarine trench to the terrain surface. The trench will be cut transecting the shoreline and extending approximately 150 feet inland and the pipelines will be placed in it. The trench will then be backfilled with select material. Native backfill from the original tundra surface will then be placed on top of the select backfill. The area where native backfill is placed on top of the select backfill will require some revegetation treatment. Excess material obtained from excavation of the shore approach trench will be transported to the Put 23 mine site or the newly opened Kuparuk River delta Northstar mine site.

The trench excavation will be performed in permafrost material during the winter, and dewatering of the trench is not expected to be required. However, if water is present in the trench, the pipelaying activities can nevertheless be performed. Seawater flooding south of the shoreline may be prevented by leaving / installing soil plugs in the trench.

The final dimensions of the trench and the position of the pipelines within the trench at the shore approach have not yet been determined, and conservative dimensions are provided. The design intent is to reduce excavation volumes to a minimum, while ensuring adequate protection for the pipelines.

The pipeline riser well may be fabricated from corrugated metal used for road culverts, or fiberglass used for manholes.

In this type of environment, it will be difficult to completely stabilize the area because of natural erosive forces. However, because this section of coastline lies shoreward of the barrier islands, coastal erosion rates are considerably less than those of unprotected, exposed coastlines. A detailed historical air photo analysis spanning the 1949 to 1996 period indicates an expected bluff erosion rate of 1 to 2 feet per year.

2.4.5.7 Rehabilitation Options

The tundra mat removed during pipeline trench excavation cannot be laid back on the restructured surface following placement of select backfill and native soils. Past experience has shown that the mat does not regenerate and what remains are chunks of dead tundra that will exist in place and unchanged for several years.

BPXA's approach to this revegetation effort will be the same as was proposed for the Badami buried pipeline. After the civil construction work has been completed and the native material has been placed on top of the select backfill, BPXA will collect a representative set of soil samples. These soil samples will be analyzed for pH, conductivity, and macronutrients. The final treatment applied to the site will depend on the results of the soil analyses, but will likely include the following:

- Lightly seed with *Puccinellia langeana* and/or *Puccinellia arctica*.
- Apply N/P/K fertilizer (20-20-20) at a rate of about 400-450 pounds / acre.

• If suitable sites exist, consider sprigging *Elymus arenarius*.

The critical element for success of this revegetation effort will be availability of a suitable seed bed for the *Puccinellia* and / or *Elymus*. Once those conditions have been set, seeding and / or sprigging can take place. Several years, perhaps on the order of three to five, may be required to establish a community of *Puccinellia* that will provide conditions for invasion of other native North Slope species.

The pad, on which the isolation valve assemblies are located, will be made of gravel transported to the site by trucks using the ice road utilized for construction of the onshore pipeline segments. It is estimated that construction of the shore approach gravel pad will be accomplished in two days, and will require ten to twelve persons such as operators of equipment and drivers. The construction activities will be performed between mid-February and the end of March. Figures 2.4-13, 2.4-14 and 2.4-15 provide details of the facilities that will be built at this location.

2.4.6 Onshore

Construction of the onshore segments of the pipelines will be accomplished using equipment and methods which have been used in the Arctic region for many years. Typically, construction includes the following activities:

2.4.6.1 Tundra Ice Road Construction

Pipeline construction activities will be performed from the surface of existing gravel roads/pads, frozen lakes and/or ice roads and pads which will be constructed with sufficient thickness and width to protect the tundra. Where required, the pad will also contain sufficient space for the traffic of construction vehicles, and will be made by the use of snow and spraying fresh water over the surface of the frozen tundra. Construction of the ice roads and pads will take place in January and February.

Figure 2.4-16 provides details of the proposed cross-section of the ice road on which the construction activities will be performed. Staging areas for the temporary storage of materials and/or equipment are shown in Figure 2.1-6.

2.4.6.2 VSM and Pipeline Installation

Five existing caribou crossings have been identified. Two are within the alignment of the oil pipeline and three within the alignment of the gas pipeline. The oil and gas pipelines will be placed within the existing caribou crossings from the existing gravel road system. No new gravel is required for placing the pipelines within these caribou crossings and therefore no expansion of the existing footprint is required.

Typically, a crossing will be constructed by excavating within the body of the existing crossing the necessary amount of gravel without penetrating the underlying tundra. Tundra insulation material and the casing pipe which serves as protection for the pipeline, and which would typically be 24 inches in diameter, will be placed. The excavated gravel will be placed back into the excavation and the crossing restored to its original configuration.

The five crossings will be modified during late July through September, before freezing of the soil increases construction difficulties. Subsequently, in late December or January the oil and gas pipelines will be placed in the casings. Figure 2.4-17 provides details of a typical caribou crossing.

The pipelaying process will commence in January by having the surveyors stake the positions where the VSMs will be installed. VSM holes will be drilled and the tailings cleared. The tailings will be transported to the Put 23 mine site or the newly opened Kuparuk River delta Northstar mine site. Then VSMs will be strung along the pipeline alignment together with the beams. The VSM assemblies will be set in the holes, which are typically filled with sand slurry or foam.

Upon completion of VSM installation on a segment of the pipeline, joints of line pipe will be transported to the site, strung along the pipeline alignment, and welded together to form a continuous string. Each weld produced in the field will be examined by NDT. The pipeline strings will then be lifted onto the VSMs, with tie-in welds performed and tested by NDT. Applying insulation to the tie-in welds will conclude the pipe-laying activities.

These activities will be performed commencing in December and continue through March. Staging areas for the temporary storage of materials and/or equipment are shown in Figure 2.1-6.

2.4.6.3 Put River Crossing

The Putuligayuk River crossing will be an above ground crossing that spans the river. VSMs will be used to support the oil pipeline across the span. The support(s) will be installed from the surface of the ice by drilling a hole through the ice and the underlying soil until the required pile length is achieved. Pile(s) will be set into the hole and slurry injected in the annulus. Then the pipeline supports will be installed and the pipeline lifted onto the support(s).

The VSMs will be designed to resist the impact forces of ice at breakup. The VSM design will be reviewed by the ADNR/JPO and the Alaska Department of Fish and Game (ADFG).

A manually operated isolation valve will be placed on each side of the river crossing. They will be installed in line and will be situated close to a supporting VSM. These valves will be protected from the environment by standard North Slope insulating jackets, and not enclosed in buildings. The use of gravel pads is not expected to be required. Access to the valves from the service road will be via catwalks that will traverse the four existing pipelines located between the road and the oil pipeline. Figure 2.4-18 provides the potential location of VSMs across the river.

2.4.6.4 Hydrotesting of Pipeline Segments

Completed segments of the pipelines will be hydrotested after they are lifted onto the VSMs. The test fluid will be pumped into the pipeline and the pressure will be increased until the desired test pressure (1.25 times the maximum allowable operating pressure) has been reached. This pressure will be maintained for a minimum of eight hours. The pressure will then be gradually reduced to atmospheric pressure and the fluid transferred to another segment of the pipeline. Handling of the test medium was described in Section 2.4.5.1.

These activities will require approximately 10 days to be completed (in mid-April) and hydrostatic testing equipment will be the principal item of equipment.

2.4.7 Facilities

At each extremity of the offshore and onshore segments of the pipelines, a valve station will be installed to permit isolation of each segment for maintenance and/or repair purposes. In addition to the above, pig launching and receiving stations will be located at both ends of each pipeline.

2.4.7.1 Valve Stations

Production Island

The pipelines will be provided with automated, quick-closure valves on the island. These facilities will be an integral part of the leak detection system and will be coupled to the SCADA system.

Shore Approach

At this location, valves similar to those used at Seal Island and connected to the SCADA system, will be installed in a building on a new gravel pad located approximately 150 feet inland of the existing shoreline.

It is not planned to build a permanent road to the nearest facility (PM-1). Surface access can be provided all year by means of soft-tired vehicles and helicopter. In order to provide quick access to the valve station, the gravel pad will be sized to accommodate a helicopter landing pad. Electrical power required to operate the valve actuators, and instrumentation will be provided by a generator. Given the exposed nature of this location and its proximity to the coastline, the facilities will be contained within an enclosure.

Put River Crossing

At this location, a manually operated valve will be installed on each side of the crossing.

Tie-ins to Existing Facilities

Valve facilities similar to those described previously will be built at the following locations:

1) The tie-in of the oil pipeline at PS-1. At this location, a check valve will be installed to prevent backflow from the pipeline (Figure 2.4-19).
2) The tie-in of the gas pipeline. Figures 2.4-20 and 2.4-21 provide details.

2.4.7.2 Pig Launching/Receiving Facilities

Pig launching and receiving facilities will be provided for the oil and gas pipelines. At the island, the facilities will be incorporated within the process module and will be permanent. Onshore, the pigging facilities may be removable, and provisions will be made at the tie-in locations to existing facilities to allow use of temporary pig launching and receiving facilities.

2.4.7.3 Gravel Pads

New gravel pads are proposed at the shore approach location and at the CCP. The pig launcher for the gas pipeline at CCP will be installed on a new gravel pad. On this same pad will be a compressor module, a gas cooling skid, a metering module and an electrical power generation skid. The new gravel pad is required to preserve the space adjacent to present CCP for routine operations and maintenance activities.

TABLE 2.4-1
PIPELINE FACILITIES

Segment	LENGTH Feet	Miles	New VSMs(ft)	Existing Access Roads (Ft)
OIL Pipeline				
Seal Island - Pt. Storkersen	31,840	6.03	N/A	N/A
Pt. Storkersen - PS-1	58,744	11.13	58,744	6,470
Totals	90,584	17.16	58,744	6,470
GAS Pipeline				
Seal Island - Pt. Storkersen	31,840	6.03	N/A	N/A
Pt. Storkersen - Dead Chicken Lake	37,856	7.17	37,856	NO
Dead Chicken Lake - CCP	16,952	3.21	16,952	16,952
Totals	86,648	16.41	54,808	16,952

TABLE 2.4-2
PIPELINES DESCRIPTION SUMMARY

ITEM	SALES OIL PIPELINE	GAS PIPELINE
Transported Substance	Processed oil to TAPS Specification	Injection gas
Substance Specific Gravity (@ S.T.P)	0.79 (water = 1.0)	0.7 (air = 1.0)
Maximum Allowable Operating Pressure (MAOP)	1480 psig	1480 psig
Normal Operating Pressure	850 psig	1250 psig
Pipeline Outside Diameter	10.750 inches	10.750 inches
Pipeline Wall Thickness		
Offshore		
Mainline	0.594 inch	0.594 inch
Riser	0.594 inch	0.594 inch
Overland		
Mainline	0.279 inch	0.279 inch
Station	0.307 inch	0.307 inch
Pipe Material Grade		
Offshore	API 5L Grade X52	API 5L Grade X52
Overland	API 5L Grade X65	API 5L Grade X65
Design Hoop Stress Factor		
Mainline	0.72	0.72
Riser/Station	0.60	0.50
External Coating		
Offshore	Fusion bonded epoxy	Fusion bonded epoxy
Overland	PUF insulation / galvanized jacket	PUF insulation / galvanized jacket
Pipeline Specific Gravity (empty)		
Offshore	1.60	1.60
Overland	Not Applicable	Not Applicable
Cathodic Protection		
Offshore	Sacrificial Anodes	Sacrificial Anodes
Overland	None	None
Test Pressure / Duration		
Mainline	1850 psig / 8 hours	1850 psig / 8 hours
Island Riser	2220 psig / 8 hours	2220 psig / 8 hours

TABLE 2.4-2
PIPELINES DESCRIPTION SUMMARY
(CONTINUED)

ITEM	SALES OIL PIPELINE	GAS PIPELINE
Inspection Piggable	Yes. Launcher/receiver located at each terminus of pipeline.	Yes. Launcher/receiver located at each terminus of pipeline.
Valves	Automated isolation valves at each terminus of pipeline and at the mainland landfall. Check valve at termination. Manually operated valves on each side of Putuligayuk River crossing.	Automated isolation valves at each terminus of pipeline and at the mainland landfall.
Pump / Compressor Station Location	Electrically-driven centrifugal pump at Northstar processing facilities T13N, E13E, Section 11	Turbine Driven Centrifugal Compressor at CCP T11N, R14E, Sec. 11
Heating / Refrigeration Stations	Aerial crude cooling station at Northstar processing facilities T13N, R13E, Section 11 Indirect Natural Gas Fired Heater at PS-1 T11N, R14E, Section 33	Aerial Cooling Station at CCP T11N, R14E, Section 11
Pipeline Design Throughput	65,000 bbl/day	100 MMSCFD
Estimated Pipeline Life	20 years	20 years
Pipeline Temperature	Annual average (inlet): 50°F Summer Average (inlet): 70°F Maximum daily average (inlet): 85°F Maximum temperature (inlet): 100°F	Operating range at shore crossing: 30°F to 70°F Maximum temperature (inlet): 100°F
Pipeline Support / Burial		
Offshore (see Note 1)		
Outside barrier islands	Buried, 7 ft depth of cover	Buried, 7 ft depth of cover
Within 3,000 ft of Seal Island	Buried, 9 ft depth of cover	Buried, 9 ft depth of cover
Lagoon	Buried, 6 ft depth of cover	Buried, 6 ft depth of cover
Overland	VSM supported	VSM supported
Design Code / Regulation	ASME B31.4 / 49 CFR Part 195	ASME B31.4 / 49 CFR Part 192

Note:

1) Locally greater depth of cover (distance from original seabed to top of pipe) will be provided in areas such as the Seal Island and Pt. Storkerson approaches. The trench will be backfilled over the pipelines.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PIPELINE ROUTES
VICINITY MAP

DATE:	SCALE:	FIGURE:
3/25/97	1" = 2.5 Miles	2.4-1

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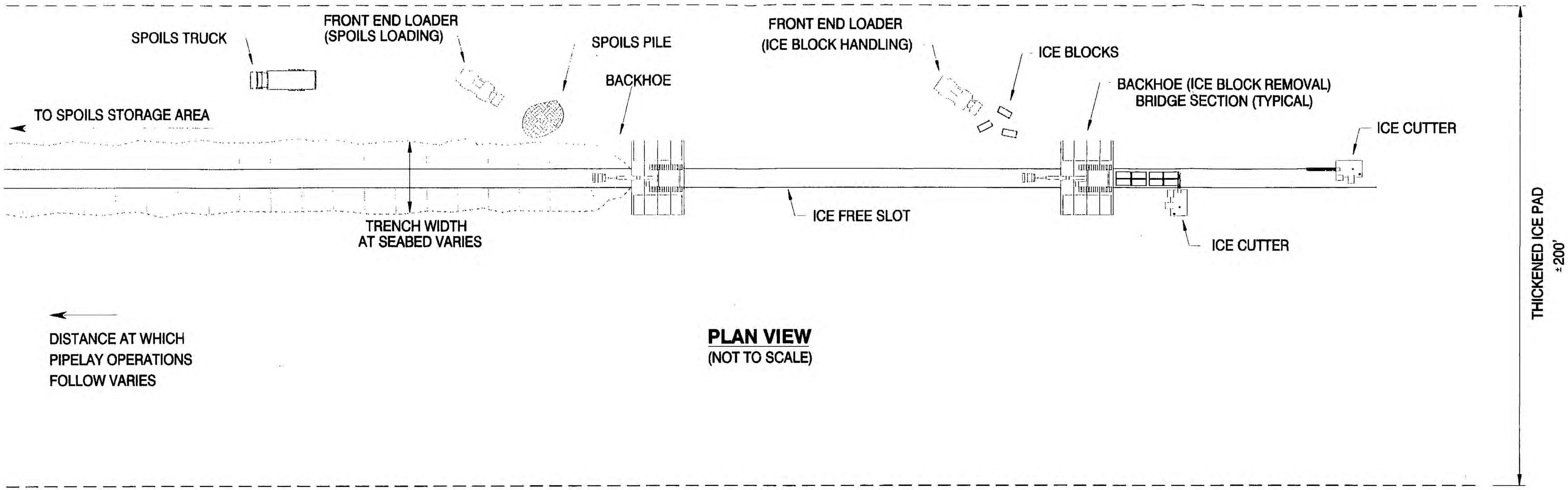
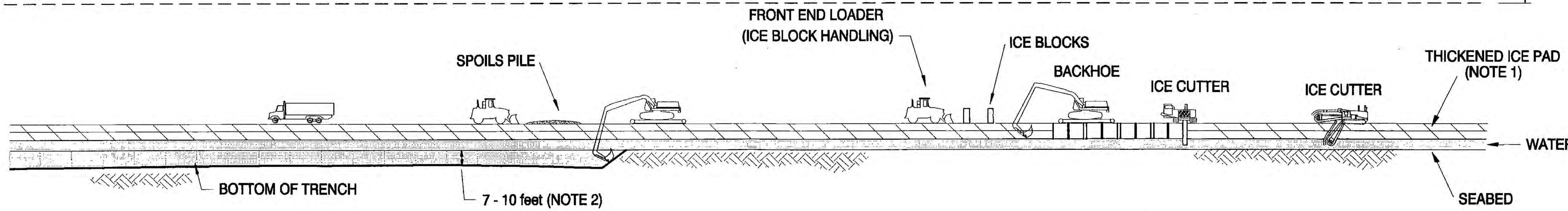


PLAN VIEW
(NOT TO SCALE)



PROFILE VIEW
(NOT TO SCALE)

NOTES:
1. ICE PAD COMPRISED OF NATURAL ICE PLUS THICKENED ICE SUFFICIENT IN THICKNESS TO SUPPORT HEAVY EQUIPMENT TRAFFIC.
2. DEPTH OF BOTTOM OF TRENCH.
3. ACTUAL NUMBER OF PIECES OF EQUIPMENT AND EQUIPMENT TYPES ARE INDICATIVE.
4. MULTIPLE TRENCHING SPREADS MAY BE WORKING SIMULTANEOUSLY AT DIFFERENT LOCATIONS ALONG THE PIPELINE ROUTE.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
EQUIPMENT SPREAD
TRENCHING

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.4-2

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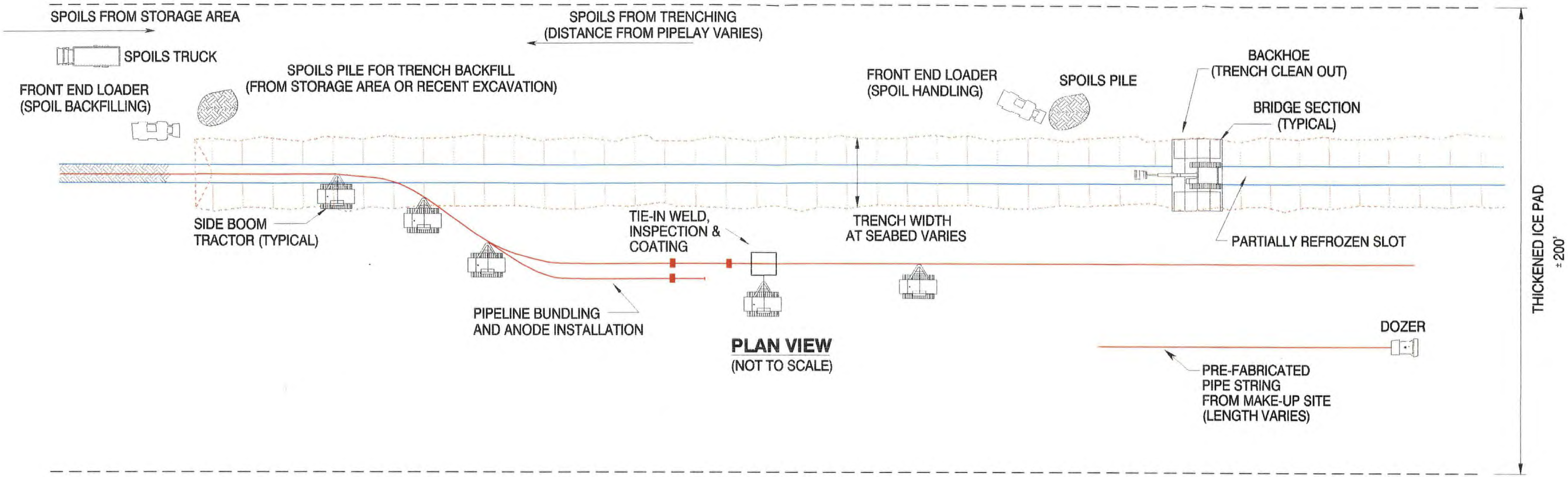
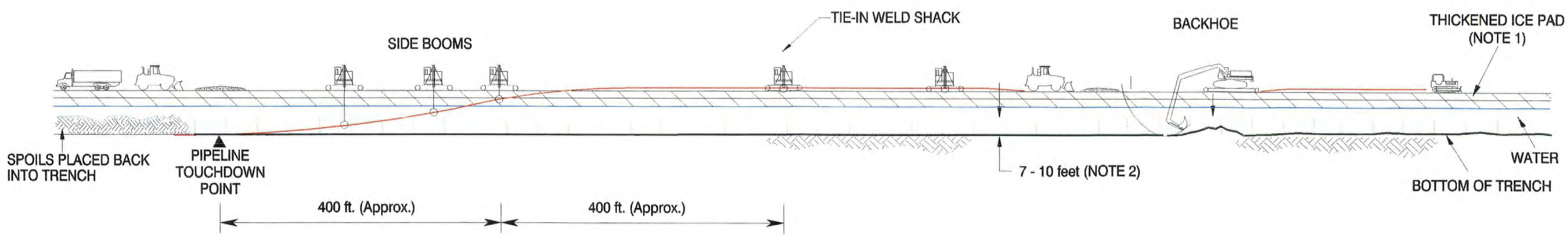


PLAN VIEW
(NOT TO SCALE)



PROFILE VIEW
(NOT TO SCALE)

NOTES:
1. ICE PAD COMPRISED OF NATURAL ICE PLUS THICKENED ICE SUFFICIENT IN THICKNESS TO SUPPORT HEAVY EQUIPMENT TRAFFIC.
2. DEPTH OF BOTTOM OF TRENCH.
3. ACTUAL NUMBER OF PIECES OF EQUIPMENT AND EQUIPMENT TYPES ARE INDICATIVE.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
EQUIPMENT SPREAD
FOR PIPELAYING

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.4-3

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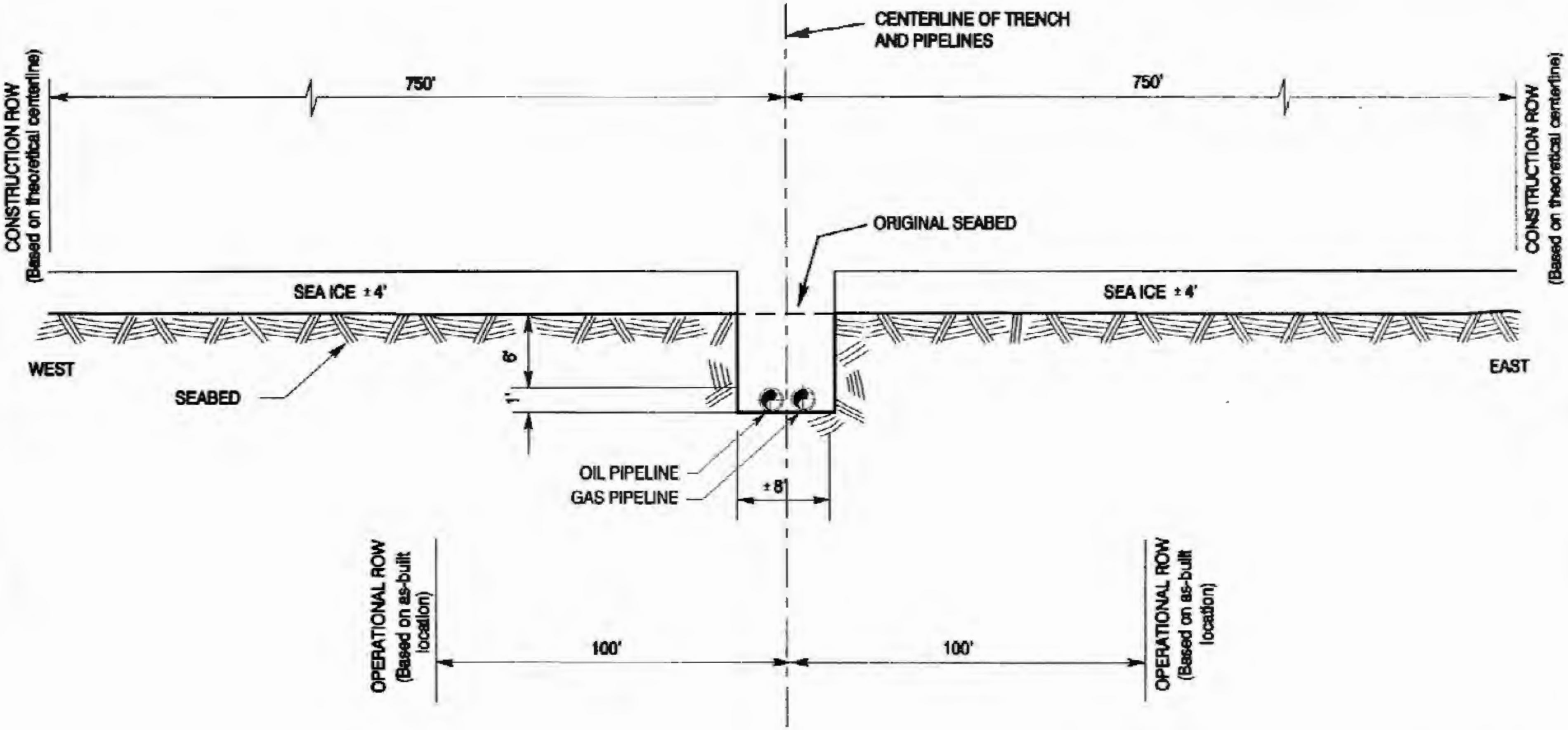
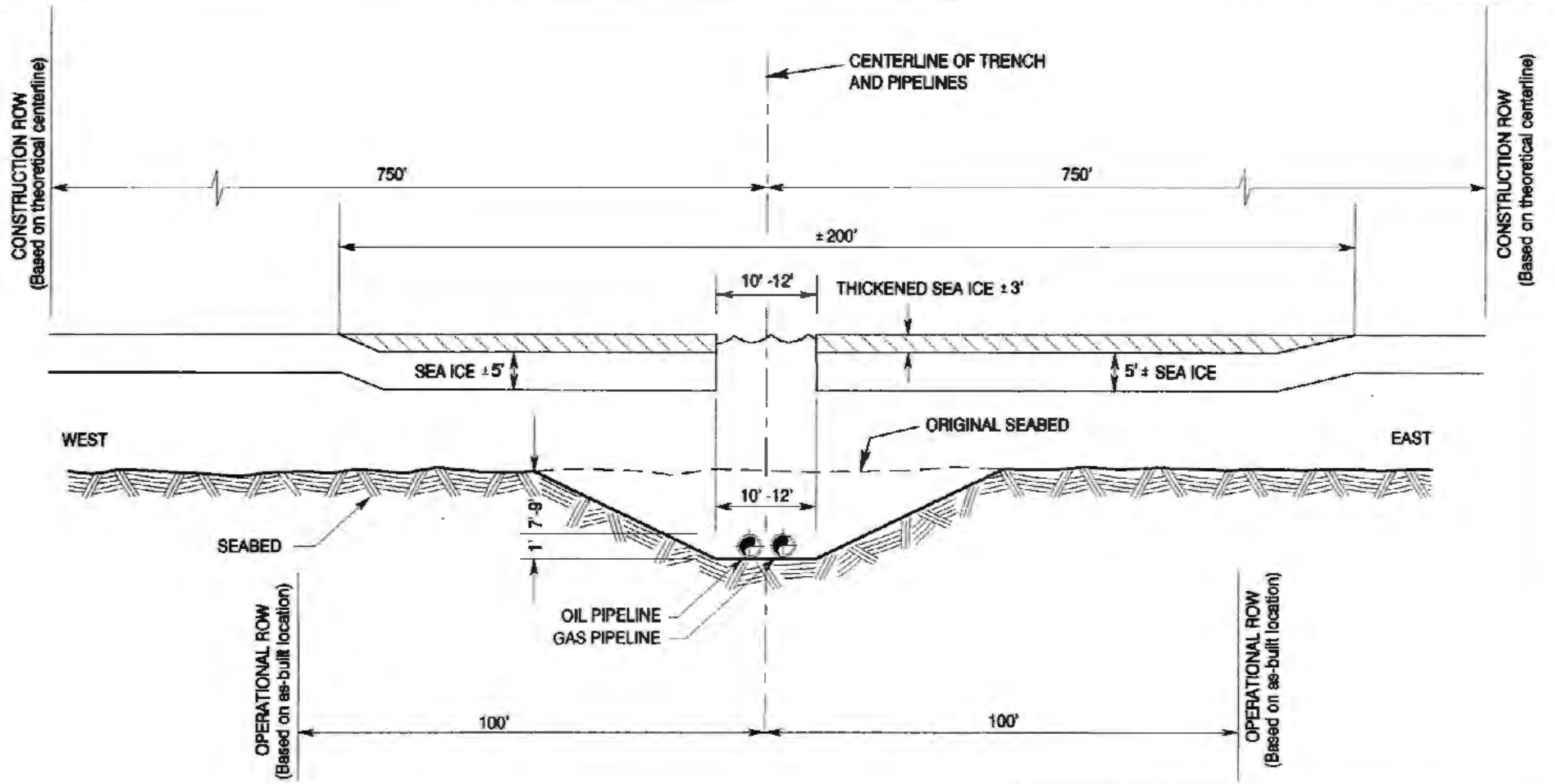


NOTES:

1. PIPELINES DEPTH OF COVER IS 6 FEET.
2. TRENCH SIDE SLOPES ARE VARIABLE, DEPENDING ON SOIL CONDITIONS. VERTICAL TRENCH SIDES ARE SHOWN.
3. PIPELINES WILL BE INSTALLED AS A BUNDLE. FOR SIMPLICITY, INDIVIDUAL PIPELINES ARE SHOWN.

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT TYPICAL TRENCH CROSS-SECTION SOUTH OF BARRIER ISLANDS OFFSHORE RIGHT-OF-WAYS		
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.4-4



NOTES:

1. PIPELINES DEPTH OF COVER IS 7-9 FEET.
2. TRENCH SIDE SLOPES ARE VARIABLE, DEPENDING ON SOIL CONDITIONS. SLOPES SHOWN ARE 1V : 2H.
3. PIPELINES WILL BE INSTALLED AS A BUNDLE. FOR SIMPLICITY, INDIVIDUAL PIPELINES ARE SHOWN.

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROECT TYPICAL TRENCH CROSS-SECTION NORTH OF BARRIER ISLANDS OFFSHORE RIGHT-OF-WAY		
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.4-5

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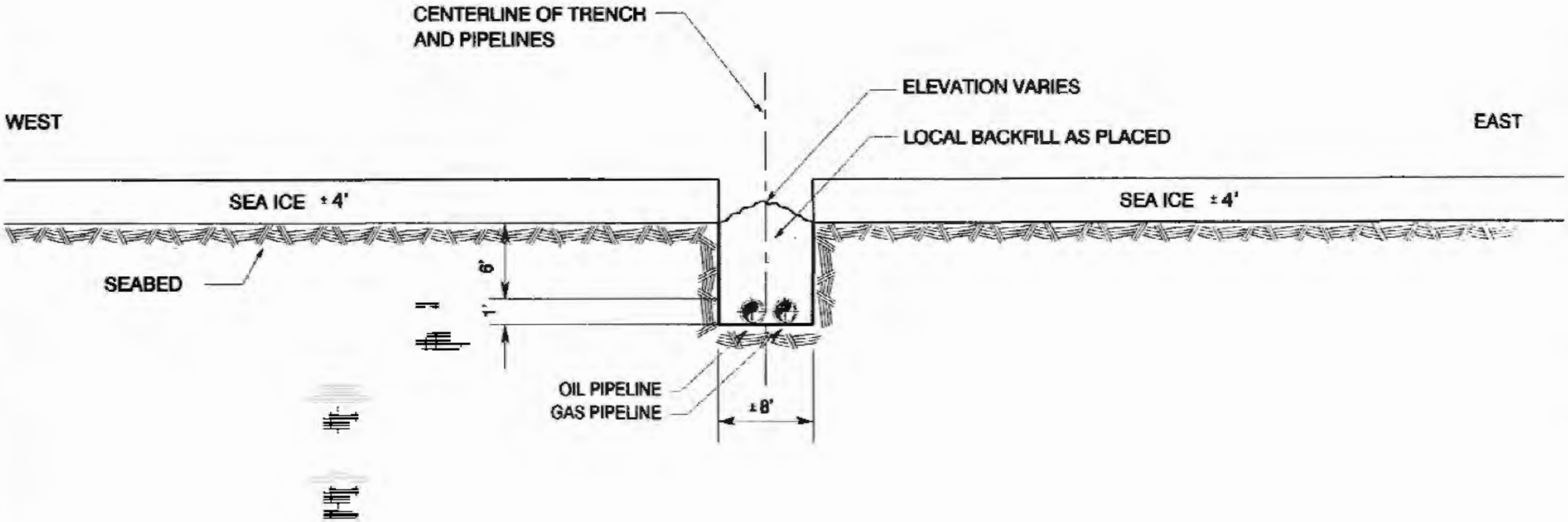


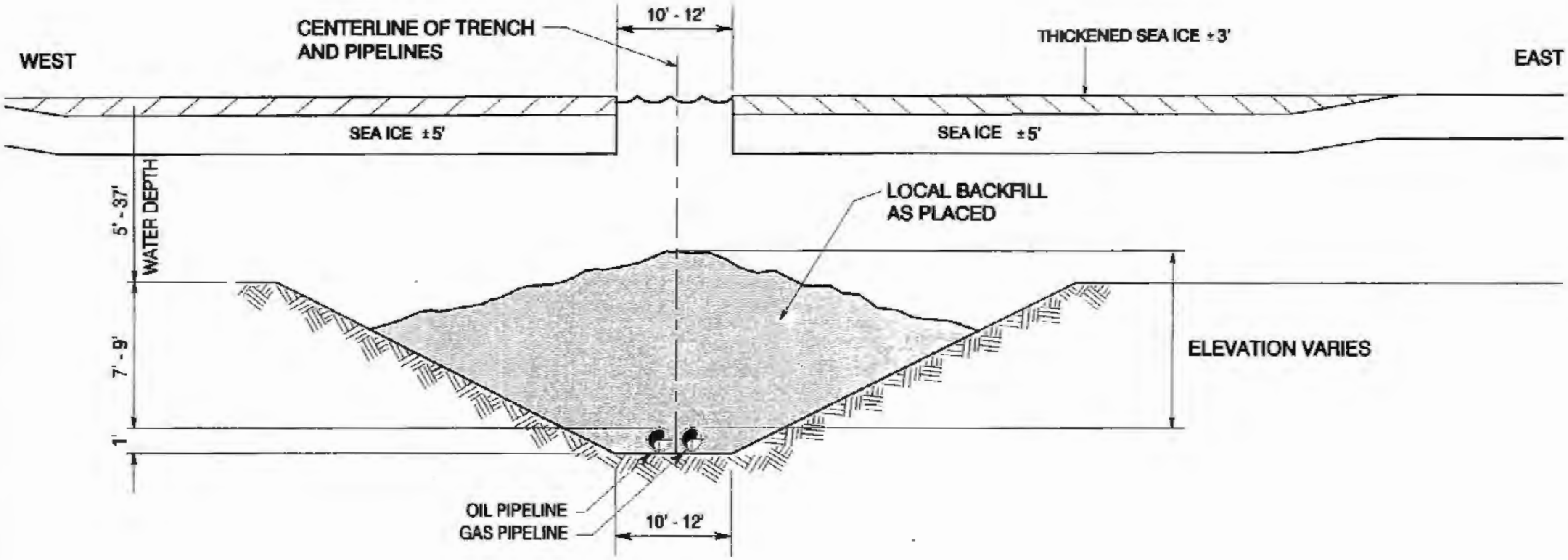
NOTES:

1. PIPELINES DEPTH OF COVER IS 6 FEET.
2. TRENCH SIDE SLOPES ARE VARIABLE, DEPENDING ON SOIL CONDITIONS. VERTICAL TRENCH SIDES ARE SHOWN.
3. PIPELINES WILL BE INSTALLED AS A BUNDLE. FOR SIMPLICITY, INDIVIDUAL PIPELINES ARE SHOWN.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
TYPICAL PIPELINES CROSS-SECTION
SOUTH OF BARRIER ISLANDS

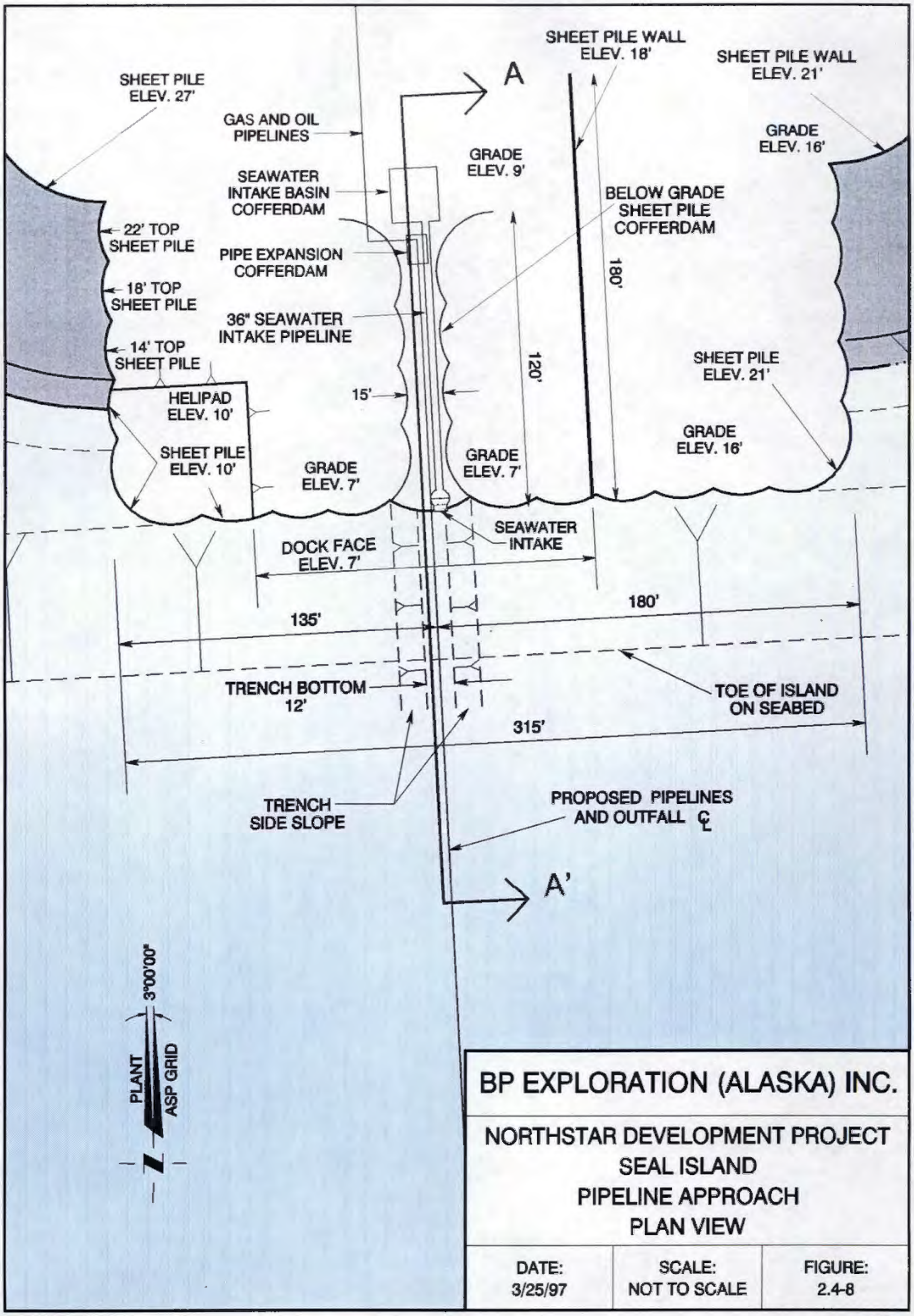
DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.4-6



NOTES:

1. PIPELINES DEPTH OF COVER IS 7-9 FEET.
2. TRENCH SIDE SLOPES ARE VARIABLE, DEPENDING ON SOIL CONDITIONS. SLOPES SHOWN ARE 1V : 2H.
3. PIPELINES WILL BE INSTALLED AS A BUNDLE. FOR SIMPLICITY, INDIVIDUAL PIPELINES ARE SHOWN.

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT TYPICAL PIPELINES CROSS-SECTION NORTH OF BARRIER ISLANDS		
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.4-7

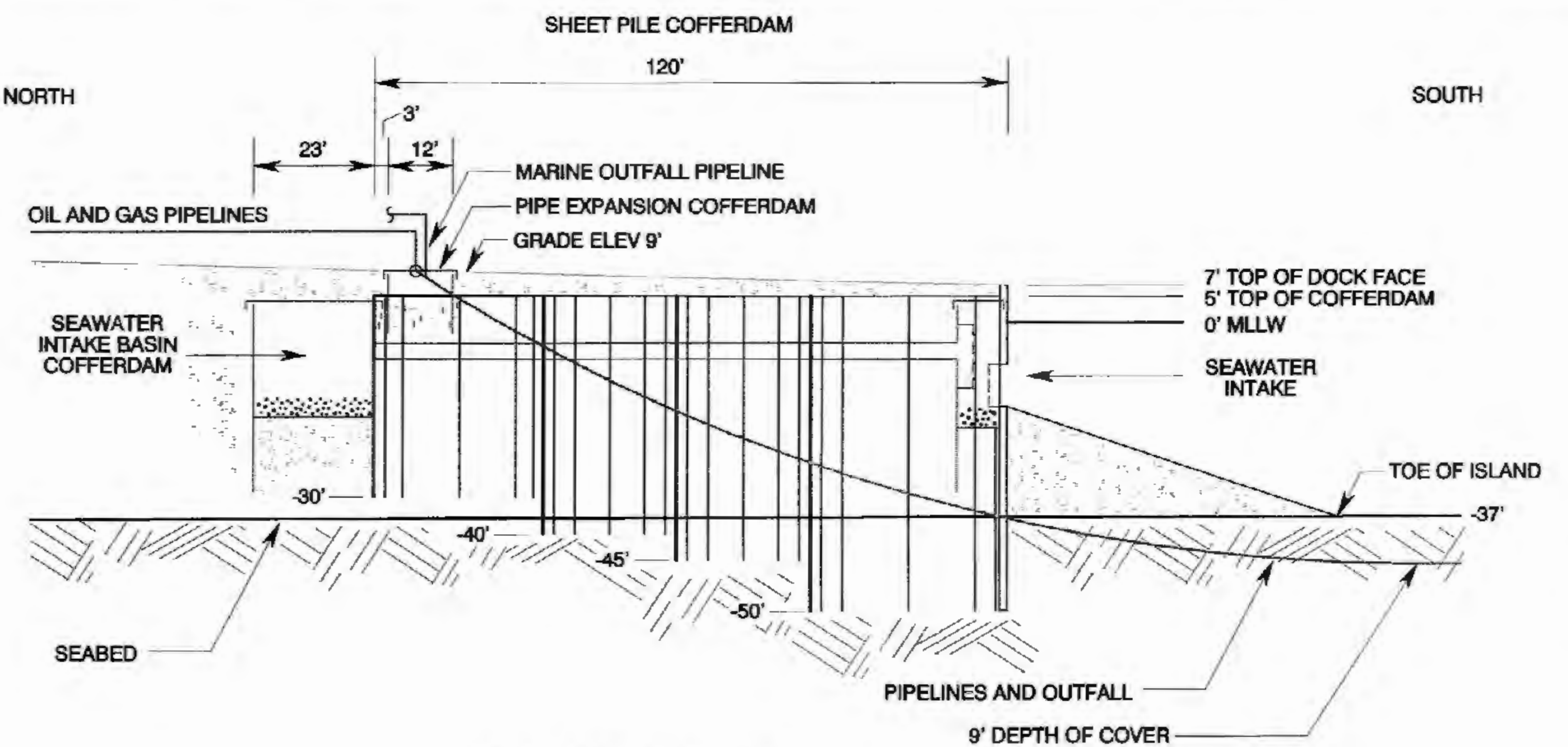


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
PIPELINE APPROACH
PLAN VIEW

DATE:	SCALE:	FIGURE:
3/25/97	NOT TO SCALE	2.4-8

nsv297.dgn



SIDE VIEW A - A'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAL ISLAND PIPELINE APPROACH COFFERDAM SIDE VIEW		
DATE: 3/25/97	SCALE: N/A	FIGURE: 2.4-9

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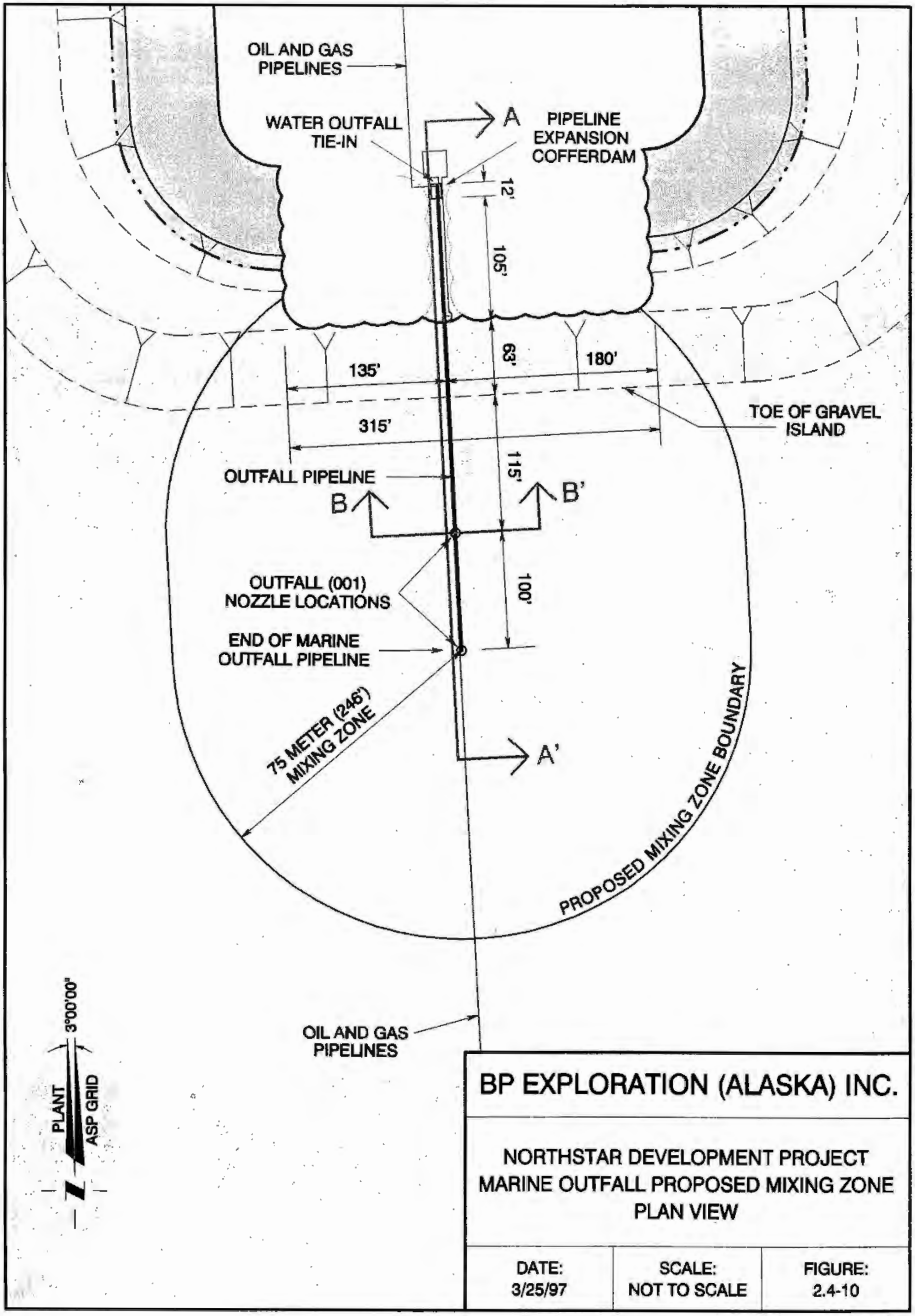
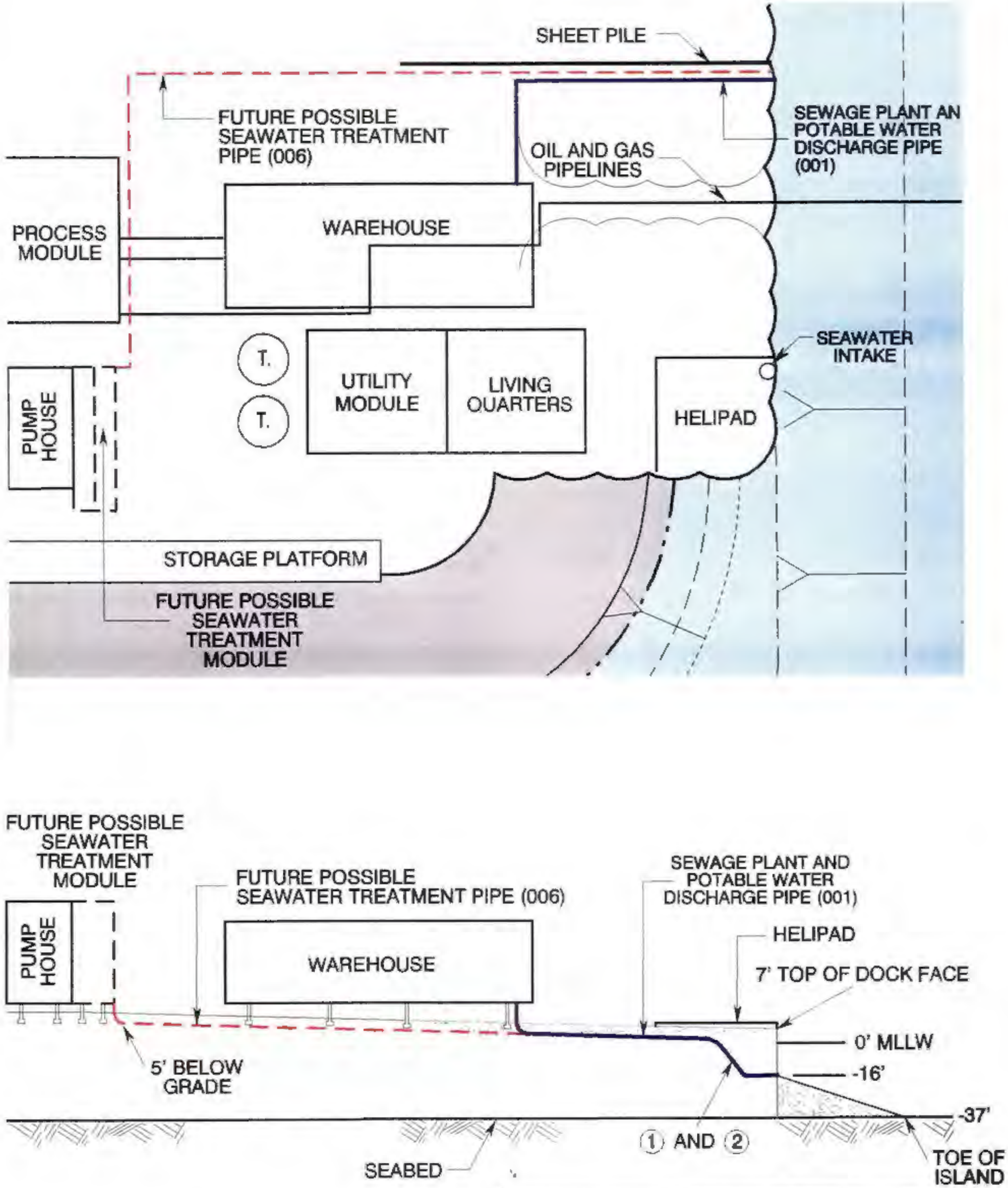


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
MARINE OUTFALL PROPOSED MIXING ZONE
PLAN VIEW

DATE:	SCALE:	FIGURE:
3/25/97	NOT TO SCALE	2.4-10

nsv297.dgn



1 FUTURE POSSIBLE
SEAWATER TREATMENT PLANT OUTFALL
DISCHARGING THRU 4" NOZZLE IN
DOCK FACE @ -16' MLLW

2 SEWAGE PLANT AND
POTABLE WATER PLANT OUTFALL
DISCHARGING THRU
2" NOZZLE IN DOCK FACE @ -16' MLLW

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
EFFLUENT OUTFALL Nos. 001 AND 006
PLAN AND ELEVATION VIEW

DATE:	SCALE:	FIGURE:
NOV. 1997	N/A	2.4-11

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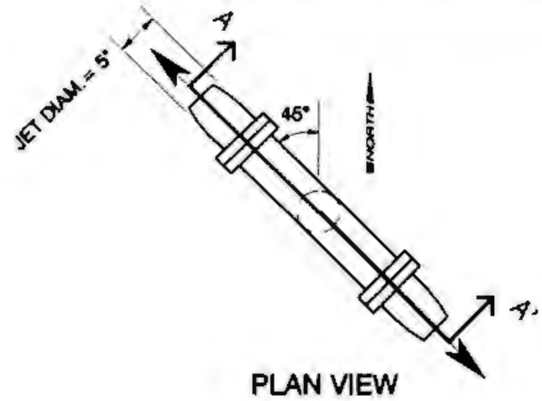
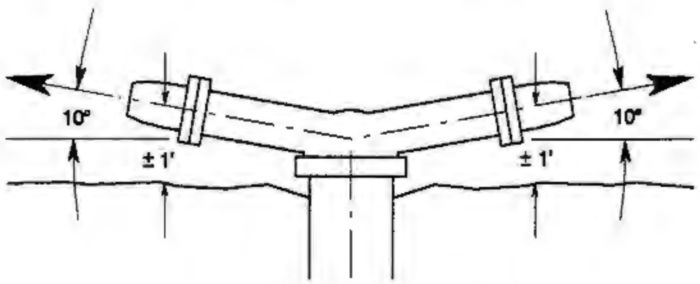
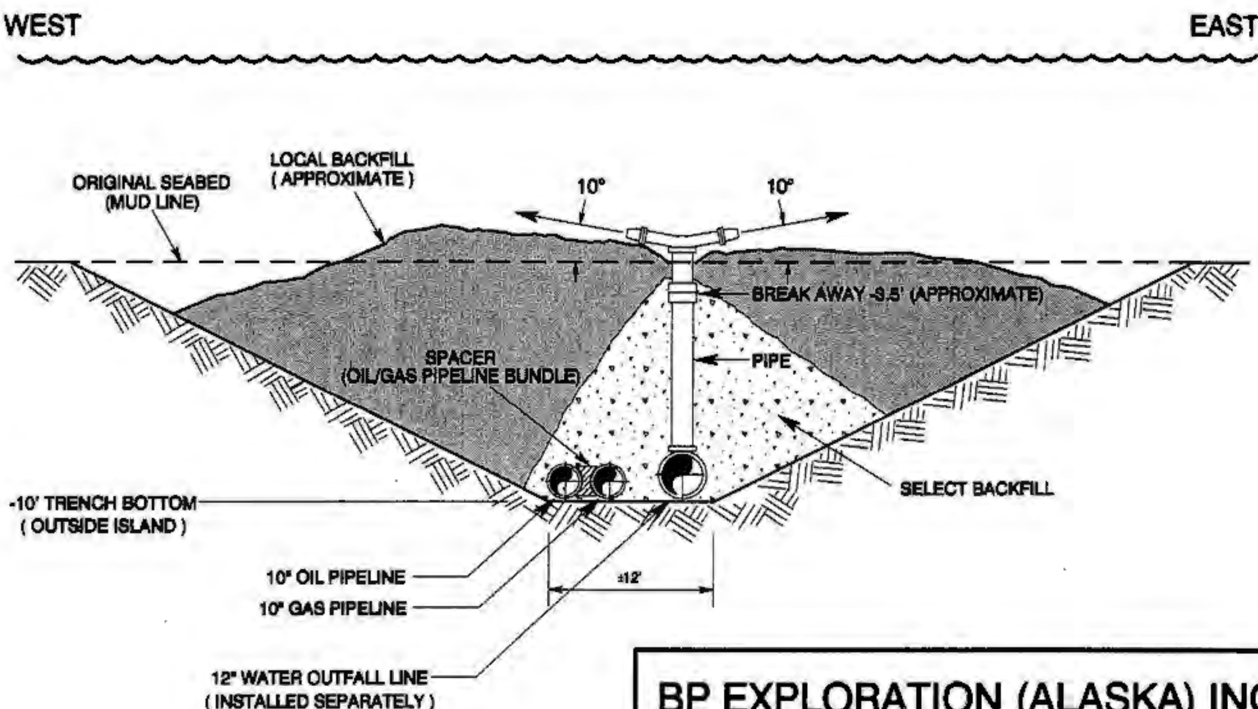


PLAN VIEW



NOZZLE DETAIL

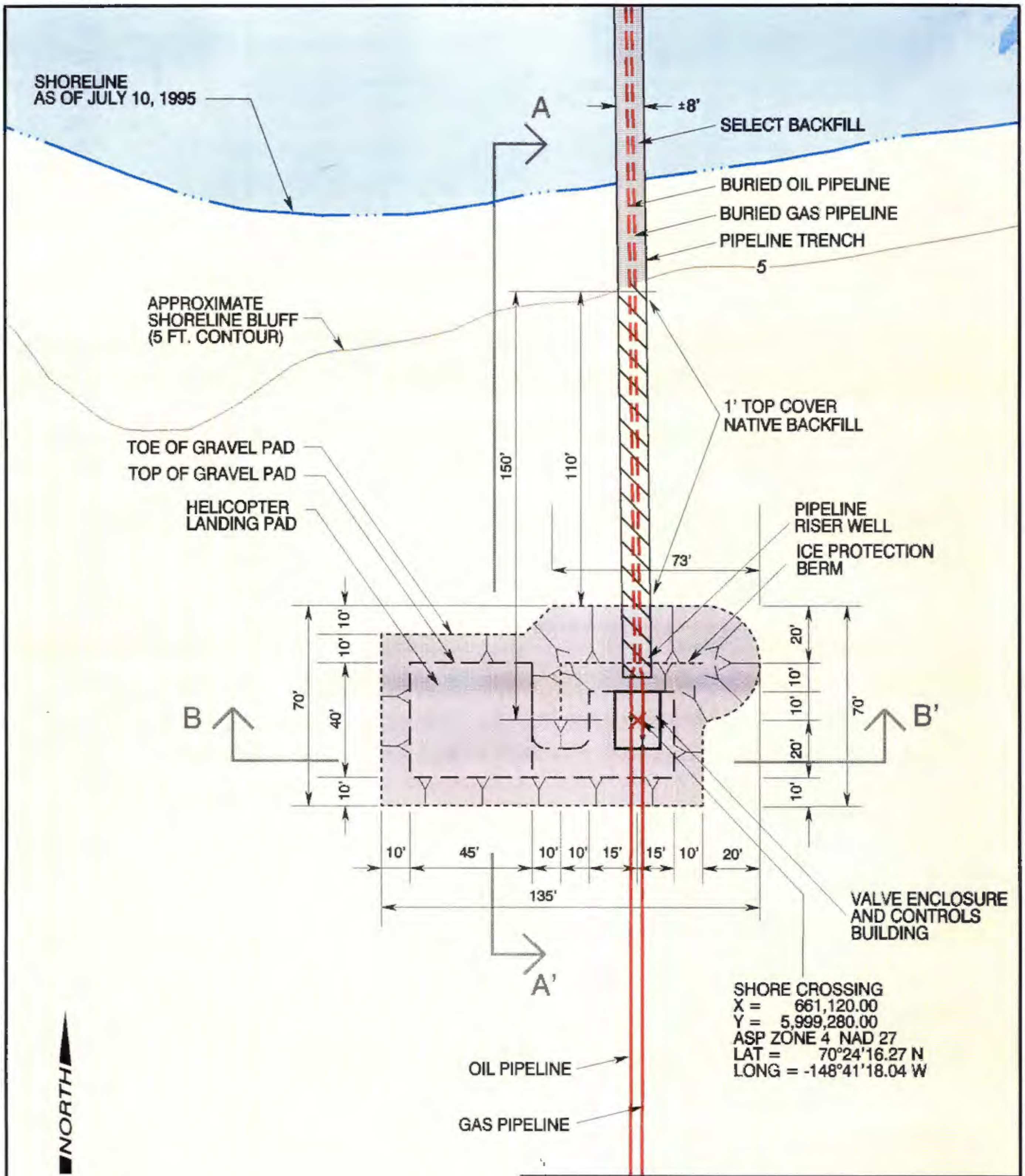


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
MARINE OUTFALL
SIDE VIEW

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.4-12

nsv297.dgn



ESTIMATED AREA OF TUNDRA COVER: 0.2 ACRES
ESTIMATED QUANTITY OF GRAVEL: 1800 CY.

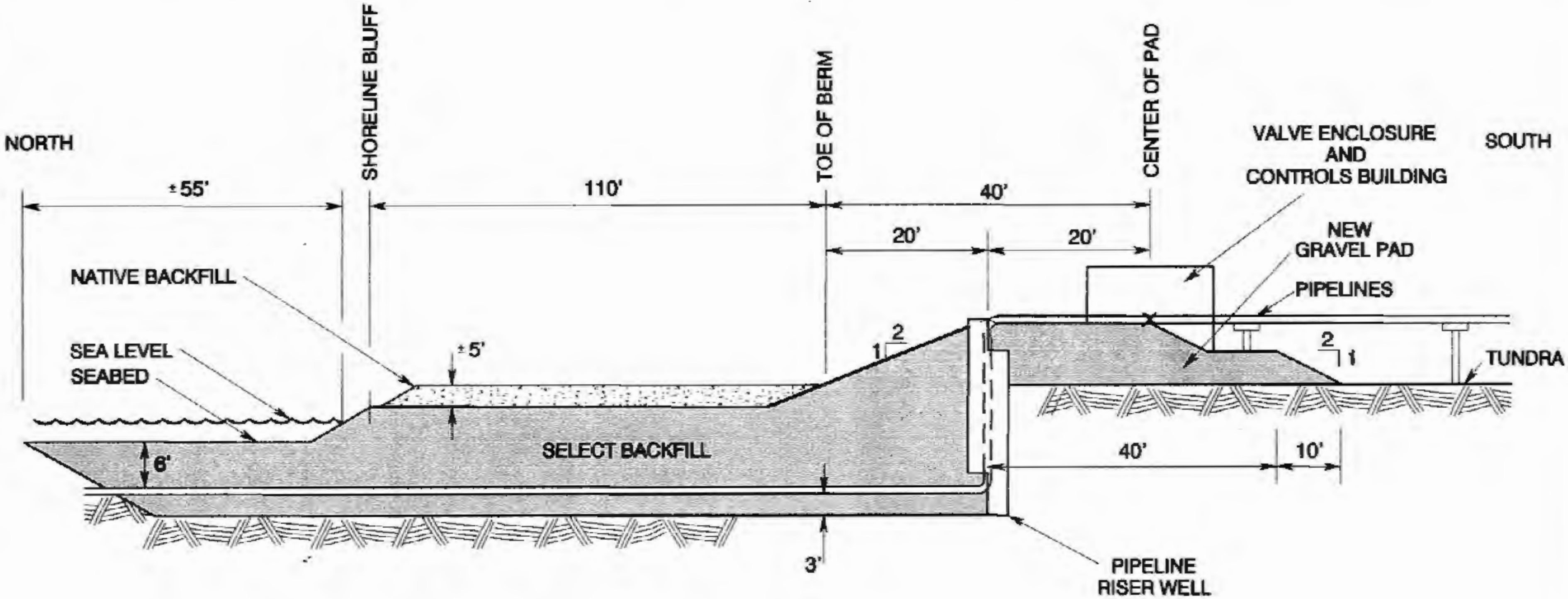
ESTIMATED AREA OF TUNDRA AFFECTED BY TRENCH: 0.02 ACRES
ESTIMATED QUANTITY OF GRAVEL FOR TRENCH: 700 CY.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
LANDFALL VALVE PAD
LAYOUT

DATE:	SCALE:	FIGURE:
NOV. 1997	1" = 50'	2.4-13

nsvp1197.dgn



SIDE VIEW A-A'

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
LANDFALL VALVE PAD
SIDE VIEW

DATE:	SCALE:	FIGURE:
NOV. 1997	NOT TO SCALE	2.4-14

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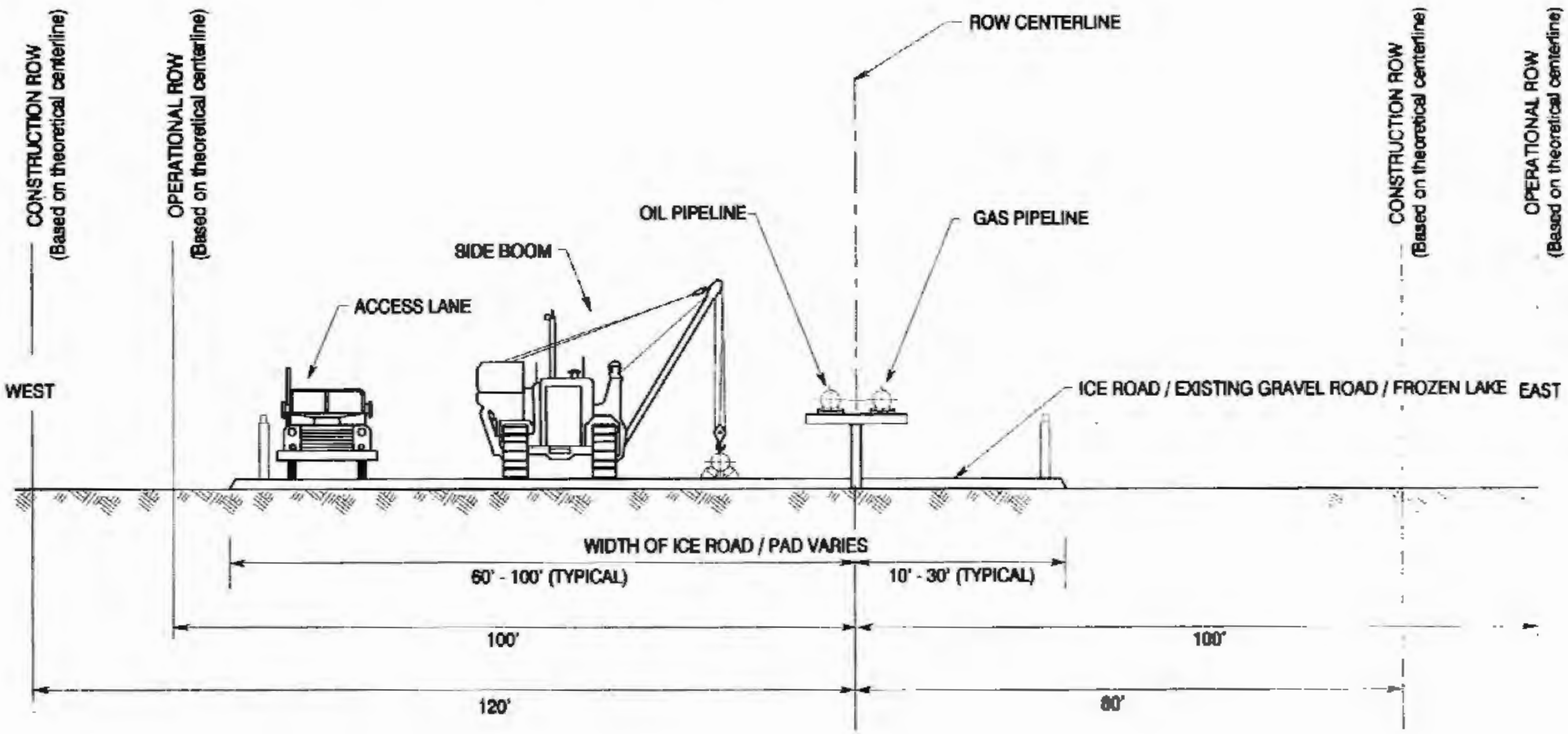


NOTES:

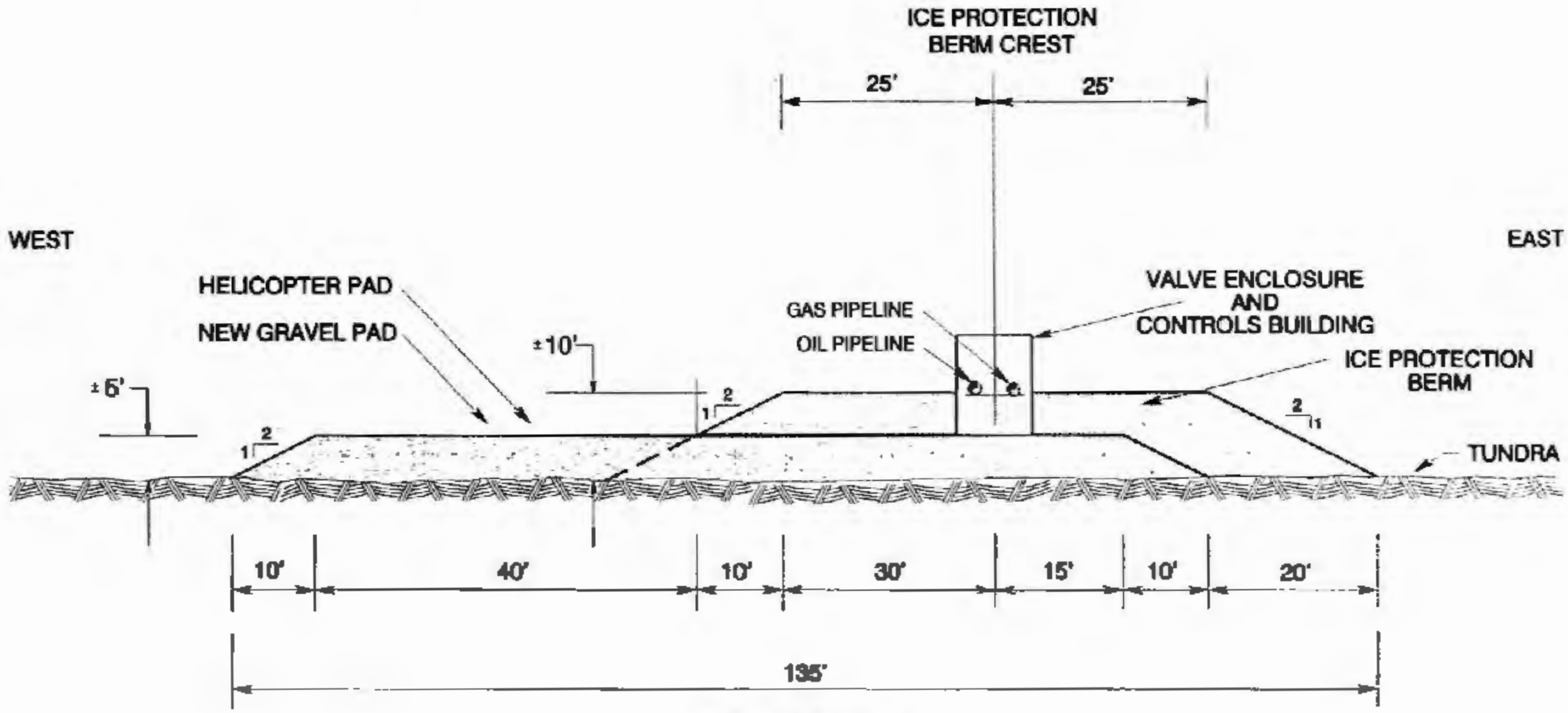
1. HEIGHT OF VSMs WILL MATCH THAT OF PARALLEL SUPPORTS ALONG EXISTING PIPELINES. FOR SECTIONS OF ALIGNMENTS WITHOUT EXISTING PARALLEL PIPELINES, BOTTOM OF PIPE ELEVATION TO BE 5' MINIMUM.
2. VSM AND PIPELINE ALIGMENT WITH RESPECT TO ROW CENTERLINE VARIES ALONG NEW PIPELINE CORRIDOR SECTIONS.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
TYPICAL PIPELINES CROSS-SECTION
ONSHORE
RIGHT-OF-WAYS

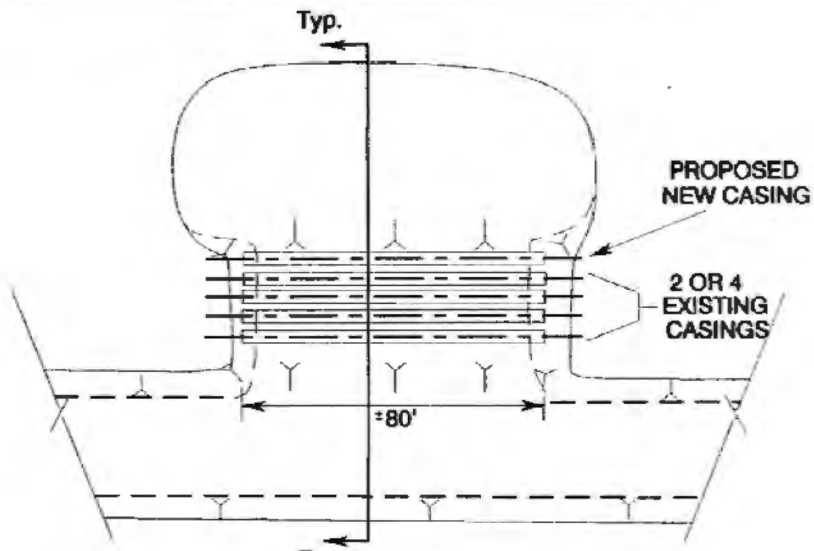
DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.4-16

nsv297.dgn

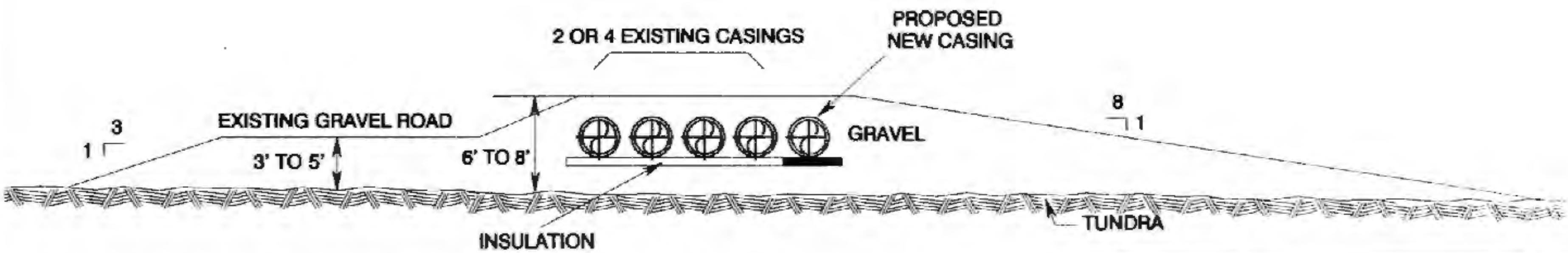


SIDE VIEW B-B'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT LANDFALL VALVE PAD SIDE VIEW		
DATE: 3/25/97	SCALE: NOT TO SCALE	FIGURE: 2.4-15



PLAN VIEW



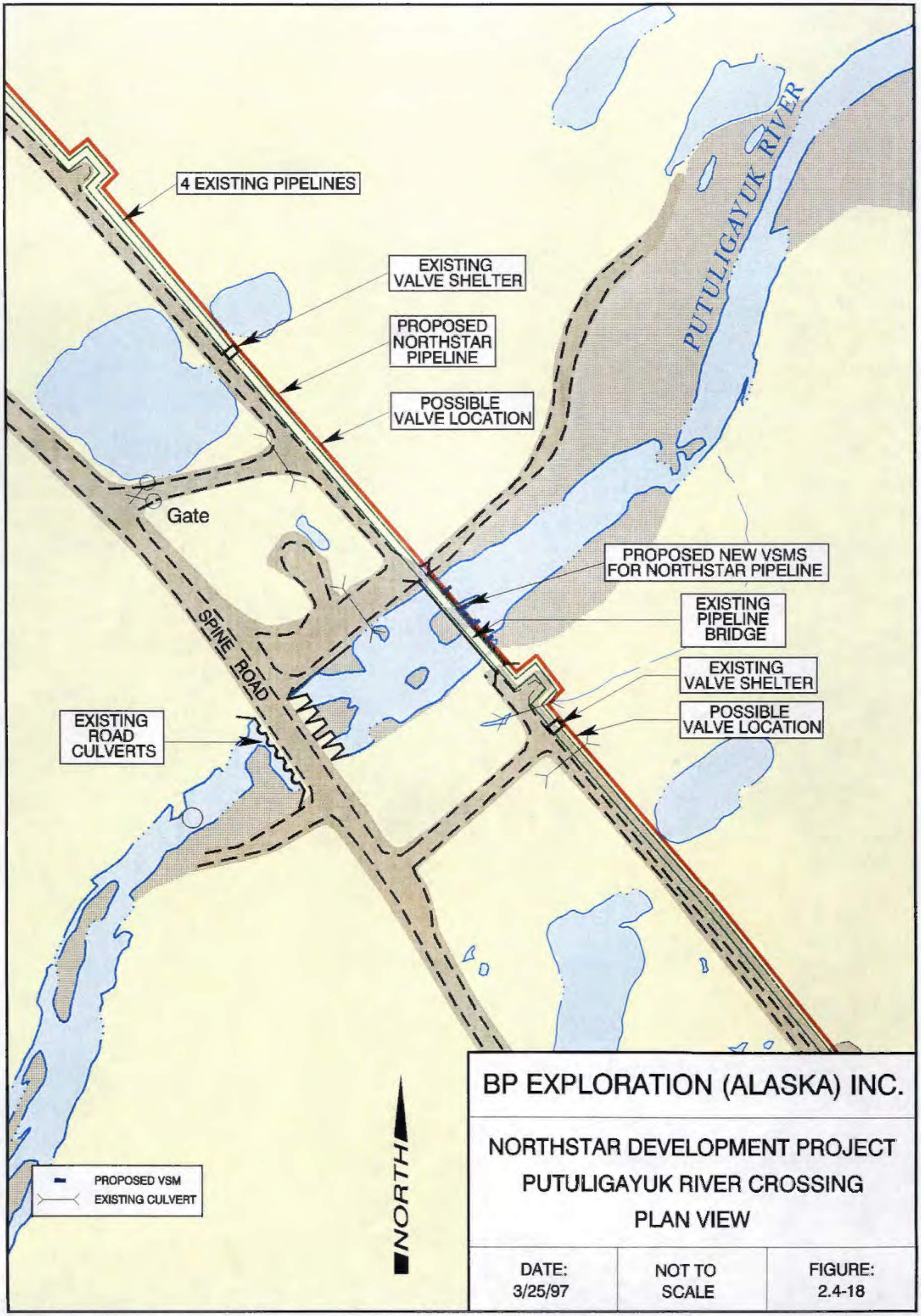
TYPICAL SECTION

NO NEW GRAVEL REQUIRED FOR NEW CASING,
NO ADDITIONAL TUNDRA AFFECTED.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
CARIBOU CROSSING
TYPICAL PLAN VIEW AND
CROSS-SECTION

DATE:	SCALE:	FIGURE:
3/25/97	N/A	2.4-17

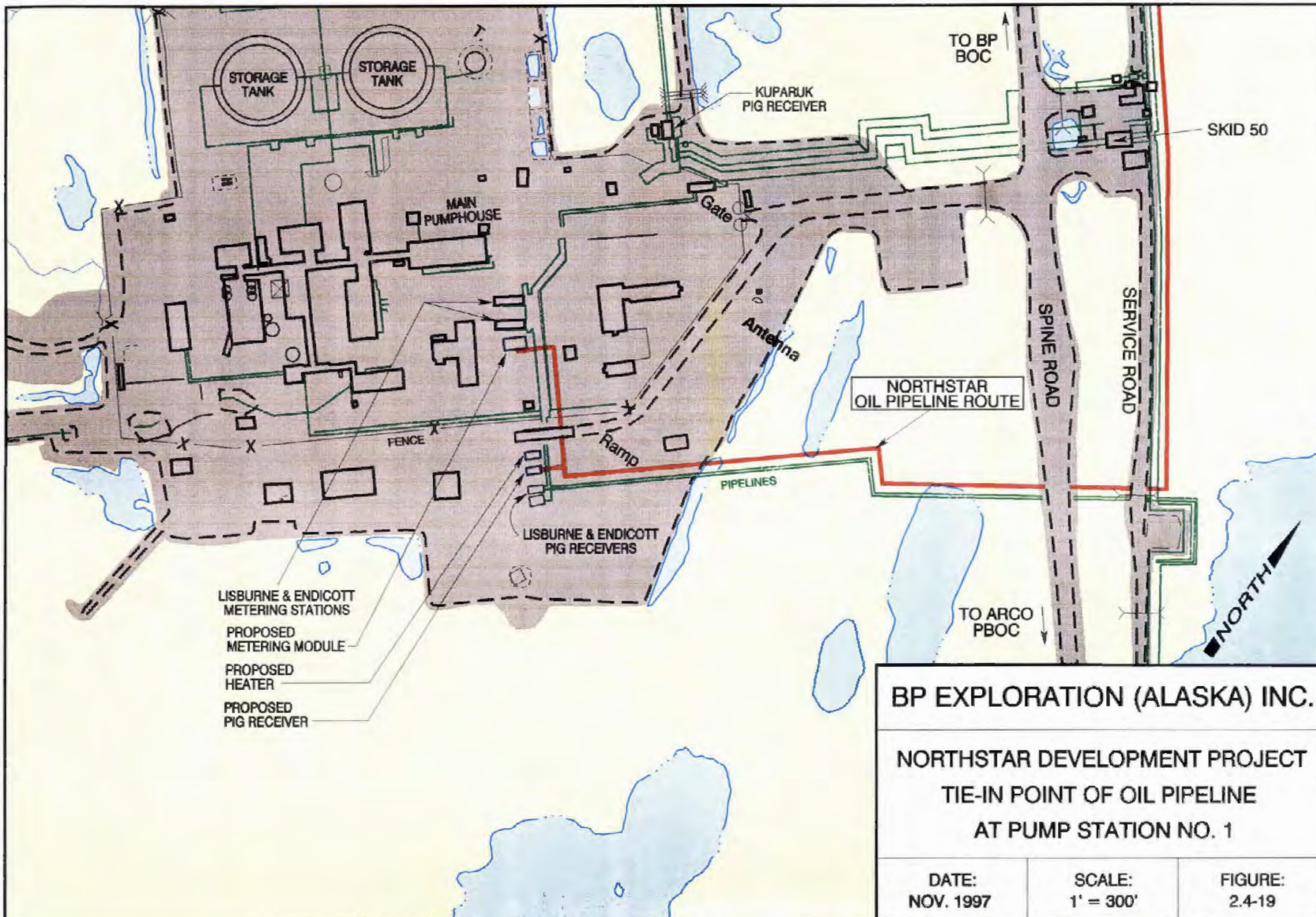


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PUTULIGAYUK RIVER CROSSING
PLAN VIEW

DATE: 3/25/97	NOT TO SCALE	FIGURE: 2.4-18

nsvp297.dgn



BP EXPLORATION (ALASKA) INC.

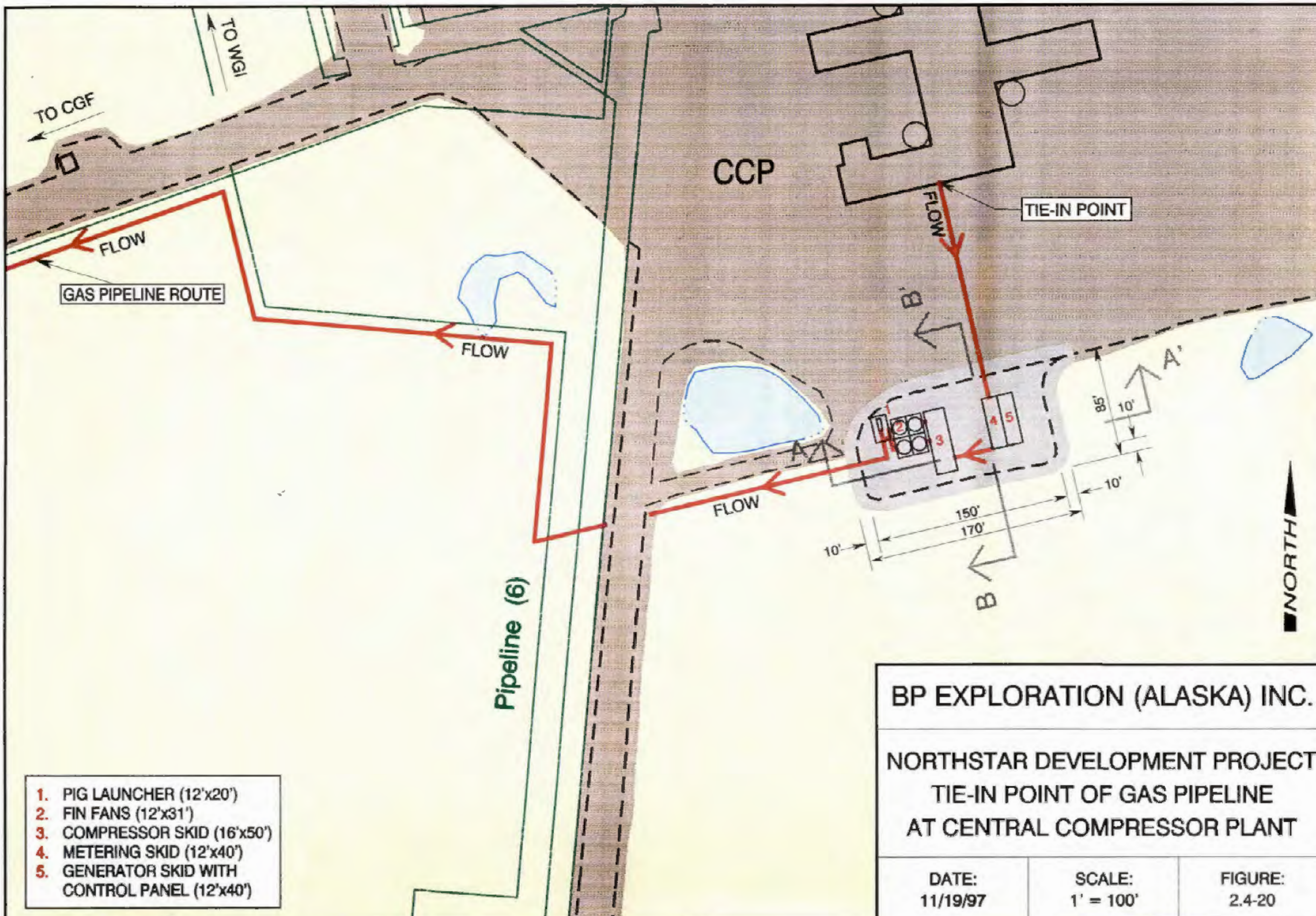
NORTHSTAR DEVELOPMENT PROJECT

TIE-IN POINT OF OIL PIPELINE

AT PUMP STATION NO. 1

DATE:	SCALE:	FIGURE:
NOV. 1997	1' = 300'	2.4-19

nsvp1197.dgn



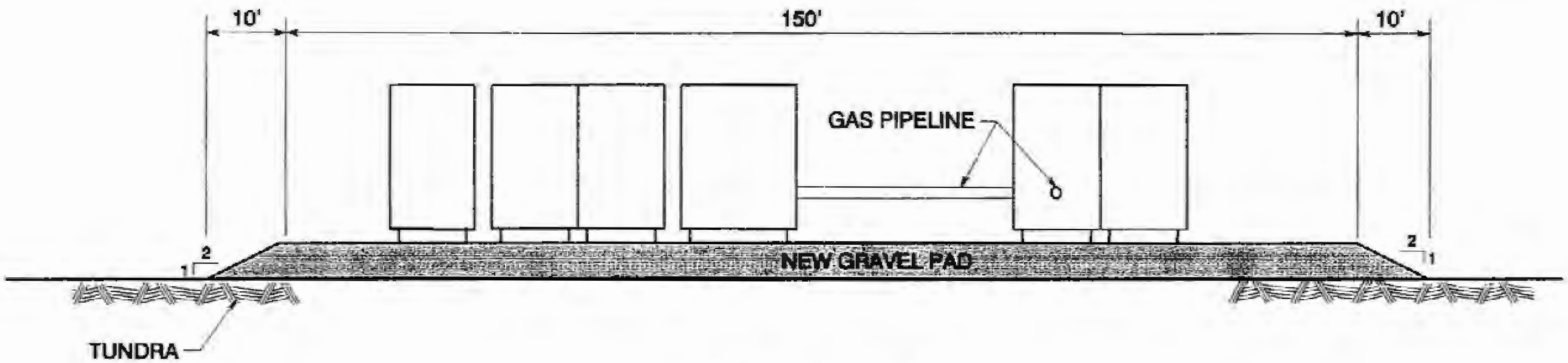
1. PIG LAUNCHER (12'x20')
2. FIN FANS (12'x31')
3. COMPRESSOR SKID (16'x50')
4. METERING SKID (12'x40')
5. GENERATOR SKID WITH CONTROL PANEL (12'x40')

BP EXPLORATION (ALASKA) INC.

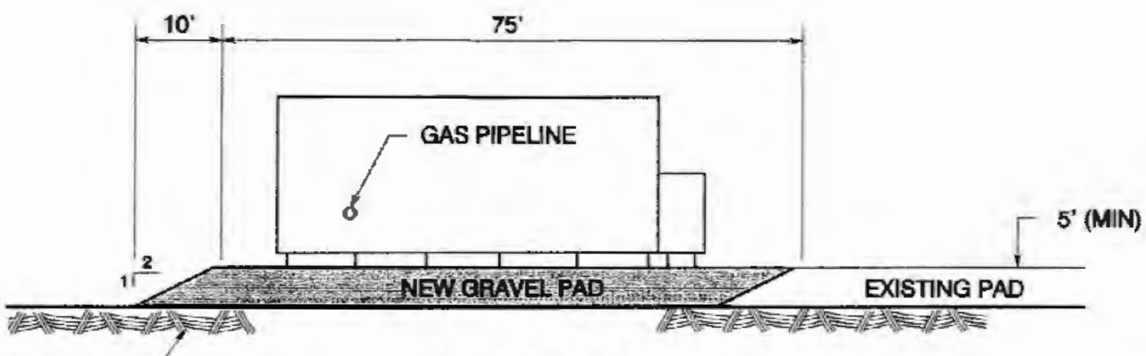
NORTHSTAR DEVELOPMENT PROJECT
TIE-IN POINT OF GAS PIPELINE
AT CENTRAL COMPRESSOR PLANT

DATE:	SCALE:	FIGURE:
11/19/97	1' = 100'	2.4-20

nsvp1197.dgn



SIDE VIEW A-A'



SIDE VIEW B-B'

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
TIE-IN POINT OF GAS PIPELINE
AT CENTRAL COMPRESSOR PLANT
SIDE VIEWS

DATE:	SCALE:	FIGURE:
11/19/97	NOT TO SCALE	2.4-21

nsv1197.dgn

2.5 DRILLING

2.5.1 Design Criteria

Siting of the well locations and allocation of space on the island for drilling operations are governed by several criteria which are summarized in Table 2.5-1. The island layout includes 23 wells, 15 of which will be oil producers, 7 will be gas injectors, and one will be a disposal well. Up to 14 additional slots can be accommodated to allow for reservoir uncertainties and in-fill drilling. The well spacings (10 feet from center to center) and drilling footprint can accommodate a number of different North Slope rigs.

A sheet pile wall (180 feet in length) shown in Figure 2.4-8, allows the eastern portion of the dock to remain level at +16 MLLW to provide a level drilling area. The western portion slopes from the dock face at +7 MLLW up in a northerly direction to +16 MLLW at approximately the middle of the island, and will be used for movement of materials and supplies from the dock to the drilling and storage areas.

The current choice of rig for this project is Nabors 33E (formerly named 3A). This rig can be broken down into light loads and trucked over a floating ice road, or mobilized by barge. The rig is supported on a sub-structure for load distribution.

2.5.2 Mobilization and Supply

For the single season construction schedule the drilling rig, drilling equipment and materials, and supplies for five wells will be mobilized by barge in September immediately after sealift of production facilities. It is anticipated that these wells will be drilled during freeze-up when the island will have to rely on helicopter for additional material supplies.

For the two season schedule the rig, drilling equipment and materials, and supplies for five wells will be mobilized by ice road in March. These wells will be drilled during break-up when the island will have to rely on helicopter for additional material supplies.

The drill crew will travel to the island by ice road or helicopter, depending on the time of year. Regular crew changes will continue until the end of the drilling phase with headcount varying from 45 to 50. Table 1.2-2 provides details of the equipment and materials that will be moved during the installation phase.

TABLE 2.5-1
DRILLING DESIGN CRITERIA

Drilling footprint	• Allow for 23 wells with the possibility to extend to 37 (depending on drilling rig) at a later date • Provide flexibility in rig selection • Should not compromise future will interventions • Facilitate storage and handling of large quantities of consumables during freeze-up and break-up • Allow for simultaneous drilling and production operations to be conducted safely
Drilling rig and equipment	• Minimize the drilling footprint and therefore the island size • Moved by ice road over floating ice or by barge • Run economically on gas or facility generated electrical power
Supply and logistics	• Minimize number and size of wells • Minimize material consumption and material movements (mud, cement, etc.)

OPERATIONS PHASE

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

3. OPERATIONS PHASE

3.1 INTRODUCTION

3.1.1 Purpose

This section discusses the operations phase of the Northstar Development. For this plan, "operations" is defined as the period from completion of installation of various facilities and turnover of those facilities to the operating group.

3.1.2 General Considerations

Northstar process facilities are located on the production island. The island location presents special challenges from an operations perspective including the following key issues:

- The facilities will be manned. Environmental risks and the value of production optimization contribute to this decision.
- Emergency evacuation of personnel from the island is of primary importance. The plan assumes helicopters as the vehicle of choice.
- Transportation to the island is by three modes: helicopter, barge, or ice road. Ice conditions limit barge traffic to three months per year (July, August, and September). Ice roads can be utilized from late December through May. The remaining four months (May, June, October, and November) require the exclusive use of helicopters for access.
- Supplies, particularly heavy bulk items, must be staged on the island during the ice-road and/or open-water windows. Perishable items, including food stuffs, will require transportation on a regular basis.
- Equipment reliability and sparing is weighed heavily against initial costs. Major maintenance opportunities will be limited due to the logistics restrictions mentioned above.
- Limited storage is available on the island. An efficient resupply strategy is essential.
- Facility shutdown and isolation of the subsea pipelines are critical.

- Waste disposal includes drilling, camp and process waste products. Section 6 of the *Final Project Description, Rev.1,* deals specifically with the various waste management methods proposed.

3.1.3 Basic Criteria

Northstar Development oil is a light, sweet crude with a relatively high gas-oil ratio of approximately 2,200 standard cubic feet per stock tank barrel (STB) and a carbon dioxide content of five percent. The reservoir is at high pressure and the wells will flow easily. The primary drive mechanism is thought to be pressure depletion. Gas re-injection will be utilized from start-up to maintain reservoir pressure and improve recovery. There is an aquifer, but the extent of pressure support is not yet known.

Reservoir fluid from producing wells is a mixture of oil, gas, and water. The process facilities separate this mixture into a sales-quality oil product for shipment to shore, gas which is re-injected into the formation, and water which is injected into the waste disposal well. An estimated nominal 65,000 barrels per day of crude oil will be produced. There will initially be approximately 15 producing wells, seven gas injection wells, and one Class I non-hazardous waste disposal well (23 total wells). All produced water will be disposed of by injection into the waste disposal well. Space for 30 to 34 wells, at a wellhead spacing of 10 feet is achievable with the current island configuration. The operational design life is 15 years. Natural gas liquids (NGLs) will be recovered from the produced gas before gas re-injection, and blended with sales oil.

BPXA's reservoir studies show that the optimum depletion method for the Northstar reservoir is gas cycling. Gas cycling utilizes re-injection of produced gas plus gas from an outside source (make-up gas) to offset reservoir withdrawals, maintain pressure, and provide a means of displacing oil from the reservoir.

The Northstar Development reservoir depletion plan calls for importing up to 100 MMscfd of gas from shore during the peak injection period. This gas will be added to produced gas, for a total peak gas injection of 600 MMscfd. The import gas will be supplied from the Prudhoe Bay Unit; however, no formal agreements have been signed at this time. In the event gas purchase negotiations are not successful, waterflood can be installed as a means of secondary recovery approximately one year after first oil start-up. Source water for the waterflood would be sea water taken through the island's seawater intake.

Nominal plant design capacities are shown in Table 3.1-1.

The wells and facilities on the island will be operated by a staff of approximately 20-25 core people housed on the island. The Northstar facility is self-contained.

3.1.4 Resource Transportation

Delivery of bulk supplies and non-perishable goods will occur during three months of open water and four to five months of ice road per year. A four-month supply criterion has been used to size storage requirements on the island. The two periods of the year limited to air access (May/June, October/November/December) do not pose a significant problem regarding island supply.

3.1.5 Training

The training curriculum of the operations personnel will include safety/environmental as well as operation facilities training. Polar bear awareness, island evacuation procedures, and arctic offshore precautions will be included.

Section 8, Health, Safety and Environmental (HSE), provides details of the training program for both the construction and operations phases.

TABLE 3.1-1
DESIGN CAPACITIES AND SPECIFICATIONS

SUBJECT	VARIABLE	CAPACITY
Design Capacities	Crude Oil to Sales	65,000 BOPD
	Gas Re-injection	600 MMscfd
	Produced Water Handling	Up to 30,000 BWPD
Specifications	Produced Gas	• Dehydrate to -20°F, • Recover NGLs to +25°F • Compress & reinject residue gas to 5,500 psig
	Produced Water	• Remove dissolved gas • De-oil to less than 50 ppm
Ambient Design Temperature	Minimum	-50°F
	Maximum	+75°F
	Mechanical Design	-20°F
	Air Cooler Design	+40°F
Site Elevation		+16 ft MLLW (work surface) +21 ft to +27 ft MLLW (sheet pile wall)
Wind		14 MPH (mean annual)
Wind Direction		NE 60% / SW 30%. Mixed 10%
Snow Load		30 Psf minimum
Earthquake Zone		1

3.2 ISLAND

3.2.1 Deck Drainage Handling / Monitoring

All island surface drainage, including rainfall, snow melt, and any spray from wave over topping, will be routed to the deck drainage sumps. The deck drainage sumps operate at a low level, and will be visually inspected to determine if sufficient water has accumulated to warrant discharge. In the event an oil sheen is observed, the contaminated water will be pumped from the sump and disposed in the onsite injection well, or transported to an approved onshore facility for processing. If no sheen is observed, the water collected in the sumps will be released into the Beaufort Sea through Outfalls 003 and 004.

Deck drainage collected in the system is not expected to contain hydrocarbons. However, a monitoring and collection system will ensure that only clean deck drainage is allowed to discharge from the island surface. Part of the ongoing operation duties will be to visually monitor the catchment basin, as well as sample and analyze drainage water, as necessary, before the water will be allowed to drain from the basin to the ocean. The facility operations and maintenance team will be responsible for administering the monitoring program and maintaining the system. The Northstar NPDES permit application includes a request for coverage of deck drainage (Outfalls 003 and 004). A detailed description of anticipated deck drainage sources and processes along with mitigative measures to minimize the risk of pollutants being discharged are included in the NPDES permit application.

3.2.2 Island Surface Management

The island surface will be re-graded to the design contours on an annual basis following spring breakup. Once barge access to the island is available, earthmoving equipment will be mobilized to the island to blade and compact the surface, and the existing gravel will be re-shaped to comply with the grading plan. Should additional material be required, it will be mined at the Put 23 mine site, hauled to West Dock, and then transported via barge to the island. Some surface subsidence is expected during the first few years. The majority of subsidence is expected near the wellheads (one to two feet) immediately next to well cellars, and will pose no safety problems. Localized subsidence around the island surface should be minimal (less than six inches) and will be managed during the re-grading efforts. If necessary, the island will again be graded just prior to freeze-up each year. This will ensure that the spring runoff and snowmelt will be directed toward the catchment basins.

3.2.3 Bench - Maintenance and Repair

The linked-concrete slope protection system has been designed to minimize any maintenance activities. The entire slope-protection system will be inspected annually, both above and below waterline, during the open-water season. This inspection will document the current condition of the armor by section. The inspection will involve visual observation of the concrete mats and the linkage hardware. The annual inspection will also include profiling of the bench and below-water slopes to detect changes from the design configuration.

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

The frequency of repairs to the Northstar slope-protection system will depend on the severity of the wave and ice conditions to which it is subjected. When repairs are required, a tracked crane will be mobilized to the island along with a small crew of divers and equipment operators. The repair work will be conducted from the bench on the outside of the sheet-pile wall. The crane will work from wooden crane mats to avoid damage to the bench surface concrete mats.

Divers will map the damaged area and detach the linkages of the blocks as required. If necessary, the damaged area will be re-graded and filter fabric will be installed by crane. Replacement mats will be made up on the bench surface and lowered via crane to replace the damaged section. The damaged blocks will be removed to a permitted disposal site.

The sacrificial gravel berm at the toe of the slope has been designed to reduce damage to the concrete mat due to wave and ice impacts. This berm is not slope-protected and, therefore, is subject to erosion and relocation during major storm events.

Previous surveys of eroded gravel islands in the Alaskan Beaufort Sea (e.g. Seal Island, Mukluk Island) indicate a predominant migration of eroded gravel from the east to the west, in response to the prevailing northeasterly winds and waves during the open water season. The direction of gravel transport will reverse under the influence of major, yet less frequent, westerly storms. The loss of gravel from the submerged berm on one side of the island will add to the volume of gravel on the other side of the island (thereby widening the berm in that area). While the gravel in the deposition area will cascade downslope to cover the adjoining seabed, the gravel will remain in contact with the island. The area of previous gravel loss may later gain gravel in response to the reversal of storm wave direction. It is expected that the northeast corner of the island (where the surface width of the berm is 100 feet) will experience predominant erosion, with the resulting gravel loss moving to the west and south. Based on the predominance of the easterly winds and waves during the summer, the northeast corner of the island is expected to be the site requiring the most frequent gravel replenishment. It is not possible to predict the exact frequency of gravel berm replenishment. During calm periods, no replenishment will be required. Should major storm events occur annually, gravel berm replenishment could be necessary on an annual basis.

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

An alternative gravel berm replenishment plan would involve "backpassing", or relocating the berm gravel from areas of deposition to areas that have sustained erosional loss. This scenario would collect the gravel from sites of deposition (likely the southwest and southeast island corners) and transfer the gravel back to the site of erosion (likely the northeast corner of the island berm). A clamshell operation would be required to retrieve the gravel. The work platform for the clamshell would either be the 75-foot wide island bench during either winter or summer, or a floating barge in summer. The recovered gravel would be returned to the site of erosional loss by loaders operating on the winter ice sheet or by barge during the open water season. Should the clamshell crane be operated from the island bench, care will be taken to protect the concrete mat slope armor from track damage. Because the "backpassing" operation requires no new gravel deliveries to the island, to the extent practicable, it is the preferred operational choice.

3.2.4 Snow Removal

During the winter months, snow removal activities will be conducted on a ongoing basis. Equipment, such as front-end loaders, and personnel on the island are adequate to handle the continual snow removal requirements. Snow is also anticipated to drift on the island surface. No analysis has been performed to quantify specific locations and extent of snow drifting. As above, it is planned as part of normal operations that snow will be cleared to maintain a safe operating surface. A Standard Operating Procedures Manual (SOP) will be developed prior to operations start-up to ensure a safe operating facility.

The SOP Manual will include a section detailing snow removal and handling procedures. These procedures will include ensuring the avoidance of contaminated snow being pushed off the island. All snow will be visually inspected for contamination before removal. Snow dumping would occur around the entire perimeter, wherever access is available. It is likely that access will be most available on the south side of the island. Uncontaminated snow will be dumped off the edge of the island onto the bench or onto the sea ice, where it will be allowed to melt and run off into the ocean during breakup. Any snow found to contain contamination will go to a snowmelter and be injected in the disposal well.

3.3 FACILITIES

3.3.1 Process/Facilities

3.3.1.1 Inlet Crude Oil

The reservoir temperature is 246°F and the pressure is 5,300 psig. The surface flowing temperature is expected to be between 130° and 180°F (170°F has been assumed for process modeling), and flowing wellhead pressure is expected to be in the range of 1,200 psig. Wellhead shut-in pressure is expected to be less than 5,000 psig. Air cooling is used to reduce the produced gas temperature to increase compression capacity and NGL recovery on a year around basis. If the flowing wellhead crude temperature exceeds 170°F, the compression capacity and volume of NGLs recovered will be slightly reduced from that calculated. Likewise, if the flowing temperature is less than 170°F, compression capacity and volume of NGLs recovered will increase slightly.

Northstar crude is significantly richer in lighter ends than any of the individual streams currently entering the Trans-Alaska Pipeline, and contains only half the C30+ content of the lightest constituents in the pipeline (C30+ refers to molecules with 30 or more carbon atoms). The gravity of Northstar crude is a nominal 42° API. The oil contains 1.3% wax, and no asphaltene was detected (above experimental uncertainty). The pour point is less than -20°F, and the oil is non-Newtonian at or below 32°F. No incompatibilities were seen when Northstar crude was mixed with Endicott, Lisburne, Point McIntyre, Milne Point, or Prudhoe Bay crudes. The oil will be cooled using air coolers at Northstar before shipment. Table 3.3-1 shows the representative analysis of Northstar crude.

3.3.1.2 Outlet Oil

The sales-quality oil will meet Trans Alaska Pipeline specifications at Pump Station #1 (PS-1) including:

- True vapor pressure (maximum): 14.2 psia at delivery temperature; 14.0 psia operating;
- Temperature (maximum): 142°F;
- Temperature (minimum): 105°F;
- Basic sediment and water (BS&W): 0.35 percent;
- Pressure (minimum): 85 psig.

In order to meet the minimum delivery temperature of 105°F, the Northstar sales oil will be re-heated in a heater located near PS-1 prior to delivery.

3.3.1.3 Residue Gas Re-injection

Residue gas re-injection pressure is approximately 5,500 psig, the temperature is 140°F, and the molecular weight is 21.9. Produced gas will be dehydrated using a triethylene glycol (TEG) system to prevent hydrate formation in the surface piping and downhole, and to minimize corrosion due to carbon dioxide.

3.3.1.4 Produced Water

Produced water is treated to reduce the oil content to less than 50 ppm, and to remove dissolved gas. The produced water stream will be injected at pressures up to 3,000 psig into the disposal well.

3.3.1.5 Process Description

The facility design concept is a single production separation train with two 50 percent high pressure gas compression trains and no dedicated backup of process equipment. To minimize air emissions, facility design and selection considerations include best available control technology (BACT), new source performance standards (NSPS), maximum achievable control technology (MACT), and assurance monitoring.

Oil Treating: A mixture of oil, water, and gas is received from the producing wells in the high-pressure separator, and is separated by phase.

Sales Oil Conditioning: Light hydrocarbon components including methane, ethane, and propane are removed from the oil, and heavier natural gas liquids (NGL) including butane and pentane are mixed with the crude. NGL recovery adds about four percent to the volume of sales oil.

Sales-quality oil is cooled using air coolers before it enters the main oil pipeline to shore. Northstar will utilize only air cooling to reduce the sales crude temperature from 153°F to 50°F (annual average) for export from the island. At PS-1, it will be re-heated to 105°F (minimum) prior to delivery in order to meet TAPS specifications.

Vapor Recovery: Recovered vapor is combined with the overhead gas from the high-pressure separator.

Gas Drying: Overhead gas and recovered vapors from the high-pressure separator are combined and cooled to 80°F using air coolers. The resulting condensed liquids and gas are separated in a filter separator, with the gas being routed to a TEG contactor where water is removed.

NGL Recovery: Produced gas contains significant amounts of NGLs — primarily butanes and pentanes — which are condensed and recovered using air cooling. The recovered NGLs are stabilized and sent to the crude stabilizer for final blending with sales oil.

Injection Gas Compression: After NGLs are recovered, the residue gas is compressed for re-injection in the Northstar reservoir. This is accomplished with two gas-turbine-driven compressors (approximately 32,000 horsepower each).

Gas imported from shore via the gas pipeline arrives at the island at high pressure. This import gas stream is high-quality natural gas that has already been dehydrated with NGLs removed and compressed onshore prior to transport to the island. Once on the island, it will combine with Northstar gas at 685 psig and be further compressed to 5,500 psig for injection.

Process Utilities: Utilities supplied at the facility include instrument air, service air, nitrogen, high-pressure and low-pressure fuel-gas systems, slop oil storage, diesel fuel storage, and heating medium. Process chemical storage is identified in Section 3.5.3.8.

Flare: A flare will provide the safe and controlled release of safety emergency vents, relief-valve discharges during process upsets, maintenance blowdowns, and other releases relating to the safety of the facility and operating personnel. The smokeless flare will meet State of Alaska opacity requirements. API 520/521 guidelines will be used for vent system and flare design.

Seawater Treatment Plant: A seawater treatment plant (STP) will only be installed if make-up gas is not available, and Northstar is required to change the optimum development plan from gas cycling to the fall-back option of waterflood. The design is such that waterflood can be implemented as a future addition approximately one year after first oil start-up.

Complete facilities for gas cycling have been engineered and will be purchased. If make-up gas needed for gas cycling is not available, one of the two 32,000 HP gas re-injection compressors will not be needed. This second unit could either be canceled or the unit can be installed as a spare.

If an STP were to be installed, as a future addition, it would be packaged in truckable skids. The deaerator tower would likely be located adjacent to a skid. This work would not involve any expansion of the island working surface. A detailed description of the Northstar STP is as follows:

Feed water:	Feed water comes from the seawater intake. The flow rate is 2,551,296 gpd maximum which has been chlorinated.
Coarse strainers:	There are two cartridge type mechanical coarse strainers. One unit is in service at all times. Debris collected from the strainers will be slurried and disposed of in the disposal well.

Media filters:	There are three media filters (102-inch diameter by six feet high), two of which are in service at all times, with the third unit being backwashed. Polyelectrolyte filter aid is injected into the feed water upstream of the filters. 23,472 gpd maximum of inlet feed water is used to backwash the filters. The backwash is discharged in the combined wastewater stream to the marine outfall.
Deaerator column:	Antifoam is added to the filtered water upstream of the deaerator column. The deaerator column is a vertical tower approximately 46 feet tall and between 84 inch/144 inch in diameter. Natural gas removes dissolved oxygen from the filtered water in the deaerator column. Oxygen scavenger is injected in the column to remove trace amounts of remaining oxygen. The natural gas with oxygen is routed from the top of the column to the flare for incineration. Corrosion inhibitor and scale inhibitor are added to the treated water stream once it leaves the deaerator in route to the water surge tank.
Water surge tank:	The water surge tank is 2,000 bbl. capacity, 30 foot diameter with a 16 foot height. It is installed in the gas cycling case as the produced water surge tank. In the waterflood case, treated seawater and produced water are combined in the surge tank prior to being routed to the injection pumps.
Guard filters:	Two (2)-micron filters (two each, with replaceable cartridge elements) are installed upstream of the injection pumps preventing solids and filter media from damaging the pumps and being injected. Cartridge filter elements are disposed of by approved methods.

Injection pumps:	Injection pumps raise the treated water pressure to 3,500 psig for injection into the Northstar reservoir. In the gas cycling case there are two 1,750 HP electric motor driven pumps (440 gpm capacity each) for disposal of produced water. For the waterflood case, three water injection pumps are required for a total injection capacity of up 2,520,000 gpd.

3.3.1.6 Electrical Power

The drilling rig will provide its own power (approximately 3,000 kilowatts) using generators fired on fuel gas imported via the gas pipeline. Once the production facilities are operational, the base-load power requirements will increase to approximately 18 megawatts and will be provided by multiple gas-fired turbine generators.

Emergency power for normal operations will be provided by two 1,230-kilowatt diesel generators. Initially, both will be in full-time service for camp and construction power. These units will be installed as part of the permanent camp utility system, and will provide life support until the main process/production facilities are in service. Electrical loads are summarized in Table 3.3-2.

Uninterruptible power supply systems provide power to the control systems and switchgear.

3.3.1.7 Lighting of Island Facilities

A design requirement for lighting the island is to direct lighting to the local area where required to assure the safe operations while minimizing misdirected lighting glare to the sea. A preliminary description of general island exterior lighting is presented in Table 3.3-3.

3.3.1.8 Instrumentation and Controls

Instrumentation and controls will follow current industry practices for remote facilities. Instrumentation features will include:

- Local and remote monitoring of well, process, and safety data,
- Pipeline leak detection,
- Automatic alarms that report out-of-normal operating conditions,
- Security systems to prevent unauthorized modifications,
- Remote terminal units (RTUs) for pipeline monitoring and transmitting data,

- Standardized instrumentation for modules and equipment,
- Monitoring the position of key pipeline and well block valves, and
- Unit shutdown and emergency shutdown system capability.

Operator consoles will be located in the control room in the process module. The operating system will display process conditions and equipment status, including any alarms, trip conditions, and fire/gas detection status. Alarms will be relayed to the operator on a real-time basis, thus allowing the operator to make rounds through the plant. Emergency shutdown devices can be activated manually, both locally and remotely.

Northstar Development sales oil will be metered on site before delivery and custody transfer to the Northstar common carrier pipeline. The oil pipeline will tie-in to PS-1. A meter prover will be installed on-site to test the sales meters. A software system for pipeline-leak monitoring will continuously compare the flow rates of the on-site meter, the pipeline tie-in meter at PS-1, and the pipeline pressure profile. Automated pipeline isolation valves are located on the island, at the shore approach, and at the tie-in point. Manual valves are installed at both sides of the Putuligayuk River crossing. The position of each automated valve and the pipeline temperature and pressure will be monitored from the control room. The operator will make any necessary decision to remotely actuate the pipeline isolation valves.

3.3.1.9 Telecommunications

A SCADA radio link system will communicate between Programmable Logic Computers (PLC) in the plant and remote terminal units along the pipeline. A voice link will connect personnel on site using mobile and portable radios. Telephone voice/data/fax communications in the facility will be integrated with paging systems, and with normal telephone carriers via a microwave link. An aviation radio and marine radio at the office will handle air-to-ground and ship-to-shore communication. A remote terminal unit (RTU) at the shore approach will be powered by generators supplying batteries.

3.3.1.10 Flare

A 215 foot high, cantilevered flare tower is located in the northwest corner of the island. The flare tower has both low pressure and high pressure flare tips. The purpose of the flare is to incinerate natural gas releases resulting from the process (safety purges of equipment, glycol regenerator, STP deaerator) and from equipment being started-up / shutdown due to maintenance. A description of the flare with the predicted flame color and brightness are provided below:

High pressure (HP) flare:	The HP flare will operate only during emergency situations for short periods while process equipment is being shutdown. Pilot and purge gas will be provided continuously to the flare tip. While flaring, the flame will be smokeless, virtually transparent, and light yellow and blue in color. Luminosity will be low because the flare is expected to be virtually transparent.
Low pressure (LP) flare:	The LP flare will operate continuously through pilot and feed gas to the system. The flame will be smokeless and yellow to light orange in color. Low luminosity is expected because the flame should be virtually transparent.

3.3.2 Air Emissions

From an emissions perspective, the Northstar project consists of several separate activities that result in the emission of air pollutants.

3.3.2.1 Construction Operations

The Northstar Development Project involves various construction tasks that vary in nature and timing, most of which occur sequentially. The first major construction task involves construction and preparation of the gravel island. Another major task is the installation of the pipelines from the shore to the island.

The Northstar Development Project facility boundary, for the purpose of air quality permitting, is the edge of the gravel island at mean low low water (MLLW). All construction activities that occur within the constructed island boundary are included in the Air Quality Control permit application. A reasonable maximum case emission inventory, valid for both single-season and two year construction schedule is presented in Table 1 below:

Table 1
Summary of Annual Emissions from
Northstar On-Island Construction Emissions

(tons/year)	CO	NOx	PM10	SO2	VOC
Maximum Annual Emissions	158.5	733.5	52.5	25.7	57.7

Off-island construction activities, such as island and pipeline construction, need not be included in the Air Quality Control permit application. Under the single-season construction schedule, annual emissions are expected to be higher than for the two-year case. Overall, the emissions from these temporary activities are expected to be very similar. The emissions estimate for the single-season case is presented in the table below:

Table 2
Summary of Annual Emissions from Off-Island Construction Emissions

(tons/year)	CO	NOx	PM10	SO2	VOC
Maximum Annual Emissions	265.4	1212.9	86.5	65.0	96.2

3.3.2.2 Drilling and Production Operations

The drilling rig's function is to drill production and injection wells at the Northstar project site. Equipment required to support these operations differ significantly from equipment required for the production facilities. The drilling rig requires a source to power (prime movers) the draw-works equipment. In addition to the prime movers, drilling rigs are typically supported by a collection of boilers, heaters, cold start engines, mud pumps, cement pumps etc.

For long term operations, the primary source of power to the drilling rig will be from the production facility power turbines. When this power is not available, the drilling rig can utilize fuel gas to generate power from the prime movers to continue drilling operations.

Once fluids are produced from the production wells, the produced streams are minimally treated to separate the gas, oil and water phases. The gas will be used as fuel for the facilities sources, and excess will be re-injected into the formation. The primary sources of air emissions from the production facilities are turbines used to provide power and gas compression, backup power sources (reciprocating internal compression engines) and various small heaters and portable sources powered by IC engines.

Table 3
Summary of Annual Emissions from Long-Term Operations
(Drilling and Production)

(tons/year)	CO	NOx	PM10	SO2	VOC
Drilling Operations	2.9	13.3	1.5	2.7	0.7
Production Facilities Operations	406.6	646.7	106.5	41.1	93.2
On-Shore Facilities Operations	52.5	148.1	8.9	2.7	5.6

TABLE 3.3-1
COMPOSITION OF NORTHSTAR CRUDE

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

Heptane plus specific gravity (60°F): 0.83

Heptane + molecular weight: 187

TABLE 3.3-2
ELECTRICAL LOAD SUMMARY

AREA	MAIN GAS TURBINE POWER			EARLY DIESEL POWER (kW)
	POWER @ 480 VOLTS (kW)	POWER @ 4,160 VOLTS (kW)	POWER @ 13,800 VOLTS (kW)	
Process Equipment	3,309			
General / Utilities	3,720			
Emergency Loads	1,532			
Large Pumps		5,450		
1st Stage Compressor			3,922	
Construction Power				850*
Drill Rig Power				3,000
Total:	8,561	5,450	3,922	3,850

* Two (2) 1,230 kW diesel generators provide early construction power and emergency backup for drilling. After startup, these units will be the emergency generators for operations.

TABLE 3.3-3 GENERAL ISLAND EXTERIOR LIGHTING

ITEM OR AREA	DESCRIPTION OF LIGHTING	APPROXIMATE ELEVATION
Living quarters (PLQ)	(3) 100 watt sodium lights on west side in main entrance to PLQ.	28' elevation above MLLW
	(7) 100 watt sodium floodlights in emergency egress stairway on south side.	1 @ 24'; 2 @ 34'; 2@ 45'; 2@ 55' elevation
	(3) 150 watt floodlights in west stairway access.	
	(3) 100 watt helicopter warning lights (red lens) on south side near helipad. One of 3 warning lights on top of windsock.	60' elevation; light on windsock at 80'
	(2) 150 watt lights internal to the wind cone of windsock.	80' elevation
	(2) 1,000 watt flood lights on south side of PLQ for loading/unloading helicopter. In service only during loading/unloading operations.	49' elevation
Helipad	(16) 40 watt amber lens runway lights around perimeter of pad.	11.17' elevation (14" above surface of pad)
Utility module	(2) 150 watt sodium lights over West entrance.	34' elevation
	(4) 150 watt sodium lights on North wall of module.	3 @ 34'; 1 @ 50' elevation
Warehouse/shop	(1) 150 watt floodlight on NW corner to light fuel island.	20' elevation
	(6) 150 watt floodlights around perimeter. 2 on south, 2 on north & 2 on east side.	42' elevation
	(9) 150 watt sodium lights in stairway access (1 or 2 in each).	30' elevation. 6 on east side facing drilling
Storage tanks	(2) 150 watt sodium lights on stairway platform to diesel & potable water tanks.	35' elevation
	(1) 150 watt floodlight on diesel tank.	60' elevation
	(3) 150 watt floodlights on North side of tank platform.	35' elevation
Flare boom	(2) 100 watt helicopter warning lights (red lens).	190' elevation
Drilling rig (Nabors 33E)	(2) 100 watt helicopter warning lights (red lens) on mast.	229' elevation
	(4) 400 watt floodlights on rig.	80' elevation
	(3) 400 watt floodlights on service building.	58' elevation
	(2) 400 watt floodlights on pipe building.	37' elevation
	(12) 400 watt floodlights on production pipe rack perimeter facing drilling pad.	45' elevation
Process module	(5) 400 watt floodlights on east side facing drilling	56' elevation
	(2) 400 watt floodlights on north side	
	(2) 400 watt floodlights on north side pipe rack area	
	(2) 150 watt floodlights in stairway between process/compressor module	43' elevation
	(2) 400 watt floodlights in front of pump house & area under elevated walkway	
Gas compressor module	(2) 400 watt floodlights on north side over pad between sheet pile wall & compressor module	56' elevation
	(3) 400 watt floodlights on east side of compressor module over conex area	56' elevation
Pump house	(2) 400 watt floodlights on west side between pump house & conex units	50' elevation

3.4 PIPELINES

3.4.1 Introduction

This section presents details of the measures that will be taken and the activities that will be performed to ensure that the operation of the Northstar pipeline system is conducted with a high degree of safety and reliability.

3.4.2 Corrosion Protection

3.4.2.1 External

The potential in the cathodic protection system will be measured annually at the ends of the pipelines. If required, the system can also be tested at midpoints by measuring the potential between the pipeline and a reference electrode. In order to perform this test, the pipeline would typically require uncovering.

In keeping with North Slope practice and BPXA's specifications and procedures, the onshore segments of the pipelines will not require application of a corrosion protection coating or cathodic protection. At locations such as road and caribou crossings, the pipelines will be coated externally to prevent localized corrosion, and tests will be conducted on a regular basis to verify performance of the coating.

3.4.2.2 Internal

Considering that the transported fluids have characteristics which would not result in the corrosion of the inside wall of the pipelines (low water and sulfur content in the sales oil, and sweet and dry injection gas), an internal protective coating will not be provided. The use of inhibitors added to the fluid streams may be considered if required by the ultimate fluid properties and operation conditions.

3.4.3 Segment Isolation

To isolate segments of the pipelines in case of an accident or for the purposes of performing inspection and maintenance, valves will be installed as follows:

- ***Oil pipeline:*** Automated, quick-closure isolation valve at each terminus of the pipeline and at the mainland shore approach. Check valve at termination point to prevent back flow. Also, there are manual valves at the Putuligayuk River crossing and the pipe segment is elevated six feet above the adjacent pipe segments over the tundra in this area.

- ***Gas pipeline:*** Automated, quick closure isolation valve at each terminus of the pipeline and at the mainland shore approach.

These facilities are an integral part of the leak detection system, and tests to ensure their correct functioning will be performed on a regular basis.

In order to provide electrical isolation between the offshore segment (which is protected by a cathodic system) and the onshore segment, insulating flanges will be welded to the pipelines. The correct functioning of these devices will be tested only if evidence exists of their being damaged or their function impaired.

3.4.4 Leak Detection

The daily operation of the pipelines will be monitored on a continuous basis by the SCADA system, and operating personnel will be provided real-time information on pipeline status. In order to ensure the correct operation of the system, regular checks will be conducted on the equipment employed, including the hardware and associated software.

In addition to the valves identified in Section 3.4.3 above, the equipment involved in the leak detection system includes the following:

- Flow meters installed at the inlet and outlet of the pipelines,
- Pressure and temperature indicators at each flow meter location (to improve the response time of the system, an additional set of pressure and temperature indicators will be installed at the shore approach location), and
- A communications link with the SCADA system, capable of updating the information as required by the leak detection system.

Monitoring pipeline conditions is also an important part of leak detection. Information on pipeline condition, both with regard to vertical and horizontal position in the trench, and condition of the wall thickness will be obtained by means of pigging devices that will be run at predetermined intervals. After reviewing the results from these inspection runs, the necessary preventative and / or corrective actions can be identified and implemented, if required. In addition, BPXA will use drillholes through the ice, over the pipeline to conduct a routine survey during the winter for any evidence of hydrocarbons that could have entered the marine environment. Regular surveillance flights of the pipeline routes will be conducted in the summer.

In the event that a leak is detected, the operator will be able to determine if the leak is situated in the onshore or offshore segment of the pipeline. By following procedures which will be addressed in the Oil Discharge Prevention and Contingency Plan (ODPCP), which is presently under preparation, the required response will be initiated.

3.4.5 Pigging

Pigging will be performed for the purposes listed below. It should be noted that the activities listed will not necessarily be performed on all pipelines.

- ***Wall thickness measurement.*** This activity can be performed with uni-directional pigs equipped with ultrasonic or with magnetic flux leakage equipment.
- ***Determination of geometry*** (axial, vertical, and possibly lateral). Specialized uni-directional pigs equipped with inertial navigational and measuring equipment are required.
- ***Assessment of mechanical damage.*** Requires the use of uni-directional specialized pigs, equipped with mechanical feelers and recording equipment.
- ***Cleaning and removal of paraffin, scale, sediment, or liquids.*** This activity is normally performed by employing uni-directional or bi-directional pigs fitted with scraper cups or brushes.
- ***Distribution of inhibitor if required.*** This activity requires the use of ordinary foam pigs.

Table 3.4-1 provides details of the proposed pig runs.

For the purpose of performing the pigging activities, the oil pipeline will have pig launching facilities at Seal Island and receiving facilities at PS-1. The gas pipeline will have a pig launcher installed onshore at the gas supply point, and the pig receiver will be located on Seal Island. Transportation of the pigs and the necessary supplies to and from the island will be part of the routine island supply.

3.4.6 Maintenance and Repairs

3.4.6.1 Maintenance

The pipelines will not require major efforts to ensure that they function in a trouble-free manner. Externally, the onshore pipelines will be visually inspected along their entire lengths by using existing roads on a year-round basis where the pipelines lie along a road, or by helicopter where the pipelines lie remote from a road.

The onshore facilities containing the isolation valves, pig launchers/receivers, and associated instrumentation and controls will be contained in enclosures. Offshore, the isolation valves and the pigging facilities will be located on the island, thus assuring their integrity and facilitating maintenance.

Internally, the pipelines will be inspected using pigs as described in the preceding section.

3.4.6.2 Repairs

Onshore

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

In order to provide quick response to minor emergencies and to perform repairs to the facilities dedicated to the pipeline flow and leak detection, spare parts and replacement materials will be maintained at Seal Island. These repairs will be done by personnel employed in facilities operation. If required onshore, these personnel may be mobilized by helicopter from the production island.

Offshore

In general terms, the complexity of a repair to the offshore segment of the pipelines will increase as the water depth increases. In the shallow waters of the lagoon, a repair, performed either in the summer or in the winter, will involve considerably less effort than a repair of the same type and magnitude performed deeper offshore water.

Damage to the body of the pipeline, caused either by internal or external corrosion or by external damage, will require that the cover over the pipelines be removed, so that the magnitude of the damage can be ascertained and the repair method implemented. The repair methods consist basically of:

- Replacing the damaged pipeline section, or
- Using an external pipeline encirclement device.

Regardless of the season in which the repair is performed, the minimum steps of excavation, welding, and pressure testing will be required. Depending on the nature of the damage, services of specialist contractors and their equipment may be required to perform activities such as blocking the flow inside a pipeline by the creation of an internal ice plug. The use of divers to assist in the operations would be required, regardless of the season in which the repair work would be performed.

In summer, operations would generally be carried out from a barge or barges on which the excavation and repair equipment has been mounted. These barges and attendant vessels, which could be obtained from the Prudhoe Bay vicinity, would operate from the staging areas located on the West Dock. In winter, repair activities would be carried out from the surface of the ice, utilizing techniques and equipment similar to those employed during the construction phase.

TABLE 3.4-1
PIG RUN SCHEDULE

ACTIVITY	SCHEDULE
WALL THICKNESS MEASUREMENT PERFORMED EARLY IN THE WINTER, SUCH THAT, IF REQUIRED, REPAIRS CAN BE CARRIED OUT IN THE SAME WINTER SEASON.	START UP. EVERY TWO YEARS THEREAFTER.
PIPELINE GEOMETRY ONLY PROPOSED FOR THE OIL PIPELINE.	START UP. ONCE EVERY YEAR FOR THE FIRST 5 YEARS. EVERY TWO YEARS THEREAFTER. ADDITIONAL GEOMETRY RUNS WILL BE CARRIED OUT IF SEVERE ICE GOUGES OR STRUDEL SCOURS ARE OBSERVED AND SUSPECTED TO HAVE OCURRED.
MECHANICAL DAMAGE	START UP (Prior to initial wall thickness or geometry pig survey). PRIOR TO EVERY WALL THICKNESS OR GEOMETRY PIG RUN.
CLEANING PIGGING INTERVAL TO BE DETERMINED AFTER COMMENCEMENT OF OPERATIONS	START UP (This will be carried out as part of pipeline commissioning). FOR THE REMOVAL OF SEDIMENT IN AN OIL PIPELINE, CLEANING PIGS ARE TYPICALLY RUN ONCE A MONTH. FOR THE REMOVAL OF WATER OR LIQUID HYDROCARBONS IN A GAS PIPELINE, THE FREQUENCY IS DEPENDENT UPON THE GAS PROPERTIES. NO LIQUIDS ARE EXPECTED FOR THE DESIGN GAS DEW POINTS, COMPOSITION, AND OPERATING CONDITIONS.
INHIBITOR DISTRIBUTION	IF THE GAS LINE REQUIRES TREATMENT WITH CORROSION INHIBITOR, IT CAN BE DISTRIBUTED AROUND THE INTERNAL DIAMETER OF THE PIPELINE USING PIGS. TYPICALLY THIS IS CARRIED OUT ON THE SAME CYCLE AS THE CLEANING PIGGING. IN THIS CASE IT WILL BE EVERY MONTH.

3.5 INFRASTRUCTURE OPERATIONS

3.5.1 Introduction

The permanent quarters, temporary construction, and infrastructure support facilities at the island will be designed to provide adequate lodging, life support, waste management, and logistics support services for:

- As many as 142 personnel during the peak of construction;
- Approximately 70 to 75 personnel during the drilling and facility operations; and
- Approximately 20 to 25 personnel during the production-only phase.

3.5.2 Scope of Supply Summary

The camp and infrastructure support facilities have essentially four types of supply/transport requirements: manpower, diesel fuel, chemicals, and consumables (including perishable and non-perishable foodstuffs).

Typically, the following chemicals are required to supply the infrastructure support facilities processes:

- *Calcium Hypochlorite powder for seawater chlorination:* approximately 2 lbs./day
- *Sulfamic or Sulfuric Acid:* 50 lb/yr.
- Def*oamer:* 0.5 ppm (34 g/day)
- *Scale Inhibitor:* 15 ppm (1 Kg/day)
- *Sodium Hypochlorite for potable water:* 0.5 ppm TRC at point of consumption.
- *Calcium Bicarbonate Powder*
- *Coagulant (alum):* 2,700 lb/yr. (waterflood case only)
- *Flocculant (polymer):* 53 lb/yr. (waterflood case only)

All resupply of process chemicals can be transported in bulk during open water or when the ice road is available.

3.5.3 Detailed Description

3.5.3.1 Permanent Living Quarters

This facility will house up to 75 personnel, and will include a kitchen/dining facility, lavatories, a recreation area, medical facility, office space, laundry, etc.

3.5.3.2 Utility Module

The utility module contains facilities that handle the following functions:

- ***Potable Water.*** This facility will consist of a single distillation type desalinization water unit with a total capacity of approximately 14,400 gpd. It produces potable water for both the living quarters (9,360 gpd) and washdown water (5,040 gpd) for operations and drilling. Washdown wastewater is collected and injected directly in the disposal well and bypasses the treatment facility. This is described in the NPDES Permit Application.

- ***Emergency Power.*** This facility will consist of two diesel fueled 1,230 KW generator sets.

- ***Wastewater Treatment.*** This consists of a single fixed-media activated-sludge treatment (FAST) system that automatically treats and disinfects all domestic sewage wastewater from the island. This is an aerobic biological process that uses fixed media for bacterial growth. A disinfection system using ultraviolet lights will be placed in the discharge stream downstream of the FAST units prior to final disposal. Treated effluent is pumped through a UV sterilizer to provide for disinfection. The system handles 9,360 gpd. Once the disposal well is drilled and operational, treated sewage will be injected. Until the disposal well is available, treated sewage will be discharged through the marine outfall line.

  The Biological Oxygen Demand (BOD) values shown in the revised NPDES Permit Application are 25 mg/l maximum daily and 15 mg/l average daily (concentration). The Total Suspended Solids (TSS) values are 34 mg/l maximum daily and 25 mg/l average daily (concentration), and 1.20 kg maximum daily and 0.26 kg average daily (mass).

This system will be operated with the effluent discharged until the Class I disposal well is drilled. The disposal well will be the first well drilled, and once the well is available, wastewater effluent will be injected.

•***Helipad.*** The helipad will be a 55 feet by 55 feet area elevated +10 MLLW on the island's gravel surface above the dock in the southwest corner of the island. This area will be lighted and restricted to use as a heliport capable of handling up to a Sikorsky 76A or Bell 212 IFR-equipped helicopter.

During break-up (May/June) and freeze-up (October to December) it is planned to transport personnel and perishable freight by helicopter. Flight time between Deadhorse and the island is approximately 20 minutes.

3.5.3.3 Warehouse/Shop Facility

This pre-fabricated building will incorporate shop space and warehousing space (including hazardous materials storage).

Specific types and quantities of hazardous materials stored will be a function of day-to-day operations. In terms of design basis, there are two designated rooms for hazardous material storage in the NW corner of the warehouse/shop. Each enclosure is approximately 15 feet by 10 feet, and is designed to meet Uniform Building Code (UBC) provisions as 'control areas'. Specific quantities stored, dispensed, handled or used within the control area are limited by the UBC. Northstar's design criteria is to restrict the amounts of hazardous materials to exempt amounts per the UBC. The hazardous material storage area will have a welded steel floor with a 3 inch by 3 inch angle-iron welded all around the inside perimeter of each room. Each room has a Heating, Ventilation and Air Conditioning (HVAC) system with outside exhaust.

3.5.3.4 Communications

The communications system will consist of a communications room, a microwave communications dish, satellite communications dish, ultra high frequency (UHF) communications antenna, non-directional radio beacon (NDB) for helicopter instrument approaches, barometer for helicopter altimeter calibration, and wind velocity readout.

3.5.3.5 Diesel/Potable Water Storage Tank Module

This modularized unit will consist of a pre-fabricated steel deck that will have one 2,100-bbl water tank and one 2,800-bbl diesel tank. It is located adjacent to the utility module. Chemical storage and additional tank descriptions are discussed in Section 3.5.3.8.

3.5.3.6 Seawater Intake Structure

The seawater intake structure will be incorporated into the island dock face. The intake structure will be buried and provide housing for the seawater lift pumps and firewater pumps, as well as future waterflood needs, if required.

3.5.3.7 Marine Outfalls

The marine outfall (described as outfall 001 in the NPDES Permit Application) handles desalination brine, treated sewage (temporary), and seawater flush.. Other wastewater effluents include fire test water (outfall 002), deck drainage (outfalls 003 and 004), construction dewatering (outfall 005), and filter backwash from a possible seawater treatment plant (outfall 006). The characteristics of these effluent streams are described in Table 3.5-1.

3.5.3.8 Chemical Storage

A description of the permanent tanks for production is given below.

Bulk tanks (outside) on foundations:

T-3020	Produced water	2,000 bbl.
T-4820	Slop oil	5,000 bbl.
T-S3-1321	Potable water	2,100 bbl.
T-S3-1202	Diesel	2,800 bbl.
T6140	Well clean-up	250 bbl.

Tanks contained inside Process Module:

T4100	Biocide	90 bbl.
T4120	Glycol	250 bbl.
T4140	Demulsifier	250 bbl.
T4160	Scale inhibitor	150 bbl.
T4180	Corrosion inhibitor #1	150 bbl.
T4200	Anti-foam	100 bbl.
T6300	Corrosion inhibitor #2	150 bbl.

Tanks contained inside Warehouse/shop:

T-S3-2210A/B	Hypochlorite mix tank	50 gal. each
Drums/totes	Lube oil for mobile equipment	

Tank contained inside Utility Module:

T-S3-1401	Effluent storage tank	950 gal.

Tanks contained inside Ball Mill:

T-S3-3007	Process	150 bbl.
T-S3-3009	Injection	550 bbl.

These permanent tanks are either inside modules or are outside on self-contained skids on foundations. The floors of these modules and skids are seal welded (with a containment lip along the perimeter). Any rain, snow melt or liquid accumulation associated with the outside tanks will drain to the sump of the respective skid, where it will be pumped to the slop oil tank for separation. Likewise, tanks inside the process modules will drain to the sump of that module, which is also pumped to the slop tank or effluent tank (for injection). There will be minimal storage and handling of chemicals in individual drums.

A description of the chemical storage plans for drilling is given below. These tanks are solely for drilling support and will be de-mobilized when drilling is completed.

Drilling fluid liquid additives:

Liquid additives for the drilling fluid will be supplied in 320 gal. tote tanks, and kept from freezing in sealed, insulated containers. The containers will be able to contain 110% of the volume of the largest tank, while the hazardous liquids (corrosion inhibitors only) will use double walled tanks. Some of the non-hazardous liquids may be stored in the warehouse.

The anticipated liquid storage requirements are as follows:

Corrosion inhibitor	4 x 320 gal totes
Drilling detergent	4 x 320 gal totes
Pipe freeing agent	6 x 320 gal totes
Defoamer	2 x 320 gal totes
Lubricant	0 x 320 gal totes

Drilling fluid and cement dry chemical additives:

Cement and barite will be stored in vertical silos. These will be connected by manifold, and located in the drilling area outside the rig footprint. Approximately 50,000 cubic feet of dry bulk storage is required, equating to 23 tanks as shown below.

The size of tanks shown is dictated by tank availability:

18 dry bulk storage silos	2,350 ft^3 capacity each

5 dry bulk storage silos 1,700 ft^3 capacity each

Sacked Materials:
Polymers, salts and other sacked materials for the drilling fluid and cement will be stored in wooden boxes approximately 4'H x 4'W x 4'L, and weighing around 2,200 lbs each. These boxes, known as sea cans, will be stacked three high and stored in the drilling area outside the rig footprint. Total number of sea cans required will be approximately 750.

Lube oils for the drilling equipment:
Lubricating oils will be supplied in 55 gal. drums, and transferred with a barrel pump to dedicated storage tanks which are an integral part of the rig. These lube oils are stored inside the rig's Service Building which has a seal welded floor similar to the process modules/skids.

TABLE 3.5-1 EFFLUENT WASTEWATER CHARACTERISTICS

EFFLUENT CONTRIBUTOR	AVERAGE FLOW	TEMPERATURE	CONSTITUENTS
Seawater flush (outfall 001a)	21,600 gpd continuous flow	Amb+ 0.7°C summer Amb+ 1.0°C winter	See NPDES Permit Application (Appendix A)
Desalination (potable water) (outfall 001b)	18,060 gpd intermittent flow	Amb+ 5.0 to 7.0°C	See NPDES Permit Application (Appendix A)
Wastewater (sewage) (outfall 001c)	9,360 gpd temporary flow	16 to18°C	See NPDES Permit Application (Appendix A)
Fire test water (outfall 002)	88,200 gal. per 30 min. annual test period (no typical flow)	Ambient temperature	See NPDES Permit Application (Appendix A)
Deck drainage (outfalls 003 & 004)	25 gpd avg. est. each (50 gpd total)	Ambient temperature	See NPDES Permit Application (Appendix A)
Construction dewatering (outfall 005)	1,000,000 gpd temporary flow	Ambient temperature	See NPDES Permit Application (Appendix A)
Seawater Treatment Plant backwash (outfall 006)	31,296 gpd	4°C winter Amb+ 0.1°C summer	See NPDES Permit Application (Appendix A)

3.6 DRILLING

A total of 23 wells will be drilled for the development of the Northstar reservoir. The first well drilled will be the Class I disposal well followed by the 15 oil producers and 7 gas injectors. After these wells have been drilled it is expected that the rig will remain on the island for possible in-fill drilling or additional wells (as a result of reservoir uncertainty). There is also the possibility that a second disposal well will be required should problems arise with the first well (see Section 3.6.3.4). At present it is assumed that up to four in-fill wells will be drilled over a two year period following completion of the 23 development well program.

3.6.1 Target Locations

Target locations for the oil producers, gas injectors, and disposal well(s) are shown in Figure 3.6-1. There are two proposed waste-disposal wells illustrated (WD-1 and WD-2) but only one of these will be drilled initially (the other will be drilled only if problems arise with the first). Also shown on the figure are the Seal Island exploration and appraisal wells, A-01 to A-04, which are abandoned. The specific target locations are subject to change as additional subsurface and production data are obtained.

3.6.2 Well Slots

The *Conceptual Engineering Report (2/96)* indicated that the number of wells proposed to be drilled was 23. The latest estimate of well count is also 23, with a well mix of 15 producers, 7 injectors, and one disposal well (2 disposal wells will be permitted).

The working surface space available for well slots varies with the particular drilling rig and the specific configuration of that rig. For example, with the proposed Nabors rig 33E, there are 37 well slots that can be drilled in the rig's present configuration.

Our design objective is to permit any of four or five different North Slope rigs to drill and workover the Northstar wells. To meet this objective, approximately one-half of the work surface (210 feet by 460 feet) has been dedicated to drilling wells.

3.6.3 Well Design

3.6.3.1 Well Profiles

The well profiles have a shallow kick-off point in the surface hole to provide departure from the 10-foot well spacings at the surface, and ensure the sail angle is reached early for the extended-reach wells. The reservoir will be penetrated at the sail angle, which will be maintained below 65 degrees to allow for wireline work and facilitate completions. Through the Miluveach and Kingak shales, the sail angle will be maintained at less than 40 degrees where possible, to provide greater hole stability, even though this may result in high sail angles in the upper intermediate hole sections of some of the extended-reach wells. Table 3.6-1 summarizes the general Northstar geology.

3.6.3.2 Casing Seats

Based on the Northstar exploration and appraisal wells and Prudhoe Bay drilling practices, the following casing seats are planned for the Northstar development:

- *20" conductor:* The conductor will be driven for all wells at approximately 120 feet true vertical depth (TVD). This will be done during the island construction.
- *Surface casing:* This casing will nominally be set in the shale barrier SV1 within the Sagavanirktok Formation (4,450 to 4,650 feet true vertical depth subsea (TVDSS).
- *Production casing:* The provisional design assumes that the intermediate hole will reach section depth above the reservoir by just penetrating the Sag River formation (approximately 10,650 feet TVDSS), once the Miluveach and Kingak shales are drilled.
- *Production liner:* The well will reach total depth just into the Kavik formation, below the Ivishak reservoir, at approximately 11,175 feet TVDSS.

Tables 3.6-2 and 3.6-3 describe the casing design for an oil producer and a gas injector respectively.

3.6.3.3 Drilling Fluids

Since fresh water will not be available in sufficient quantities for drilling, muds and completion brines will be formulated using sea water which differs from current onshore North Slope practice.

3.6.3.4 Class I Disposal Well

Two Class I disposal wells are planned for Northstar Island (WD-1 and WD-2), although only one will be drilled initially (see Figure 3.6-1). The wells have approximately 1,600 feet of separation at 4,100 feet TVDSS (the top of the upper injection zone).

The well design calls for 20-inch conductor at 120 feet,13-3/8-inch surface casing set at approximately 3,750 ft TVDSS, 9-5/8" casing set at approximately 6,300 ft TVDSS with a 4-1/2-inch completion set at approximately 4,000 feet TVDSS. Although a detailed design remains to be carried out, the data presented in Table 3.6-4 outlines the assumed criteria for the wells.

The waste volumes of mud and cuttings for each type of well are listed below:

- Producer Well 8,000 bbl
- Injector Well 12,500 bbl
- Disposal Well 4,500 bbl

If the first well fails (mechanical, geological or volume at capacity), then the second well will be drilled (after having attempted workover on the first well). In the interim, wastes that would be normally disposed into the disposal well will either be temporarily stockpiled on the island for disposal at a later date and/or transported to an approved onshore disposal facility. Third party agreements are in place for Class I waste disposal at the PBU, Drill Site 3 oily waste injection well. The Underground Injection Control Permit Application, Class I Industrial Wells dated June 1996 is included in Appendix A.

3.6.4 Well Control

There are three types of development wells (oil producer, water injector and gas injector). All wells will have subsurface safety valves in the completion string and all wells will have wellheads and Christmas trees consisting of:

- master valve (manual),
- surface safety valve (actuated),
- wing valve (manual), and
- swab valve (manual).

The well cellars for all wells will be lined with an eight foot diameter culvert set in the gravel pad, then six inches of cement will be poured in the base.

The pressure regimes which exist at Northstar are normally pressured and very similar to those originally found in the Prudhoe Bay field. In the seven exploration and appraisal wells drilled to date on the structure, there have been no well control incidents or indications of shallow gas accumulations. However, for all development wells there will be a diverter installed for drilling all surface hole sections, and a Blowout Preventer (BOP) stack will be utilized for drilling all intermediate and reservoir hole sections.

The BPXA/Arco Shared Services Drilling Policy will be adhered to at all times during planning and execution of the development wells. The well control aspects of planning and drilling are covered in the BP Well Control Manual. In addition, all well control training, operational practices, procedures, rig equipment, and testing will be in accordance with Alaska Oil and Gas Conservation Commission (AOGCC) regulations. All drilling superintendents and drilling engineers will have a valid MMS Well Control certificate.

In the event that a well control incident escalates to a blowout, a relief well may be required. If the relief well is required to intersect an underground blowout, it is possible that the development drilling rig can be moved to another island slot to drill the well. Alternatively, the dock area may be able to accept either the development rig or an alternate rig for the relief well. Should a surface blowout occur, it may not be possible to utilize either the development rig or the island itself as a surface drilling location. The rig type to be utilized for this relief well will depend on the season and location in the problem well which requires intersecting. Should the island be unavailable, then man-made (Northstar Island) or natural islands (barrier islands) may be utilized or, if appropriate, a mobile structure could be mobilized.

3.6.5 Drilling Manpower

During the operations phase, regular crew changes for the drill crew and service personnel will take place by ice road in the winter and by helicopter during the rest of the year. The number of drilling personnel on the island will be approximately 50. Once the initial development drilling phase is completed, the drill crews will be demobilized. The crews will be mobilized once again for in-fill drilling programs as required. All drilling personnel will have the following training:

TRAINING REQUIREMENT	UPDATES REQUIRED	ESTIMATED TRAINING TIME (hr)
Safety Orientation/PPE	Initial	1.5
Confined Space Entry	Initial	1.5
HAZCOM	Annual	2.0
Hazardous Mats. in Workplace	Annual	1.5
Blinding (Process Line Operating)	Annual	1.5
Safe Work Practices/Permitting	Annual	1.5
Lockout/Tagout	Annual	2.0
Hydrogen Sulfide	2 yrs	2.0

TRAINING REQUIREMENT	UPDATES REQUIRED	ESTIMATED TRAINING TIME (hr)
SCBA	Annual	2.5
Ionizing Radiation (NORM)	Initial	1.0
Hearing Conservation	Annual	1.5
Fire Extinguisher (Field Training)	Annual	1.0
Atmospheric Testing Devices	Initial	0.5
Respiratory Protection	Annual	1.0
Electrical Safety (Unqualified)	Annual	1.5
Respiratory Fit Testing	3 yrs	
Pulmonary Function Test	3 yrs	
First Aid	3 yrs	4.0
CPR	2 yrs	4.0
STOP Training - Rig Supervisors	Initial	
ICS - Basic Overview	Annual	0.5
Hazwoper Level 1	Annual	1.5
Enviro 1: Achieving Enviro Excell.	Initial	1.0
Polar Bear Awareness	Initial	0.5

In addition, well control training will be in accordance with AOGCC regulations. All drilling superintendents and drilling engineers will have a valid MMS Well Control certificate.

3.6.6 Drilling Equipment and Materials

The drilling rig and its associated drilling equipment will remain on the island until the end of the in-fill drilling program after which the rig and equipment will be demobilized. Demobilization should take no longer than one week, and will involve around 60 loads.

Drilling materials will be moved to the island by ice road in the winter and by barge in the open-water season. Materials will be stockpiled on the island so that drilling can continue during freeze up and break up, when the means of supply are restricted.

TABLE 3.6-1
NORTHSTAR GENERALIZED GEOLOGY

FORMATION	TOP (FT) TVDSS	COMMENTS
Gubik	0	
Sagavanirktok	800	
Prince Creek/Ugnu	4,700	Waste Injection Zone
Schrader Bluff	6,300	
Colville Muds	6,900	Shale barrier
HRZ	8,500	
Kalubik	8,600	
Kuparuk	8,775	
Miluveach	9,125	Drilling hazard
Kingak	9,600	Drilling hazard
Sag River	10,650	
Shublik	10,750	
Ivishak	10,850	Reservoir
Kavik	11,175	Logging sump

TABLE 3.6-2
OIL PRODUCER PRELIMINARY CASING DESIGN (ULTRA-SLIM HOLE)

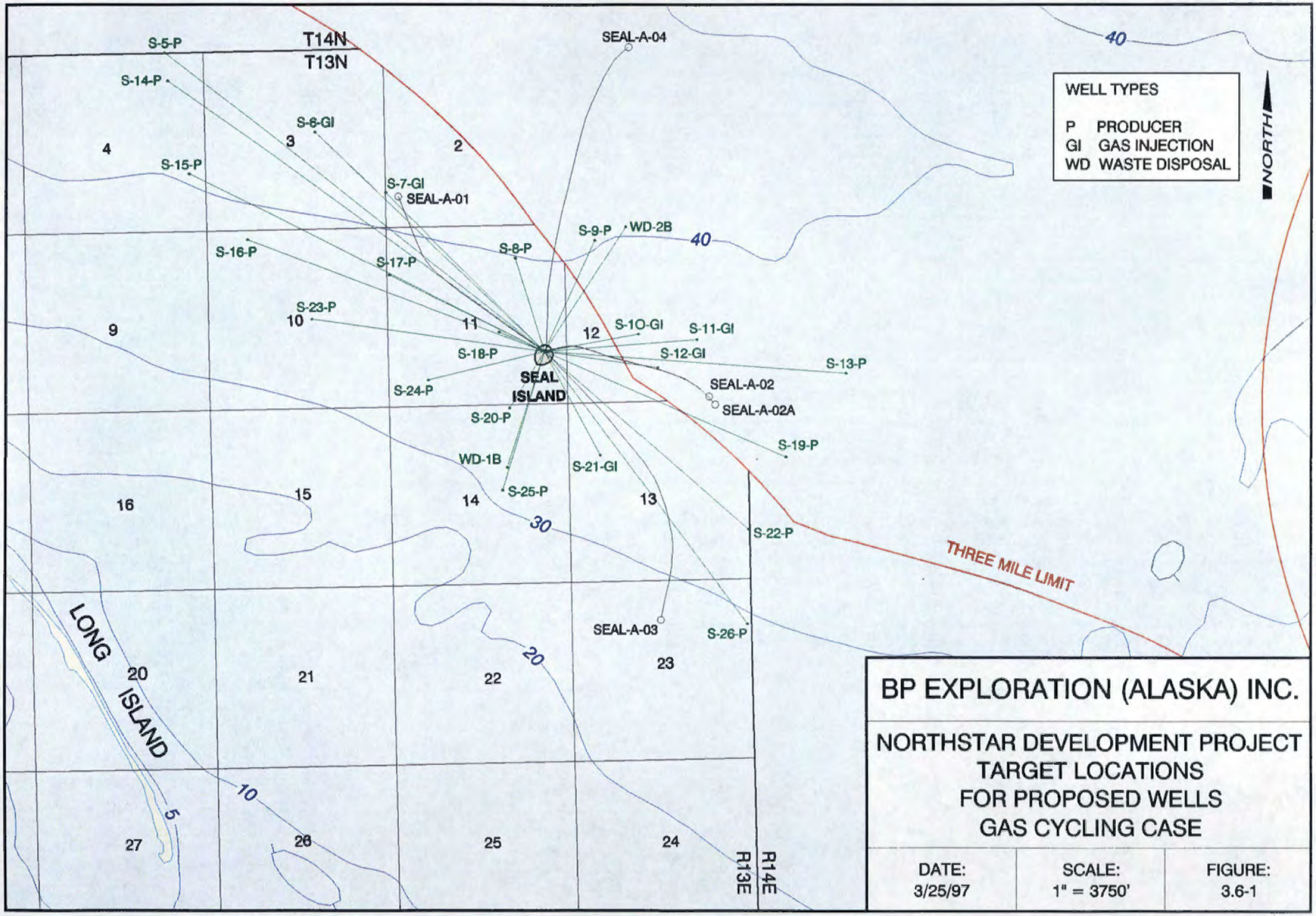
HOLE SIZE	CASING	CASING OD	FORMATION
Driven	Conductor	20"	Gubik
12-1/4"	Surface	9-5/8"	SV1 Shale
8-1/2"	Production	7"	Sag River
6"	Production liner	4-1/2"	Kavik

TABLE 3.6-3
GAS INJECTOR PRELIMINARY CASING DESIGN (BIG BORE)

HOLE SIZE	CASING	CASING OD	FORMATION
Driven	Conductor	20"	Gubik
16"	Surface	13-3/8"	SV1 Shale
12-1/4"	Production	9-5/8"	Sag River
8-1/2"	Production liner	7"	Kavik

TABLE 3.6-4
NORTHSTAR CLASS I (INDUSTRIAL) DISPOSAL WELL DESIGN CRITERIA

CRITERIA	WD-1	WD-2
Azimuth (approx.)	N220E	N48E
Kick-off point	500 ft subsea	500 ft subsea
Sail angle	40 degrees	45 degrees
Drop in sail angle at ± 4,200 ft TVD	± 25 degrees	± 25 degrees
Total depth	6,500 ft subsea	6,500 ft subsea
Well separation	± 2,100 ft	Best possible
Top upper confining zone (Top SV6 Shale)	3,010 ft subsea	3,010 ft subsea
Base upper confining zone (Base SV6 Shale)	3,300 ft subsea	3,300 ft subsea
Upper injection zone (Top SV2 Sand)	4,000 ft subsea	4,000 ft subsea
Lower injection zone (TMBK Marker)	4,730 ft subsea	4,730 ft subsea
Liner setting depth	± 6,300 ft subsea	± 6,300 ft subsea
Well total depth	± 6,500 ft subsea	± 6,500 ft subsea
Lower confining zone (Top Seabee Shale)	6,880 ft subsea	6,880 ft subsea



BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
TARGET LOCATIONS
FOR PROPOSED WELLS
GAS CYCLING CASE

DATE:	SCALE:	FIGURE:
3/25/97	1" = 3750'	3.6-1

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3.7 RESERVOIR

The Northstar field, discovered in 1983 by Shell Oil Company, is a hydrocarbon accumulation located approximately six miles offshore in the Beaufort Sea, north of the Prudhoe Bay field. Shell and Amerada Hess appraised the discovery by drilling five wells and obtaining two-dimensional seismic data. The wells were drilled from two manmade gravel islands in approximately 40 feet of water.

3.7.1 General Reservoir Description

The giant Alaskan oil fields, including Prudhoe Bay and Kuparuk, lie along the geologic structure known as the Barrow Arch, which trends northwest-southeast. This arch is bounded to the north by a rift margin, which deepens into a true rift in the present-day offshore region. Northstar is located among the down-stepping faults of the rift margin. It is a gently dipping (less than three degrees) faulted anticline trending northwest-southeast. The reservoir formation is the Prudhoe Bay member of the Ivishak Formation of the Sadlerochit Group, which is the same reservoir as the 20-billion-plus-barrel oil-in-place Prudhoe Bay field. At the Northstar location, the Ivishak is 325 feet of mostly pebbly sandstone and pebble conglomerate. The pebbles are mostly chert, some of which is microporous; and the sands are mostly quartz. The lower parts of the reservoir are marine deltaic deposits, which grade upward into braided fluvial deposits.

Ivishak sediments at Northstar are coarser grained and more cemented than the sediments in the Prudhoe Bay field, with lower porosities and permeabilities. The Northstar oil leg is approximately 260 feet thick, with an oil/water contact estimated to be at 11,100 feet subsurface and a predicted gas/oil contact at 10,839 feet.

The Sag River Formation, which is a secondary reservoir target at Prudhoe, appears to be very tight at Northstar (approximately one millidarcy) and was never tested. Upside reserves at Northstar could be improved if a way can be found to make the Sag River productive.

The Northstar crude is very light (42° API), volatile, with viscosity around 0.14 centipoise, and a favorable water/oil mobility ratio. The oil is slightly under saturated (reservoir pressure = 5300 psig. and bubble pressure = 5100 psig.) Initial gas/oil ratios were approximately 2200 scf/stb. Wells are expected to have productivity in the range of two to four stock tank barrels (STB) / psi drawdown. The Northstar oil is very different from the heavier oils found to the south in Prudhoe Bay (26° API). No gas cap has been proven to exist, but it has been predicted from RFT and PVT data that a small gas cap (<3% HCPV) may exist.

3.7.2 Reservoir Characteristics

3.7.2.1 Trap

The Northstar prospect is defined by three-way dip closure on the east, west, and south, with fault seal and dip closure on the north. The most likely area of the reservoir is approximately 9,000 acres.

Seismic-based structural mapping by BPXA, Shell, and Amerada Hess all show the prospect to be a faulted, low-relief anticline. It is uncertain how separate the Northstar Island area is from the Seal Island area. The structure is a relatively simple fault block tilted towards the northwest, and becomes a more complex faulted anticline to the southeast. The bulk of the reserves are to the southeast in the Seal Island area. Faults that juxtapose Ivishak on Ivishak are probably not sealing. In the Prudhoe Bay field, the faults more commonly act as high-permeability thieves and fluid conduitsthat adversely affect reservoir performance. Knowledge of the location of faults is important for development.

3.7.2.2 Depletion Plan and Reserves

The Northstar reservoir contains an estimated 260 million barrels of original oil in place. Optimal recoveries at Northstar are obtained with pressure support from water and/or gas injection. The two mechanisms offer different advantages but higher recoveries are obtained from the 100% gas cycling process.

In the waterflood case, seawater and produced water would be injected into six water injection wells located at the periphery of the field. In addition, 95% of the produced gas (remainder used for fuel) is compressed to 5,500 psig and re-injected at the crest of the structure. Water injection is required in addition to 95% of produced gas re-injection to maintain reservoir pressure and optimize recovery. Based on reservoir simulation studies and field analogs (Prudhoe Bay) recoveries in the range of 51% to 61% can he expected with waterflood and 95% of produced gas re-injection.

Higher recoveries can be attained with a 100% gas cycling process and the Northstar facility design is hased on gas cycling (with capability to fall-hack and implement waterflood should an outside source of make-up gas be unavailable). Reservoir recoveries with pure gas cycling range between 56% and 66%. In this case, instead of using water, make-up gas is imported to the island and injected to maintain reservoir pressure and to optimize recovery. Recovery improvement occurs as a result of transfer of hydrocarbons from the in-situ oil phase to the injected gas phase. Laboratory slim tube experiments conducted at reservoir conditions with Northstar crude and reservoir simulation studies have both shown the gas cycling mechanism to be highly efficient. The strong interactions between the Northstar oil and the injected lean gas can result in additional recovery. Other benefits include, a reduction in operating cost due to reduced water handling facilities, and not requiring a seawater treatment plant. Gas cycling is the optimal development plan. It provides up to a peak of 65,000 barrels oil per day (BOPD) production rate, while waterflood provides a 50,000 BOPD peak rate. Although there is no water injection some water production is expected, particularly from the periphery wells that will be completed close to the oil-water-contact (OWC). Produced water will be injected into the disposal well.

The source of make-up gas for Northstar will be residue gas (natural gas liquids having been removed) purchased from the Prudhoe Bay Unit. The tie-in point for delivery to the Northstar gas pipeline will be the CCP. Northstar presently does not know the cost to the project of make-up gas as negotiations are on-going and a formal agreement has not yet been signed.

The Northstar facilities are designed to allow waterflood to be implemented as a fall-back option if make-up gas is not available. Gas cycling for Northstar is more economically attractive than waterflood since it adds reserves, accelerates production, and reduces maintenance and operating expenses.

BPXA has sanctioned Northstar based on a most-likely recoverable reserves of 145 million barrels.

DECOMMISSIONING and ABANDONMENT

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

4. DECOMMISSIONING AND ABANDONMENT

Detailed plans for the decommissioning of Northstar would be prepared near the end of field life. Decommissioning would be conducted in accordance with the provisions of Federal, State and local laws, regulations, and permit conditions. In general, the applicable laws and regulations provide for discretion with respect to rehabilitation requirements in such agencies as the Alaska Department of Natural Resources (Commissioner) and the U.S. Army Corps of Engineers (District Engineer). This flexibility allows for consideration of the environmental effects of decommissioning relative to leaving certain facilities in place and other site-specific factors. Decommissioning may involve removal and salvage of offshore and onshore surface facilities and equipment. Subsurface pipelines may be purged, plugged, and left in place. The gravel island may be abandoned in place with some slope protection removed allowing the island to erode. The actual method of island abandonment would have to be determined through an assessment of the environmental effects of the alternatives.

SCHEDULE

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

5. SCHEDULE

5.1 PURPOSE

This section provides a description and rationale for the proposed seasonal scheduling of construction activities (independent of the one or two season alternatives), and comparative descriptions of the single season and two season construction programs are summarized in Figures 5.3-1 and 5.3-2 respectively. Both single season and two season construction alternatives are described throughout this document. BPXA will carry forward both alternatives for planning purposes until greater clarity is provided with respect to external factors affecting project scheduling.

5.2 CONSTRUCTION STRATEGY

The overall construction strategy for the Northstar project is to use the winter construction season to its maximum advantage allowing the use of conventional or adapted onshore construction equipment and techniques. The limited open water season in the Beaufort Sea combined with its remoteness and reduced accessibility with respect to mobilizing marine equipment (e.g. pipe laying vessels, ocean-going barges) makes construction significantly more expensive, extends project execution schedules and entails some risks with respect to equipment mobilization and construction windows.

5.2.1 Ice Road Construction

Ice road construction would commence in December to support onshore and offshore pipeline construction, mine site access and gravel haul, and island construction. The pace of this activity is dependent upon weather, particularly low air temperatures (best when sub-zero degrees Fahrenheit). The use of ice roads allows on-ice trench excavation and pipe laying activities, and the bulk truck haulage of gravel and other materials to the island and pipeline route locations with virtually no impact to the marine or terrestrial environments. Ice road routes are shown in Figure 2.1-6.

5.2.2 Mine Site Development

The proposed Northstar gravel mine site, as described in Section 7, provides the most logistically favorable gravel resource location to the project. Winter mine site development and closure provides the most logistically and environmentally preferable method for developing a new gravel resource for the project.

5.2.3 Island Construction

The Northstar Development Project is a stand-alone, self-contained, offshore drilling and production facility located on a gravel island which will include all support infrastructure and necessary facilities. This island will be built over the existing Seal exploration island with the gravel haul and placement occurring during the winter construction season. BPXA has no proposal nor contingency plans for summer island gravel placement in the event that adverse weather or ice conditions preclude completion of these activities in winter. If work is incomplete at end of winter, BPXA will finish the island the following winter thereby incurring a year's delay to the project.

The work on the island, once the gravel is placed, will involve installing the spread footing foundations and sheet pile for the island perimeter which will be completed by August 15. The other activities will involve placement of the island slope protection, which consists of linked concrete mats. These materials will be transported by ice road in late winter or by barge from West Dock during the open water season.

BPXA's winter island construction plan introduces certain risks to the development schedule, but BPXA believes it is the alternative offering the greatest control of non-project related constraints and the alternative with possibly the least impact on the environment. Risks to construction include a late winter or early break up that could reduce the winter construction season window.

Gravel hauling and placement, installation of island slope protection, plus the installation of modules and mobilization of the drilling rig would be nearly impossible in a single open water season. Island construction in the open water season requires mobilization of ocean going barges from the Lower 48. Gravel haul would involve a two stage operation with trucks transferring to barges at West Dock or other locations. This would incur a significant cost premium to the island construction. Winter island gravel construction allows the use of conventional construction equipment that is readily available in the Prudhoe Bay area.

5.2.4 Pipeline Construction

As with the gravel island construction, pipeline construction is only planned as a winter operation. In the event that adverse weather, ice conditions or other factors preclude installation or completion of the Northstar pipelines in winter, installation or completion of those pipelines would be conducted in the following winter season. No offshore summer season pipeline installation is planned as a contingency. Technical Note (TN) 750, Open Water Contingency, that was submitted to the Joint Pipeline Office (JPO) is no longer applicable.

Two pipelines are planned for the Northstar Development. The crude oil sales line will be a 10-inch line running from the island to a tie-in at Pump Station 1 (PS-1). A 10-inch gas line to supply gas to the island will begin at the Prudhoe Bay Unit (PBU) Central Compressor Plant (CCP).

Preparatory work, such as road and caribou crossings, will be performed in the summer. The remainder of the construction activities will take place in winter.

The onshore pipeline construction will start in December and be completed in May. Ice roads will be built to access the pipeline routes during construction.

The offshore portion will be six miles in length and will be constructed between December and April. The crude oil sales and supply gas pipelines will be buried together in a common trench and backfilled. The trenching will be done from thickened ice using excavation and other construction equipment.

The proposed winter Northstar offshore pipeline installation techniques are essentially adaptations of onshore construction and installation technology utilizing conventional construction and pipe laying equipment. Marine pipeline installation, though technically feasible, necessitates mobilization of equipment from the Lower 48 or overseas requiring transit into the Beaufort Sea during the open water season. Because of the mobilization distance and limited access season to the Beaufort Sea, marine (open-water) construction ties up equipment for up to a year with a significant cost premium relative to winter construction. Laying pipeline inside the barrier islands in the open water season would require extensive seabed excavation to accommodate the passage and working of shallow draft construction vessels. As with gravel island work, summer pipeline construction may be environmentally less preferable than winter construction.

5.2.5 Facilities Sealift Installation

The timing of module installation is tied to the fact that the modules have to be transported by sealift from their tidewater fabrication location in Anchorage to Seal Island. In the remote event that access to the Beaufort Sea is precluded by sea ice during the open water season (e.g. at the Point Barrow pinch point), project start up could be delayed one year although island construction and drilling could continue.

5.2.6 Drilling

In the single season program, the drilling rig will be barged to Seal Island after the modules are off-loaded. Drilling will commence as soon as construction equipment has been demobilized from the island. An early freeze-up could reduce ability to stockpile drilling supplies on the island and drilling operations would be curtailed until an ice road was available for transport of drilling supplies. This could result in a delay of first oil production. These risks are compounded by a single season construction schedule due to logistics of mobilizing the drilling rig to the island at the same time as module installation (and demobilization of slope protection equipment) is occurring. In the two season scenario the rig would be mobilized over an ice road in the winter in the year following island completion.

5.3 ONE AND TWO SEASON ALTERNATIVES

Figures 5.3-1 and 5.3-2 provide a summary of the construction activities and scheduling for single season and two season construction programs respectively. BPXA's preferred program is to conduct construction in two seasons thus separating island construction and pipeline installation. This reduces logistical problems and schedules construction work more efficiently. However, a single season may be required as a result of permit scheduling and/or other factors external to the project. Further schedule and activity descriptions are provided in the various topical chapters of this document. Additional information on the rationale for the alternatives considered and deleted with respect to construction techniques and scheduling is available in the Northstar Development Project Conceptual Engineering Report that was submitted to Dames & Moore and the EIS team in February 1996.

5.3-1 Single Season Construction Schedule

Figure 5.3-1 shows the optimum scenario for a one year construction schedule of the Northstar project. As shown all major construction work, including island construction, onshore and offshore pipeline installation, and module installation and hook-up, will all occur within one year. The only exception to this will be the installation of road and caribou crossings, which will take place during the third quarter of the previous year.

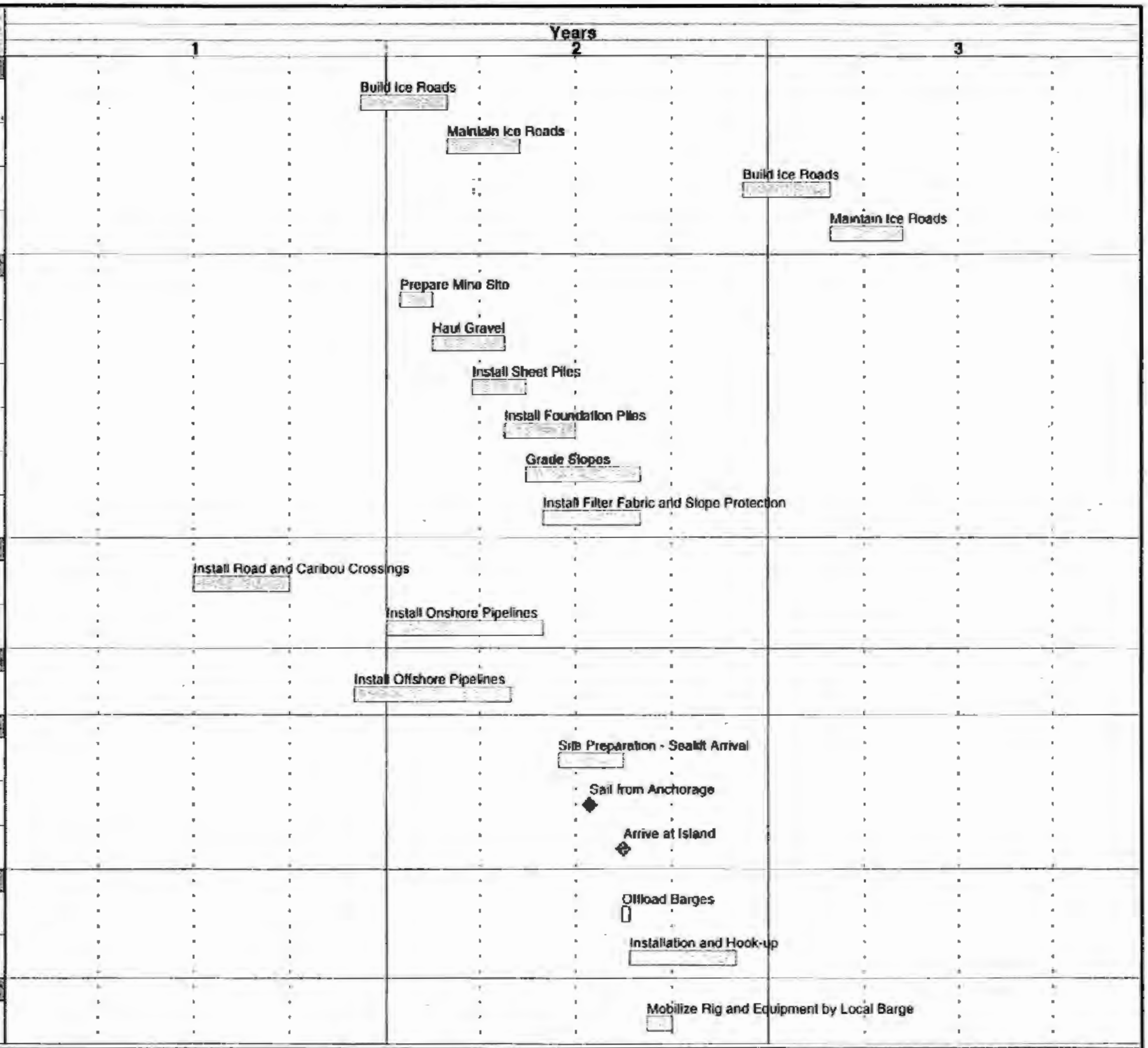
Ice roads for use in the construction of the island and installation of the offshore pipeline will be built and maintained in the winter. These roads will be reconstructed in the winter of the following year to allow supply of consumables during the drilling effort. The drilling effort will start in the first year with the mobilization of the rig and associated equipment by barge in late summer. Immediately following the mobilization of the rig, drilling will commence and will continue forward, with first oil expected late in the first quarter of the following year.

5.3-2 Two Season Construction Schedule

Figure 5.3-2 shows the optimum scenario for a two year construction schedule of the Northstar project. As shown, all work associated with construction of the island and installation of the infrastructure facilities will occur within a single year. Installation of road and caribou crossings will take place during the third quarter of the same year. This leaves the installation of the onshore and offshore pipelines, transport, installation and hook-up of the process modules, and drilling mobilization in the following year.

Ice roads for use in the construction of the island will be built and maintained in the winter. Ice roads to the island will be constructed in the winter of the following year to allow for installation of the offshore pipelines, mobilization of the rig and associated equipment and supply of consumables for the drilling effort. Immediately following the mobilization of the rig, drilling will commence and will continue forward, with first oil expected early in the first quarter of the following year.

ACT. ID	ACTIVITY DESCRIPTION
Ice Road	
01-010	Build Ice Roads
01-020	Maintain Ice Roads
01-030	Build Ice Roads
01-040	Maintain Ice Roads
Build Island	
02-010	Prepare Mine Site
02-020	Haul Gravel
02-050	Install Sheet Piles
02-060	Install Foundation Piles
02-070	Grade Slopes
02-090	Install Filter Fabric and Slope Protection
Onshore Pipelines	
03-010	Install Road and Caribou Crossings
03-020	Install Onshore Pipelines
Offshore Pipelines	
04-010	Install Offshore Pipelines
Sealift Modules	
05-010	Site Preparation - Sealift Arrival
05-020	Sail from Anchorage
05-030	Arrive at Island
Module Installation	
06-010	Offload Barges
06-020	Installation and Hook-up
Drilling	
07-010	Mobilize Rig and Equipment by Local Barge



Early Bar
Progress Bar

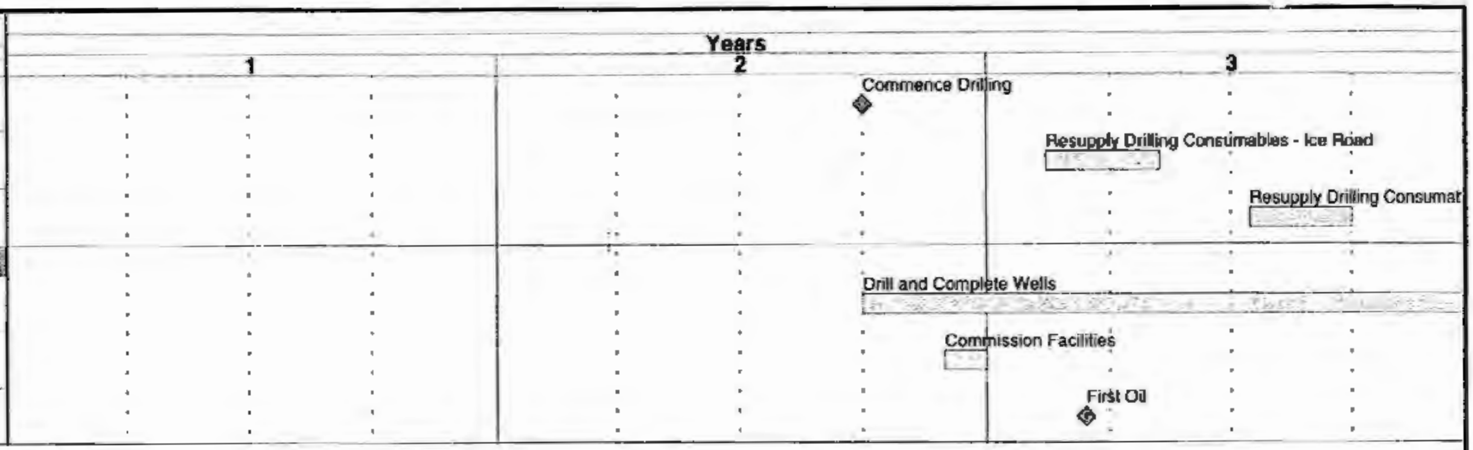
Plot Date 26MAR97

0531

Sheet 1 of 2

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-1 Single Season Program

ACT. ID	ACTIVITY DESCRIPTION
07-020	Commence Drilling
07-030	Resupply Drilling Consumables - Ice Road
07-040	Resupply Drilling Consumables - Barge
Operations	
08-020	Drill and Complete Wells
08-010	Commission Facilities
08-030	First Oil



Early Bar
Progress Bar

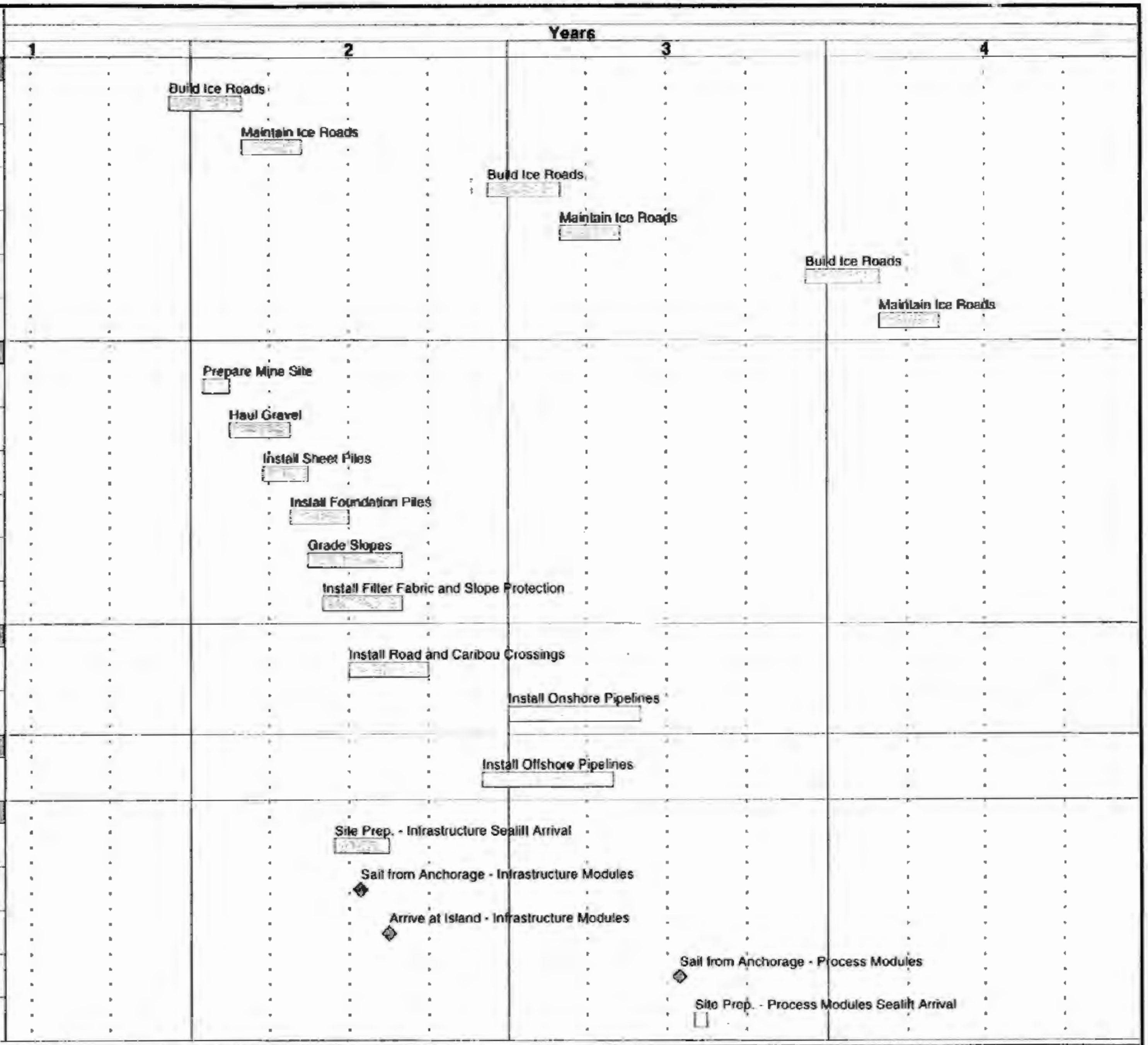
0531

Sheet 2 of 2

Plot Date 25MAR97

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-1 Single Season Program

ACT. ID	ACTIVITY DESCRIPTION
Ice Road	
01-010	Build Ice Roads
01-020	Maintain Ice Roads
01-030	Build Ice Roads
01-035	Maintain Ice Roads
01-040	Build Ice Roads
01-050	Maintain Ice Roads
Build Island	
02-010	Prepare Mine Site
02-020	Haul Gravel
02-050	Install Sheet Piles
02-060	Install Foundation Piles
02-070	Grade Slopes
02-090	Install Filter Fabric and Slope Protection
Onshore Pipelines	
03-010	Install Road and Caribou Crossings
03-020	Install Onshore Pipelines
Offshore Pipelines	
04-010	Install Offshore Pipelines
Sealift Modules	
05-010	Site Prep. - Infrastructure Sealift Arrival
05-020	Sail from Anchorage - Infrastructure Modules
05-030	Arrive at Island - Infrastructure Modules
05-050	Sail from Anchorage - Process Modules
05-040	Site Prep. - Process Modules Sealift Arrival



Plot Date 31MAR97

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Early Bar
Progress Bar

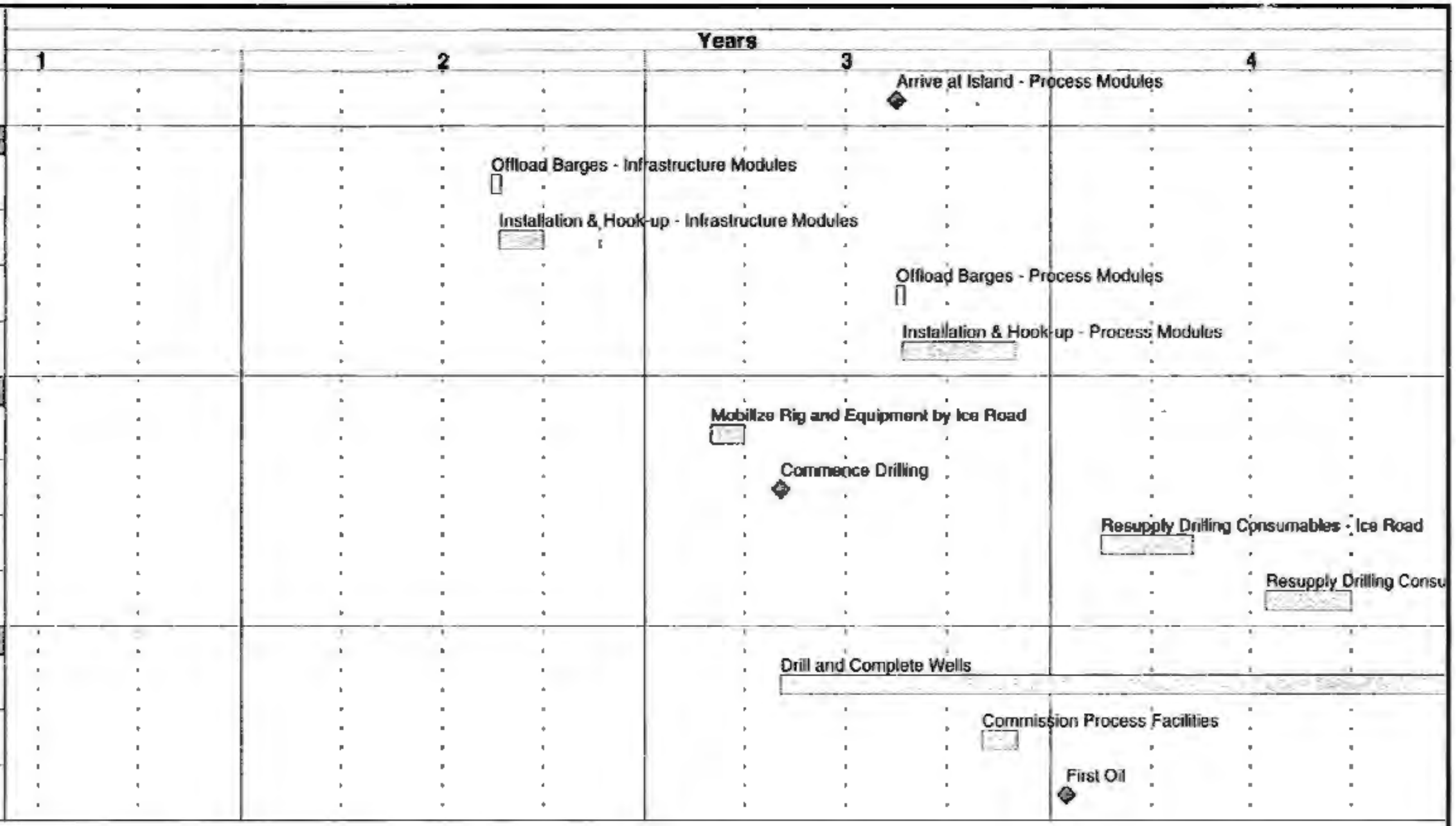
0532

Sheet 1 of 2

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-2 Two Season Program

BP

ACT. ID	ACTIVITY DESCRIPTION
05-060	Arrive at Island - Process Modules
Module Installation	
06-010	Offload Barges - Infrastructure Modules
06-020	Installation & Hook-up - Infrastructure Modules
06-040	Offload Barges - Process Modules
06-050	Installation & Hook-up - Process Modules
Drilling	
07-010	Mobilize Rig and Equipment by Ice Road
07-020	Commence Drilling
07-030	Resupply Drilling Consumables - Ice Road
07-040	Resupply Drilling Consumables - Barge
Operations	
08-020	Drill and Complete Wells
08-010	Commission Process Facilities
08-030	First Oil



Plot Date 31MAR97

Early Bar
Progress Bar

0532

Sheet 2 of 2

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-2 Two Season Program

WASTE MANAGEMENT PLAN

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

6. WASTE MANAGEMENT PLAN

BPXA has nearly 20 years of operating experience on the North Slope of Alaska as operator of the Prudhoe Bay Unit Western Operating Area, Milne Point Unit, and Endicott, as well as over 30 years of oil and gas exploration experience in the Arctic. As a result of this experience, BPXA has developed and implemented numerous waste management techniques designed to minimize, or in some cases eliminate, discharges of wastes to the environment. At all times, the primary consideration in waste management strategy has been compliance with all applicable federal, state, and local government requirements.

For the Northstar project, there are several environmental considerations that must be factored into the design for the island and associated facilities. The waste management strategy must address disposal of domestic and production waste streams at a small offshore facility, seasonal availability of some disposal options, alternatives for waste disposal should a primary system not be available, disposal of wastes uniquely associated with oil and gas production and related processes, and changes in types and quantities of wastes during construction and operations. Past experience regarding waste minimization, product substitution, beneficial reuse, and recycling will be an integral part of BPXA's overall waste management strategy for the Northstar Development Project.

The following sections describe the general waste management approach BPXA will follow during construction, drilling, and production operations of the Northstar Development Project. First, the major regulatory considerations are reviewed and then BPXA's approach to meet those regulatory requirements are presented. Section 6.2 provides a listing of the kinds of wastes anticipated for the Northstar Development Project with a brief description of the waste handling approach for the wastes.

6.1 MANAGEMENT APPROACH

6.1.1 General

BPXA's strategy for Northstar Development Project waste management consists of waste minimization to the greatest extent possible coupled with onsite disposal wherever practical. The design considerations associated with implementing this strategy include site access, onsite storage capability, and regulatory compliance.

Site access mechanisms vary based on the time of year, and may be severely limited with regard to hauling waste off site during certain portions of the year. During the open water season, access to and from the facility will be by vessel. During the winter months, access will be via an ice road to the site. During both of these times of year, hauling of waste off site is possible, but not necessarily the most cost effective option. In the spring and fall (breakup and freezeup), access to the island will be limited to helicopter transportation. During these times, waste which could not be managed onsite may have to be stored for transportation to other BPXA disposal facilities during the summer and winter travel periods.

Due to the relatively small size of the island, onsite storage of waste material will be limited. As such, onsite disposal options discussed in this Waste Management Plan will be utilized to the fullest extent practical.

The final factor in design considerations associated with Northstar waste management is regulatory compliance. It is BPXA's policy to employ waste minimization techniques to the greatest extent possible in our North Slope operations and that there will be no discharge of drilling wastes or produced fluids to the marine environment. From a permitting perspective, two primary permitting activities are being conducted to achieve BPXA's waste management strategy for this project.

The first of these activities includes permitting two Class I non-hazardous waste disposal well locations. The availability of a Class I disposal well will enable the Northstar facility to handle essentially all of the drilling waste as well as facility-generated wastewater onsite as opposed to transporting this material to other North Slope facilities. A grind and inject facility is being incorporated into the facility design to facilitate handling of drilling muds and cuttings. The UIC Class I Industrial Well permit application was submitted to the U.S. Environmental Protection Agency (EPA) for review and approval on June 25, 1996.

The second major waste disposal permitting activity is that of obtaining the National Pollutant Discharge Elimination System (NPDES) Permit. The NPDES Permit Application was submitted to the EPA for review and approval on February 4, 1997. The permit application addresses all effluent streams expected to result from the Northstar Development Project. The effluents will include temporary camp domestic and sanitary waste water during construction since the Class I disposal well is not expected to be complete during this phase of the project development, desalination unit wastes and sea water treatment plant backwash (possible future). BPXA also anticipates occasional discharges associated with testing the fire control system as well as sanitary and domestic wastes associated with the camp during the occasional times when the Class 1 disposal well is not available for injection. Storm water runoff will be permitted under the NPDES Permit as deck drainage. Except for permitted NPDES discharges associated with the Northstar facility, no process streams will be designed to discharge into the environment. The majority of facility operations will be located in modules or containment areas where there is little risk of a release.

This Waste Management Plan describes waste disposal options for waste generated during Construction, Drilling, and Operations phases of the Northstar Development Project based on the strategy and design considerations outlined above.

6.1.2 Construction

Winter construction operations will utilize ice roads and the existing Prudhoe Bay gravel road infrastructure to provide access between the construction locations and existing North Slope waste management facilities. Wastes generated during the initial construction stages of the project will be backhauled to waste injection facilities for disposal.

Wastes generated during island construction activities during open water will be consolidated onsite and transported to shore and managed at approved facilities or stored onsite until access is available.

Additional options for waste disposal will become available as the Drilling and Facility Operations phases of the project progress.

6.1.3 Drilling

Due to limitations on space available, onsite disposal options for the disposal of drilling wastes will be used to the fullest possible extent. Onsite disposal options include a disposal well, a cuttings grind and inject unit, annular injection, and an incinerator.

A Class I disposal well is the first well scheduled to be drilled. As a contingency, if the Class I permit is not received by the time the well is completed, plans will be in place to permit the well as Class II until the Class I permit is issued. The Class I well will be authorized to receive all non-hazardous Class I fluids and all Class II fluids. A Class II well will be restricted to Class II fluids only. In both cases, operational restrictions on the well may place physical or chemical restrictions on the type of material approved for disposal.

6.1.4 Facilities Operations

Due to limitations on the space available, onsite disposal options will be used to the fullest possible extent. Onsite disposal options include a disposal well, a cuttings grind and inject unit, and an incinerator. Waste material that must be transported off the island for disposal will be transported by vehicles using ice roads during the winter months and vessels during the summer open water period. During breakup, this material will be stored until transport options are available or carried to shore using alternative means of transportation, such as helicopters.

It is anticipated that by the time the Facility Operations phase has commenced, the Class I Disposal Well permit will be in-hand. If the permit has not yet been obtained, Class I fluids will either be reused in the drilling process, back hauled to existing North Slope facilities, or temporarily stored on site until the permit is obtained.

The Class I well will maintain stringent operational and record keeping requirements as mandated by the U.S. Environmental Protection Agency (EPA). A Waste Analysis Plan which, will include information on waste tracking and waste identification, will be submitted for approval to the EPA prior to commencement of Class I disposal operations.

6.2 DISPOSAL OPTIONS

The following discussion of waste disposal options for specific wastes is for all three phases of the Northstar Development Project unless identified otherwise by waste type.

6.2.1 Non-Hazardous Solid Waste

Non-hazardous solid waste consisting of trash, food wastes, wood debris, metal debris and construction debris, during the construction phase, will be segregated onsite at main collection points into burnables and non-burnables and recyclable scrap and stored in designated dumpsters. Burnables will be transported to processing facilities in Deadhorse or incinerated at Seal Island in a permitted incinerator. Non-burnables and recyclable scrap will be transported to Deadhorse facilities for processing.

6.2.2 Oily Trash

Non-hazardous oily trash consisting of oily rags and sorbents, drained oil filters, rags and sorbents with non-hazardous chemicals, oily pit liners, empty oil and grease containers, and oily debris will be collected and stored onsite in designated lined and labeled dumpsters. The waste will be incinerated onsite in a permitted incinerator or transported to Deadhorse facilities for processing.

6.2.3 Oily Solids from Vessels

During the facilities operations phase, oily solids from process tanks, vessels, and lines will require handling and disposal. The oily solids will be slurried and disposed of in the disposal well or transported to other North Slope facilities for management. These types of solids are exempted from hazardous waste determination and will not be tested prior to disposal.

6.2.4 Drilling Mud

Drilling mud generated during drilling operations at Northstar will either be disposed of in the permitted Class I disposal well or through annular injection. If neither of these options is available (e.g., for the very first well drilled), mud may be stored onsite until disposal is available or transported to existing Prudhoe Bay facilities for disposal, such as the CC-2A grind and inject facility.

6.2.5 Drill Cuttings

Surface hole drill cuttings generated during drilling operations will either be crushed, ground and injected in a slurry into the disposal well. Below surface hole cuttings will be ground and injected in a slurry to the disposal well or into a well annulus. Cuttings may be temporarily stored until disposal option becomes available.

6.2.6 Non-Hazardous Class I Fluids

Until onsite Class I fluid disposal is available, non-hazardous waste fluids, including certain chemicals, tank rinse, sump fluids, and contaminated snow melt, generated during construction will be transported to existing North Slope facilities for disposal under third-party use agreements. Approval from the disposal facilities will be obtained prior to transport. Temporary onsite storage consisting of portable tanks or tank trucks may be necessary while approvals are acquired.

After initiation of the drilling phase of the Northstar Development Project, fluids will be evaluated for reuse in the drilling process. The Class I well will be utilized for disposal of non-hazardous Class I fluids after the Class I permit is obtained. All materials will be documented to be non-hazardous prior to disposal.

6.2.7 Class II Fluids

Class II fluids, defined as those fluids originating in the well bore such as produced water, well returns from workovers and fluids generated from process vessels will be disposed of in the disposal well. These types of fluids are exempted from hazardous waste determination and will not be tested prior to injection. Certain fluids, such as mud and slurried cuttings, may be disposed of through annular injection.

All volumes of materials injected for disposal will be documented to meet agency reporting requirements.

6.2.8 Recyclable/Reusable Fluids

All fluids consisting of used oils, diesel, glycol, and other hydrocarbons, chemicals, or snow melt determined to be recyclable or reusable materials in accordance with state and federal regulations will be managed as such and not as waste products.

Used oil will be segregated from other materials and stored in containers marked with the words "Used Oil". All used oil will be tested to verify acceptability for recycling and inserted into the crude oil stream at Northstar or other North Slope facilities. Testing may consist of a halogens screen and flash point test. Used oil generated during the construction phase will be transported to existing facilities for insertion into the crude oil stream after testing. Used oil generated from a known source with known inputs (such as from a turbine within the facility) will be evaluated for recycling based on MSDS information.

All other materials determined to be potentially reusable will, at a minimum, be visually inspected to verify contents. Suitable materials will be labeled with the container contents and stored until reused. Testing will be conducted on fluids which are found to be questionable. All materials determined to be unsuitable for reuse or recycling will be managed as a waste material and characterized for disposal.

6.2.9 Hazardous Waste

All wastes determined to be hazardous according to the Resource Conservation and Recovery Act (RCRA) will be managed in accordance with all federal and state guidelines. Hazardous waste will be placed in drums or other approved containers for storage. All containers will be marked with the contents, the date generated, and the words "Hazardous Waste". All containers will be stored in a containment area with an impermeable steel deck. All hazardous waste will be transported to management facilities located in the Lower 48 for recycling and/or disposal.

RCRA compliance files will be maintained onsite which will include information on waste identification, transportation manifests, and all correspondence with state and federal agencies regarding hazardous waste shipments.

6.2.10 Gray Water

Gray water generated from construction, drilling and facility operations will be injected into the disposal well, once available. In the event that the disposal well is unavailable for injection, gray water will be discharged under a NPDES permit.

6.2.11 Sewage Sludge

Sewage sludge generated from camp operations will either be injected down the Class I disposal well, when available, or backhauled to existing North Slope facilities for treatment and disposal.

6.2.12 Incinerator Ash

Ash generated from waste incinerators will be characterized in accordance with RCRA guidelines. Ash determined to be hazardous will be managed as hazardous waste. Ash determined to be non-hazardous will be transported to Deadhorse facilities for processing, or slurried and injected into the disposal well onsite.

6.2.13 Contaminated Snow

Contaminated snow generated from spill cleanup operations during the facilities operations phase of the project will be melted onsite and injected into the disposal well. Only non-hazardous melt water will be disposed of in the well. Snow with the potential for testing as hazardous will be segregated and melted in a designated bin to recover material for reuse.

Contaminated snow generated from spill cleanup operations during the construction and drilling phases of the project may be temporarily stored at the point of generation and/or at a central storage location, or transported as generated to disposal facilities. Storage areas will consist of impermeable containment. During drilling the snow may be melted onsite and reused as a fluid in the drilling process or injected into the disposal well as either a Class I or Class II fluid. Until the Class I permit is obtained, snow contaminated with fluids not suitable for melting and reuse in the drilling process will be transported to existing North Slope facilities for disposal.

Storage logs will be maintained onsite for all material added to containment areas. The information documented will include volume, material spilled, date of generation, and certification that the material is non-hazardous.

Snow contaminated with gravel, soil, trash, wood, and other debris will be staged on the island and melted by natural or mechanical means. All resulting debris will be recovered and disposed.

6.2.14 Contaminated Gravel

Contaminated gravel and soil generated from spill cleanup operations will be remediated onsite or at other North Slope facilities. Gravel will be recovered for pad maintenance or other uses. If needed, storage areas will consist of impermeable containment and will be constructed in accordance with Alaska Department of Environmental Conservation (ADEC) guidelines for storage of contaminated material. Remediation may consist of incineration, washing, and inject or other approved technology.

Storage logs will be maintained onsite for all material added to containment areas. The information documented will include volume, material spilled, date of generation, and verification that the material is non-hazardous.

6.4.15 Naturally Occurring Radioactive Material

Naturally Occurring Radioactive Materials (NORM) may be present in some production facilities and BPXA takes a pro-active approach to identification and proper handling of NORM materials. Well tubulars and piping will be scanned for NORMs when they are pulled from a well or removed from the process. Piping and tubulars that show indications of NORMs will be stored on the island. When enough NORM active pipe has been accumulated, it will be transported to a Prudhoe Bay area facility, specially designed for NORM removal using high pressure water. The resultant water based slurry will be injected in a Class II disposal well (currently CC2A).

6.4.16 Special Cases

The following items may be used during the construction and drilling phases of the development and, if so, will be managed in accordance with the following procedures indicated for Facility Operations.

- ***Empty Drums:*** Due to waste minimization efforts and limited storage space, drum stock will be kept to a minimum. Empty drums will be stored onsite and backhauled to existing BPXA North Slope facilities for flushing, crushing, and processing. Empty drum storage will be in secondary containment if there is any threat residual fluids will be released from the drums or if the physical condition of the drums will result in the contamination of snow or gravel (i.e., the drums are "dirty").
- ***Aerosol Cans:*** Aerosol cans that are completely empty (nothing is heard or felt when shaken) will be placed in the non-burnable dumpster. Non-empty cans will be punctured and the contents collected utilizing a drum-mounted can crusher. Punctured cans will be placed in the non-burnable dumpster and the contents will be characterized for disposal. Aerosols will not be emptied into facility sumps.
- ***Lead Acid Batteries:*** Lead acid batteries will be segregated from waste streams and stored inside until transported to Deadhorse to exchange for new batteries with the supplier. Lead acid batteries that are not standard size (e.g., from heavy equipment) may not be accepted by suppliers for exchange and may have to be transported to recycling facilities in the Lower 48.
- ***Medical Waste:*** Medical waste will be stored in containers marked "Medical Waste" and will be sent off site to a regulated medical waste incinerator for disposal.
- ***Fluorescent Light Tubes:*** Fluorescent light tubes will be collected, crushed into drums or maintained in original packaging, and sent to recycling facilities in the Lower 48. Crushing will be accomplished by

utilizing a manually fed drum-mounted unit which crushes the tubes and deposits the debris in the drum.

- ***Used Oil Filters:*** Used oil filters will be punctured and hot drained onsite as generated. The collected oil will be screened for halogens and flash point prior to insertion into the crude stream and the drained filter will be placed in the oily trasb dumpster.
- ***Radioactive Waste:*** All radioactive waste will be characterized for disposal as generated. Common sources of radioactive waste are exit signs and smoke detectors. These materials will be stored in containers with the contents clearly identified.

NORTHSTAR GRAVEL MINE SITE
MINING AND REHABILITATION PLAN

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

7. NORTHSTAR GRAVEL MINE SITE MINING AND REHABILITATION PLAN

BP Exploration (Alaska) Inc. (BPXA) proposes to develop a new gravel mine site in support of the Northstar Development Project. The mine would be used entirely by the Northstar project and all mining operations would be completed in one winter season. This mining and rehabilitation plan is required by the Alaska Department of Natural Resources/Division of Land in support of the new Materials Sale Contract for which BPXA is currently applying.

As much as possible, the amended plan has incorporated recommendations of resource agencies conveyed during a May 16, 1996 meeting held in Fairbanks with BPXA representatives. Those agencies included the Alaska Departments of Fish and Game (ADFG), Natural Resources, Division of Land (ADNR/DL), and the U.S. Fish and Wildlife Service (USFWS).

7.1 SUMMARY OF MINING AND REHABILITATION PLAN

Mining is targeted to begin in February. Snow and ice will be stripped and, if necessary, overburden material will be pushed to the side. The gravel will be removed in two 20-foot lifts allowing for a shallow littoral area along the south side and a potential shallow area along the west end. An estimated 1.2 million cubic yards of material is available from the site.

During development of the mining plan, it was necessary to permit a source large enough to construct the entire island in the event that re-use of existing gravel currently located at the existing Seal Island site was not possible due to erosion. To build an island of the proposed size in water depths of approximately 40 feet below MLLW without considering the use of the material from the existing island, would require 1.2 million cubic yards. Northstar is counting on reusing the maximum amount of gravel as practicable without mechanical recovery. If current erosion rates are maintained there will be approximately 400,000 to 500,000 cubic yards of existing material incorporated into the core of the new island. The balance will be mined and hauled from the new pit.

The "potential overburden bench" is the proposed final disposal location for the material stripped off the surface and deemed "unusable" or "unsuitable" as island construction material. Since limited geotechnical information is available, the amount of stripping is impossible to calculate and therefore the word "potential" is used for temporary overburden. The stockpile storage area will be an ice pad where unusable material will be stored until the usable gravel is extracted. The material will then be pushed into the pit prior to final ahandonment and flooding.

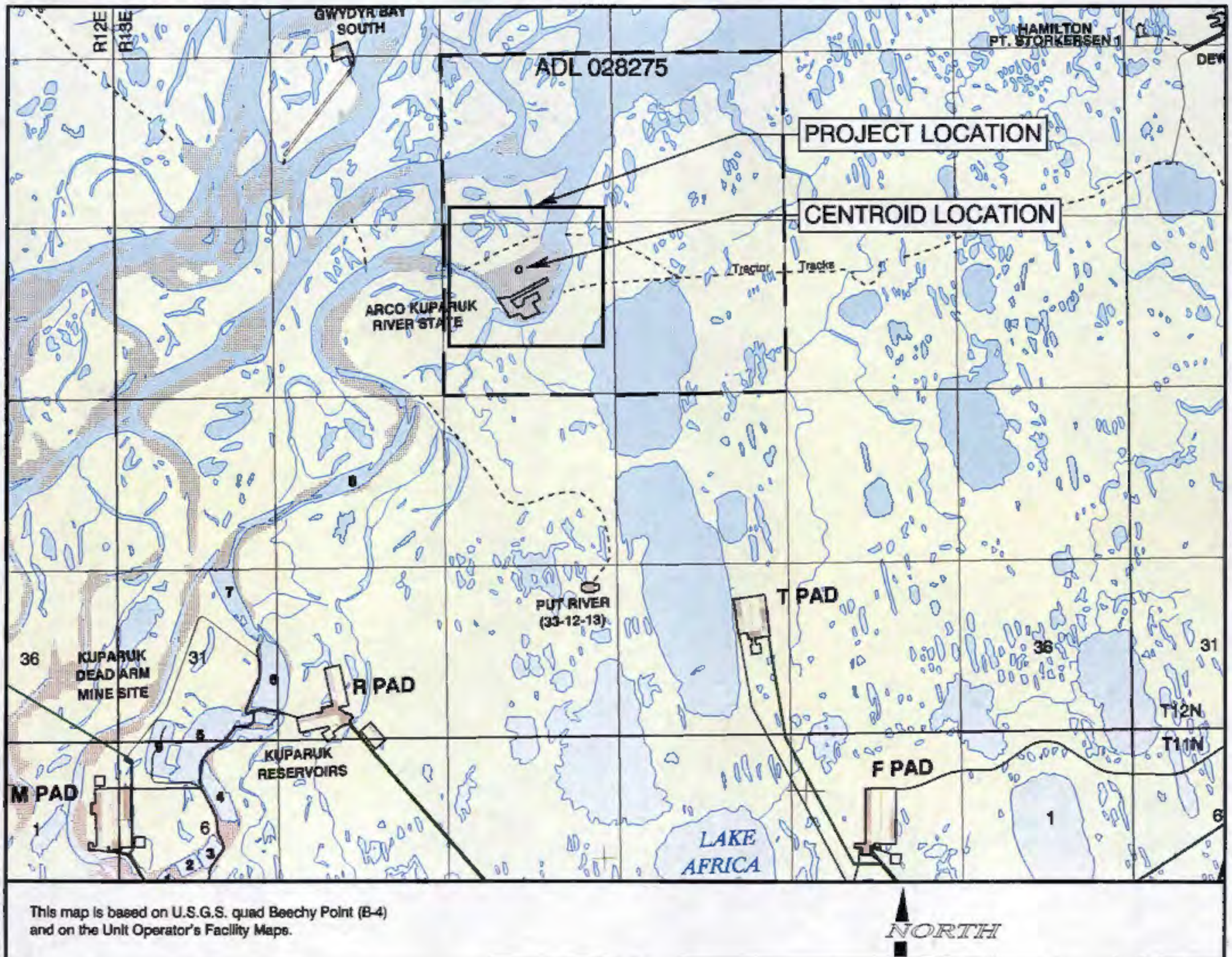
After mining is completed, a six foot deep breach will be dug connecting the mine site to the Kuparuk River. At break-up in the spring, water will back flow into the site, creating a shallow/deep water fish habitat. Due to the proximity of the site to Gwydyr Bay, the site will become brackish during the summer and remain brackish in the following years.

7.2 SITE CHARACTERISTICS

The proposed mine site lies east of the main channel of the Kuparuk River approximately two miles up the Kuparuk River from Gwydyr Bay (see Figure 7.2-1). The mine site is located within Section 21 of Township 12 North, Range 13 East, Umiat Meridian on State lease ADL 028275 (see Figures 7.2-1 and 7.2-2).

The site is in a region of riverine barrens and flood plain alluvium. The elevated ridges in the vicinity of the mine site are sand dune barrens. Aerial photographs of the site document that the site is for the most part unvegetated. To the north of the mine site area, vegetation is predominately aquatic sedge, moist-graminoid tundra and dry prostrate shrub tundra. The mine site is in an area of tidal influence and the shifting channels of the Kuparuk River.

During winter, wildlife use of the area is extremely limited, with Arctic foxes, Snowy Owls, and Common Ravens likely present. During summer, the ponds and wetland complexes to the north of the proposed material site may be used by waterfowl, loons, and tundra nesting shorebirds. Prior to freeze-up, Canada and White-fronted geese may be present in the general area. The area of the proposed material site probably receives limited use by wildlife, because it is largely devoid of vegetation and has little standing water.



This map is based on U.S.G.S. quad Beechy Point (B-4) and on the Unit Operator's Facility Maps.

PROJECT LOCATION:

CENTROID FOR NORTHSTAR MINE SITE

LAT. = 70° 22' 58.85" NORTH
LONG. = 148° 51' 12.11" WEST

X = 641,000.00 FEET EAST
Y = 5,991,000.00 FEET NORTH
ALASKA STATE PLANE ZONE 4, NAD 27

SEC. 21, T12N, R13E, UMIAT M.

ADL # 028275

DATUM: MEAN SEA LEVEL

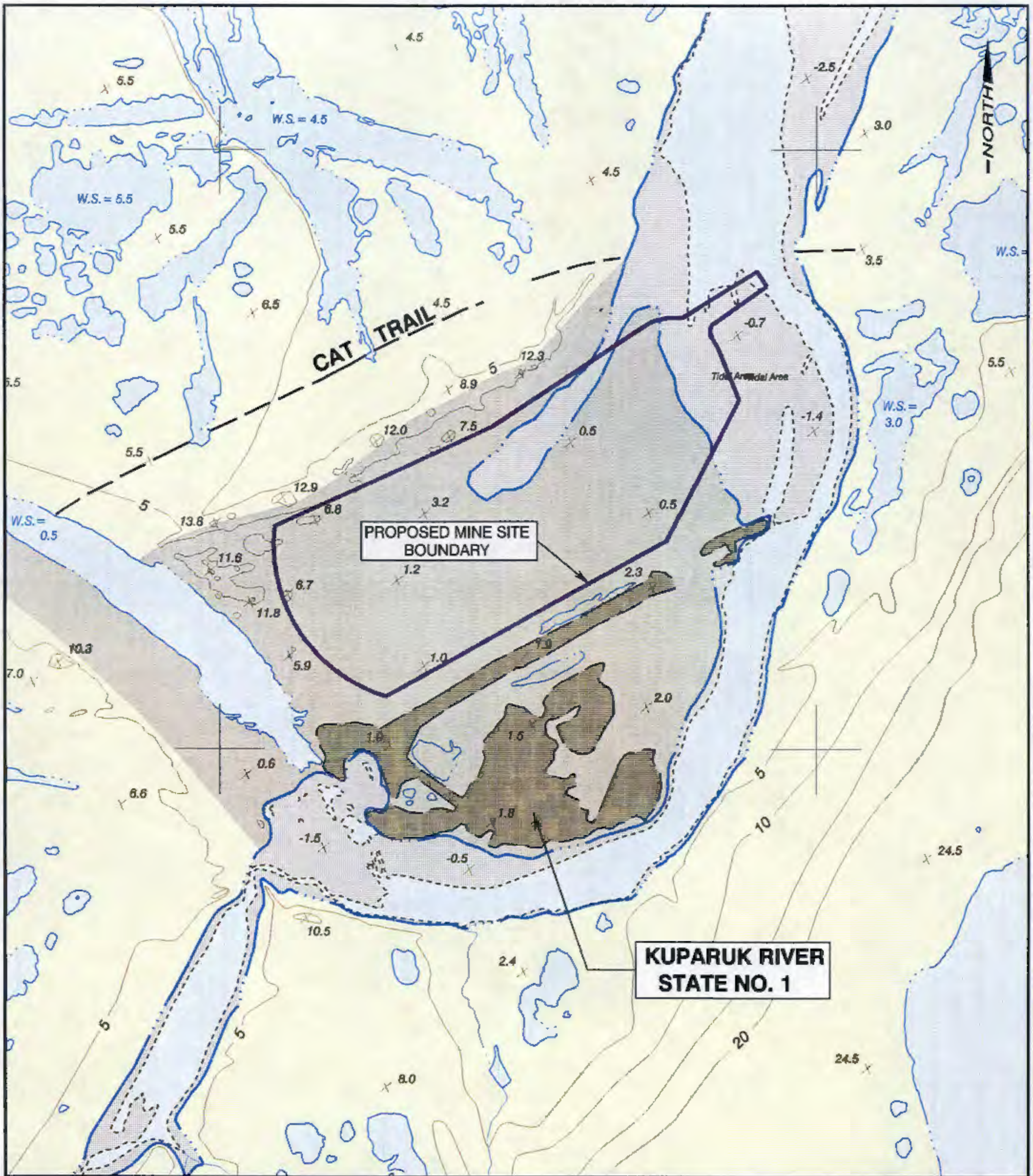
PURPOSE: MINE SITE DEVELOPMENT

ADJACENT PROPERTY OWNER:
STATE OF ALASKA

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
VICINITY MAP

DATE:	SCALE:	FIGURE:
3/25/97	1" = 1 MILE	7.2-1



Mapped from photography of July 10, 1973, updated from 1995 photography. This map meets National Map Standards AT 1" = 500'. Horizontal datum NAD 1927 based on USC&GS monumentation, coordinate system Alaska State Plane Zone 4. Vertical datum mean sea level established by observation at East Dock in 1968 by F.M. Lindsey and Associates. Prepared by AeroMap US Inc. of Anchorage, AK for BP Exploration (Alaska) Inc.

- TUNDRA
- TIDAL AREA
- NON VEGETATED UPLAND
- MAN MADE FACILITY

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
CURRENT CONDITIONS

DATE:	SCALE:	FIGURE:
3/25/97	1" = 600'	7.2-2

gp13116.dgn

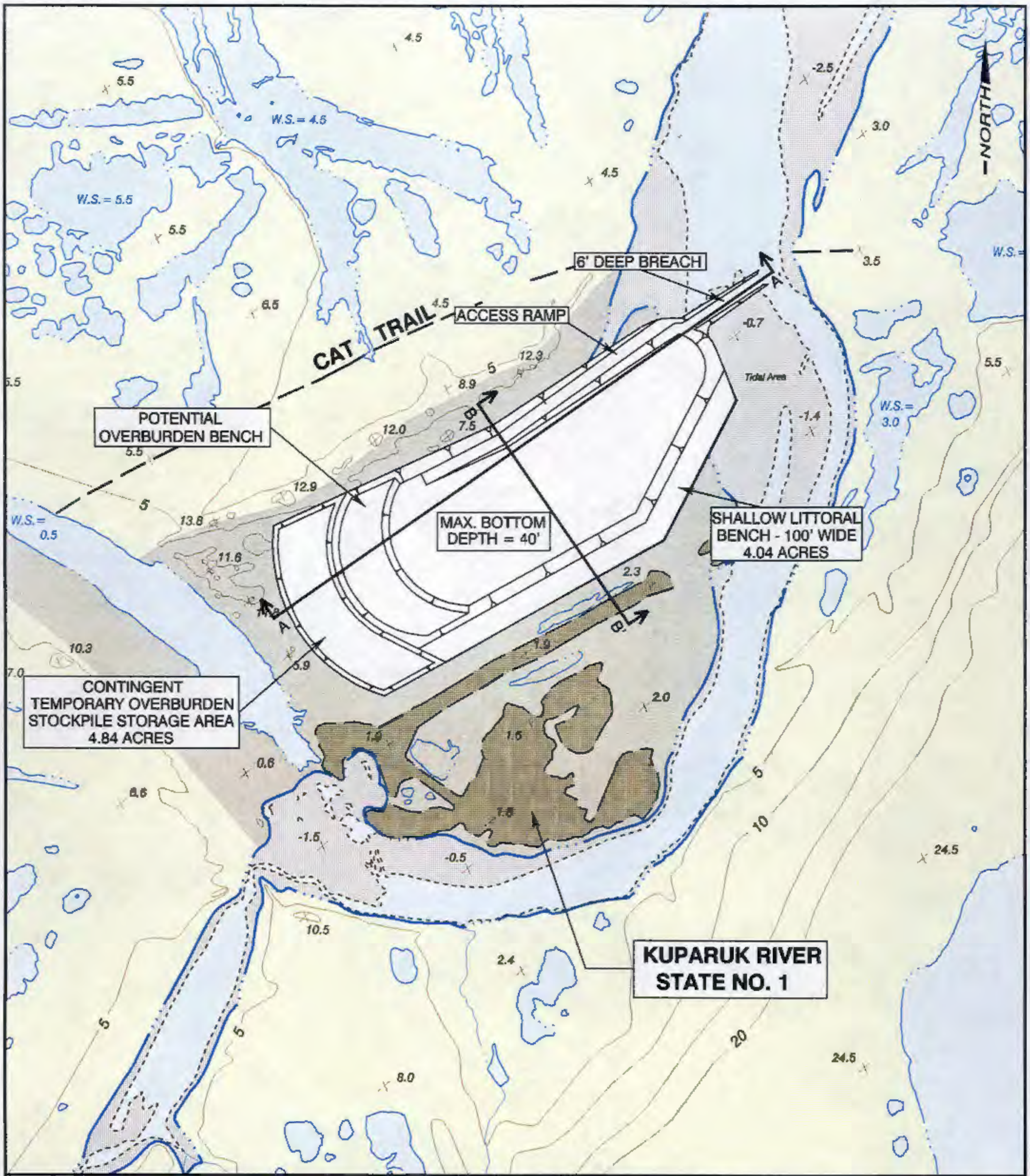
7.3 MINING PLAN

Gravel extraction at the mine site is targeted to occur over one winter season beginning in February. The total surface area of the mine site activities encompasses approximately 35 acres. The pit will be mined to a depth of approximately 40. Access into the pit will be by way of a 50-foot wide ramp running along the northern boundary of the pit. A shallow littoral area encompassing approximately 4.0 acres will be created along the southern boundary of the mine site.

Snow and ice will first be removed and placed adjacent to the mine site. If it is determined to be unusable, the overburden material will be stripped and temporarily stockpiled. This will be conducted in two phases. First, the western portion of the pit will be stripped of overburden material and stockpiled along the western edge of the pit (see Figures 7.3-1 and 7.3-2). The exposed gravel will then be prepared for removal by blasting the first 20-foot lift. After the first 20-foot lift is removed from the stripped section, the overburden material from the eastern portion of the pit will be placed within the pit against the western end of the excavated area allowing for the blasting and excavation of the first lift to continue (see Figure 7.3-2). This will avoid double handling of the eastern overburden material and will create a potential additional shallow water habitat. After the first lift is completed, blasting and excavation of the second, and final, 20-foot lift will commence.

An approximately 6-foot deep breach will be constructed at the eastern end of the pit to connect the mine site to the Kuparuk River. The bottom of the breach will be excavated to a level approximately two feet below the mean low water line of the river.

After the excavation has been completed, the overburden material on the western edge of the pit will be pushed back into the pit on top of the material from the eastern portion of the pit, potentially creating a shallow littoral area along the western end. Due to the uncertainty regarding the amount of overburden material available, it is not possible to predict accurately the final depth of the western shelf. The snow and ice removed from the site will then be pushed back into the pit in an effort to minimize disruptions to natural drainage patterns.



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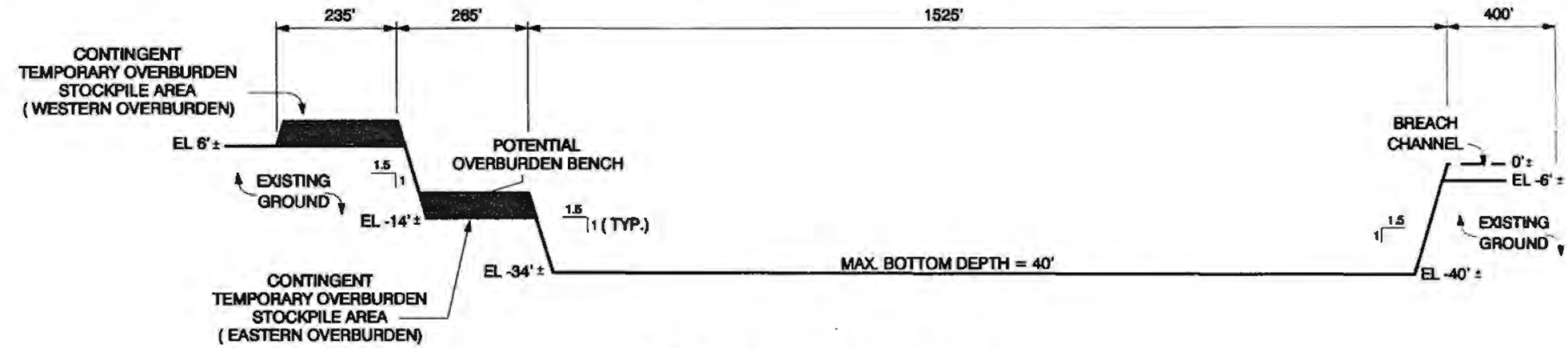
	POTENTIAL MINE AREA - ACRES
PROPOSED MINE AREA	35.59 ACRES
EXCAVATION AREA	30.75 ACRES
TEMPORARY STOCKPILE	4.84 ACRES
AREA OF LITTORAL BENCH	4.04 ACRES
GRAVEL (TO DEPTH -40')	1,266,000 CY

BP EXPLORATION (ALASKA) INC.

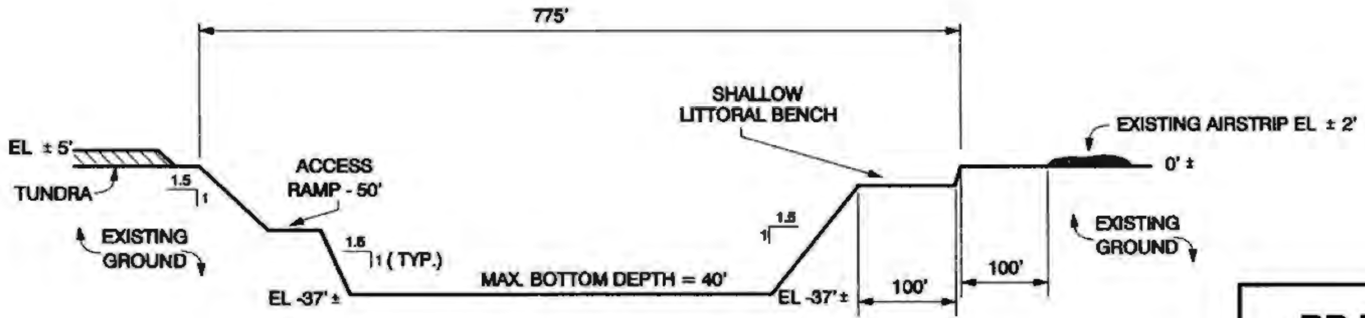
NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
MINE DEVELOPMENT PLAN VIEW

DATE:	SCALE:	FIGURE:
3/25/97	1" = 600'	7.3-1

gp13117.dgn



CROSS SECTION A-A'



CROSS SECTION B-B'

BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT PROPOSED MINE SITE MINING AND REHABILITATION PLAN MINE DEVELOPMENT CROSS SECTIONS		
DATE: 3/25/97	SCALE: NOT TO SCALE	FIGURE: 7.3-2

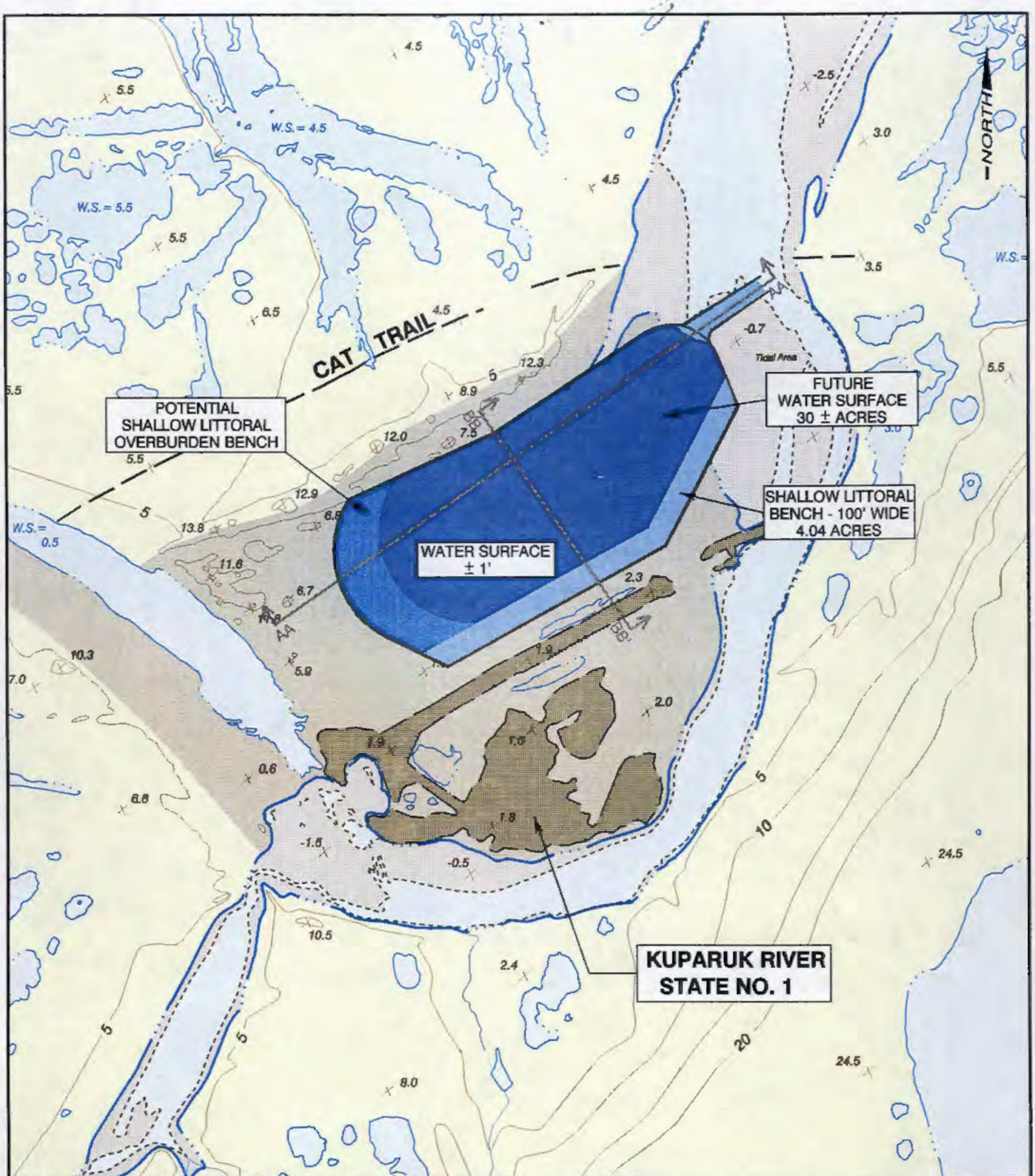
7.4 REHABILITATION PLAN

During spring, the Kuparuk River will begin break-up in its headwaters and flow will proceed down river. As the melt water reaches the sea ice, it will begin to back-up and flood the lower reaches of the river. This back flow will begin to fill the excavated mine site. As break-up continues, the flooded mine site water elevation will reacb a point of equilibrium with the Kuparuk River. It is anticipated that this will occur sometime during the spring and summer.

This mining and rehabilitation plan will create an approximately 30-acre combination shallow water/deep water environment with approximately 4.0 acres of shallow littoral area along the south side of the mine site (see Figures 7.4-1 and 7.4-2). Shallow littoral areas will be approximately six feet deep with the rehabilitated mine site's deepest point being approximately 40 feet deep. Additional shallow littoral acreage may be created along the western end of the mine site if the site contains unusable overburden material.

Due to its proximity to Gwydyr Bay, the rehabilitated mine site will become brackish and create an anadromous fish habitat. Fish access to the pit will be provided by the breach excavated at the northern end of the pit.

In an effort to minimize future impacts on drainage and to protect sand dunes in the area, the western end of the pit has been located approximately 420 feet from the bank of an intermittent channel of the Kuparuk River. This channel appears to experience flow only during high water events. The large buffer will minimize any potential erosional impacts to the mine site area caused by any future diversion of this channel into the pit and will additionally avoid the need to stockpile overburden in the sand dune area.



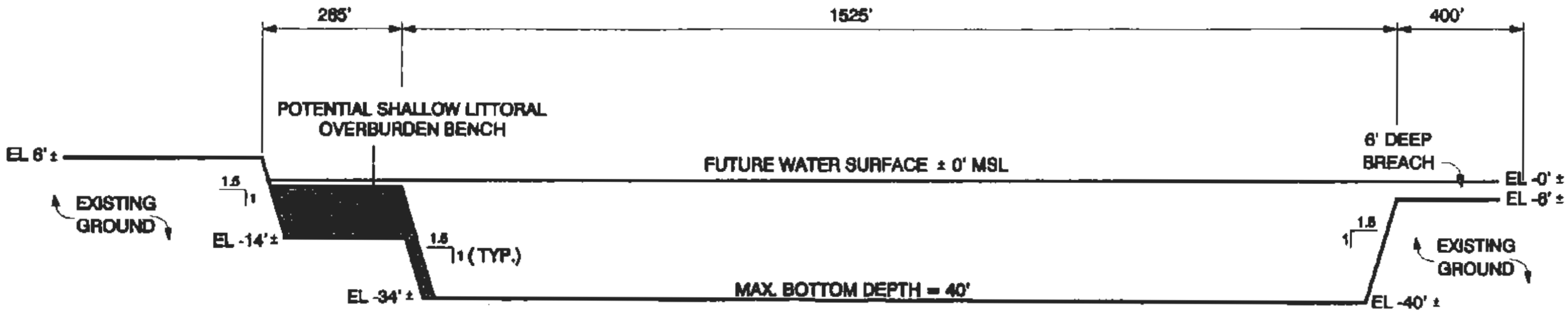
Mapped from photography of July 10, 1973, updated from 1995 photography. This map meets National Map Standards AT 1" = 500'. Horizontal datum NAD 1927 based on USC&GS monumentation, coordinate system Alaska State Plane Zone 4. Vertical datum mean sea level established by observation at East Dock in 1968 by F.M. Lindsey and Associates. Prepared by AeroMap US Inc. of Anchorage, AK for BP Exploration (Alaska) Inc.

BP EXPLORATION (ALASKA) INC.

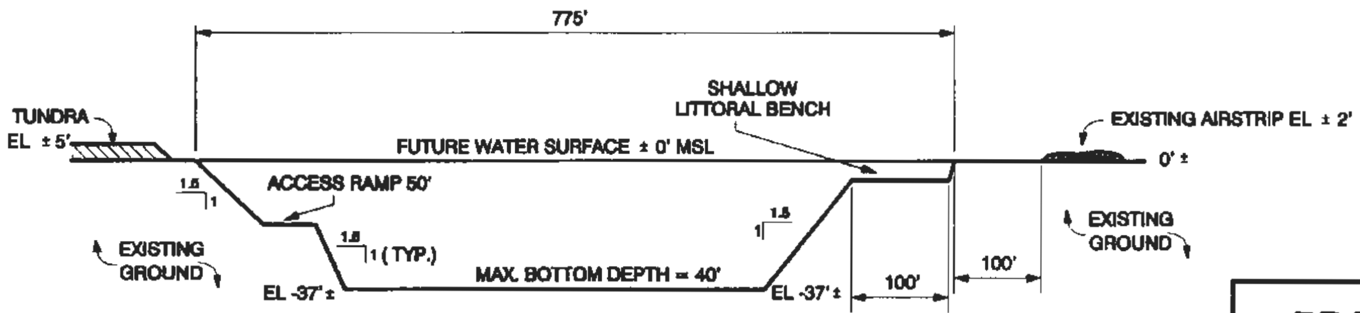
NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
CONCEPTUAL PLAN VIEW

DATE:	SCALE:	FIGURE:
3/25/97	1" = 600'	7.4-1

gp13118.dgn



CROSS SECTION AA-AA'



CROSS SECTION BB-BB'

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
PROPOSED MINE SITE
MINING AND REHABILITATION PLAN
CONCEPTUAL PLAN CROSS SECTIONS

DATE:	SCALE:	FIGURE:
3/25/97	NOT TO SCALE	7.4-2

GP13118.dgn

7.5 MINING PLAN CONTINGENCIES

BPXA currently involves plans to add gravel to expand the existing Seal Island. Due to seasonal storms eroding gravel from the existing unprotected island, the final quantity of gravel available will only be known after surveys are conducted prior to island construction.

If gravel quantities required for the expansion of Seal Island are significantly less than the 1.2 million cubic yards, the mining plan will be modified accordingly and the footprint for the mine will be reduced and all mining will take place in the western half of the proposed site.

All features of the mining and rehabilitation plan will be constructed as identified including the 100 foot wide shallow littoral area and two lifts of gravel resulting in a maximum depth of 40 feet.

Three core holes were drilled at the proposed mine site location late in the spring of 1996 to determine the quality and quantity of gravel. Preliminary field results indicate that the gravel appears to be abundant and of good quality. If, however, when mining operations commence, more unusable material is encountered than anticipated, more material will remain in the excavated pit when abandoned.

7.6 ALTERNATIVES CONSIDERED

7.6.1 Existing Gravel Mine Sites

Mining gravel from existing North Slope gravel resources was considered when developing the mining plan for the Northstar Development Project. The closest mine site to the project area is the Kuparuk Deadarm Mine Site located in the Prudhoe Bay Unit Western Operating Area. Mining gravel from this site would require removal of 625,000 cubic yards of tundra overburden. Additionally, it increased the overhaul distance substantially and subsequently the transport costs. The cost was prohibitive to the project and the alternative was eliminated from further consideration.

7.7 PERMITS

The following permits are being applied for in support of the proposed Northstar mine site:

- U.S. Army Corps of Engineers - Sections 10 and 404
- Alaska Department of Natural Resources, Division of Lands - Material Lease Sales
- Alaska Department of Fish and Game - Fish Habitat Permit
- North Slope Borough - Development Permit

HEALTH, SAFETY AND ENVIRONMENTAL (HSE) PLAN

NORTHSTAR DEVELOPMENT PROJECT
FINAL PROJECT DESCRIPTION

8. HEALTH, SAFETY AND ENVIRONMENTAL (HSE)

8.1 INTRODUCTION

Health, safety and environmental protection are of the highest importance to BPXA. The Northstar Development Project will be designed, constructed, operated and maintained in full compliance with BPXA's Operations Integrity Assurance System (OIAS). The OIAS program, modeled after accepted best practices and performance standards, is designed to ensure that all facilities are designed, constructed and operated to the highest health, safety, and environmental standards. The OIAS program dictates management responsibilities and requires that awareness of these standards be incorporated into all project activities. The program includes a framework for risk management, facilities design, construction, operation, personnel training, and incident preparedness.

Health, safety and environmental (HSE) requirements for the Northstar Development Project will be specified in a project HS&E Plan covering the design, construction and operations phases. HSE requirements differ for each project phase and these requirements are described herein.

8.2 DESIGN PHASE

8.2.1 General

HSE requirements will be incorporated into the design phase of the project by implementing certain design requirements, reviews, audits and plans. These include:

- ***Hazard and Operability (HAZOP) for Process Hazard Analysis:*** This technique will identify inadequacies with respect to safety and operability in design of process flow sequences.
- ***Facility Site Reviews (FSR):*** The conceptual island layout and the detailed design layout will be subject to an FSR. This review will ensure that the location, layout and orientation of process plant, utility modules, control rooms, camps, wells, and drill rig are such that hazards from gas release, fire, explosion and escalation are all minimized.
- ***Technical Safety Audit (TSA):*** This review is a six-stage independent audit procedure carried out at discrete stages of a project. These audits address worker and public safety issues. The initial TSA will review the conceptual design for technical soundness, facility and pipeline integrity, and safe operating conditions. As the TSA process continues, through the various stages of preliminary design, detailed engineering, construction, pre-commissioning, and post commissioning, the audit will progressively focus on design details, construction plans, and operational issues.

8.3 CONSTRUCTION PHASE

8.3.1 General

HSE provisions will be very important during the construction phase of the island and pipelines. Established safe construction practices together with a strong quality control/quality assurance program will be used to ensure the health and safety of the project personnel and the public, and the minimization of environmental impact during and after construction of the island and pipelines. All personnel will observe and comply with all applicable federal, state, and local laws and regulations related to public health and safety, and the environment.

8.3.2 Construction Safeguards

Several programs will be implemented during construction to maximize health and safety protection and minimize environmental impacts. These programs include:

- Oil Discharge Prevention and Contingency Plan (ODPCP)
- Ice roads to prevent tundra damage
- Protection and repair of project area vegetation
- Polar bear interaction plan
- Project personnel training on environmental awareness
- Permit compliance training
- Quality Control/Assurance, e.g., welding inspection, hydrotesting, etc.
- Evacuation Plans (medical and emergency)
- Safety and environmental risk analysis
- Safety procedures, training, and meetings
- Technical Safety Audit for construction phase
- Waste Management Plan

8.4 OPERATIONS PHASE

8.4.1 Operational Systems

Northstar Operations will include extensive policies, procedures and systems for implementing a safe and environmentally sound operation. Examples are:

- Pre startup safety reviews
- Work Permit system for routine, hot work, vessel entry, etc.
- Safe out procedure for electrical and rotating equipment
- Annual certification of pressure safety valves (PSVs)
- Polar bear interaction plan
- Project personnel training on environmental awareness
- Permit compliance training
- Tool box safety meetings
- Pre-job task analysis and safety reviews
- Loss Control Incident Report review meetings
- Field safety meetings
- HSE committee meetings
- Work group safety meetings
- Loss control facility walk through
- Plant change review meetings
- Emergency shutdown procedures
- Contractor safety meetings
- Audit and master punchlist follow-up meetings
- Oil Discharge Prevention and Contingency Plan (ODPCP)
- Island evacuation plans (medical & emergency)
- Periodic Fire and Gas System Testing
- Annual testing of subsurface safety valves
- Storage and handling of hazardous chemicals and materials
- Monitoring systems for pipeline leak detection
- Waste Management Plan

8.4.2 Management of Change

A Management of Change procedure will be developed and implemented to ensure that changes or replacements to systems and equipment will maintain operational integrity and conformance to design standards.

8.4.3 Process Safety Management (PSM)

PSM regulations are imposed by OSHA and are also covered by OIAS. These regulations will be strictly followed as they are crucial components of the operating integrity of the Northstar facilities. Key elements of PSM are:

- Employee Participation
- Process Safety Information
- Process Hazard Analysis
- Operating Procedures
- Training
- Contractors
- Pre-startup Safety Reviews
- Mechanical Integrity
- Hot Work Permits
- Management of Change
- Incident Investigations
- Emergency Planning and Response
- Compliance Audits

8.4.4 Inspection and Maintenance

A quality assurance program and maintenance program will be established to ensure adequate inspection and repair programs are utilized to protect personnel as well as facilities.

8.4.5 Spill Response

Spill response equipment will be pre-staged at strategic locations, including the island and onshore for response to potential spills on the island or from the offshore or onshore pipeline. Extensive spill response plans and strategies will be developed for Northstar facilities and pipelines. Operations and support personnel will be trained to handle minor spills including appropriate cleanup and disposal procedures. Island personnel will also initiate spill response measures on larger spills and then coordinate activities with assisting groups such as Alaska Clean Seas, other trained local response teams, and BPXA teams from Prudhoe Bay, Milne Point and Endicott.

Weekly meetings between ADEC and BPXA are presently being held regarding requirements for the Northstar Oil Discharge Prevention and Contingency Plans (ODPCPs). As part of this process, detailed spill response scenarios are being developed for a blowout in open water, blowout in broken ice, offshore under ice pipeline leak.

Development of these scenarios is being done in close coordination with ADEC and MMS. All appropriate response strategies will be evaluated in the development of these scenarios.

APPENDICES

APPENDIX A

EPA NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

NPDES PERMIT APPLICATION
FINAL

NORTHSTAR UNIT DEVELOPMENT

BP Exploration (Alaska) Inc.
P.O. Box 196612
900 East Benson Boulevard
Anchorage, AK 99519-6612

05 December 1997

NPDES PERMIT APPLICATION
05 DECEMBER 1997 REVISION LOG

The final permit application is dated 01 October 1997 in which the page numbers and version date are located in the footer of every page (with the exception of the Attachments). To ensure that every copy of the permit application is current, a revision log is provided listing all of the changes by page number since the final release (01 October 1997). "Rev. 1.0" has also been included in the footer of each changed page. This revision log should be inserted at the front of the permit application, immediately in front of the Form 1 cover sheet.

VERSION	DATE	CHANGES
0	01 October 1997	final submittal
1.0	05 December 1997	Form 1, Exhibit XI-3, page 7
1.0	05 December 1997	Form 2D, page 1
1.0	05 December 1997	Form 2D, page 2
1.0	05 December 1997	Form 2D, Exhibit 1, page 8
1.0	05 December 1997	Form 2D, Exhibit 1, page 9
1.0	05 December 1997	Form 2D, Exhibit 1, page 10
1.0	05 December 1997	Form 2D, Exhibit 1, page 11
1.0	05 December 1997	Form 2D, Exhibit 2, page 12
1.0	05 December 1997	Form 2D, page 15
1.0	05 December 1997	Form 2D, Exhibit 5, page 19
1.0	05 December 1997	Form 2D, page 20
1.0	05 December 1997	Form 2D, Exhibit 7, page 24
1.0	05 December 1997	Form 2D, Exhibit 8, page 27
1.0	05 December 1997	Form 2D, page 29
1.0	05 December 1997	Form 2D, page 35
1.0	05 December 1997	Form 2D, page 40
1.0	05 December 1997	Form 2D, Exhibit 14, page 42
1.0	05 December 1997	Form 2D, Exhibit 14, page 43
1.0	05 December 1997	Form 2D, Exhibit 15, page 44
1.0	05 December 1997	Form 2D, page 45
1.0	05 December 1997	Form 2D, Attachment 8

NPDES PERMIT APPLICATION
13 MARCH 1998 REVISION LOG

The final permit application is dated 01 October 1997 in which the page numbers and version date are located in the footer of every page (with the exception of the Attachments). To ensure that every copy of the permit application is current, a revision log is provided listing all of the changes by page number since the final release (01 October 1997). "Rev. 2.0" has also been included in the footer of each changed page. This revision log should be inserted at the front of the permit application, immediately after the 05 December 1997 Revision Log (page i).

VERSION	DATE	CHANGES
2.0	13 March 1998	Form 1, Exhibit XI-2, page 6
2.0	13 March 1998	Form 1, Exhibit XI-3, page 7
2.0	13 March 1998	Form 2D, Exhibit 10, pages 31-33
2.0	13 March 1998	Form 2D, Exhibit 11, page 34
2.0	13 March 1998	Form 2D, Exhibit 12, page 38
2.0	13 March 1998	Form 2D, Exhibit 12, Attachment 7, page 3
2.0	13 March 1998	Form 2D, Exhibit 15, page 44

EPA FORM 1

GENERAL INFORMATION

Please print or type in the unshaded areas only
(fill–in areas are spaced for elite type, i.e., 12 characters/inch).

Form Approved. OMB No. 2040-0086. Approval expires 5-31-92.

FORM 1 GENERAL — EPA — U.S. ENVIRONMENTAL PROTECTION AGENCY

GENERAL INFORMATION

Consolidated Permits Program
(Read the "General Instructions" before starting.)

I. EPA I.D. NUMBER

F | | D

LABEL ITEMS

I. EPA I.D. NUMBER

III. FACILITY NAME

V. FACILITY MAILING ADDRESS

PLEASE PLACE LABEL IN THIS SPACE

VI. FACILITY LOCATION

GENERAL INSTRUCTIONS

If a preprinted label has been provided, affix it in the designated space. Review the information carefully; if any of it is incorrect, cross through it and enter the correct data in the appropriate fill–in area below. Also, if any of the preprinted data is absent *(the area to the left of the label space lists the information that should appear)*, please provide it in the proper fill–in area(s) below. If the label is complete and correct, you need not complete Items I, III, V, and VI *(except VI-B which must be completed regardless)*. Complete all items if no label has been provided. Refer to the instructions for detailed item descriptions and for the legal authorizations under which this data is collected.

II. POLLUTANT CHARACTERISTICS

INSTRUCTIONS: Complete A through J to determine whether you need to submit any permit application forms to the EPA. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "X" in the box in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if your activity is excluded from permit requirements; see Section C of the instructions. See also, Section D of the instructions for definitions of bold–faced terms.

SPECIFIC QUESTIONS	YES	NO	FORM ATTACHED	SPECIFIC QUESTIONS	YES	NO	FORM ATTACHED
A. Is this facility a **publicly owned treatment works** which results in a **discharge** to **waters of the U.S.**? (FORM 2A)		X		B. Does or will this facility *(either existing or proposed)* include a **concentrated animal feeding operation** or **aquatic animal production facility** which results in a **discharge** to waters of the U.S.? (FORM 2B)		X	
C. Is this a facility which currently results in **discharges** to **waters of the U.S.** other than those described in A or B above? (FORM 2C)		X		D. Is this a proposed facility *(other than those described in A or B above)* which will result in a **discharge** to **waters of the U.S.**? (FORM 2D)	X		X
E. Does or will this facility treat, store, or dispose of **hazardous wastes**? (FORM 3)	X			F. Do you or will you inject at this facility industrial or municipal effluent below the lowermost stratum containing, within one quarter mile of the well bore, underground sources of drinking water? (FORM 4)		X	
G. Do you or will you inject at this facility any produced water or other fluids which are brought to the surface in connection with conventional oil or natural gas production, inject fluids used for enhanced recovery of oil or natural gas, or inject fluids for storage of liquid hydrocarbons? (FORM 4)	X			H. Do you or will you inject at this facility fluids for special processes such as mining of sulfur by the Frasch process, solution mining of minerals, in situ combustion of fossil fuel, or recovery of geothermal energy? (FORM 4)		X	
I. Is this facility a proposed **stationary source** which is one of the 28 industrial categories listed in the instructions and which will potentially emit 100 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an **attainment area**? (FORM 5)	Not Applicable Application to ADEC			J. Is this facility a proposed **stationary source** which is NOT one of the 28 industrial categories listed in the instructions and which will potentially emit 250 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an **attainment area**? (FORM 5)	Not Applicable Application to ADEC		

III. NAME OF FACILITY

1 SKIP NORTHSTAR DEVELOPMENT PROJECT

IV. FACILITY CONTACT

A. NAME & TITLE *(last, first, & title)*	B. PHONE *(area code & no.)*
2 COCKLAN-VENDL MARY, Senior Environmental Scientist	907 564 4766

V. FACILITY MAILING ADDRESS

A. STREET OR P.O. BOX

3 PO Box 196612 900 E. BENSON BLVD.

B. CITY OR TOWN	C. STATE	D. ZIP CODE
4 ANCHORAGE	AK	99519

VI. FACILITY LOCATION

A. STREET, ROUTE NO. OR OTHER SPECIFIC IDENTIFIER

5 SEAL ISLAND – STEFANSSON SOUND

B. COUNTY NAME

C. CITY OR TOWN	D. STATE	E. ZIP CODE	F. COUNTY CODE *(if known)*
6 DEADHORSE	AK	99734	

CONTINUED FROM THE FRONT

VII. SIC CODES (4-digit, in order of priority)

A. FIRST		B. SECOND	
7 1311	(specify) Crude oil production	7	(specify)
C. THIRD		**D. FOURTH**	
7	(specify)	7	(specify)

VIII. OPERATOR INFORMATION

A. NAME: 8 BP EXPLORATION (ALASKA) INC.

B. Is the name listed in Item VIII-A also the owner? [X] YES [ ] NO

C. STATUS OF OPERATOR (Enter the appropriate letter into the answer box; if "Other", specify.)
F = FEDERAL
S = STATE
P = PRIVATE
M = PUBLIC (other than federal or state)
O = OTHER (specify)

P (specify)

D. PHONE (area code & no.): A 907 564 5111

E. STREET OR P.O. BOX: PO Box 196612 900 E. BENSON BLVD.

F. CITY OR TOWN: B ANCHORAGE

G. STATE: AK

H. ZIP CODE: 99519

IX. INDIAN LAND

Is the facility located on Indian lands? [ ] YES [X] NO

X. EXISTING ENVIRONMENTAL PERMITS

A. NPDES (Discharges to Surface Water): 9 N SEE EXHIBIT X-1	D. PSD (Air Emissions from Proposed Sources): 9 P
B. UIC (Underground Injection of Fluids): 9 U SEE EXHIBIT X-1	E. OTHER (specify): 9 SEE EXHIBIT X-1 (specify)
C. RCRA (Hazardous Wastes): 9 R SEE EXHIBIT X-1	E. OTHER (specify): 9 SEE EXHIBIT X-1 (specify)

XI. MAP

Attach to this application a topographic map of the area extending to at least one mile beyond property bounderies. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements.

XII. NATURE OF BUSINESS (provide a brief description)

BP Exploration (Alaska) Inc. is in the business of discovering and developing economical accumulations of petroleum and natural gas. BPX has a 51 percent stake in the Prudhoe Bay oilfield which was discovered in 1969, as well as large interests in other North Slope fields, notably Kuparuk, Milne Point, and Endicott.

XIII. CERTIFICATION (see instructions)

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A. NAME & OFFICIAL TITLE (type or print): DAVID A. WALLACE, HSE BUSINESS MANAGER

B. SIGNATURE: [signature] Acting for David A. Wallace

C. DATE SIGNED: 10/1/97

COMMENTS FOR OFFICIAL USE ONLY

FORM 1, EXHIBIT X-1

The following representative permits have been issued to BP Exploration (Alaska) Inc. (BPX) and are currently active for facilities located on the North Slope of Alaska:

Existing NPDES EPA Permits

NPDES — AK0038661 11/22/91 through 12/23/96 (continued discharge under administrative extension)
Endicott sewage/gray water/sea water treatment plant

NPDES — AK0028606 7/1/83 through Indefinite
Central sewage treatment facility — Prudhoe BOC
Companion Alaska DEC permit 9036DB001

NPDES — AK0051667 1/19/93 through 1/18/98
Mine site dewatering — Kuparuk Deadarm

NPDES — AK0050938 1/19/93 through 1/18/98
Mine site dewatering — Duck Island pit

NPDES — AKR00A022 9/9/92 through 9/9/97
Stormwater discharge — Endicott

NPDES — AKR00A023/9/92 through 9/9/97
Stormwater discharge — Prudhoe WOA

NPDES — AKR00A905
Stormwater discharge — Milne Point

Existing RCRA EPA Permits

RCRA — Interim status storage facility at Prudhoe C-pad
— Waiting on Part B approval
— Generator reference No. AKD000643239

RCRA — Endicott Field - small quantity generator
— Generator reference No. AKD980834675

RCRA — Milne Point Field - small quantity generator
— Generator reference No. AKD980977680

Other Federal Permits

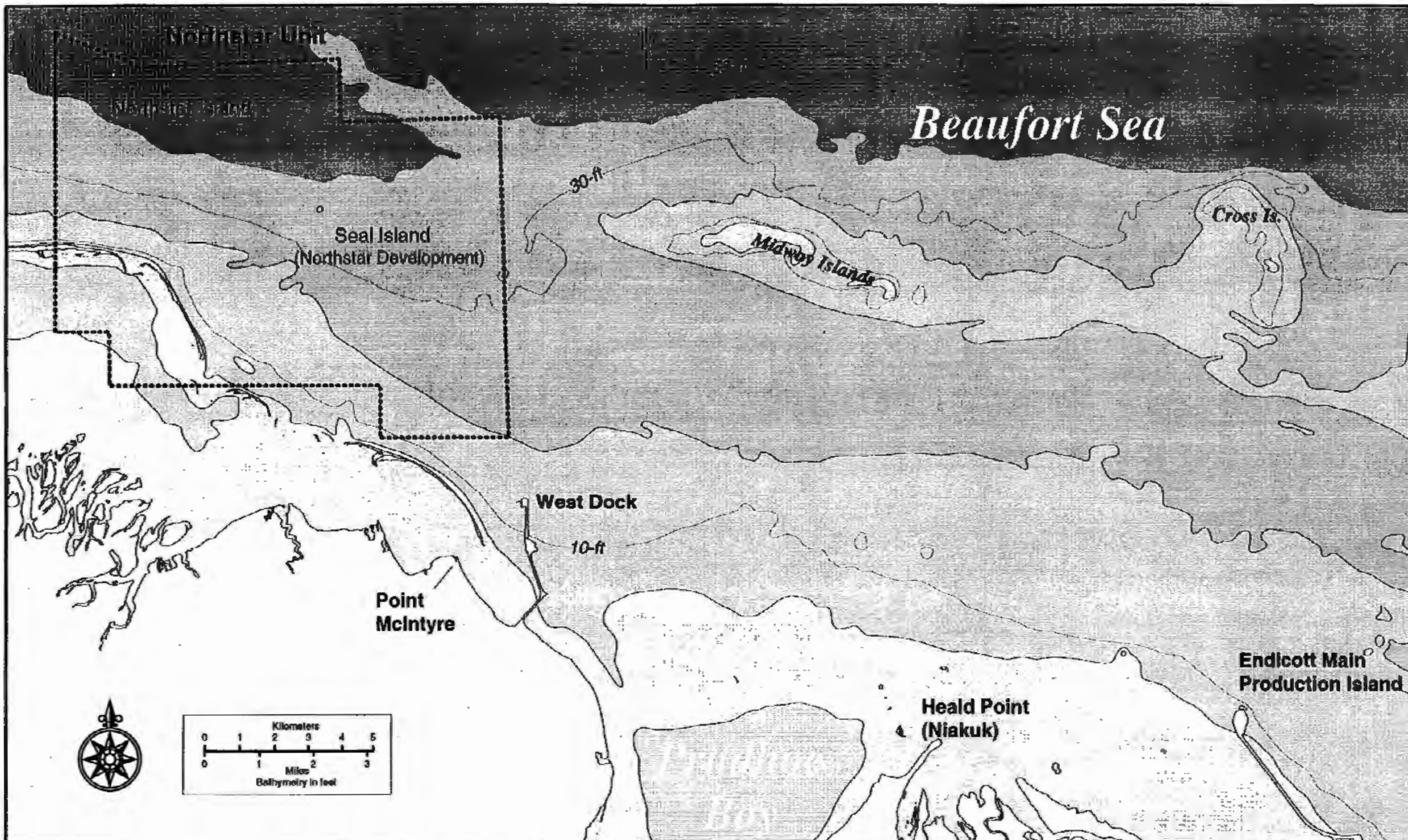
PSD Permits	—	under state authority, see State Permits below

State Permits

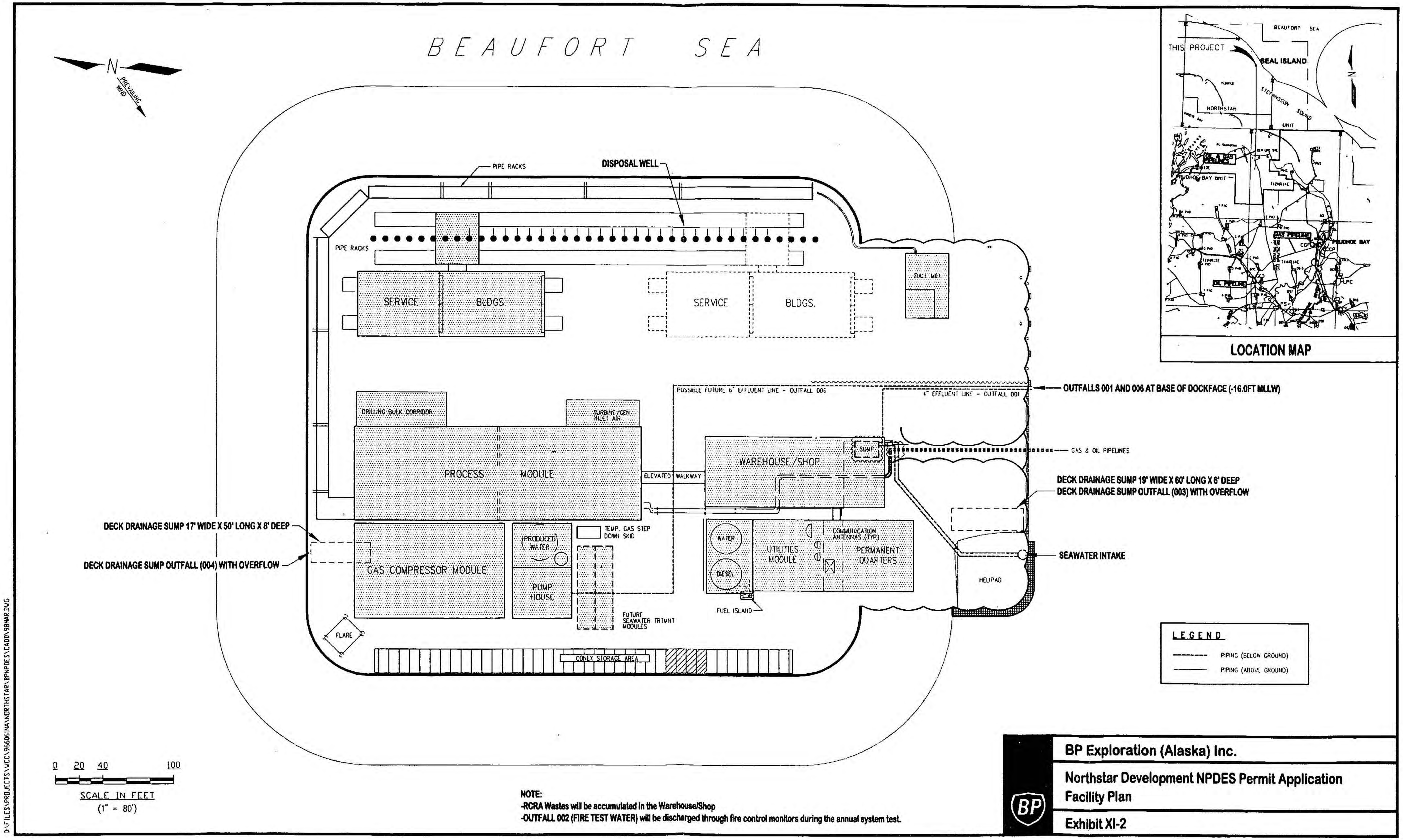
UIC Class II Permits	—	Endicott Area Injection Order, AOGCC AIO #1
Waste Disposal Permits	—	Waste Disposal (Class II Injection), 8436-DB003
Air Quality Control Permits	—	AQC Operations, 9373-AA007
	—	AQC MPI/SDI Testing, 8636-AA001
	—	1990 AQC for Fire Training, 9536-AB001
Other	—	DIU General Lease Operations Permit, LONS 84-99
	—	Endicott Pipeline R/W Lease (State), ADL 410562 (7-507-1)

Local Permits

Development Permits	—	General Endicott Development Permit, NSB DIU 85-04
	—	General Causeway Development Permit, NSB DIU 85-05



BP EPA FORM 1 General Information Form	NORTHSTAR UNIT AND THE PRUDHOE BAY AREA	Exhibit XI-1

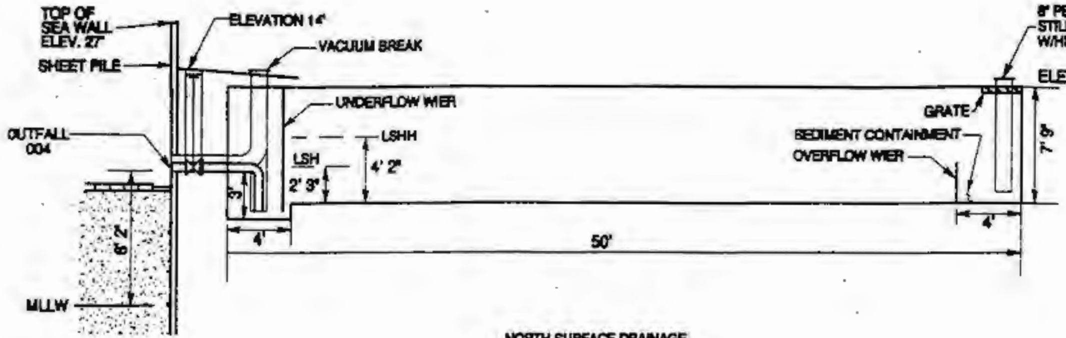


NOTE:
-RCRA Wastes will be accumulated in the Warehouse/Shop
-OUTFALL 002 (FIRE TEST WATER) will be discharged through fire control monitors during the annual system test.

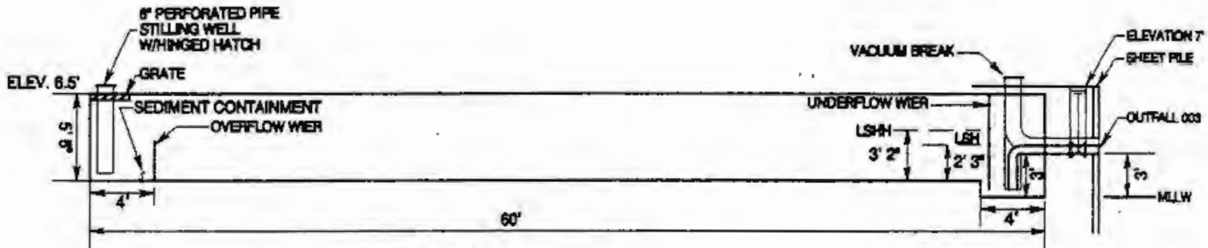
BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Facility Plan

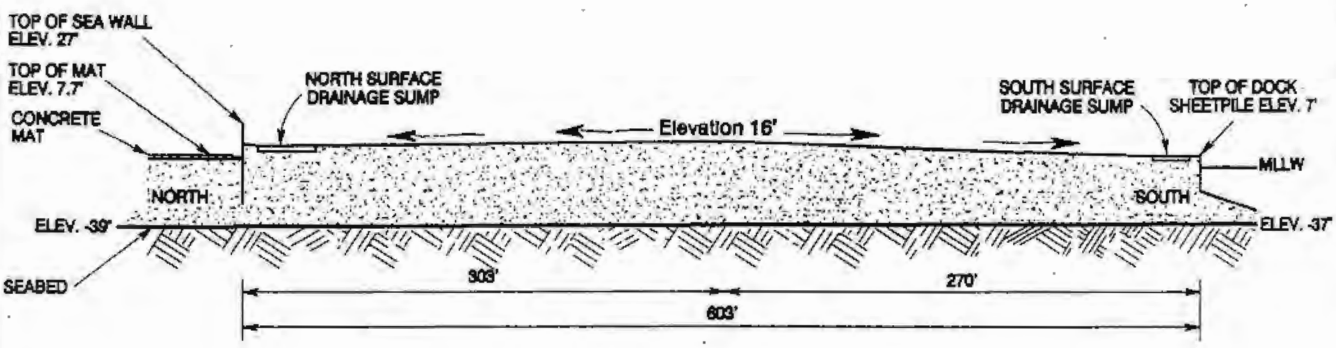
Exhibit XI-2



NORTH SURFACE DRAINAGE
SUMP FOR OUTFALL 004



SOUTH SURFACE DRAINAGE
SUMP FOR OUTFALL 003



SURFACE DRAINAGE

SOURCE:
BPXA'S FINAL PROJECT DESCRIPTION
(BPXA, 1997 : FIG. 2.1-15 #1659)

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
GRADING AND DRAINAGE
SIDE VIEW

DATE: 13 March 1998	SCALE: NOT TO SCALE	EXHIBIT XI - 3

REV. 2.0, bs13734.dgn

EPA FORM 2D

NEW SOURCES AND NEW DISCHARGES APPLICATION FOR PERMIT TO DISCHARGE PROCESS WASTEWATER

Please type or print in the unshaded areas only	EPA ID Number *(copy from Item 1 of Form 1)*	Form Approved OMB No. 2040-0086 Approval expires 7-31-88

Form 2D NPDES

EPA New Sources and New Dischargers Application for Permit to Discharge Process Wastewater

I. Outfall Location

For each outfall, list the latitude and longitude, and the name of the receiving water.

Outfall Number *(list)*	Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Receiving Water *(name)*
001(a)	*70*	*29*	*30*	*148*	*41*	*37*	***Beaufort Sea, Stefansson Sound** (continuous flush discharge)*
001(b)	*70*	*29*	*30*	*148*	*41*	*37*	***Beaufort Sea, Stefansson Sound** (potable water discharge)*
001(c)	*70*	*29*	*30*	*148*	*41*	*37*	***Beaufort Sea, Stefansson Sound** (wastewater discharge)*
002	*70*	*29*	*30*	*148*	*41*	*37*	***Beaufort Sea, Stefansson Sound** (fire water discharge)*
003	*70*	*29*	*30*	*148*	*41*	*37*	***Beaufort Sea, Stefansson Sound** (deck drainage sump outfall)*

II. Discharge Date *(When do you expect to begin discharging?)*

(second quarter) 1999

III. Flows, Sources of Pollution, and Treatment Technologies

A. For each outfall, provide a description of (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and stormwater runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

Outfall Number	1. Operations Contributing Flow *(list)*	2. Average Flow *(include units)*	3. Treatment *(Description or List Codes from Table 2D-1)*
001(a)	*Continuous Flush wastewater*	*21,600 gpd*	*1-T (screening)*
			2-F (disinfection - chlorine)
			2-E (dechlorination)
			4-B (ocean discharge thru outfall)
001(b)	*Brine effluent associated with the*	*3,528 gpd*	*1-T (screening)*
	Potable Water System		*1-D (distillation)*
	(vapor compression distillation)		*2-C (chemical precipitation)*
			2-F (disinfection - chlorine)
			2-E (dechlorination)
			4-B (ocean discharge thru outfall)
	Note: gpd = gallons per day		

NEXT PAGE

Please type or print in the unshaded areas only

EPA ID Number *(copy from Item 1 of Form 1)*

Form Approved
OMB No. 2040-0086
Approval expires 7-31-88

Form 2D NPDES

EPA New Sources and New Dischargers Application for Permit to Discharge Process Wastewater

I. Outfall Location

For each outfall, list the latitude and longitude, and the name of the receiving water.

Outfall Number *(list)*	Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Receiving Water *(name)*
004	70	29	30	148	41	37	Beaufort Sea, Stefansson Sound (deck drainage sump outfall)
005	70	29	30	148	41	37	Beaufort Sea, Stefansson Sound (construction dewatering)
006	70	29	30	148	41	37	Beaufort Sea, Stefansson Sound (STP waterflood outfall)

II. Discharge Date *(When do you expect to begin discharging?)*

(second quarter 1999)

III. Flows, Sources of Pollution, and Treatment Technologies

A. For each outfall, provide a description of (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and stormwater runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

Outfall Number	1. Operations Contributing Flow *(list)*	2. Average Flow *(include units)*	3. Treatment *(Description or List Codes from Table 2D-1)*
001(c)	Effluent discharged from the	2,800 gpd	1-T (screening)
	Wastewater Treatment System		1-D (distillation)
	temporary discharge during periods		2-C (chemical precipitation)
	that the Class I/II injection well is not		3-A (activated sludge)
	available		2-H (disinfection - ultraviolet light)
			5-A (aerobic digestion)
			2-E (dechlorination)
			4-B (ocean discharge thru outfall)
		Sludge Disposal	[4-D (underground injection)
			Or Disposal at Approved Onshore Facility]
	Note: gpd = gallons per day		

———— NEXT PAGE ————

Please type or print in the unshaded areas only	EPA ID Number *(copy from Item 1 of Form 1)*	*Form Approved OMB No. 2040-0086 Approval expires 7-31-88*

Form 2D NPDES **EPA**

New Sources and New Dischargers
Application for Permit to Discharge Process Wastewater

I. Outfall Location

For each outfall, list the latitude and longitude, and the name of the receiving water.

Outfall Number *(list)*	Latitude			Longitude			Receiving Water *(name)*
	Deg	Min	Sec	Deg	Min	Sec	

II. Discharge Date *(When do you expect to begin discharging?)*

(second quarter 1999)

III. Flows, Sources of Pollution, and Treatment Technologies

A. For each outfall, provide a description of (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and stormwater runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

Outfall Number	1. Operations Contributing Flow *(list)*	2. Average Flow *(include units)*	3. Treatment *(Description or List Codes from Table 2D-1)*
002	Seawater discharged through the	typically no flow	4-A (discharge to surface waters)
	Fire Test Water Distribution		1-T (screening)
	System		
003	Deck Drainage Sump Outfall	25 gpd	4-A (discharge to surface waters)
004	Deck Drainage Sump Outfall	25 gpd	4-A (discharge to surface waters)
005	Construction Dewatering Outfall	1,000,000 gpd	4-A (discharge to surface waters)
			1-T (screening)
006	Filter backwash from the	31,296 gpd	4-B (ocean discharge thru outfall)
-	Waterflood Seawater		1-Q (multimedia filtration)
	Treatment Plant		1-T (screening)
			2-F (disinfection - chlorine)
			2-E (dechlorination)

B. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item III-A. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

C. Except for storm runoff, leaks, or spills, will any of the discharges described in item III-A be intermittent or seasonal?

☐ Yes *(complete the following table)* ☒ No *(go to item IV)*

Outfall Number	1. Frequency		2. Flow		
	a. Days Per Week *(specify average)*	b. Months Per Year *(specify average)*	a. Maximum Daily Flow Rate *(in mgd)*	b. Maximum Total Volume *(specify with units)*	c. Duration *(in days)*

IV. Production

If there is an applicable production-based effluent guideline or NSPS, for each outfall list the estimated level of production (projection of actual production level, not design), expressed in the terms and units used in the applicable effluent guideline or NSPS, for each of the first 3 years of operation. If production is likely to vary, you may also submit alternative estimates (attach a separate sheet).

Year	a. Quantity Per Day	b. Units of Measure	c. Operation, Product, Material, etc *(specify)*
			Not Applicable

CONTINUE ON NEXT PAGE

EPA ID Number *(copy from item one of Form 1)*

VII. Other Information *(Optional)*

Use the space below to expand upon any of the above questions or to bring to the attention of the reviewer any other information you feel should be considered in establishing permit limitations for the proposed facility. Attach additional sheets if necessary.

See Attachment 1

VIII. Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

A. Name and Official Title *(type or print)*	B. Phone No.
DAVID A. WALLACE / HSE Business Manager	**(907) 564-5053**
C. Signature	**D. Date Signed**
for David A. Wallace	10/1/97

ATTACHMENT 1

BPXA believes that for the expected discharges at the Northstar facility, a number of parameters can be excluded from monitoring for the following reasons:

- Based on the effluent generating process the parameters are not reasonably expected

- The NPDES program provides a mechanism for eliminating certain parameters if existing information is adequate to support less stringent requirements.

Regulatory Background
Under 40 CFR Part 122 .21(g)(7)(i)(B) reporting requirements may be waived for individual point sources or for a particular industry category for one or more of the following pollutants if the applicant had demonstrated that such a waiver is appropriate because information adequate to support issuance of a permit can be obtained with less stringent requirements:

- Biological Oxygen Demand (BOD5)
- Chemical Oxygen Demand
- Total Organic Carbon
- Total Suspended Solids
- Ammonia (as N)
- Temperature (both winter and summer)
- pH

Potable Water (Desalination Unit) Discharge (Outfall 001b)
Historical monitoring requirements for the reverse osmosis (RO) unit effluent at Endicott have not included the testing of the following parameters:

- Biological Oxygen Demand (BOD5)
- Chemical Oxygen Demand
- Total Organic Carbon
- Total Suspended Solids
- Ammonia (as N).

Testing for similar discharges at Endicott and other North Slope facilities has not been conducted. Following this precedent we believe that this testing should not be required for desalination unit effluent at the Northstar facility.

Wastewater (Sewage) Discharge (Outfall 001c)
As required at other North Slope facilities such as Endicott, it is expected that for the temporary sewage discharge, only the following parameters will be measured:

- Biological Oxygen Demand (BOD5)
- Total Suspended Solids.

Fire Water Test Discharge (Outfall 002)
Historical monitoring requirements for fire water discharge at Endicott have not included the testing of the following parameters:

- Biological Oxygen Demand (BOD5)
- Chemical Oxygen Demand
- Total Organic Carbon
- Total Suspended Solids
- Ammonia (as N).

Testing for similar discharges at Endicott and other North Slope facilities is not required, and therefore results do not appear in existing permits. Following this precedent and due to the fact that this intermittent discharge is not expected to contain any of these parameters at levels above ambient, we believe that this testing should not be required for fire test effluent at the Northstar facility.

Possible Seawater Treatment Plant Backwash Discharge (Outfall 006)
Historical monitoring requirements for the seawater treatment plant backwash effluent at Endicott have not included the testing of the following parameters:

- Biological Oxygen Demand (BOD5)
- Chemical Oxygen Demand
- Total Organic Carbon
- Ammonia (as N)

Testing for similar discharges at Endicott and other North Slope facilities has not been conducted. Following this precedent we believe that this testing should not be required for STP backwash effluent at the Northstar facility. Only Total Suspended Solids will be monitored from this flow.

EPA FORM 2D

OVERVIEW

Exhibit 1

Seal Island Seawater Process Overview

Seawater Intake

It is anticipated that the average volume of seawater entering the intake sump each day will be 40,500 gallons. Of this amount, 6,300 gallons will be diverted to the potable water system, 21,600 gallons to the continuous flush system, and 12,600 gallons to the drilling system and ball mill. If Waterflood is chosen for enhanced oil recovery (EOR), the average system intake will increase to a total of 2,591,796 gallons per day (gpd). It is planned that a small amount of unchlorinated seawater will be routed through the fire pumps and back to the sump on a weekly basis. In the event of a fire, seawater will be directly pumped into the fire water distribution system for fire suppression. Exhibit 2 provides a flow chart of the entire process that uses seawater.

Seawater Chlorination

There are three waste streams that supply effluent to Outfall 001:

- Continuous flush discharge, Outfall 001(a)
- Desalination (potable water) unit discharge, Outfall 001(b)
- Wastewater (sewage) discharge, Outfall 001(c)

Seawater will be chlorinated immediately downstream of the intake sump to prevent biological growth. Chlorine will be injected into the utility water feed line which supplies seawater to the Continuous Flush System, Potable Water System, and the Drilling System & Ball Mill (Exhibit 2). Chlorine, in the powder or tablet form of calcium hypochlorite [$Ca(OCl)_2$ - MSDS provided in Attachment 9] will be dissolved in two 40 gallon (gal) containers for a total daily volume of 80 gal. This solution will be injected into the feed line to maintain a chlorine concentration of 0.2 ppm. A Capital Controls Company, Inc. Residual Analyzer, Model 1870E, (Attachment 2) installed immediately downstream of the chlorine injection pump will continuously monitor the feed line chlorine concentration (Unit #A1, Exhibit 2). If the chlorine concentration varies beyond engineering specifications, the online residual analyzer will signal an electronic controller (Capital Controls Company, Inc. Controller, Model 1451) to change the chlorine injection rate to maintain the 0.2 ppm feed line concentration (Attachment 3).

The concentration of calcium hypochlorite in the 80 gal of solution is 1.2 percent by weight, whereas the solubility at 15°C permits up to 12 percent by weight. Thus, all of the calcium hypochlorite is expected to remain in solution.

The equilibrium concentration of chlorine in water at 15.56°C and atmospheric pressure (14.7 pounds per square inch) is 6.9 pounds per 100 gal, or 5.5 pounds per 80 gal. To maintain 0.2 ppm chlorine concentration in the feed line, 4.48 pounds (net) of chlorine will be dissolved in 80 gal of water. Thus, all of the chlorine will be in solution.

Effluent

Effluent from the desalination process (see Exhibits 4 and 5), continuous flush system (Exhibit 3), and any temporary discharge from the wastewater treatment plant (Exhibits 6 and 7) will be routed through outfall 001. While the normal discharge of the wastewater treatment plant effluent will be through the Class I/II injection well, this waste stream will be diverted to the marine outfall during facility construction and periods when the injection well is not operable. The desalination process will be done in batches, and desalination wastes (brine with a salinity up to 65 ppt), will be intermittently commingled with a continuous flow of 21,600 gpd of chlorinated seawater through the system. The continuous flush is needed to prevent biofouling of the discharge lines, and also eliminate possibility of ice formation within the lines.

Effluent from the wastewater treatment plant will normally be injected into the disposal well along with washdown water, and process water/effluent from the drilling system and ball mill. In the event that the disposal well is not operable, domestic wastewater will be temporarily discharged through marine outfall 001. Activities generating washdown water, and the operation of the drilling system and ball mill will be halted until the disposal well is once again operational. No washdown water drilling wastes, or produced water will be routed through outfall 001.

The commingled waste streams are expected to have a water temperature between 2°C and 4°C. In the absence of engineering estimates, conservative assumptions for temperature were used for dilution computations in the *Draft Northstar Development Unit Mixing Zone Application*. The Mixing Zone Application assumed a worst case 5°C discharge during winter conditions; however, the water temperature met Alaska water quality standards within 2.3 meters (m) or 7.5 feet (ft) of the outfall. During summer conditions, dilution computations for the worst case discharge temperature of 8.1°C indicated that Alaska water quality standards were achieved at the 5-m (16.4-ft) mixing zone boundary.

Dechlorination

The only waste stream that is expected to contain residual chlorine is the continuous flush. The commingled waste streams from the continuous flush, desalination unit, and wastewater treatment plant will pass through a dechlorinator prior to marine discharge. Total residual chlorine (TRC) will be scavenged by injecting a solution of sodium metabisulfite ($Na_2S_2O_5$) into the combined waste streams of Outfall 001. This dechlorination process is a chemical reaction that is anticipated to occur within 10 seconds after injection into the combined waste stream. The following facilities in the Prudhoe Bay area use sodium metabisulfite or similar sulfite compounds to dechlorinate the waste stream prior to discharge:

- BPXA Endicott facility (NPDES Permit AK-003866-1)
- BPXA Prudhoe Bay Central Sewage Treatment Facility (CSTF) (NPDES Permit AK-002860-6)
- ARCO Alaska, Inc. Kuparuk Seawater Treatment Plant (NPDES Permit AK-004335-4)

Attachment 4 is a detailed description of the dechlorination process and states that the reactions between seawater and the sodium sulfite salts (sodium sulfite, sodium bisulfite, sodium metabisulfite, sodium thiosulfate) are identical with the following results:

1. Sulfite salts dissociate in water to sulfur dioxide gas:

$$SO_2 + H_2O = H^+ + HSO_3$$
$$NaSO_3 + H_2O = Na^+ + HSO_3$$
$$NaHSO_3 + H_2O = Na^+ + HSO_3$$
$$Na_2S_2 + H_2O = Na^+ + HSO_3$$

2. Sulfite ions react instantaneously with free and combined chlorine:

$$SO_3^{-2} + HOCl = SO_4^{-2} + Cl^- + H^+$$
$$SO_3^{-2} + HOBr = SO_4^{-2} + Br^- + H^+$$
$$SO_3^{-2} + NH_2Cl = SO_4^{-2} + Cl^- + NH_4^+$$
$$SO_3^{-2} + NH_2Br = SO_4^{-2} + Br^- + NH_4^+$$

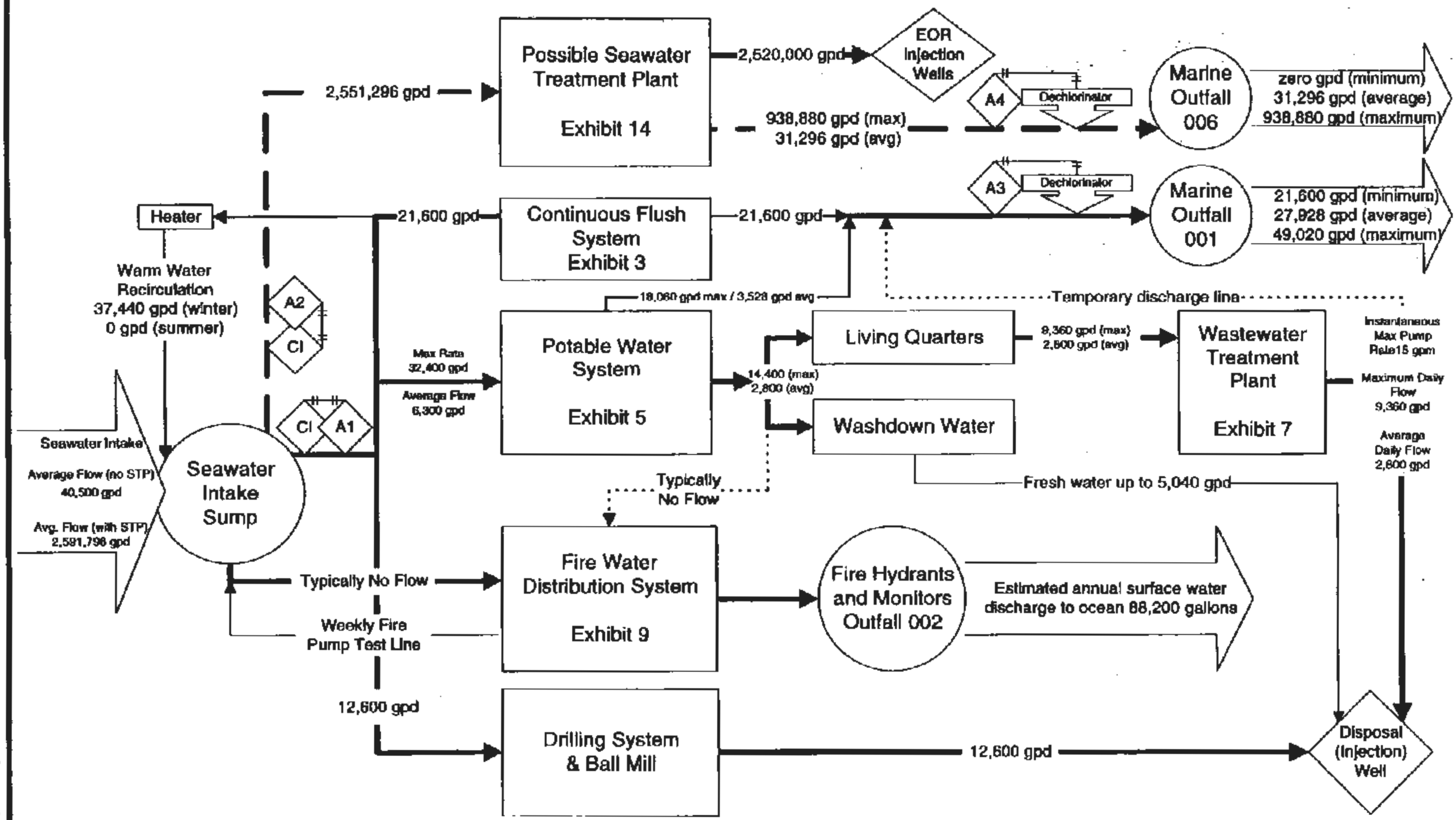
The reaction products are mainly sulfite and sulfate ions which are abundantly and naturally found in seawater.

Engineering control philosophy for dechlorination includes the installation of a residual chlorine analyzer (Capital Controls Company, Inc. Residual Analyzer, Model 1870E) immediately upstream of the sodium metabisulfite injection point (Unit #3 on Exhibit 2). Engineering specifications require that a minimum detectable concentration of TRC remain in the fluid stream prior to dechlorination. Sufficient sodium metabisulfite will be added to assure the total residual chlorine concentration is reduced to 2 ppb or less. If the chlorine concentration varies beyond engineering specifications, the online residual analyzer will signal an electronic controller (Capital Controls Company, Inc. Controller, Model 1451) to change the sodium metabisulfite injection rate.

The fire test water distribution system (outfall 002, Exhibits 8 and 9) is expected to discharge approximately 88,200 gallons of untreated seawater annually to the ocean. The final discharges covered under this NPDES application are deck drainage (outfalls 003 and 004, Exhibits 10 and 11; not shown on Exhibit 2), and construction dewatering (outfall 005, Exhibits 12 and 13; not shown on Exhibit 2).

Exhibit 1
Seal Island Seawater Process Overview

If waterflood is chosen for enhanced oil recovery, then the seawater treatment plant (STP) option will be implemented. If implemented, 2,520,000 gpd will be injected into the waterflood wells. STP operations will include a filter backwash cycle that will result in a maximum instantaneous flow from the backwash effluent of 652 gpm routed intermittently to marine outfall 006 (see Exhibits 14 and 15). On average, the daily volume of backwash effluent is expected to be 31,296 gallons. A separate chlorination and dechlorination system will be utilized for this waste stream The systems will be identical to those used to chlorinate and dechlorinated waste streams entering outfall 001.



Notes:
gpd = gallons per day
gpm = gallons per minute
A# = online residual chlorine analyzer with designated Unit #
Cl = system chlorinator using $Ca(OCl)_2$
Washdown water will not be discharged through a marine outfall.

BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Seal Island Seawater Process Line Diagram

Exhibit 2

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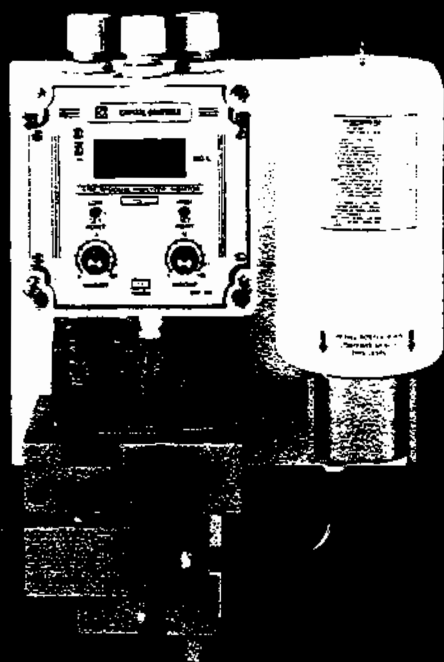
ATTACHMENT 2

CAPITAL CONTROLS RESIDUAL ANALYZER
MODEL 1870E

Chlorine Residual Analyzer — Series 1870E



Capital Controls

ISO 9001 Certified

Capital Controls' Series 1870E chlorine residual analyzer technology has been independently tested and proven to be a reliable analyzer for continuous, accurate residual analysis.

The amperometric-based instrument is designed to continuously analyze free or total chlorine, chlorine dioxide, potassium permanganate, iodine, bromine or other oxidants for water, wastewater, cooling water and other process water applications.

Series 1870E features a field selectable monitoring range from 0-0.1 to 0-20 mg/l. The analyzers incorporate a constant, direct-drive electrode cleaning system which eliminates signal drift and the need for frequent recalibration. Internal high and low set points are standard.

The analyzer's reagent and sample are gravity fed eliminating the need for metering pumps. Extra large gold and copper electrodes are used for maximum signal strength. Sample temperature variations are compensated within the measuring cell, thereby providing consistent residual values.

Series 1870E analyzers are constructed of corrosion-resistant materials. Each unit is pre-piped and pre-wired requiring only field connection to service points. All components and controls are accessible from the front of the unit to permit ease of observation of solution level, sample flow, electrode cleaning system and adjustment of set points.

- **Continuous on-line operation**
- **High-reliability**
- **Field-proven**
- **Multiple ranges - selectable up to 20 mg/l**
- **High and low alarm points**
- **Automatic cleaning system**
- **Direct measurement of free or total chlorine**
- **High/low band control for chemical feed systems**
- **Highly accurate low level readings**

210.0001.0
(Formerly A1.11870E)

Applications

- **Wastewater**: Feed-forward dechlorination control; Effluent monitoring
- **Industrial wastewater**: Effluent control
- **Power Industry**: Effluent monitoring to meet NPDES and M.O.E. discharge limits
- **Drinking water disinfection**: In-plant and finished water monitoring and control
- **Food and beverage**: Zero verification after carbon filtration
- **Pharmaceuticals**: Zero verification after carbon filtration; simplification of validation procedures
- **Swimming pool disinfection:** Accurate control of chlorine residual
- **Cooling water monitoring and control:** Control of slime and algae in piping and heat exchangers and throughout the tower

Design Features

- **Gravity feed reagent**: Provides the analyzer with a sample pH of 4.5-4.8 which increases the stability and strength of the generated signal
- **High and low alarm set points**: Monitor and control chlorine and other residual oxidants within a concentration band by using high and low alarm set points that are easily adjusted on the front panel. LED lights indicate an alarm has occurred. A latching contact option is available to provide band control for high-low feed control systems
- **Large cell**: The extra large gold and copper electrodes provide maximum signal strength
- **Automatic cleaning**: A continuous direct-drive cleaning system maintains a constant level of electrode cleanliness
- **Ease-of-use:** All components and controls are accessible from the front of the unit to permit ease of observation of solution level, sample flow, electrodes and adjustment of set points
- **Accurate**: The 2% accuracy of the unit is ideal for monitoring and control of water, wastewater and industrial process water
- **Mounting:** Easy mounting is accomplished through the mounting panel where all components are attached. Units can also be supplied in a floor or wall cabinet
- **NEMA 4X**: The electronics enclosure is NEMA 4X for protection

Principle of Operation

A sample liquid is delivered to the constant head weir at an approximate rate of 500 ml/minute. The excess overflows to drain. (Figure 1).

The sample then passes through the annular space between the two fixed electrodes in the sensing cell. As it passes, a small DC current is generated in direct linear proportion to the amount of residual present in the sample. The residual value is displayed on the digital indicator in mg/l.

The surfaces of both electrodes are kept clean by the continuous action of PVC spheres agitated by a motor-driven rotating striker. This constant cleaning eliminates signal drift and recalibration, and provides an accurate residual measurement. A thermistor compensates for sample temperature variation.

The liquid reagent is stored in a single bottle and fed from a constant head reservoir through a rotary valve. This configuration adds the precise amount of solution during each valve rotation. The reagent bottle supplies 7 days of use before refilling is required. An optional reagent feed system may be adapted for pH buffering using carbon dioxide gas for water treatment applications.

Specifications

Instrument Range: Field selectable 0-0.1, 0-0.2, 0-0.3, 0-0.5, 0-1, 0-2, 0-3, 0-5, 0-10, 0-20 (mg/l) (Others available, consult factory)

Resolution: 0.001 mg/l (1 ppb)

Power Requirements: 120 Vac, 60 Hz, or 240 Vac, 50 Hz, single phase

Output Signal: Isolated 4-20 or 0-20 mAdc into a maximum of 800 ohms or 0-50 mVdc

Sample Flow: 500 ml/minute

Sample Temperature Range: 32° to 120°F (0° to 50°C)

Speed of Response: 4 seconds from sample entry to display indication. 90% of full scale response within 1½ to 2 minutes

Ambient Temperature: 32°F to 120°F (0°C to 50°C)

Sample Limitations: Samples containing high concentrations of metal ions or certain corrosion inhibitors may effect analyzer operation. At low residual levels (less than 0.1 mg/l) variations in sample dissolved oxygen level may affect the residual reading. Consult factory for specific applications.

Accuracy:0.003 mg/l or ±2% of range whichever is larger. (see sample limitations)

Reagent Requirements:

Residual	Reagent
Chlorine (Free)	pH buffer (or CO_2 gas)
Chlorine (Total)	pH buffer (or CO2 gas) & potassium iodide
Chlorine Dioxide	pH buffer and glycine
Potassium Permanganate	pH buffer
Iodine	pH buffer
Bromine	pH buffer and potassium iodide
Other Oxidants	Consult Factory

Shipping Weight: 14 lbs. (6.4 kgs)

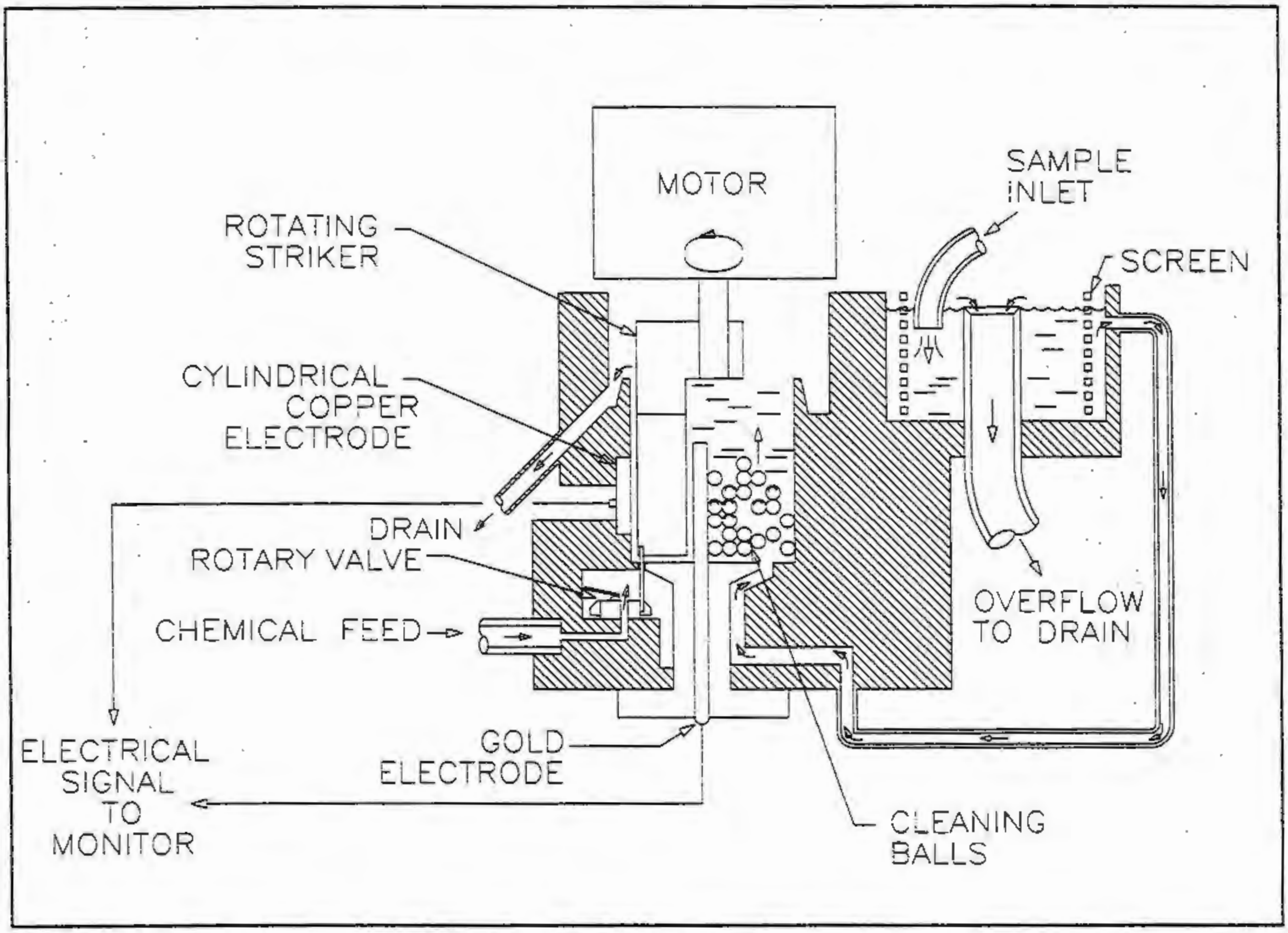


Figure 1 - Series 1870E Flow Diagram

Model Information Code

Model 1 8 7 0 E _ _ _ _ _ _ _ _ _

Chemical
C - Free Chlorine
T - Total Chlorine
P - Potassium Permanganate
R - Bromine
I - Iodine

Buffer Feed
B - pH 4
C - Carbon dioxide gas

Mounting
1 - Wall Panel
2 - Floor Cabinet
3 - Wall Cabinet

Voltage
1 - 110/120 Vac. 60 Hz, single phase
2 - 220/240 Vac. 50 Hz, single phase

Relay Contacts
1 - Dual set point alarm contacts
2 - Dual latching set point alarm contacts

Signal Output
1 - 4-20 mAdc
2 - 0-20 mAdc
3 - 0-50 mVdc

Range (in mg/l)
01 - 0-0.100
02 - 0-0.200
03 - 0-0.300
04 - 0-0.500
05 - 0-1.000
06 - 0-2.000
07 - 0-3.00
08 - 0-5.00
09 - 0-10.00
10 - 0-20.00

Warranty and Capability

Capital Controls offers a one (1) year limited warranty on all residual analyzers.

Capital Controls is ISO9001 certified to provide quality and precision materials, and specializes in disinfection technologies, water quality monitors and instrumentation for water and wastewater. Over 30 years of industrial and municipal application experience in the water and wastewater industries is incorporated into the equipment design to provide the highest quality comprehensive solutions for the global market.

Brief Specification

The residual analyzer shall continuously analyze a water sample in an amperometric type of cell and produce a current proportional to the free chlorine residual in the sample. The range of the analyzer shall be field selectable for 0 to 0.100, 0.200, 0.300, 0.500, 1.000, 2.000, 3.00, 5.00, 10.00, 20.00 mg/l. The residual analyzer shall be a wall mounted design within a NEMA 4X enclosure. The electrodes shall be fixed and shall be continuously cleaned by the action of small spheres moved in a spatial action between the surfaces by a motor-operated striker.

Automatic temperature compensation shall be provided. The sensing cell shall consist of fixed gold and copper electrodes. The isolated output signal shall be 4-20 or 0-20 mAdc into a maximum of 800 ohms, or 0-50 mVdc. The cell shall be kept clean by a motor direct-driven plastic striker agitating small PVC spheres against both electrodes to keep dirt and other interfering substances from the face of the electrodes and eliminate signal drift. The cleaning operation shall be continuous. Separate high and low set points shall be provided and shall be adjustable from the front of the unit from 0-100% of the range. Each set point shall have a corresponding light on the face of the unit. A latching contact option shall provide band control.

The analyzer shall operate from a 110/120 Vac, 60 Hz or 220/240 Vac, 50 Hz single phase power supply.

Liquid reagent shall be gravity fed from a single bottle, constant head reservoir through a rotary valve. The unit shall have a specified accuracy of 0.003 mg/l or ±2% of range, whichever is larger.

Design improvements may be made without notice.

Represented by:

SITTINGBOURNE, U.K.

DIDCOT, U.K.

HONG KONG

MALAYSIA

Capital Controls

Capital Controls Company, Inc.
3000 Advance Lane, P.O. Box 211
Colmar, PA 18915
Tel: 215-997-4000
Fax: 215-997-4062

A Severn Trent Company

Pub. No. 187-1 11/94 6M

ALASKA INSTRUMENT COMPANY, INC.
P.O. BOX 230087 • ANCHORAGE, ALASKA 99523-0087 • (907) 561-7511

August 5, 1997

B.P. Exploration
P.O. Box 196612
900 E. Benson Blvd.
Anchorage, Alaska 99519-6612

Attention: Mr. Arthur LeMaster, Veco Engineering

Subject: User list of Capital Controls 1870 E analyzer and 1451 controller

Dear Mr. LeMaster,

The following represents some current users of the above referenced products. If a more extensive list is required I can accommodate that request.

City of Lynnwood, Washington-Don Davis-206-670-6272-1870E and 1451

City of Tacoma, Wa.-Al Medak-206-502-8210-3 ea. 1870 analyzers used with gas chlorinators

City of Bellingham, Wa.-Bill Evans-360-676-6592-3 ea. 1870 analyzers also used with gas chlorinators

City of Eau Clair, Wisconsin-Steve Hayden, Utility Engineer-715-839-6117-Discharge into Chipawa River

City of Deroha, Iowa-Dave Halverson-WWTP Chief Operator-319-382-3410

City of Aitkin, MN-Tom Klingelhoffer-WWTP-218-927-2527-Discharge into wetlands

City of Sauk Centre, MN-Arnie Blaskowiski-WWTP Operator-612-252-2203-Discharge into Sauk River.

Please call if you have further questions.

Regards,

Steve Barnett

Steve Barnett
Account Manager

ATTACHMENT 3

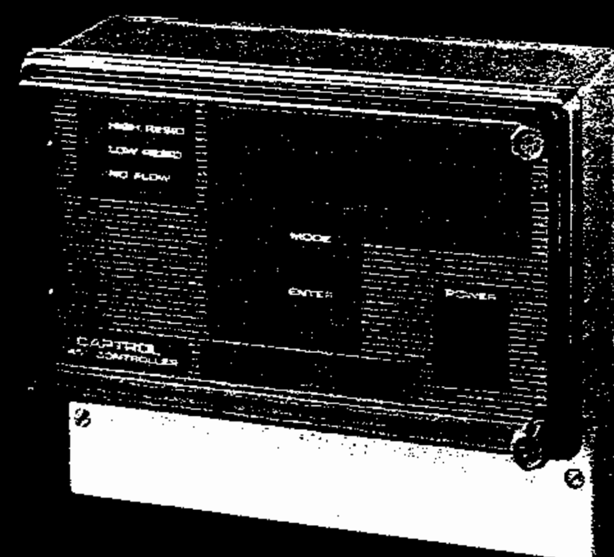
CAPITAL CONTROLS CONTROLLER
MODEL 1451

CAPTROL® MODEL 1451

CAPITAL CONTROLS COMPANY, INC.

MICROPROCESSOR-BASED CONTROLLER

- Microprocessor-based digital electronics
- Digital alphanumeric displays
- Six field configurable control modes
- 4:1 dosage turn-up
- Single loop backup to compound loop control
- ISO 9001 Certification



Capital Controls CAPTROL® Model 1451 controller offers a host of exciting features that make it uniquely suited to disinfection, oxidation, and water quality monitoring and control. Standard output provides a 4-20 mA signal for controlling a broad range of valves or chemical feed pumps. Microprocessor-based digital electronics and digital alphanumeric displays vastly simplify setup and operation. Fully field configurable control modes can be changed easily and rapidly using front panel controls. Overall quality and reliability are assured and maintained through Capital Controls' ISO 9001 certification.

Microprocessor-based electronics automatically adjust the control valve or metering pump to maintain desired feed rates based upon input signals from the plant flow meter and/or residual analyzer or water quality monitor.

User configurable control modes, specific to automating chlorination and ammoniation water treatment applications, include flow proportioning, residual and compound loop, cascade control as well as dual input feedforward control with internal multiplier for feedforward dechlorination.

Four pushbutton switches, conveniently located on the front panel, provide for rapid setup and simplified operation including manual positioning of the control valve or metering pump. Field conversion to any control mode is accomplished by simple pushbuttom mode commands selected by the operator. An internal battery protects setup parameters up to four days in the event of a power failure.

Control range adjustment of dosage (loop gain) on the flow input signal extends upwards to a ratio of 4:1 or down to zero permitting the operator to accommodate an oversized flow meter or oversized control valve or metering pump. Dosage adjustment is automatic with microprocessor control in compound loop.

Microprocessor-based control provides precise control around set point in compound loop by automatically adjusting process lag time for changes in flow rate. It also provides uninterrupted operation in the event that one compound loop input signal is lost by automatically transferring to single loop control.

L.E.D. alarm indicators mounted on the front panel for easy viewing alert the operator to conditions of low or no plant water flow, and high or low deviation of residual beyond limits preset by the operator. Each alarm includes relay contacts for control of remote warning and control devices.

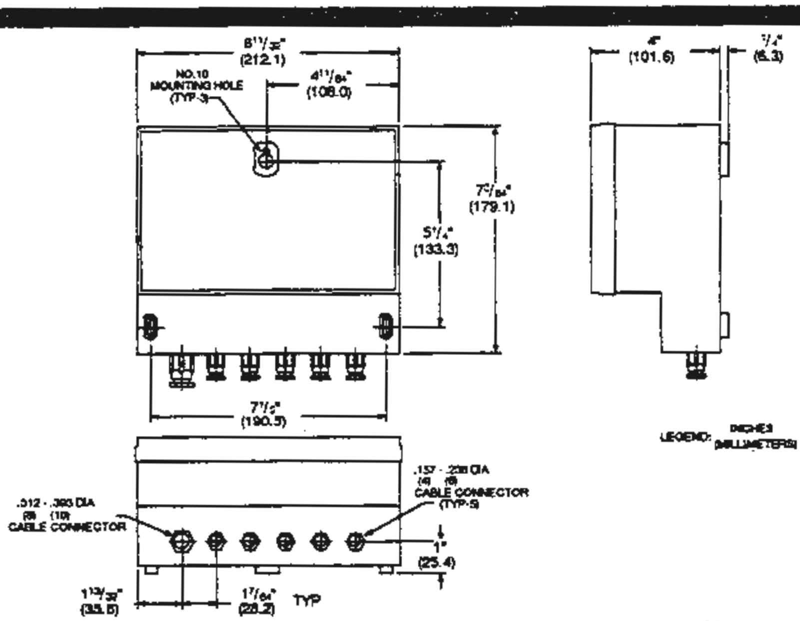
Safe operation of a vacuum gas feed system is enhanced through the provision of a discrete input for connection of high/low vacuum switches which close the control valve and cutoff gas feed, after a 30 second timeout, in the event of abnormal vacuum conditions. For plants requiring backup operation, a duty/standby discrete switch input provides for operator selection of the active and backup system.

Enclosure design protects internal circuits from water and dust, and provides separate access to electronics and wiring terminals for easy cabling and enhanced personnel safety.

General Specifications

Control Technology:	Microprocessor
Data Protection:	Four (4) day internal battery backup (NiCd battery rated at 6 V, 280 mAhr)
Display:	Liquid Crystal Display (LCD), 48 characters with adjustable contrast; anti-glare protection on display window
Indicators:	Light Emitting Diode (LED) alarm indicators for low/high residual set point deviation, and low water flow
Control Modes	
a. Chlorination:	Flow proportioning, residual, or compound loop or cascade control
b. Dechlorination:	Flow proportioning control or dual input feedforward control with built-in multiplier
Power Requirements:	120/240 ±20%Vac, 50/60 Hz, Single Phase,
Fuse:	0.5A Slow Blow
Power Consumption:	12 Watts
Relay Contacts:	5 Amps @ 240 Vac or 28 Vdc, resistive load, SPDT, for low water flow, low/high residual set point deviation, and duty/standby alarm
Input Signals	
a. Flow signal:	Isolated 4-20 mAdc, 249 ohms input impedance, or 1-5 Vdc
b. Residual signal:	Isolated 4-20 mAdc, 249 ohms input impedance, or 1-5 Vdc
c. Switch inputs:	Dry contacts rated 5V, 0.5A
Current Output Signal:	0-20 mAdc or 4-20 mAdc, 1000 ohms maximum
Range of Adjustments	
a. Integral:	0-250%
b. Dosage:	0-400% (4:1 turn-up; turndown to zero)
c. No (Low) Flow:	0-20%
d. Lag Time:	1092 Minutes Maximum
Ambient Temperature:	14°F to 122°F (-10°C to 50°C)
Enclosure:	NEMA 12 (IP 54)
Mounting:	Wall or Surface
Weight:	5 lbs. (3 kgs)

Dimensions



Design improvements may be made without notice.

Represented by:

EUROPEAN HEADQUARTERS
Crown Quay Lane,
Sittingbourne, Kent
ME 10 3JG U.K.
Tel: 0795-476241
Telex: 96536 CAPCO G
FAX: 0795-479052

BELGIUM

HONG KONG

CAPITAL CONTROLS COMPANY, INC.

P.O. Box 211, Colmar, PA 18915 U.S.A.
Tel: 800-523-2553,
Outside U.S.A. 215-822-2901
Fax: 215-822-8640

Pub. No. 1292-2 4/94 5M

ATTACHMENT 4

DECHLORINATION CHEMISTRY

UUL

BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

EXPRESS MAIL AND FACSIMILE

December 12, 1991

Mr. Charles E. Findley
Director, Water Division
U.S. Environmental Protection Agency, Region 10
200 Sixth Avenue
Seattle, WA 98101

NPDES Permit AK-003866-1
Endicott Development Project
Dechlorination of Wastewater Plant Effluent

Dear Mr. Findley:

In accordance with Sections IV.B and IV.C of the above-referenced NPDES permit, BP Exploration (Alaska) Inc. (BPX) requests approval to begin immediate testing of a dechlorination system in the sanitary/domestic wastewater treatment plant (WWTP) at the Endicott Base Operations Center (BOC). Dechlorination will be necessary to meet new NPDES permit restrictions on total residual chlorine (TRC) that take effect on December 23, 1991. Because this date is approaching rapidly, we request your attention to this matter as soon as possible.

As of December 23, 1991, permissible levels of TRC in the effluent (Section I.A. of new permit) may not exceed 1 milligram per liter (mg/l) (daily maximum) or 0.5 mg/l (weekly and monthly average). The previous permit (Section I.C) stipulated a minimum TRC level of 1.0 mg/l. A new effluent limit for fecal coliform (FC) bacteria also takes effect on December 23. Batch tests at our plant indicate that FC levels will be well in excess of the maximum limit of 400 colonies per 100 milliliters when treated with 0.5 mg/l chlorine. Therefore, it will be necessary to increase the chlorine dosage in the WWTP to provide adequate disinfection and meet the fecal coliform limits.

Before discharge, TRC will be reduced to permissible levels by addition of anhydrous sodium bisulfite (sodium metabisulfite) to the chlorine contact tank as shown on the attached sketch (Attachment 1). The required concentration of the sodium bisulfite solution is estimated at 10 mg/l, based on batch tests, but precise concentrations and contact times will have to be established by full scale operational tests.

During this period, residual chlorine levels in the effluent are expected to fluctuate between the current permit limits (≥ 1.0 mg/l) and the new limits (≤1.0 mg/l daily, 0.5 mg/l weekly and monthly average). BPX therefore requests a ten-day transitional period, effective immediately, to bring the system into equilibrium before the new permit limits take effect. The alternative is to cease ocean discharge, which will place considerable operational and economic burdens on our facility.

Attachment 2 reviews the chemistry of sulfite dechlorination. A Material Safety Data Sheet (MSDS) for sodium metabisulfite is also enclosed. We note that similar dechlorination systems have recently been approved at BPX's Prudhoe Bay Central Sewage Treatment Facility (CSTF) (NPDES Permit AK-002860-6) and at ARCO Alaska, Inc.'s Kuparuk Seawater Treatment Plant (NPDES Permit AK-004335-4).

BPX has submitted these plans to the Alaska Department of Environmental Conservation for State approval.

If you have any questions, please contact Carol Klein of my staff at (907) 564-4079. My department FAX number is (907) 564-5020. I appreciate your assistance.

Sincerely,

Janet D. Platt for

Steven D. Taylor, Manager
Environmental and Regulatory Affairs, Alaska

SDT/JDP/CAK

Attachments

cc: Tim Wingerter, ADEC Fairbanks
George Wilson, ADEC PCRO Anchorage
Burney Hill, EPA Seattle

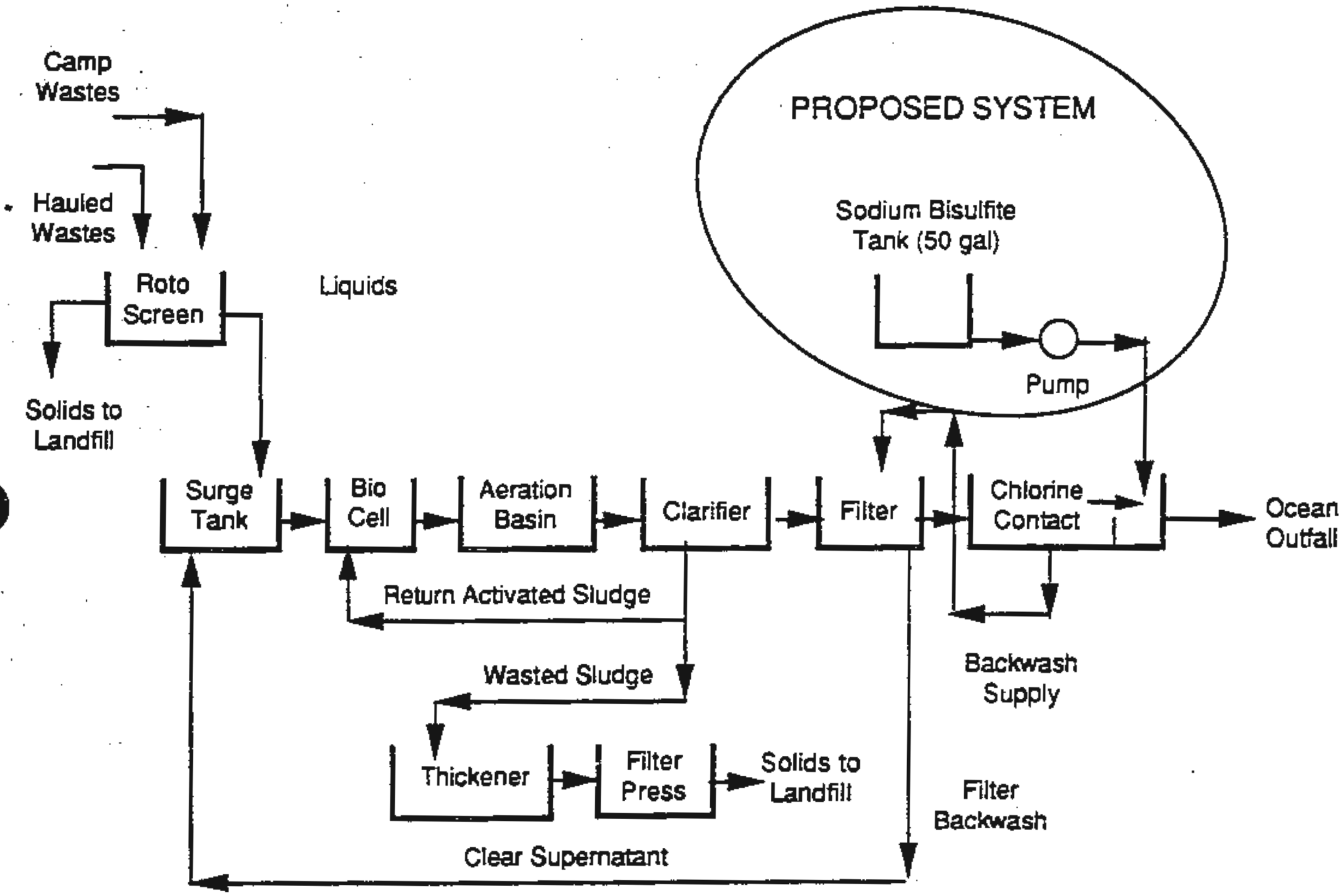
RETAIN THIS NUMBER-CUSTOMER RECEIPT WILL BE MAILED TO YOU.
RB998017394US

bcc: Endicott Plant Engineer
Endicott HSEQ

File: PC/DIU/NPDES/Gen/Corr

Attachment 1

PROPOSED DECHLORINATION SYSTEM
ENDICOTT BOC WASTE WATER TREATMENT PLANT
NPDES PERMIT AK-003866-1



ATTACHMENT 2

DECHLORINATION WITH SULFITE COMPOUNDS

General Information

Beside sulfur dioxide gas, there are four sulfur compounds to be considered: sodium sulfite, sodium bisulfate, sodium metabisulfite and sodium thiosulfate. Sodium thiosulfate is in solution, but is used almost entirely as a laboratory chemical. It is not a satisfactory dechlorinating agent for plant use because its reaction with chlorine is slow. Sulfur dioxide gas is not easily handled. Sodium sulfite, Sodium bisulfite and sodium metabisulfite are practical dechlorinating chemicals. The reactions of sodium sulfite salts are identical. Sodium Sulfite ($NaSO_3$) is available in tablet form and was selected over other sulfite salts to minimize problems associated with the mixing and handling of concentrated sulfite solutions.

Reactions with Residual Chlorine

Sulfite salts dissociate in water identically to Sulfur Dioxide gas as follows:

$$SO_2 + H_2O \rightarrow H^+ + HSO_3$$
$$NaSO_3 + H_2O \rightarrow NA^+ + HSO_3$$
$$NaHSO_3 + H_2O \rightarrow NA^+ + HSO_3$$
$$Na_2S_2 + H_2O \rightarrow NA^+ + HSO_3$$

Sulfite ions react instantaneously with free and combined chlorine as follows:

$$SO_3^{-2} + HOCl \rightarrow SO_4^{-2} + Cl^- + H^+$$
$$SO_3^{-2} + HOBr \rightarrow SO_4^{-2} + Br^- + H^+$$
$$SO_3^{-2} + NH_2Cl \rightarrow SO_4^{-2} + Cl^- + NH_4^+$$
$$SO_3^{-2} + NH_2Br \rightarrow SO_4^{-2} + Br^- + NH_4^+$$

For practical purposes the reactions described above are complete in matter of seconds (<10).

Each part of chlorine residual removed requires 0.9 part of sulfur dioxide gas, 1.78 parts of sodium sulfite, 1.46 parts of sodium bisulfite and 1.34 parts of sodium metabisulfite. Actual practices however, indicate the requirements to be about 20-25% more.

The products of the reactions are mainly sulfite and sulfate ions which are abundantly and naturally found in seawater.

EPA FORM 2D

CONTINUOUS FLUSH DISCHARGE (OUTFALL 001)

Exhibit 3
Continuous Flush System

A constant flow of 21,600 gallons per day (gpd) of chlorinated seawater will be drawn through the system to prevent ice formation and blockage in the effluent waste lines connected to outfall 001 (Exhibit 2). The only other full time waste stream to be discharged through outfall 001 is the potable water (desalination unit) brine effluent. However, the desalination unit produces effluent in batches only when there is a demand for potable water. Effluent discharged from the wastewater (sewage) treatment plant is anticipated to be routed through outfall 001 during facility construction and during periods when the injection well is not operable. All of these waste streams will be commingled with the resulting stream passing through a dechlorinator.

It is estimated that minimal amounts of residual chlorine will be consumed in the water passing through the Continuous Flush system. There are no engineering studies available to BPXA that quantify the consumption of chlorine for seawater drawn from the offshore Beaufort Sea. Using the most conservative assumption that no chlorine will be consumed, the maximum residual chlorine concentration to reach the dechlorinator will be 0.2 ppm. This waste stream will be commingled with the desalination brine and sanitary and domestic wastewater. Prior to ocean discharge, this effluent will be dechlorinated as described in Exhibit 1.

The temperature increase attributed to heat transfer from process water equipment (e.g., pumps, piping, etc.) is nominal for the Continuous Flush System, waste stream 001(a). During the summer open-water season, it is expected that the water temperature will rise 0.7°C above ambient water temperatures. During winter months, the warm water recirculation system will be activated to prevent frazil ice development in the seawater intake, resulting in an estimated water temperature increase of 1.0°C.

Continuous Flush 001(a) Estimated Temperature for Summer Conditions	
Ambient Seawater Temperature	0°C to 1.8°C
Heat Increase from process water equipment	0.7°C
Estimated Waste Stream Temperature	0.7°C to 2.5°C

Continuous Flush 001(a) Estimated Temperature for Winter Conditions	
Ambient Seawater Temperature	-1.5°C
Heat Increase from process water equipment	0.7°C
Heat Increase from warm water recirculation	0.3°C
Estimated Waste Stream Temperature	-0.5°C

In addition to temperature, the physical properties of interest in the continuous flush system are pH, and Total Suspended Solids (TSS). Chlorine in the form of calcium hypochlorite will be introduced into the effluent to reduce equipment biofouling. Prior to discharge, the continuous flush system waste stream will be commingled with the desalination blowdown (brine) and the wastewater (sewage) treatment system. Sodium metabisulfite will be injected into the commingled stream to reduce TRC concentrations to acceptable Alaska water quality levels. A detailed discussion on chlorination and dechlorination is presented in Exhibit 1. The effluent pH will vary slightly from ambient conditions as a result of the chlorination/dechlorination process; however, the pH is expected to vary no more than 0.1 pH units from ambient. The table below summarizes the pollutants and physical properties of the effluent.

CONTINUED FROM THE FRONT	EPA ID Number *(copy from item 1 of Form 1)*	Outfall Number ***001(a) continuous flush***

V. Effluent Characteristics

A, and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instructions for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See table 2D-2 for Pollutants)*
Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

Continuous Flush System 1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
Flow (gallons per minute)	***21,600 gpd***	***21,600 gpd***	***1 (BPX Northstar Alliance Design)***
Temperature (winter)	***ambient + 1°C***	***ambient + 1°C***	***1 (BPX Northstar Alliance Design)***
Temperature (summer)	***ambient + 0.7°C***	***ambient + 0.7°C***	***1 (BPX Northstar Alliance Design***
pH	***ambient ± 0.1pH***	***ambient ± 0. 1pH***	***3 (Endicott BOC Sanitary and Domestic Wastes)***
Total Residual Chlorine	***≤ 2 ppb***	***≤ 2 ppb***	***1 (BPX Northstar Alliance Design)***
Salinity	***Ambient***	***Ambient***	***1 (BPX Northstar Alliance Design)***
Total Suspended Solids (concentration)	***Ambient***	***Ambient***	***1 (BPX Northstar Alliance Design) based on maximum ambient TSS of 5 mg/l***
Total Suspended Solids (mass)	***0.4 kg***	***0.81 kg***	***1 (BPX Northstar Alliance Design) based on maximum ambient TSS of 5 mg/l***

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	***Outfall 001(a) continuous flush***

C. Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

1. Pollutant	2. Reason for Discharge
Not Applicable	

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
No arctic analog facility was identified.	

EPA FORM 2D

DESALINATION (POTABLE WATER) UNIT DISCHARGE (OUTFALL 001)

It is anticipated that an average of 6,300 gallons per day (gpd) of chlorinated sea water will be diverted through the desalination unit for the production of fresh water at the Northstar facility (Exhibit 5). The maximum input rate for the system is 32,400 gpd.

Desalination

The MECO Model PEE600M3C Vapor Compression Desalination Plant is planned to be used at the Northstar facility and Attachment 5 contains a detailed description of the unit. Vapor compression desalination is a method of evaporating seawater whereby the energy in the evaporated vapor is enhanced by compression. This energy is then used to evaporate additional seawater. The process begins by boiling seawater inside a bank of tubes. The generated vapor passes through a mist separator to remove any entrained water droplets. The pure vapor is withdrawn by a compressor resulting in compressed steam with increased pressure and temperature. The higher energy steam is discharged to the evaporator, located on the outside of the tube bank, where its latent heat is transferred to the seawater inside the tubes. The cycle repeats as more vapor is generated. The condensate (distilled water) is withdrawn by a distillate pump and discharged through a plate heat exchanger that transfers most of the heat to the incoming seawater. The heat exchanger is designed to minimize the energy consumption of the system.

Continuous injection of maintenance chemicals including scale-control additives and foamer, which are safe for drinking water, will be added during the process. Periodic injection of sulfuric or sulfamic acids will flush mineral buildup in the desalination plant. Attachment 9 contains the Material Safety Data Sheets (MSDS) for the recommended maintenance chemicals.

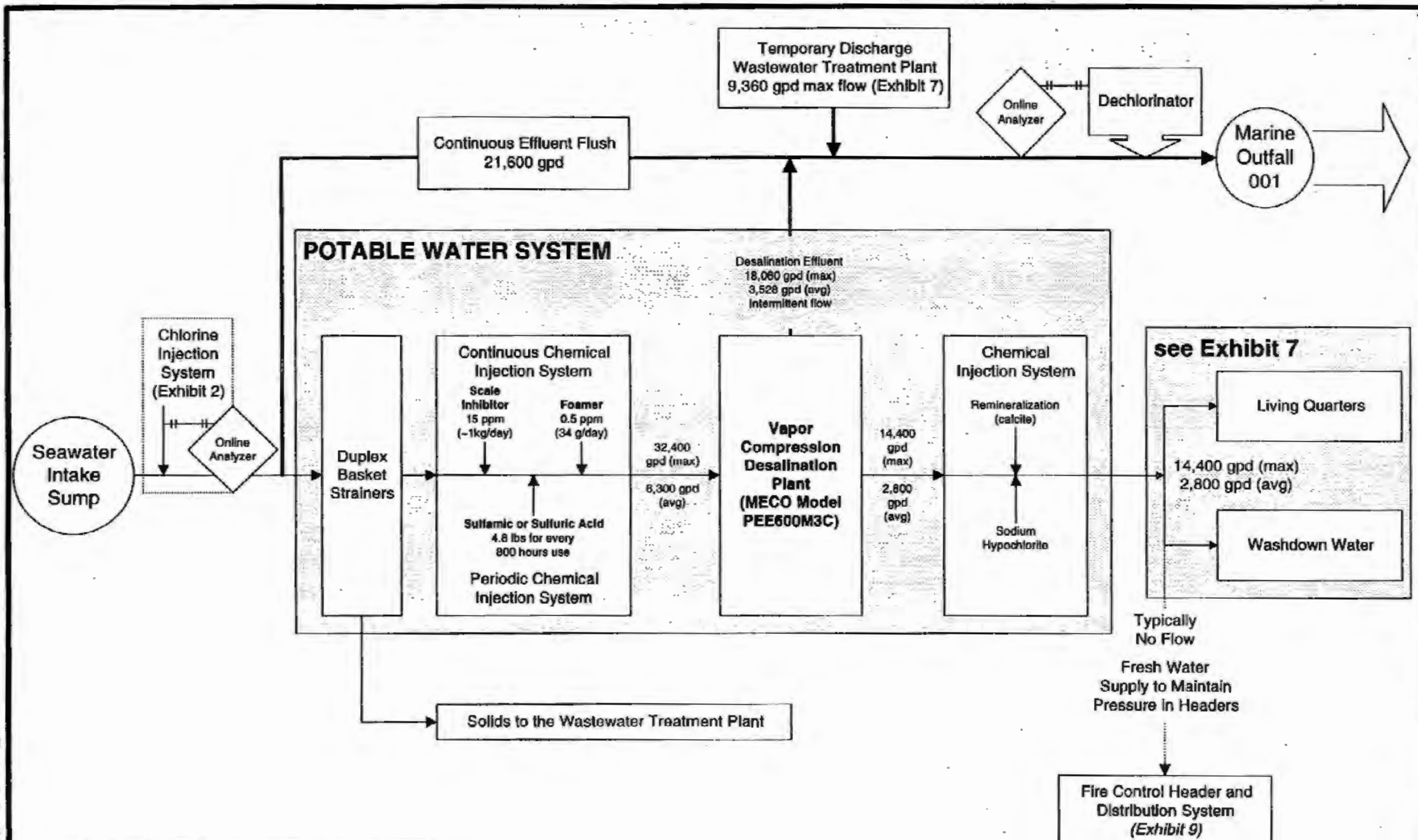
Effluent Discharge

The maximum effluent discharge from the desalination plant for the Northstar Development project is estimated to occur in intermittent pulses at a rate of 18,060 gpd; however, it is anticipated that the daily average discharge is 3,528 gpd. The desalination process will concentrate naturally occurring minerals and salts in the seawater to approximately twice the ambient salinity; that is, in winter when ambient salinity is 32.4 ppt, brine salinity will be about 65 ppt. Conversely, in summer brine salinity will vary between 32 ppt and 65 ppt depending upon the current hydrographic conditions.

The vapor compression desalination unit results in distilled water which is the source of potable water for the facility. The excess feed water which does not evaporate (blowdown) contains concentrated dissolved solids and salts; however, the chlorine that enters the desalination unit will be off gassed and vented into the atmosphere. Thus, it is expected that the desalination blowdown or brine will not contain residual chlorine.

Exhibit 4 Outfall 001(b)
Desalination (Potable Water)

The engineering specifications provided by the manufacturer (MECO) indicate the effluent will have a temperature increase of 5°C to 7°C from ambient conditions. The manufacturer determined that total dissolved solids will increase to 65 to 70 parts per thousand (‰) for an ambient seawater containing 36‰. Typical Beaufort Sea receiving waters have salinities between 14‰ and 30‰ in the summer and 32‰ in the winter, thus, it is expected that the desalination blowdown water (brine) have a salinity between 60‰ and 65‰. While the feed water to the desalination unit contains chlorine, the distillation process will result in the off gassing of chlorine and thus the blowdown waste stream is not expected to contain chlorine. TSS associated with this waste stream has not been quantified; however, it is assumed to be less than ≤10 mg/l.



Notes:

ppm = parts per million
gpd = gallons per day
‰ = parts per thousand

BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Seal Island Potable Water (De-Sal) Line Diagram

Exhibit 5

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V. Effluent Characteristics

A, and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instructions for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See table 2D-2 for Pollutants)*
Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

Potable Water System 1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
Flow (gallons per day)	*18,060 gpd*	*3,528 gpd*	*1 (BPX Northstar Alliance Design)*
Temperature (winter)	*ambient + 7°C*	*ambient + 6°C*	*1 (BPX Northstar Alliance Design)*
Temperature (summer)	*ambient + 7°C*	*ambient + 6°C*	*1 (BPX Northstar Alliance Design)*
pH	*ambient - 0.85pH*	*ambient - 0.50pH*	*3 (Endicott Desalination Unit Wastes)*
Salinity (winter)	*65‰*	*65‰*	*1 (BPX Northstar Alliance Design)*
Salinity (summer)	*65‰*	*32 to 65‰*	*1 (BPX Northstar Alliance Design)*
Total Residual Chlorine	*0 ppb*	*0 ppb*	*1 (BPX Northstar Alliance Design)*
Total Suspended Solids (concentration)	*approx. 2 times ambient*	*approx. 2 times ambient*	*1 (BPX Northstar Alliance Design) based on maximum ambient TSS of 5 mg/l*
Total Suspended Solids (mass)	*0.68 kg*	*0.13 kg*	*1 (BPX Northstar Alliance Design) based on maximum ambient TSS of 5 mg/l*

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	***Outfall 001(b) potable water***

C. Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

1. Pollutant	2. Reason for Discharge
Not Applicable	

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
UNOCAL ***Paul Bartolowitz*** ***(907) 776-6840***	***Production Facility*** ***Cook Inlet, Alaska*** ***(MECO PEE300M3C Vapor Compression Desalination Plant)***
Endicott Development ***(Desalination Unit)***	***Duck Island Unit*** ***Beaufort Sea, Stefansson Sound, Alaska*** ***(offshore of the Sagavanirktok River)***

ATTACHMENT 5

TECHNICAL SPECIFICATION
MECO MODEL PEE600M3C
VAPOR COMPRESSION DESALINATION PLANT

MECO®

TECHNICAL SPECIFICATION
MECO MODEL PEE600M3C
VAPOR COMPRESSION DESALINATION PLANT

PROCESS DESCRIPTION

Vapor compression desalination is a method of evaporating sea water in which the energy in the evaporated vapor is enhanced by compressing it and used in turn to evaporate the in coming sea water. Liquid is boiled inside a bank of tubes and the generated vapor then passes through a mist separator to remove any entrained water droplets. The pure vapor is withdrawn by a compressor, where the energy imparted results in compressed steam with increased pressure and temperature. This higher energy compressed steam is discharged to the evaporator, on the outside of the tube bank, where it gives up most of its energy (latent heat) to the sea water inside the tubes. More vapor is thus generated and the process is repeated. The condensate (distilled water) is withdrawn by the distillate pump and is discharged through a plate heat exchanger transferring most of its heat to the incoming sea water. The excess feed water which did not evaporate (blowdown) is also pumped through a plate heat exchanger where it also transfers its heat to the in coming sea water, preheating the sea water prior to entering the evaporator. This heat exchange minimizes the energy consumption of the system and eliminates the need for any additional cooling water. The system operates continuously once manually started.

The water produced is distilled at positive pressure above the atmospheric boiling point and therefore is free of any harmful bacteria, and requires no further disinfecting.

Some make up heat is necessary for continuous operation. This is automatically furnished from an external steam source as demanded by the evaporator (most often by an electric immersion heater supplied as part of the system).

The MECO Vapor Compression Water Desalination Plant is self contained, assembled on a rigid steel skid, completely piped, wired, tested and painted. The package consists of an evaporator, a centrifugal compressor, all necessary heat exchangers, a deaerator for removing non-condensable gasses, centrifugal pumps for removing distillate and blowdown, and control and instrument panels. A detailed description of the individual components is contained in the following pages.

A. Evaporator:

The evaporator is a vertical tube, natural "super circulating" rising film design. It incorporates enhanced heat transfer double fluted tubes which are expanded into tube sheets at each end. The shell is fitted with removable top and bottom heads, the bottom head being fitted with MECO's patented "TARGA" gas sparger tube for reintroduction of CO_2 into the feed water to assist the injected chemicals

in minimizing the formation of alkaline scale. A simple weir gate maintains the correct feed water level, which can be observed in a gauge glass. Another gauge glass is fitted to indicate the level of distilled water. Observation sight glasses are strategically located to monitor correct operation and inspect the evaporator internals.

Material: Tubes - Arsenical Aluminum Brass UNS C68700
Tube Sheets - 90/10 Cu Ni UNS C70600
Shell - 90/10 Cu Ni UNS C 70600
Mist Eliminator - 316 Stainless Steel

B. Vapor Compressor:

The compressor is a simple, single stage centrifugal type which is designed and manufactured by MECO specifically for this service. It consists of a bearing housing, shaft, impeller and impeller housing (suction adapter and closure plate). Mechanical shaft seals are employed to prevent oil leakage. Anti-friction bearings are lubricated by a pressurized full flow oil system complete with pump, filter and oil cooling heat exchanger. The oil level is monitored by an oil level gauge in the sump of the bearing housing. An open atmospheric chamber is located between the steam seal and impeller end oil seal, to prevent the steam from entering the bearing housing, and prevent the oil from entering the evaporator should a failure of the seals occur. The compressor is mounted on the evaporator and driven by an electric motor via suitably guarded "V" belts.

Material: Bearing Housing - Ductile Iron
Impeller - Type 718 Inconel
Impeller Housing - Cast Bronze
Shaft - K500 Monel

C. Deaerator:

The deaerator serves three (3) very important functions; it removes oxygen from the feed water to reduce the effects of corrosion, it collects and re-circulates CO_2 for MECO's patented TARGA system, and it vents non-condensable gasses to atmosphere.

MECO®

The deaerator is a vertical cylindrical tower partially filled with 1" packing and complete with sump level indication via a gauge tube. Feed water is distributed over the top of the packing through a spray nozzle in counter direction to the stripping steam supplied by the compressor. This steam is used to strip CO_2, oxygen and nitrogen from the feed water as it cascades through the packing. The steam also increases the temperature of the feed water, which enhances the stripping process. The gasses rise to the top of the deaerator where they are either vented to atmosphere, or injected into the evaporator through the TARGA sparger tube.

Material: Tower - 90/10 Cu Ni
Packing - High Temperature Noryl
Spray Nozzle - Teflon

D. Heat Exchanger(s):

The unit is equipped with a plate and frame heat exchanger to recover the heat from the out going distillate and blowdown, and transfer it to the feed. This is accomplished through a MECO designed three (3) stream heat exchanger.

Material: Plates - Titanium ASTM B265
Gaskets - EPDM
Support Plates - Steel

E. Pumps:

Each unit uses two (2) MECO heavy duty pumps for blowdown and distillate removal. Both pumps use mechanical face seals to prevent leakage. They are driven by an electric motor using a "V" belt drive. If insufficient or fluctuating feed water pressure is present, a feed water pump can be supplied as an optional extra.

Material: Housings - Al Brz UNS C95200
Impellers - Al Brz UNS C95200
Shafts - K500 Monel
Bearing Housings - Ductile Iron

F. **Immersion Heater:**

A tank complete with electric heating elements and level control switch is supplied to heat the water in the unit during start up, and supply make up heat during unit operation. An external steam source may be substituted for this heater.

Material: Tank - 90/10 Cu Ni UNS C70600
Heating Elements - Incoloy

G. **Chemical injection Systems:**

An injection system is supplied for each of the following:

- M-237 Scale Inhibitor: Continuous injection of a scale inhibitor minimizes the formation of alkaline scale in the evaporator and heat exchanger.

- M-236 Foamer: Injection of foamer enhances unit performance by reducing the surface tension of the water in the evaporator thus ensuring good natural percolation. Some feed waters require little or no injection of foamer due to the presence of organics in the water.

- Chemical Cleaning: Even with the continuous injection of a scale inhibitor, soft alkaline scale in the form of magnesium hydroxide and calcium carbonate will form and reduce the efficiency of the heat transfer surfaces. Periodic on line cleaning by the injection of sulfuric or sulfamic acid into the feed water will neutralize and remove these scales, which will be discharged with the blowdown. This cleaning process takes from 10 - 20 minutes and must be done every 800 - 1,000 hours of operation. The unit does not have to be shut down during cleaning, and it will continue to produce good water while being cleaned.

Each Injection System Consists Of:

- One (1) polyethylene tank complete with lid.

- One (1) solenoid driven diaphragm pump. The injection rate is set by manually adjusting the stroke length and/or the stroke frequency. Each pump includes control dials to adjust the injection rate, an on/off switch, pilot lights and all necessary check valves. Standard materials are polypropylene head and fittings, and a Teflon diaphragm. The power at 115V AC 50/60 Hz is supplied from the main control panel via a transformer.

- A CPVC isolation ball valve and PVC screen are supplied at the tank. The chemicals exit through this valve and screen and through a check valve to the point of injection. Tubing on the scale inhibitor system is 316 stainless steel, PVC for the foamer system and polypropylene for the cleaning system. Also included in the cleaning system is a CPVC manually operated 3 way ball valve to divert acid to either the feed water stream or the blowdown stream as required.

H. Electrical System:

- Control Panel: The NEMA 4 enclosure houses all of the high voltage equipment, consisting of: the main and individual circuit breakers, all motor starters and a step down transformer. The door is fitted with an incoming circuit breaking interlocking handle to prevent the door from being opened while the power is on.

- Instrument Panel: The NEMA 4 enclosure houses control relays, a salinity indicator, a feed water flow indicator and adjustment control, an hour meter, an annunciator, indicator lamps and all mode and function switches. In addition to these controls, there are locally mounted pressure gauges, thermometers and oil and water gauge glasses to monitor the unit for proper operation. The annunciator and alarm systems cover the following safeties:

  - 1) Evaporator high water level (system shutdown).
  - 2) Compressor surge switch (system shutdown).
  - 3) Compressor low oil pressure (system shutdown).
  - 4) Low feed water pressure (system shutdown).
  - 5) Compressor high oil temperature (system shutdown).
  - 6) High salinity with automatic dump to waste (alarm only).

- All motors are TEFC, marine duty, 50^0 C ambient temperature, Class B insulation.

- All cable is marine type, thermoplastic nylon insulated and armored with a stainless steel braided sheath (US Coast Guard approved). MECO's wiring procedures conform to the National Electric Code.

- Control circuitry is all transformed to 115V regardless of the input voltage being supplied to the unit.

I. Piping:

Cold sea water piping is CPVC (chlorinated polyvinylchloride). Heated sea water piping, distillate and blowdown piping is 90/10 Cu Ni. All of these materials are the most suitable for their intended service.

J. Insulation:

The evaporator, immersion tank, deaerator and all hot piping are insulated to reduce heat loss due to radiation and to keep the surface temperature below

120^0 F (50^0 C) for the protection of operating personnel. The insulation consists of 1" - 2" (2.5 - 5 cm) thick fiberglass board glued to the surface and covered with fiberglass cloth. The cloth is then impregnated with a water proof sealant.

K. Skid:

All of the previously described components are pre-assembled and then mounted on a rigidly designed oil field type skid. This skid is constructed of structural steel members welded together in accordance with procedures written to AWS D 1.1, sand blasted to white metal, and prime painted with a zinc based primer prior to mounting of any components.

L. Testing, Painting and Preparation For Shipment:

Every unit is subject to continuous monitoring and inspection during construction in accordance with MECO's rigid Quality Control System. All pressure components are hydrostatically tested to one and one half the maximum design pressure. The compressor is test run under load in a specially designed test stand. The completed unit is then performance tested in the factory using brackish water with a TDS of 5,000 - 7,000 PPM as a feed water source. During this test, all electrical, mechanical and safety functions are thoroughly scrutinized and made to perform under actual operating conditions. Once shake down and equipment checks are complete, the unit is run for a minimum of four (8) hours and a complete set of data readings are recorded for inclusion with the units O&M manual.

After testing is completed, the unit is properly masked and then painted with a three (3) part painting system in accordance with MECO procedure #9500001. This procedure details the proper surface preparation, the application technique and thickness of each coat, the drying time for each coat and the atmospheric conditions that must be present in order to paint.

Prior to shipment, all unpainted exposed metallic surfaces are protected with a rust preventative coating. The compressor is filled with a rust inhibitor and then drained. The instrument panel is protected with a sheet of plywood.

The unit is bolted to a sturdy wooden pallet, using steel bolts at appropriate locations along the units length. The unit is then covered with polyethylene sheeting which is battened down to the pallet with wooden strips. All four (4) sides and the top are then covered with stud reinforced plywood sheets covered with water proof paper. The completed box is banded in two (2) directions with the appropriate width steel banding secured with banding clips. The box is then marked in accordance with customer instructions using 2" (5 cm) high letters.

PERFORMANCE DATA

1. Input and Output Flows:

    a. Distillate/Product @ 20 PSIG (1.4 BAR) - 10 GPM (54.5 M^3/D)

    Guaranteed Quality <u>5 PPM</u> Maximum Total Dissolved Solids

    b. Brine/Blowdown @ 5 PSIG (0.35 BAR) - 12.5 GPM (68.13 M^3/D)

    c. Sea Water/Feed @ 30-40 PSIG (2-3 BAR) - 22.5 GPM (122.63 M^3/D)

    The temperature of the exiting flows will be 12-14° F (5-7° C) above feed water temperature. Feed flow rate is 2.25 x product flow for sea water having a TDS of 36,000 PPM. Higher TDS requires a higher feed rate to maintain the blowdown at 65,000 - 70,000 ppm TDS.

2. Energy Consumption:

    a. Compressor Motor 40 HP
    b. Distillate and Blowdown Pump Motor $1^1/_2$ HP
    c. Immersion Heaters 70 KW
    d. Operating Load 60 KW Average
    e. 100 KWH/1,000 Gal (26.4 KWH/M^3)

3. Chemicals:

M-237 Scale Inhibitor	15 PPM in the Feed
M-236 Foamer	0.5 PPM in the Feed

4. Utilities:

    Air @ 80-100 PSIG (5.5-7 BAR) clean dry air is required intermittently to operate flow control valves. Power required is 460/415 V/3 Ph/60/50 Hz.

MECO®

CUSTOMER CONNECTIONS
WEIGHTS AND DIMENSIONS

1. Customer Connections:

   Feed: 2" FPT
   Blowdown: 1" FPT
   Distillate: 1 1/2" FPT
   Drain: 1/2" FPT
   Air Supply: 1/4" FPT

2. Weights and Dimensions:

Unit Only	Boxed for Shipping
126" L x 75" W x 92" H (3.2M x 1.91M x 2.34M) 8200 Lbs. (3720 Kg)	617 FT^3 (17.47 M^3)

MECO®

MECHANICAL EQUIPMENT COMPANY, INC.
ESTIMATED CHEMICAL SUPPLY
ONE YEAR (350 DAY) OPERATION

MECO MODELS PEE - PD - PES 600M3C

Continuous Injection Chemicals

Chemical	Daily Usage	Annual Usage	Available Pk. Sizes	Recommended 1 Yr. Supply
M-236 Foamer	66.6 ml	23.3 (6.5 gal)	1, 5 or 51 gallon containers	1x5 gallon 2x1 gallon containers
			COST	$184.00 USD
M-237 Scale Inhibitor				
Standard Seawater	1036 ml	362.6 l (96 gal)	1, 5 or 55 gallon containers	2x55 gallon containers
			Cost	$4,600.00 USD
Mid-East Seawater	1214 ml	424.9 l (112 gal)	1, 5 or 55 gallon containers	2x55 & 2x1 gallon containers
			Cost	$4,700.00 USD

Periodic Cleaning Chemical

Chemical	Annual Usage	Available Pk. Sizes	Recommended 1 Yr. Supply
M-104 Sulfamic Acid	90 lb 4.8 lb per on-line cleaning	50 lb containers	2 x 50 lb container
		Cost	$222.00 USD

Total Standard Seawater$5,006.00
Total Mid East Seawater$5,106.00

NOTE: Cleaning chemical usage is only estimated as it depends on seawater conditions and operating procedures.

MECO®

THERMAL DESALINATION PLANTS AROUND THE WORLD

MECHANICAL VAPOR COMPRESSION DISTILLATION UNITS (MVC):

PEE	Electric VC plants, followed by capacity in USGPH
PD	Diesel VC plants, followed by capacity in USGPH
PES	Steam VC plants, followed by capacity in USGPH

The above are followed by suffixes M, M3A, M3B and M3C, with the model no. M being the oldest and M3C being the latest model.

Materials of Construction:	Shell:	90/10 Copper Nickel
	Tubes:	Aluminum Brass or 90/10 Copper Nickel
	Tubesheets:	90/10 Copper Nickel
	Exchanger Plates:	Titanium

MULTI EFFECT THERMAL COMPRESSION DISTILLATION UNITS (METC):

4METC — TC plants prefixed with no. of effects and followed by capacity in m^3/Day

Materials of Construction:	Shell:	316 Stainless Steel or 90/10 Copper Nickel
	Tubes:	Aluminum Brass or 90/10 Copper Nickel with Titanium on the top rows (All Titanium in Condenser)
	Tubesheets:	316 Stainless Steel or 90/10 Copper Nickel
	Exchanger Plates:	Titanium

MULTI STAGE FLASH DISTILLATION UNITS (MSF):

14SF — MSF units prefixed with no. of stages and followed by capacity in m3/Day

Materials of Construction:	Shell:	90/10 Copper Nickel
	Tubes:	Aluminum Brass or 90/10 Copper Nickel
	Tubesheets:	90/10 Copper Nickel
	Waterboxes:	90/10 Copper Nickel

WASTE HEAT DISTILLERS (ST):

ST600 — ST units are based on USGPH.

Materials of Construction:	Shell:	90/10 Copper Nickel
	Tubes:	Aluminum Brass or 90/10 Copper Nickel
	Tubesheets:	90/10 Copper Nickel

CUSTOMER	MODEL	YEAR	S/N	LOCATION
1. ABU DHABI CO. FOR ONSHORE OIL OPERATIONS (ADCO)	PEE600M3C	1982	3153	Asab
	PEE600M3C	1981	3015	Asab
	PEE600M3C	1983	3240	Shah
	PEE600M3C	1981	3227	Shah
	PEE600M3C	1986	2757	Bu Hasa
	PEE1250M3B	1981	3058	Asab
2. ABU DHABI DEFENCE FORCE (ADDF)	PD400M3B	1980	2762	Al Hamra
	PD600M3C	1983	3250	UAE
3. ABU DHABI MARINE OPERATING CO. (ADMA-OPCO)	PEE330M	1974	2410	USEAP
	PEE330M	1974	2411	USEAP
	PEE330M	1976	2413	ZWEAP
	PEE300M3B	1979	2768	ZWEAP
	PEE300M3C	1982	3143	USEAP
	PEE400M3B	1980	2939	Barge Al Hyleh

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(ADMA-OPCO con't)	PEE400M3B	[illegible]	2940	Barge Al Hyleh
	PEE300M3B	1981	2949	USAAP
	PEE300M3B	1981	3005	USAAP
	PEE600M3B	1981	2972	ZWAAP
	PEE600M3B	1981	2973	ZWAAP
4. ADMASCO DRILLING	PEE300M3C	1982	3155	Rig 1 UAE
	PEE300M3C	1982	3156	Rig 2
	PEE300M3C	1982	3187	Rig 3
	PEE300M3C	1982	3152	Rig 3
	PEE300M3C	1982	3202	Rig 4
	PEE300M3C	1982	3203	Rig 4
5. ABU DHABI OIL CO.	PEE2100M3C	1992	7212	Mubarras
(ADOC-JAPAN)	PEE2100M3C	1986	3339	Island,
	PEE2100M3C	1986	3404	UAE
	PEE2100M3C	1986	3376	
6. ABU DHABI POLICE	PEE600M3C	1985	3275	UAE
7. AL FARAH GEN.	PD300M3B	1979	2773	Asab
TRADING	PD300M3B	1979	2774	
	PEE300M3B	1981	2928	
8. AMOCO	2SF50	3217	3217	Egypt
9. ANDOC	PEE200M3B	1979	2901	Tawash 1
	PEE200M3B	1979	2902	Tawash 1
	PEE300M3B/C	1991	3066	Tawash 2
10. ARABIAN OIL CO	PEE300M3B	1985	3319	Neutral Zone
	PEE300M3B	1989	4027	
	PEE300M3C	1990	7058-1	
	PEE300M3C	1990	7058-2	
11. ARAMCO RABIGH	PES15000M3B	1982	3389	Saudi,
(EX-SAMAREC & PETROMIN	PES15000M3B	1982	3388	Rabigh
PETROLA)	PES15000M3B	1982	3390	Community
	PES15000M3B	1982	3387	
	PES15000M3B	1982	3391	
	PES15000M3B	1982	3386	
	PES15000M3B	1982	3215	Saudi
	PES15000M3B	1982	3160	Rabigh
	PES15000M3B	1982	3214	Refinery
	PES15000M3B	1982	3383	
	PES15000M3B	1982	3159	
	PES15000M3B	1982	3384	
	PES15000M3B	1982	3385	
12. ARCO	PEE200M3C	1993	7303 A	Offshore, China
	PEE200M3C	1993	7303 B	
	PEE300M3C	1991	7141	Alaska, USA
13. ARCTIC ALASKA	PES2100M3C	1988	7018 A	Alaska, USA
	PES2100M3C	1988	7018 B	
	PES2100M3C	1988	7019 A	
	PES2100M3C	1988	7019 B	
14. BAHRAIN	PD600M3B	1981	2825	Hawar Island,
DEF. FORCE	PD600M3B	1981	2826	Bahrain
15. BEAN DREDGING	ST300	1995	7446	Dredge, USA
16. BIMINI BLUE WATER RESORT	PEE400M3C	1995	7387	Caribbean

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17. BUNDUQ OIL CO.	PEE600M3C	1984	3273	U.A.E.
	PEE600M3C	1990	7051	
18. BYRNE DRILLING	PEE600M3C	1996	7344	Bahrain
19. CALPINE MONTEREY	ST600	1996	7469	California, USA
20. CHEVRON	ST100	1995	7423 A	Offshore, USA
	ST100	1995	7423 B	
	PEE1250M3B/C	1984	3338	
	PEE1250M3B/C	1984	3292	
	PEE1250M3B/C	1984	3293	
	PEE1250M3B	1983	3253	California, USA
	PEE1250M3B	1983	3254 A	
	PEE1250M3B	1983	3254 B	
21. CHIYODA CORP.	PES7500M3C	1994	7304	Ras Laffan
	PES15000M3C	1994	7305	Qatar
	PES7500M3C	1994	7338	
22. CLIFFS DRILLING	PEE600M3C	1993	7277	Offshore, USA
	ST300	1993	7243	
23. COASTAL EQUIPMENT	ST600	1990	7081	Singapore
	ST300	1985	3377	
	ST300	1985	3378	
24. CONOCO	ST100	1988	4034	Offshore
	ST100	1988	4038	
25. COZUMEL	MSF132-18	1973	2260	Cozumel, Mexico
	MSF132-18	1973	2261	
26. DANA DRILLING	PEE300M3C	1982	3123	Rig 2
	PEE300M3C	1983	3208	Rig 1
27. DELTA MARINE SERVICES	PEE660M	1975	2417 A	Barge 318
	PEE660M	1975	2417 B	Nigeria
28. DHABI DRILLING	PEE330M	1972	2279	Rig 37
	PD330M	1972	2223	Rig D.D.1
	PEE300M3B	1980	2892	Rig D.D.2
	PEE300M3B	1980	2893	Rig D.D.2
29. DHABI ENTERPRISES (Sh. Nahyan bin Mubarak)	PEE600M3C	1989	3851	Shelealah, UAE
30. ELF	PEE600M3C	1990	7096	Angola
31. ESSAR PROJECTS (India)	PEE600M3A	1973	2449	Barge 207
	PD600M3C	1984	3239	" "
32. ESSO THAILAND	12SF6600	1985	3349	Theiland
33. GULF OIL CORP.	PEE1250M3B	1981	3053	Cabinda Gulf
	PEE1250M3B	1981	3054	Angola
34. GULF MARINE SERVICES (GMS)	PEE300M3B	1982	3131	Barge Naashi
	PEE300M3B	1982	3132	"
	PD300M3B	1982	2913	
	PEE300M3B/C	1992	2965	Barge Khawla
35. IMS BAHRAIN	PD300M3B	1980	3004	Barge 334 BAH

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36. JAPAN DRILLING CO.	PEE600M3A	[illegible]	36-1371A	Rig Hakurya VI
(JDC)	PEE600M3A	1979	36-1371B	"
37. KAMINE	2ST600	1994	7393	New York, USA
38. LATSIS	PEE6250M3B	1980	3035	Crown Prince Palace
	PEE6250M3B	1980	3036	Saudi Arabia
39. MANSAL	PEE400M3C	1982	3170	Deema
OFFSHORE	PEE400M3C	1982	3171	Deema
	PEE400M3C	1982	3172	Murjan
	PEE600M3A	1976	2645	Deema
	PEE600M3C	1987	3337	Murjan
	PEE600M3C	1993	7192	Ahmed
	PEE600M3C	1993	7151-2	Ahmed
	PEE600M3B	1979	2736	Ahmed
40. McDERMOTT INT.	PD600M3B	1983	3212	DB-7 UAE
	PD600M3B	1983		DB-7
	PD660M	1972	2373	DB-8
	PEE660M	1970	2277	DB-8
	PEE1250M3B	1983	3144	DB-27
	PEE1250M3B	1983	3145	DB-27
	PEE1250M3B	1983	3146	DB-27
	PEE600M3B	1982	3088	LB-26
41. MINERA ESCONDIDA	PES15000M3B	1992	7272	Chile
42. MINISTRY OF ELECTRICITY	PD1250MA	1977	2570	Kumzar, Oman
& WATER, OMAN	PD1250MA	1977	2571	Kumzar
	PD1250MA	1977	2572	Shairsha
	PD1250MA	1977	2574	"
	PD1250MA	1977	2575	"
	PD1250MA	1977	2576	"
43. MOBIL OIL	PEE300M3C	1992	7211	Nigeria
	PEE200M3C	1994	7319-1	"
	PEE200M3C	1994	7319-2	"
44. MOHAMED MOJAL GROUP	PEE600M3C	1991	7151-1	Barge, Saudi
45. NATIONAL DRILLING CO.	PEE300M3C	1985	3321	Rig ND1 U.A.E.
(NDC - U.A.E.)	PEE300M3C	1985	3323	Base Camp
	PEE400M3B	1995	7434	Rig ND4
	PEE400M3B	1979	2954	Rig ND8
	PEE400M3B	1979	2955	Rig ND9
	PEE400M3B	1979	2956	Rig ND9
	PEE400M3B	1979	2958	Rig ND10
	PEE400M3B/C	1979	3033	Rig ND11
	PEE400M3B/C	1979	3034	Rig ND11
	PEE400M3C	1991	7112-1	Rig ND2
	PEE400M3C	1991	7112-2	Rig ND2
	PEE400M3C	1991	7111-1	Rig ND3
	PEE400M3C	1991	7111-2	Rig ND4
	PEE400M3C	1982	3185	Rig ND16
	PEE400M3C	1982	3186	Rig ND16
	PEE400M3C	1994	7327	Rig ND1
	PEE400M3C	1982	3177	Rig ND17
	PEE400M3C	1982	3178	Rig ND17
	PEE300M3A	1982	36-2254A	OMIV
	PEE300M3A	1982	36-2254B	OMIV
	PEE400M3C	1992	7193-1	Rig ND21
	PEE400M3C	1992	7193-2	Rig ND21

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46. NATIONAL IRANIAN OIL CO.	14SF6600	[illegible]	7164-A	Lavan Island,
	14SF6600	1992	7164-B	Iran
47. NATIONAL PETROLEUM CONSTRUCTION CO. (NPCC)	PEE600M3C	1986	3343	Ship HLS2000
	PEE600M3B	1978	2840	" "
	PEE600M3B	1982	3154	Barge DLB1000
	PEE600M3B	1982	3110	" "
	PEE600M3B/C	1983	3251	C.B.3
	PEE300M3C	1985	3270	SEP 150
	PEE300M3B	1980	2916	" "
	PEE600M3C	1994	7343	Stock
	PEE600M3C	1994	7365	Barge SEP 350
	PEE600M3C	1994	7366	Barge SEP 350
	PEE600M3C	1994	7367	Barge PLB 648
	PEE600M3C	1994	7368	Barge SEP 250
	PEE600M3C	1994	7369	Barge PLB 648
48. NAVAGARE INTERNATIONAL	PEE300M3C	1992	7207	Mexico
49. NEWFOUNDLAND OFFSHORE	PEE1250M3C	1992	7237	Hibernia Platform Canada
50. NOBLE DRILLING	PEE600M3C	1991	7152	Offshore, India
	PEE600M3C	1988	3360	
51. OFFSHORE INT.	PEE330M	1972	2280	Rig Antares
52. ONGC	PEE300M3C	1992	7121-1	Rig Sagar Gaurav
	PEE300M3C	1992	7121-2	Rig Sagar Shakthi
	PEE600M3C	1990	4014	BLQ-2-Offshore P/F
	PEE300M3C	1992	7141	Rig Sagar Jyothi
	PEE100M3B	1984	3248	
53. OPMI BAHRAIN	PEE600M3C	1983	3237	Barge WB7
	PEE600M3C	1983	3236	"
	PEE600M3A	1978	2763	Barge Hercules
	PEE660M	1974	2416	KP1
	PEE330M	1973	34-1413 A	"
	PEE330M	1973	34-1413 B	"
54. PACIFIC GAS & ELECTRIC (PG&E)	PES9900M3B	1987	3607	California, USA
	PES9900M3B	1987	3608	
55. PACIFIC TRANSPORT LTD.	PEE600M3C	1993	3249	Barge "WB 75"
	PEE300M3B/C	1993	3051	Barge "Offshore Base"
56. PETROLA INT.	PES15000M3B	1981	3158	Rabigh
	PES15000M3B	1981	3213	Refinery, Saudi
	PES15000M3B	1981	3157	Athens, Greece
	PD6250M3B	1976	3009	M/T Petrola 34
	PD6250M3B	1976	3010	"
	PD6250M3B	1976	3011	M/T Petrola 33
	PD6250M3B	1976	3012	"
	PD6250M3A	1974	2674	Margarita, Greece
57. PHILLIPS PETROLEUM	2SF075	1993	7309 A	Offshore, China
	2SF075	1993	7309 B	
	PEE400M3C	1994	7273	
	PEE400M3C	1994	7257	
58. QATARGAS	PEE600M3C	1995	7360	Qatar
	PEE600M3C	1995	7361	(Offshore)
59. SANTA FE	2ST600	1989	4058	Offshore

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60. SAUDI NAVY	PEE600M3C	1990	7067	Saudi Arabia
	PEE55M3A	1978	2765	Vessel PGG 511
	PEE55M3A	1978	2766	Vessel PGG 512
	PEE55M3A	1978	2767	Vessel PGG 513
	PEE55M3A	1978	2768	Vessel PGG 514
	PEE55M3A	1978	2769	Vessel PGG 515
	PEE55M3A	1978	2770	Vessel PGG 516
	PEE55M3A	1978	2771	Vessel PGG 517
	PEE55M3A	1978	2772	Vessel PGG 518
	PEE55M3A	1978	2773	Vessel PGG 519
61. SEA & LAND	PD300M3C	1982	3047	Rig GD4, Oman
	PD300M3C	1982	3055	"
62. SEDCO FOREX	PEE300M3B	1982	3020	Rig 20, UAE
	PEE300M3B	1982	3021	"
	PEE300M3B/C	1982	3018	Saudi
	PEE300M3B/C	1982	3019	"
	ST600	1982	3195	
	ST600	1981	3070	710, Brazil
	ST600	1996	7473	710
	ST800	1996	7471	Abacan, Nigeria
63. S.E.R.E.P.T.	PEE300M3A	1980	36-1517	Tunisia
	PEE300M3A	1980	36-1518	
64. SHEIKH HAMDAN BIN ZAYED	PEE1250M3C	1991	7153 A	Garnain
	PEE1250M3C	1991	7153 B	Island, UAE
65. SHELL OFFSHORE	PEE100M3C	1989	7064	USA
66. SWIRE PACIFIC	PEE400M3A		36-1387	"Pacific Constructor"
67. TEXACO OIL	PEE400M3C	1989	7027	Nigeria
68. TECHNIPETROL	4METC900	1996	7415	Savola Sugar
	4METC900	1996		Refinery, Jeddah
69. UNITED ARAB EMIRATES, NAVY	PEE400M3C	1986	3708	Qaffay Island
	PEE400M3C	1986	3709	
70. U. S. ARMY CORP. ENGINEERS	PEE2100M3C	1983	3282-1	Sinop, Turkey
	PEE2100M3C	1983	3282-2	
	PEE2100M3C	1983	3282-3	
71. U. S. COAST GUARD	2SF300	1989	3590	
	2SF300	1989	3591	
	2SF300	1989	3592	
	2SF300	1989	3593	
72. U. S. NAVY	PEE400M3C	1994	7348	Harkness
	PEE400M3C	1994	7379	Chauvenet
	PEE300M3C	1992	7177 A	
	PEE300M3C	1992	7177 B	
	PEE300M3C	1992	7210	
	PEE400M3C	1989	7085	
	PEE400M3N	1992	7249 A	DDG Class Ships
	PEE400M3N	1992	7249 B	
	PEE400M3N	1992	7231 A	
	PEE400M3N	1992	7231 B	
	PEE400M3N	1991	7165 A	
	PEE400M3N	1991	7165 B	
	PEE400M3N	1991	7166 A	

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(U. S. NAVY Con't)	PEE400M3N	[illegible]	7166 B	
	PEE400M3N	1991	7104 A	
	PEE400M3N	1991	7104 B	
	PEE400M3N	1991	7104 C	
	PEE400M3N	1991	7104 D	
	PEE400M3N	1991	7104 E	
	PEE400M3N	1991	7104 F	
	PEE400M3N	1991	7105 A	
	PEE400M3N	1991	7105 B	
	PEE400M3N	1991	7105 C	
	PEE400M3N	1991	7105 D	
	PEE400M3N	1989	7033 A	
	PEE400M3N	1989	7033 B	
	PEE400M3N	1987	3868	
	PEE400M3N	1987	3869	
	PEE400M3N	1987	3870	
	PEE400M3N	1987	3871	
	PEE400M3N	1987	3872	
	PEE400M3N	1987	3873	
	PEE400M3N	1987	3874	
	PEE400M3N	1987	3875	
	PEE400M3N	1987	3876	
	PEE400M3N	1987	3877	
	PEE400M3N	1987	3878	
	PEE400M3N	1987	3879	
	PEE400M3N	1987	3880	
	PEE400M3N	1987	3881	
	PEE400M3N	1987	3597	
	PEE400M3N	1987	3596	
	PEE400M3N	1982	3189	
	PEE400M3N	1982	3173	
	PEE400M3N	1982	3174	
73. UNOCAL	PEE300M3C	1991	7146	Alaska, USA
74. WESTERN EGYPTIAN	PEE100M3C	1991	7103	Offshore, Egypt
PETROLEUM CO. (WEPCO)	PEE200M3C	1989	7045	
75. WESTERN OCEANIC	ST300	1980	2951	Apollo 1
	ST300	1980	2952	Apollo 2
76. ZAKUM DEVELOPMENT	PEE200M3C	1986	3344	CPC Platform
OIL CO. (ZADCO)	PEE300M3C	1990	7059	UAE
	PEE2100M3C	1984	3204	Arzannah
	PEE2100M3C	1985	3373	Island
77. ZAPATA	ST300	1991	7131	Offshore, USA
78. ZURN/ NEPCO	2METC1135B	1995	7444	Hawaii, USA

EPA FORM 2D

WASTEWATER (SEWAGE) DISCHARGE (OUTFALL 001)

The wastewater treatment plant will receive all of the domestic sewage and sanitary waste generated at the Northstar Production facility. It is anticipated that the maximum flow through the wastewater treatment plant will be 9,360 gallons per day (gpd), with an average flow of 2,800 gpd. The Class I/II injection well is the primary disposal method; however, in the event that the injection well is not available, the wastewater effluent will be diverted through the marine outfall 001.

All domestic sewage and sanitary waste will pass through the wastewater system. Secondary treatment of the domestic sewage and sanitary wastewater stream will be accomplished using a D-Series FAST® System (Fixed Activated Sludge Treatment), manufactured by Smith & Loveless, Inc. (see Attachment 6). The FAST system is a patented aerobic biological process that employs fixed media for bacterial growth. Sewage enters the media tank; microbes normally found in sewage attached to fixed media metabolize organic materials present in the sewage. No pretreatment, maceration, or screening is required. The fixed media allows formation of a much larger microbial population than would otherwise be possible, thereby providing consistent treatment despite surges and other variations in loading.

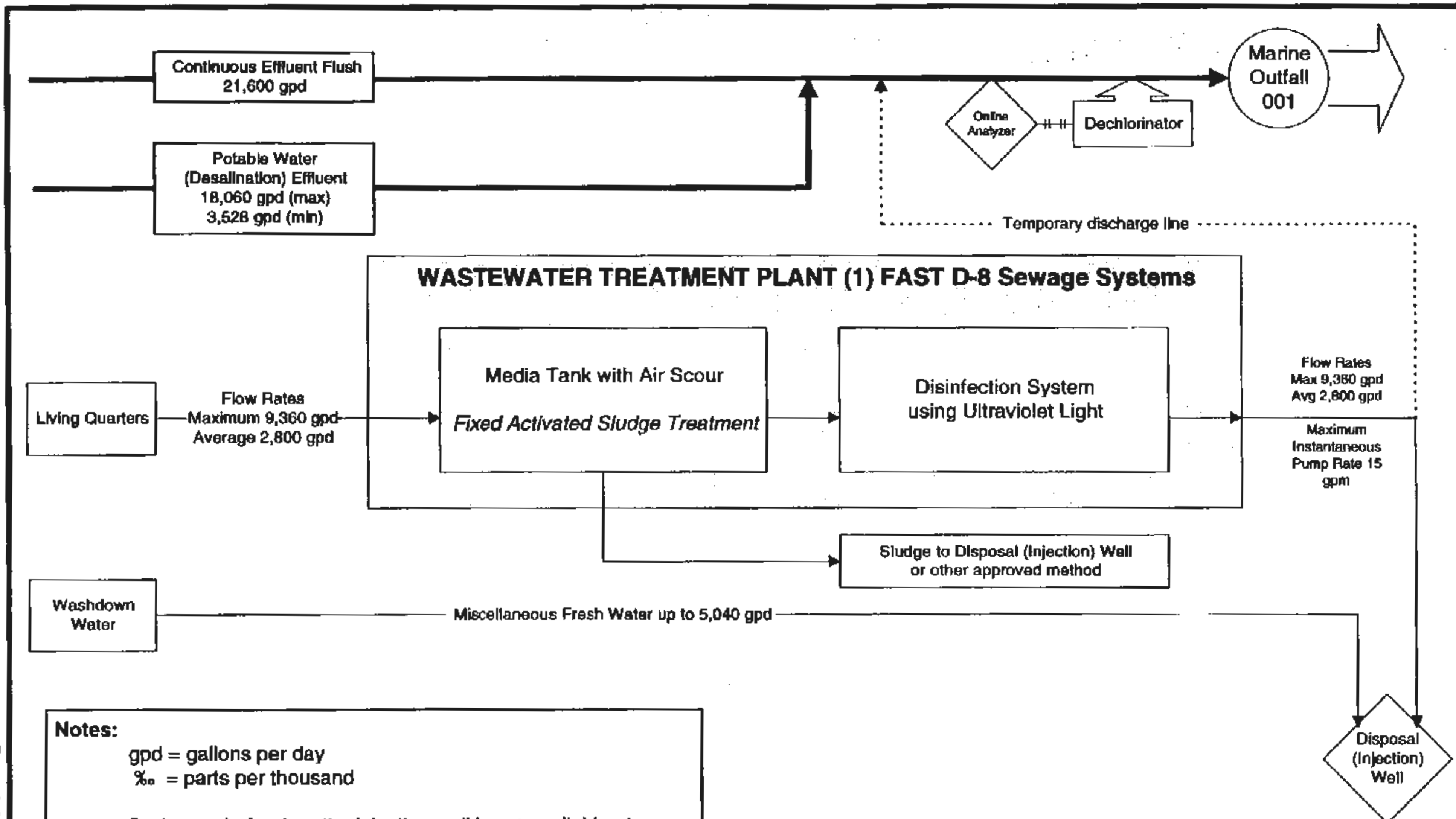
A disinfection system using ultraviolet lights will be placed in the discharge stream between secondary treatment and final disposal. The disinfection system will be designed for the output capacity from the FAST® units. Typically, the wastewater stream will be discharged through the Class I/II injection well. However, during facility construction and periods when the Class I/II injection well is not available, the wastewater treatment plan effluent will be commingled with the continuous flush and potable water (desalination unit) effluent. The resulting commingled stream will pass through a dechlorinator prior to marine discharge.

Chlorine in the form of calcium hypochlorite or sodium hypochlorite will be injected into the potable water system immediately downstream of the desalination unit (see Exhibit 7). This fresh water is supplied to the Living Quarters and throughout the facility for washdown water. It is expected that all of the chlorine will be consumed by domestic sewage (e.g., toilets, showers, lavatories, laundry, kitchen sink and dishwasher, etc.) uses and in the media tank of the wastewater treatment plant (FAST® Sewage System, D-Series). Effluent discharged from the media tank will be sterilized with ultraviolet light, thus, no residual chlorine is expected to be discharged from the wastewater (sewage) system.

The wastewater (sewage) discharge will be directed through marine outfall 001 during periods when the on-site injection well is not available. The FAST® Sewage System, D-Series treatment plant will process domestic sewage generated from water uses in the living quarters. The expected effluent temperature is expected to be approximately the same as the interior module temperature of 16°C to 18°C.

Chlorine is expected to be completely consumed in the process, so no TRC is expected in the effluent. Effluent discharged from the media tank will be sterilized with ultraviolet light, thus, no residual chlorine is expected to be discharged from the wastewater (sewage) system. Biological oxygen demand, 5-day (BOD5), pH, and TSS are expected be similar to the domestic waste discharge at the Endicott Facility, and thus maximum and average values were determined by reviewing the 1994 Endicott DMR (Endicott domestic wastewater Outfall 001a). Fecal coliform values were determined by reviewing Endicott DMRs from 1992 to present.

The sludge resulting from the secondary treatment will be discharged through the onsite injection well. However, in the event that the injection well is not available, the sludge will be disposed onshore at an approved facility within the Prudhoe Bay area.



Notes:

gpd = gallons per day
‰ = parts per thousand

During periods when the injection well is not available, the wastewater effluent will be discharged through the marine outfall. Washdown water will never be discharged through outfall 001.

1 FAST D-8 Units to be installed in parallel.

BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Seal Island Sewage Treatment Plant Line Diagram

Exhibit 7

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V. Effluent Characteristics

A, and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instructions for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See table 2D-2 for Pollutants)*

Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

Wastewater Treatment System 1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
Biological Oxygen Demand (BOD) (concentration)	25 mg/l	15 mg/l	3 (Endicott BOC Wastewater Treatment Plant)
Biological Oxygen Demand (BOD) (mass)	0.89 kg	0.16 kg	3 (Endicott BOC Wastewater Treatment Plant)
Total Suspended Solids (TSS) (concentration)	34 mg/l	25 mg/l	3 (Endicott BOC Wastewater Treatment Plant)
Total Suspended Solids (TSS) (mass)	1.2 kg	0.26 kg	3 (Endicott BOC Wastewater Treatment Plant)
Flow (gallons per day)	9,360 gpd	2,800 gpd	1 (BPX Northstar Alliance Design)
pH	7.7	7.15	3 (Endicott BOC Sanitary and Domestic Wastes)
Fecal Coliform (concentration)	210 FC No./100ml	16 FC No./100ml	3 (Endicott BOC Wastewater Treatment Plant)
Temperature (all seasons)	18°C	16°C to 18°C	1 (BPX Northstar Alliance Design)
Salinity (all seasons)	0 (fresh)	0 (fresh)	1 (BPX Northstar Alliance Design)
Total Residual Chlorine	0 ppb	0 ppb	1 (BPX Northstar Alliance Design)

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	***Outfall 001(c)*** ***wastewater***

Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

. Pollutant	2. Reason for Discharge
Not Applicable	

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
Endicott Development (Wastewater Treatment System)	***Duck Island Unit Beaufort Sea, Stefansson Sound, Alaska (offshore of the Sagavanirktok River delta)***

ATTACHMENT 6

FAST SEWAGE SYSTEMS
D-SERIES

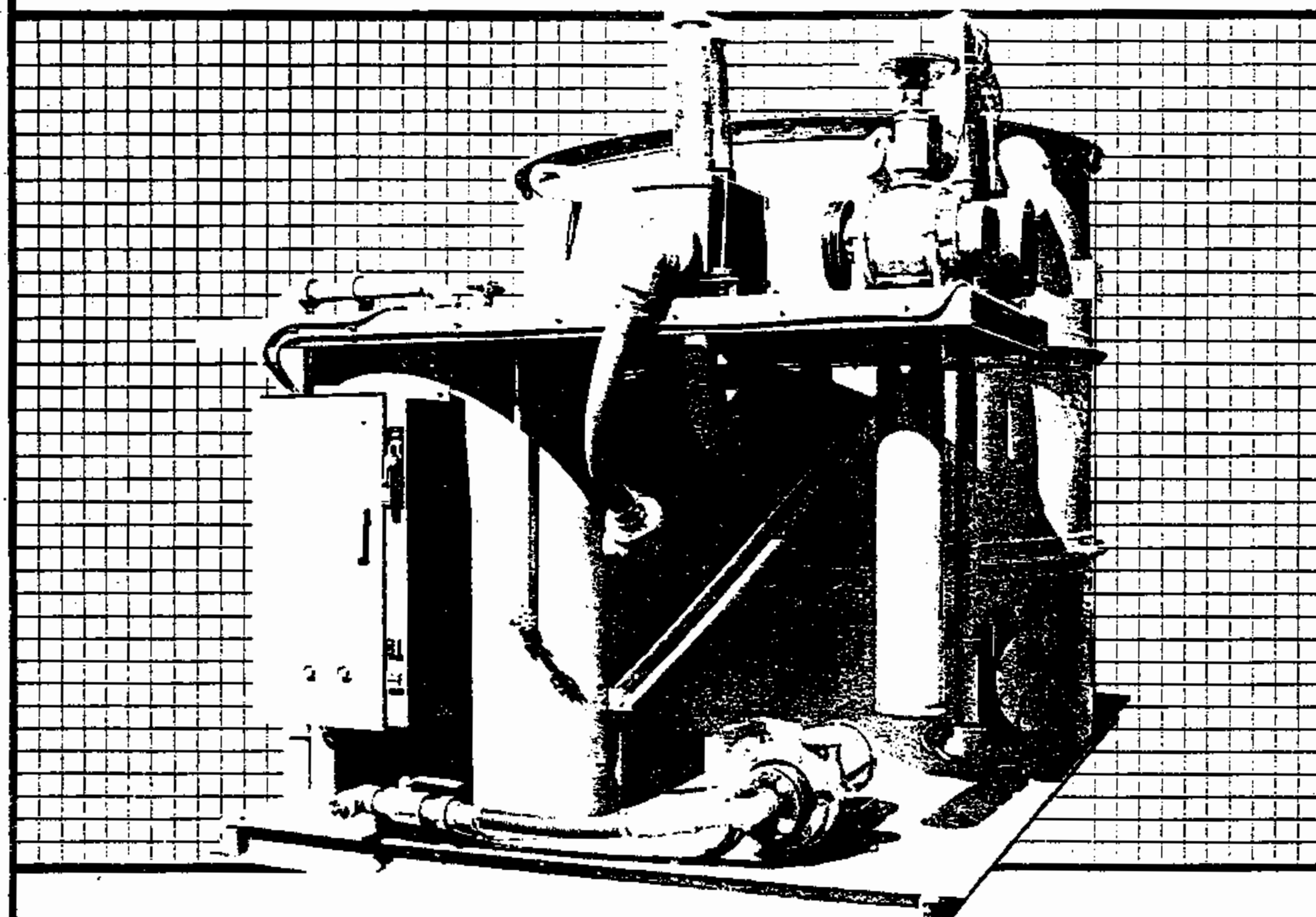
FAST®

SEWAGE SYSTEMS

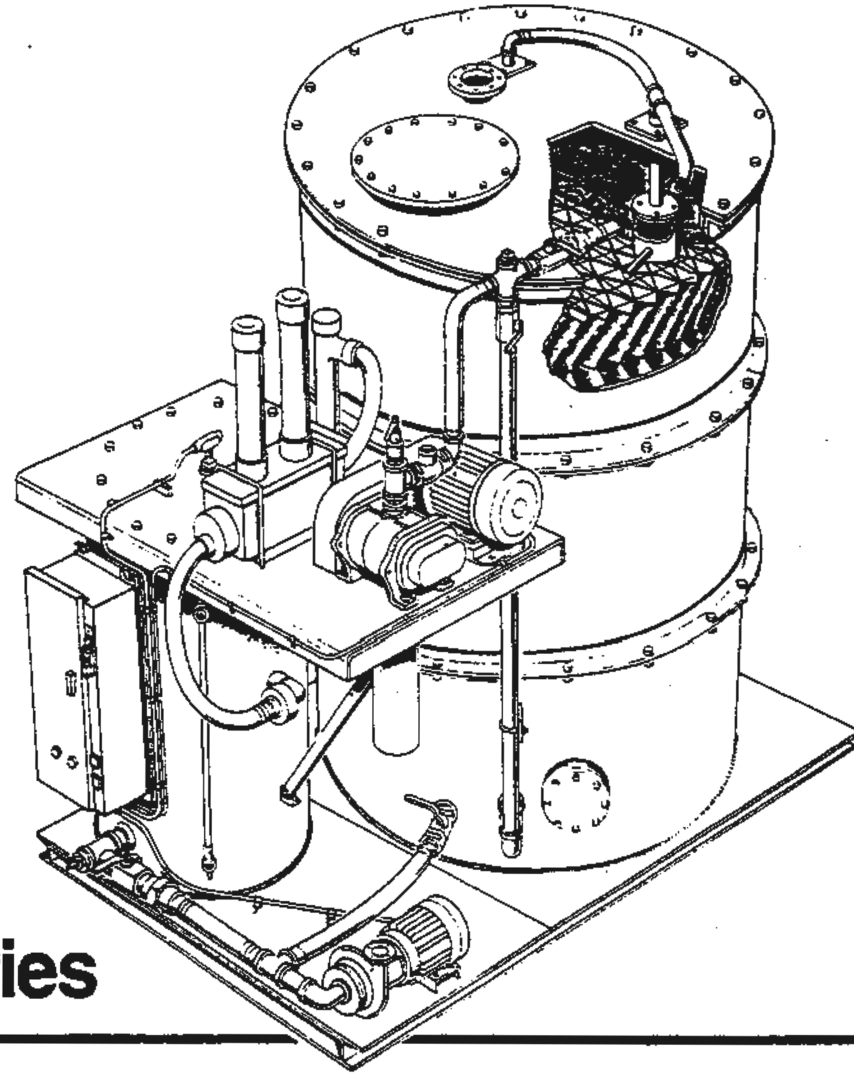
D-Series

Brochure 3051

Complete Package Units for New or Existing Vessels.



- Fully assembled, factory tested, skid-mounted systems.
- Available in bolt-together construction for ease of installation aboard existing vessels.
- Certified by USCG (Type II), IMO and Environment Canada.
- Designed and built per ABS and USCG Engineering Standards. Also available per C.S.I., Bureau Veritas, Det Norske Veritas, Germanischer Lloyd, Lloyd's Register, Nippon Kaigi Kyokai, Polske Rejestr Statkov and Registry of the USSR Standards.



D-Series

Each D-Series FAST® System (Fixed Activated Sludge Treatment) is completely assembled, wired and tested on its own foundation. The unique design provides the greatest possible flexibility in locating and installing the system aboard ship.

Where space and access permit, the D-Series System can be installed as a unit. Shipboard connections and installation labor are reduced to an absolute minium.

The D-Series Media Tanks and Machinery Module can be furnished on separate foundations to use available space to the best advantage, and the Media Tank itself can be furnished in bolt-together sections. All D-Series Systems are factory assembled, wired and tested. Bolt-together units can be broken down and reassembled in place.

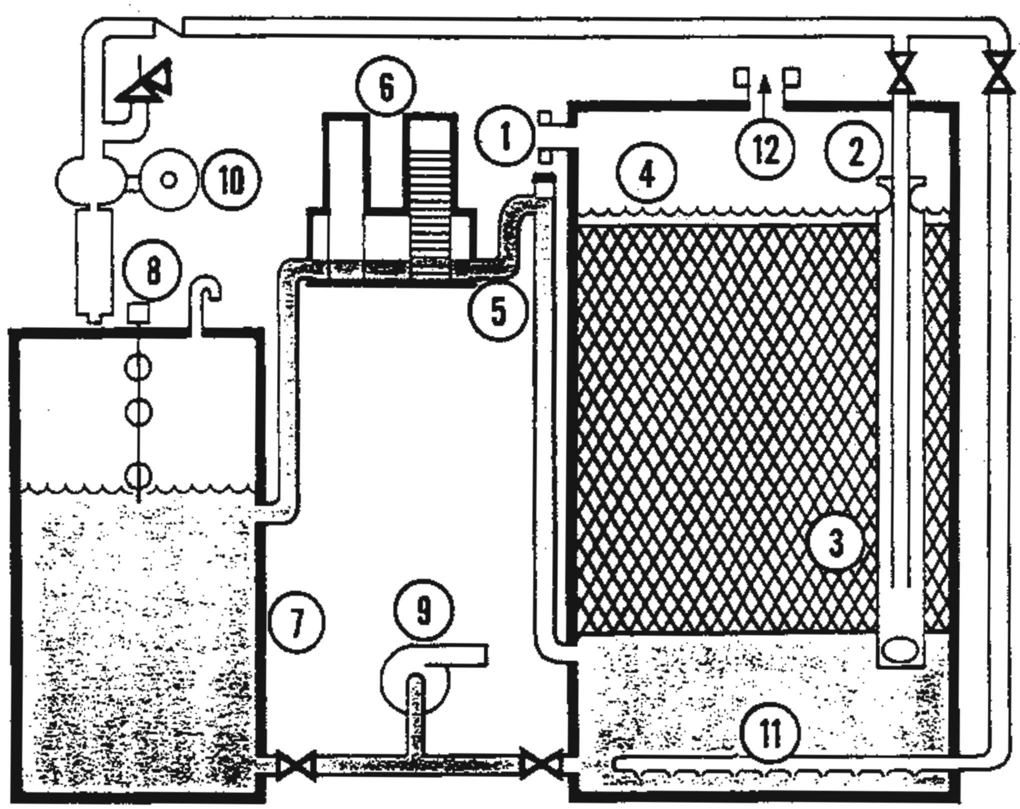
Fully certified FAST® sewage treatment systems are available in capacities up to 175,000 GPD. They are the best marine treatment systems in the world.

FAST®s oil/water separators are also the best in the world, the only fully certified units able to break emulsions. These units produce oil-free water despite the presence of detergents.

Formerly a division of St. Louis Ship, FAST® Systems is now part of the Commercial Division of Smith & Loveless, Inc. Smith & Loveless® offers you the most extensive wastewater treatment technology, expertise, experience, and know-how in the world.

Equipment is manufactured in the U.S., Canada, Australia, and the E.E.C. Service is available worldwide. Please call us.

FLOW DIAGRAM



1. SEWAGE INLET—No macerator or bar screen required. Any combination of black and grey waters can be piped into a common inlet.

2. AIRLIFT—Circulates and aerates contents to prevent foul odors. High turbulence breaks up solids and throws foreign objects to the side for later disposal by the process.

3. MEDIA—Microorganisms present in sewage grow on its surface area and digest the sewage. Media never needs replacement or manual cleaning.

4. SPILLOVER—Maintains constant water level. Raw sewage cannot enter spillover.

5. TRAP—Positive water seal keeps odors out of the engine room.

6. TABLET CHLORINATOR—Simple, low cost, effective and reliable. Water flow dissolves tablets: no flow, no chlorine used.

7. WET WELL—Provides contact time for chlorine to disinfect water. Sized for peak flow periods.

8. FLOAT SWITCH—Located on tank centerline to prevent spurious tripping due to vessel motion.

9. DISCHARGE PUMP—Complete with all controls necessary for automatic operation, may be fitted on the system.

10. ROOTS BLOWER—Slow speed, reliable, long life.

11. AIR SCOUR—Built in cleaning system uses air from blower. No need for manual cleaning.

12. VENT—No foul odors.

D-SERIES UNIT SPECIFICATIONS

General. Package unit, assembled and wired on steel skid, tested at factory before shipment. Includes valves, machinery and controls necessary for automatic operation.

Certifications. USCG Type II for Inspected Vessels, IMO, Canadian Great Lakes.

Classification Societies. American Bureau of Shipping, Canada Steamship Inspection, Bureau Veritas, Det Norske Veritas, Germanischer Lloyd, Lloyd's Register, Nippon Kaigi Kyokai, Polski Rejestr, Statkov, Registry of USSR.

Wastewaters Treated. Any combination of raw, unscreened, fresh or salt water domestic sewage from standard or vacuum toilets, personal wash water, laundry or galley.

Effluent Quality. Equal to or better than any known marine standard worldwide. Test reports available on request.

Process. Fixed Activated Sludge Treatment (FAST®) patented aerobic biological process employs fixed media as site for microbial growth.

Rated Capacity. Refer to Table.

Load Variations. Unit shall operate properly and meet regulatory requirements at any loading from zero to overload capacity, including surges at change of watch, changes in crew size and changes in salinity of flushing water.

Overload Capacity. Up to 50% of rated capacity. The average daily load shall not exceed:

Duration (days)	1	2	3	4	5 or more
Average load	150%	115%	105%	105%	100%

Operation. Sewage enters media tank above constant water line. Microbes normally found in sewage attach to fixed media and use organic material in sewage as food. Use of fixed media permits formation of much larger microbial population than would otherwise be possible, providing consistent treatment despite surges and other variations in loading. Unit can be bypassed at sea up to 3 weeks, then fully treated as the vessel enters controlled water. No obnoxious odors.

Compressed air operates airlifts to aerate and circulate contents of tank. Turbulence throws foreign objects to side of tank. Compressed air can be valved to air scour and clean tank before draining.

Process is inherently self-regulating. There are no adjustments, and proper operation does not depend on skill of personnel. Units will handle any objects which can pass through a toilet. No pretreatment, maceration, or screening is required.

Disinfection. USCG and IMO certified units employ solid tablet chlorine feeders. Dosage is proportional to flow. Canadian Great Lakes certified units employ ultraviolet sterilization in lieu of chlorination.

Equipment.

Basic Unit. Single vertical cylindrical media tank. Single vertical cylindrical chlorine contact tank. Unit incorporates structural steel skid, tablet chlorinator, air pressure regulator and orifice plate and gravity overboard connection.

Aeration Blower (if required). Roots rotary lobe blower, belt drive, belt guard, relief valve, discharge check valve, silencer, motor and motor starter in lieu of pressure regulator and orifice plate. Fully assembled on system.

Discharge Pump (if required). Close-coupled centrifugal, isolation valves, float switch in contact tank for automatic operation, motor and motor starter. Fully assembled on system.

Pump is 85-5-5-5 marine bronze with stainless steel shaft and hardware.

Duplex Discharge Pumps (if required). Two identical pumps per above, isolation and discharge check valves, standby pump starts automatically when high level float switch in contact tank energized, each pump sized for 100 percent duty, either pump can be selected as duty pump. Fully assembled on system.

Canadian Great Lakes Package (if required). U.V. sterilizer and chart recorder for remote mounting in lieu of chlorinator. Discharge pump(s) required.

Modular Construction (if required). Media tank shall be assembled on its own structural base. The contact tank, chlorinator and machinery shall be assembled as a machinery module on a separate structural base for remote installation. This will permit installation of the system in locations where sufficient space is not available for installation as a unit.

Modular Media Tank (if required). For installations in existing vessels where access to the intended machinery space is limited. The media tank shall be furnished in bolt-together sections. Each section shall pass through a clear opening of dimensions as listed on the Data Table.

Remote Alarm Panel (if required). Visible and audible alarms for high level and blower off. Low UV alarm included with Canadian Great Lakes Package.

Construction. All welded ABS Grade A (ASTM A-36) steel with bolted tank top, full structural steel skid, lifting lugs. Minimum section thickness 1/4 in. (6mm). Bulkheads reinforced to withstand USCG/IMCO test head. All penetrations and tank seams full welded both sides.

Corrosion Protection. Interior and exterior surfaces grit blasted to white metal (S.S.P.C. 5). Two coats polyamide epoxy tank lining to 12–14 mils DFT. Assembly hardware and threaded tank nozzles stainless steel.

Electrical Equipment

Voltages. 208/230/460/575 VAC 3Ø 60 Hz and 380 VAC 3Ø 50 Hz standard.

Motors. Totally enclosed fan cooled, marine duty, 50° ambient, Class F insulation.

Controls. Across the line starting, overload protection all 3 phases, marine duty, NEMA 4/ IP65 enclosure, terminal board for external connections, manual overrides.

Electric Service Required. Refer to Table.

Explosion Proof Equipment. Per USCG Electrical Engineering Regulations 46 CFR Part 111.80-5(C) for Class I, Division 2, Group D hazardous locations.

Piping. Schedule 40 steel, schedule 80 PVC or CPVC as applicable. All water piping external. Valve types and materials suitable for intended purpose.

Consumables. Chlorine consumption for continuous operation estimated at:

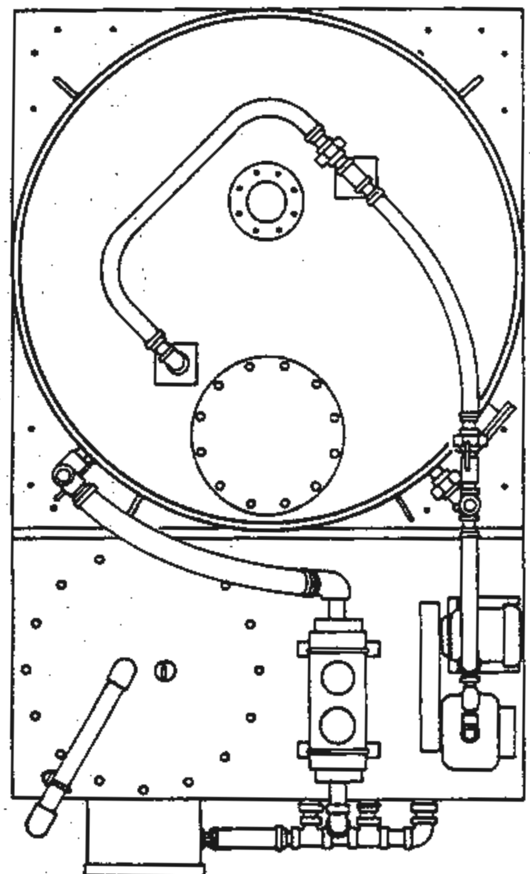
Waste Water	Chlorine Tablets (Lb/Man/Year)
Black water, vacuum toilets	0.4
Black water, conventional toilets	2.7
Gray water	3.5

Ultraviolet lamps to be replaced at 8,000 hour intervals, yearly for continuous operation.

Options Available. Non standard voltages, special electrical enclosures, tank insulation and heaters for low temperature operation, metric (DIN) flanges, special tank and machinery arrangements are available. Consult factory.

Specifications are subject to change without notice.

TECHNICAL DATA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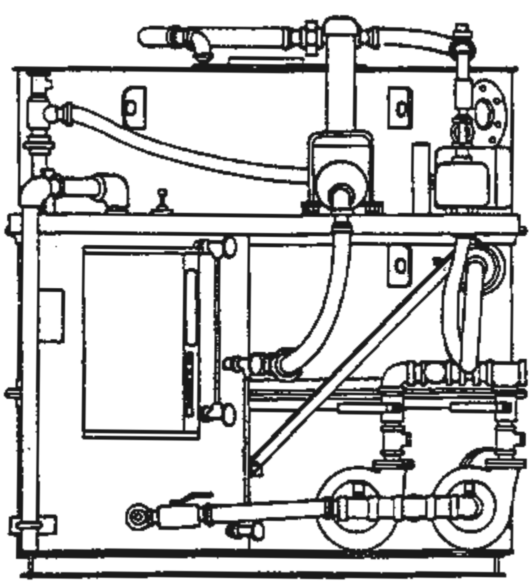
The crew sizes shown on Data Table are for treatment of black water only from persons working and living aboard. If other types of sewage are to be treated, add appropriate factors given below to obtain service factor. Multiply service factor by actual crew size to obtain equivalent black water crew size and use this figure to select a unit from the table.

Type of Sewage	Service Factor
Toilets and urinals (black water)	1.00
Showers and lavatories	0.42
Laundry	0.31
Galley sink and dishwasher	0.33
Galley garbage sewage	1.21
Total all domestic sewage	3.27

For persons working but not living aboard, or living but not working aboard, count each of these as one-half person to obtain equivalent crew size.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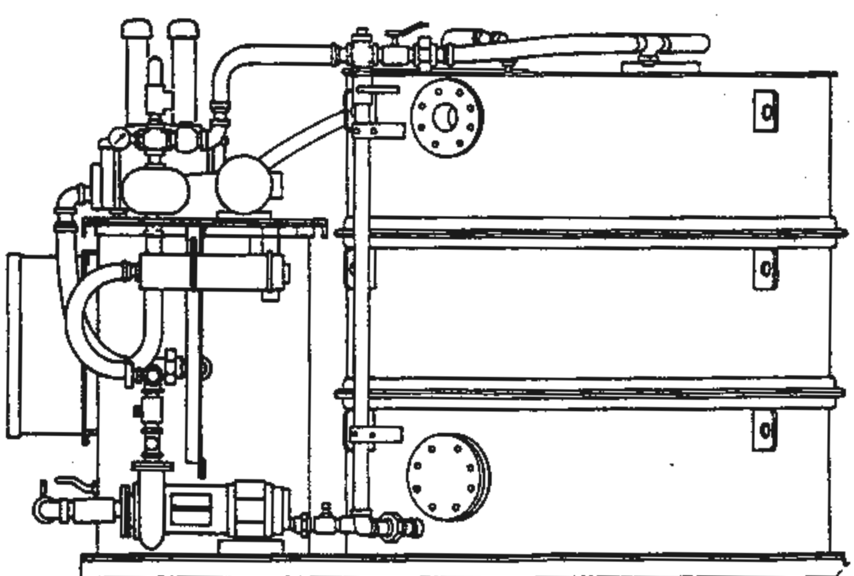
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FAST® D-SERIES ENGINEERING DATA

MODEL	D1	D2	D3	D4	D5	D6	D7	D8	D9
RATED CAPACITIES - PERSONS									
USCG/IMO EFFLUENT	44	67	96	145	183	257	386	606	874
30/30 EFFLUENT	24	37	54	80	105	147	212	342	493
OVERALL DIMENSIONS (FT)									
COMPLETE UNIT									
LENGTH	6.9	8.0	9.3	10.8	12.1	13.9	15.0	18.1	21.8
WIDTH	3.9	4.6	5.5	6.5	7.3	8.6	8.5	10.5	12.5
HEIGHT	6.8	7.0	7.2	7.3	7.5	7.6	9.7	10.3	10.3
CLEAR HEIGHT REQD ABOVE DECK FOR FULL ACCESS (FT)									
UNIT ON SKID	8.5	8.6	8.8	8.8	9.0	9.0	11.1	11.3	11.4
TANKS WITHOUT SKID	8.2	8.3	8.3	8.3	8.5	8.5	10.6	10.7	10.8
MODULAR CONSTRUCTION - ACCESS OPENING REQD (FT)									
MEDIA TANK SECTIONS									
LENGTH = WIDTH	3.9	4.6	5.5	6.5	7.3	8.6	8.5	10.5	12.5
HEIGHT	2.3	2.3	2.4	2.4	2.5	2.5	3.2	3.4	3.4
MACHINERY MODULE - COMPLETE									
LENGTH	3.9	4.6	5.5	6.5	7.3	8.6	8.5	10.5	12.5
WIDTH	2.5	2.8	3.2	3.7	3.9	4.5	5.3	6.3	7.5
HEIGHT	5.1	5.1	5.3	5.3	5.4	5.4	5.4	5.6	5.6
WET WELL ONLY									
LENGTH	1.9	2.3	2.6	3.1	3.3	3.9	4.7	5.8	7.0
WIDTH	1.9	2.3	2.6	3.1	3.3	3.9	4.7	5.8	6.8
HEIGHT	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
ESTIMATED WEIGHTS (LBS)									
SHIPPING	2,700	3,300	4,200	5,300	6,200	7,700	9,400	14,000	18,000
OPERATING	5,900	8,100	11,000	16,000	20,000	27,000	36,000	55,000	78,000
PIPE SIZES (IN)									
GRAVITY SEWAGE INLET	4	4	6	6	6	6	6	8	8
PUMP DISCHARGE									
SIMPLEX	1-1/2	1-1/2	1-1/2	1-1/2	1-1/2	1-1/2	1-1/2	2	2-1/2
DUPLEX	2	2	2	2	2	2	2	2-1/2	3
MEDIA TANK VENT	3	4	4	6	6	8	6	8	10
VACUUM SYSTEM MAKEUP WATER	1/4	1/4	1/4	3/8	1/2	1/2	3/4	1	1-1/2
STANDARD DISCHARGE PUMP									
MAX STATIC LIFT	45	45	45	45	45	40	35	35	70
MOTOR HORSEPOWERS									
BLOWER	1	1 1/2	2	3	5	5	5	7 1/2	10
DISCHARGE PUMP	1 1/2	1 1/2	1 1/2	1 1/2	1 1/2	1 1/2	1 1/2	2	5
EXTERNAL AIR SUPPLY									
PIPE SIZE (IN)	1/2	3/4	3/4	1	1	1-1/2	1	1-1/2	1-1/2
SCFM REQUIRED	21	32	47	70	88	124	115	181	261

NOTES:

1. Units are rated for use with any combination of conventional and vacuum toilets.
2. Units are rated in persons using service factors. Do not use GPD to select units.
3. Units are available with separate black and gray water inlet connections.

Exclusive Benefits of FAST®

FAST® (Fixed Activated Sludge Treatment) is a unique and patented wastewater treatment process. It is the result of many years of university and industrial research, and continuous marine service aboard vessels of all types.

Microorganisms normally found in sewage grow on fixed Media in an oxygen-rich environment and use incoming sewage as food. The process produces a clear, odorless effluent in one step.

The water in the Media Tank is clear because the microbial culture is attached to the Media rather than being kept in suspension, as is done in extended aeration systems. FAST® does not require a separate clarifier or settling tank, thereby eliminating the serious operating problems associated with clarifiers, such as variable effluent quality, periodic foul odors and the need for frequent adjustments.

FAST® is inherently self-regulating. There are no adjustments. The ratio of microorganisms to sewage is much higher than in extended aeration systems. This "fly-wheel effect" permits FAST® to handle the wide variations in loading typical of marine service. Surge loads at change of watch and temporary changes in crew size do not adversely affect effluent quality. The performance of FAST® is not dependent on the skill of the operator.

FAST® will accept and treat any combination of sewage delivered by the ship's piping system including conventional and vacuum toilets, laundry, garbage disposals and showers. Unlike other systems, no screening, pretreatment or maceration is required.

- ☐ Clogging is practically impossible.
- ☐ The Media never requires maintenance or replacement.
- ☐ The only maintenance required is replenishment of the chlorine supply and routine lubrication.
- ☐ FAST® effluent exceeds all known standards. Local regulations can change, you can change trade route or area of operations, but your FAST® system will keep you in compliance worldwide.

A note on periodic pumpout: All secondary treatment processes produce a residual sludge. In FAST®, this nonbiodegradable fraction is reduced to the absolute minimum by the process and stored in the Media Tank. Although periodic pumpout is necessary to consistently obtain the very best effluent quality (and we recommend it), periodic pumpout is not required to meet USCG Type II requirements. Each FAST® system incorporates built-in pumpout capability to avoid possible future obsolescence.

FAST® works equally well in fresh, salt or brackish water, and accommodates rapid changes in salinity associated with coastal sailing.

FAST® systems are built to last. Steel tanks are externally reinforced to provide a rigid backing for our epoxy coating system. Tank interiors are blasted to white metal, then painted with multiple color-contrasting coats of epoxy resin to insure thorough coating and long tank life. All internal components are stainless steel, PVC or polyethylene.

Each item of machinery is selected for reliability, and extensively tested in service before being specified for general use.

Chlorine disinfection is normally used, providing the simplest and most economical method available. Ultraviolet disinfection is available to meet the rigorous performance and monitoring requirements of Canada's Great Lakes Regulations. Existing FAST® systems can be retrofitted with the ultraviolet disinfection and monitoring kit.

A wide variety of FAST® treatment systems and accessories is available to meet your particular requirements. Our MiniJect®, a patented and superior pneumatic ejector, provides reliable transfer of raw sewage in cases where gravity flow is not possible.

Our experienced engineering staff will be pleased to assist you in selecting the best treatment and transfer system for your vessel. Let us help you bring your installation into compliance and keep there at the lowest total cost.

FAST®

Systems

S&L®

Smith & Loveless, Inc.
Commercial and Industrial Divisions
3240 North Broadway
St. Louis, MO 63147-3515
Phone: (314) 621-2536 Fax: (314) 621-1952

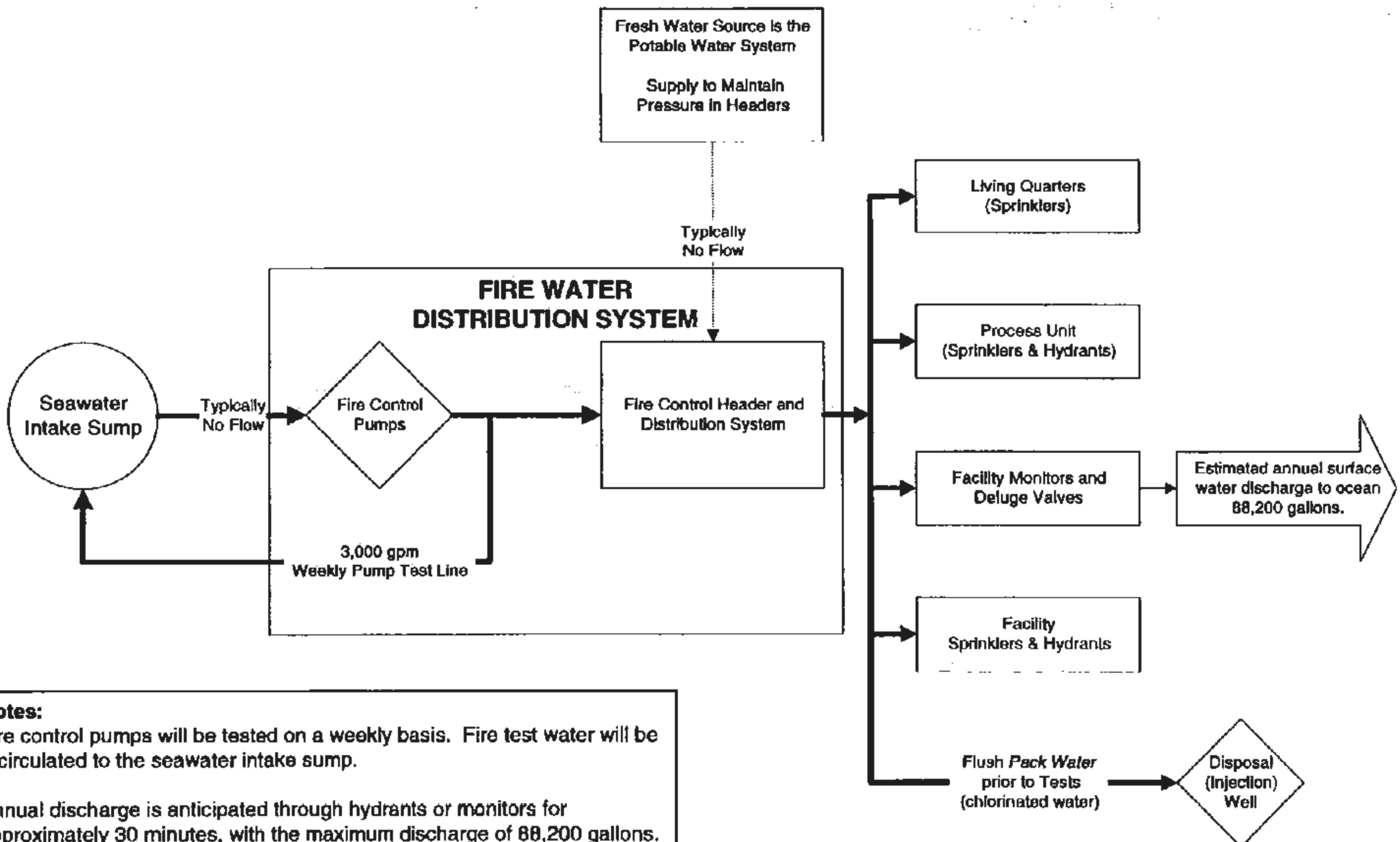
EPA FORM 2D

FIRE TEST WATER DISCHARGE (OUTFALL 002)

Exhibit 8 Outfall 002
Fire Test Water Distribution System

While there typically will be no continuous flow, the fire water distribution system will provide emergency seawater supply throughout the Northstar Production Facility to suppress and extinguish fires. This system is designed to pump up to 3,000 gallons per minute (gpm) of seawater from the seawater intake sump through a header and distribution system to sprinklers, hydrants, monitors and deluge valves (Exhibit 9). The fire water distribution system is designed to have constant pressure and water supply to all lines for instant release in the event of a fire. Fresh potable water (pack water) will be supplied to maintain water pressure in the header and distribution lines.

This discharge is expected to be an intermittent minor waste stream, and not a continuous or regular discharge. Weekly tests of the fire control pumps will circulate seawater from the seawater intake sump through the pumps and directly back in the seawater intake sump. This seawater is untreated and will have nothing added. The process is not expected to change the temperature of the seawater from ambient. Annual testing will be conducted on the whole system such that seawater will be discharged through selected hydrants and/or monitors to ensure adequate water pressure is available for fire control. After construction, as-built drawings of the facility will be used to determine the exact volume of the fire header and distribution system. Immediately prior to the annual test, the pack water containing chlorine will be flushed from the lines and disposed through the onsite injection well. To assure that only untreated seawater is discharged into the Beaufort Sea, the operators will flush the fire system header and distribution system with twice the volume of the header and distribution system. Consequently, no residual chlorine will be discharged into the marine environment. The annual test will discharge untreated seawater directly over the side of Seal Island and directly onto the surface waters of the Beaufort Sea. It is anticipated that 88,200 gallons will be discharged for a 30 minute test period, with a maximum flow rate of 3,000 gpm.



Notes:

Fire control pumps will be tested on a weekly basis. Fire test water will be recirculated to the seawater intake sump.

Annual discharge is anticipated through hydrants or monitors for approximately 30 minutes, with the maximum discharge of 88,200 gallons.

Pack water (chlorinated potable water) will be flushed and disposed into the injection well prior to fire water tests.

Fire control test water will be discharged directly into the Beaufort Sea.

BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Seal Island Fire Test Water Line Diagram

Exhibit 9

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	Outfall Number **002 fire test water**

V. Effluent Characteristics

A and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instructions for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See table 2D-2 for Pollutants)*
Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

Fire Water Distribution System 1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
Flow (gallons per minute)	***3,000 gpm***	***0***	***1 (BPX Northstar Alliance Design)***
Temperature (summer)	***ambient***	***ambient***	***1 (BPX Northstar Alliance Design)***
pH	***ambient***	***ambient***	***1 (BPX Northstar Alliance Design)***

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	***Outfall 002** fire test water*

Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

1. Pollutant	2. Reason for Discharge
Not Applicable	

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
Endicott Development (Fire Test Water Distribution System)	***Duck Island Unit Beaufort Sea, Stefansson Sound, Alaska (offshore of the Sagavanirktok River delta)***

EPA FORM 2D

DECK DRAINAGE (OUTFALLS 003 & 004)

Deck Drainage
The Northstar Development will be a petroleum production facility situated on Seal Island, a man-made gravel island in the Beaufort Sea. To prevent accidental releases of spill chemicals or petroleum into the surface waters of the Beaufort Sea, a deck drainage and collection system will be installed to capture potential pollutants.

Since Seal Island is in the arctic marine environment, deck drainage sources include precipitation (e.g., snow, rain, etc.), storm waves, and sea spray. The facility will incorporate the best management practices (BMPs) to assure water released through the deck drainage collection system meets or exceeds regulatory discharge requirements. Based on historical spill reports from the Endicott Main Production Island (MPI), the most likely fluid releases at the Northstar facility include:

- Equipment malfunctions (leaking valves and gaskets, ruptured hoses) typically caused by cold weather problems
- Fluid transfers (overfilling) typically caused by operator inattention
- Vehicles (fluid leaks) typically maintenance items

At the Northstar facility, the majority of operations will be located in modules or containment areas where there is little risk of a release escaping to the environment. Deck drainage runoff is expected to occur only between May and September, when ambient temperatures are above freezing.

Snow Accumulation
Uncontaminated snow may be deposited on the sea ice adjacent to Seal Island, where it will gradually melt into the Beaufort Sea during the spring breakup. Uncontaminated snow is defined as having no discoloration or petroleum/chemical odor. Certain locations such as wellheads and parking areas are particularly susceptible to minor spills and leaks, thus the snow from these areas will always be placed in the melt tank and thawed for proper disposal. Additionally, contaminated snow or snow mixed with gravel will not be deposited onto the adjacent sea ice. Snow that is collected from these areas will be placed in a melt tank with the resulting liquid either being injected into a permitted disposal well or, if necessary, transported off-site for proper disposal at a permitted facility.

Collection System, Sumps, and Outfall Design
Surface drainage of rainfall, snow melt, and wave overtopping will be managed by a simple gravity drainage and catchment system. The sumps are sized for a 2 hour retention time based on a predicted 10 year storm event using Barter Island precipitation data. The surface of the island will be graded such that all deck drainage will collect in two sumps; the north sump will be situated in the northwest corner of the island and the south sump will be located on the dock immediately east of the helideck, (see Form 1, Exhibit XI-2). The north sump will drain an area of

approximately 157,000 square feet (ft^2), which is about 69 percent (%) of the island working surface. The south sump will drain about 72,000 ft^2, or 31% of the island surface.

The drainage sumps (Outfalls 003 and 004) will be buried steel boxes. Sump dimensions are provided in Form 1, Exhibit XI-2. Each sump will have a shutoff valve and 6 inch drain line extending from the sump base to the sheet pile wall. The shutoff valves will normally be kept in the closed position. There will be one open 12 inch overflow line in the north sump and one open 10 inch overflow line in the south sump. Each sump will have an overflow wier at the inlet end for sediment containment, an underflow wier located at the outlet end designed to capture and prevent oily discharges, and a slotted stilling well that will allow viewing from above of the undisturbed liquid surface for the detection of the presence of an oil sheen.

Each sump will be equipped with two alarms, a high level alarm and a high high level alarm. The high level alarm will sound when the water level in the sump reaches the minimum volume to allow for discharge. The high high level alarm will sound when the water level is at ½ of the working volume. The working volume is 28,300 gal for the north sump and 19,800 gal for the south sump. The alarms will sound at both the main control room and in the security office if the sump level reaches either of the predetermined levels.

During the winter months, this collection system and sumps will be largely inactive due to subfreezing temperatures. When snow melt and runoff begin, it will be necessary to thaw the sump, a task which is accomplished by applying heat, either through the use of portable heaters or by the use of pre-installed heat tracing, or by use of both methods.

Sump and Outfall Operation

The sump discharge valves will remain closed until discharge is warranted. Each deck drainage sump is fitted with an inspection stilling well and will be visually inspected for the presence of sheen prior to discharge of each batch. In the event an oil sheen is observed, the contaminated water will be pumped from the sump and disposed of through the onsite injection well, or transported to an approved onshore facility. Otherwise, if no oil sheen is observed, the water collected in the sumps will be released into the Beaufort Sea through Outfalls 003 and 004.

In the event of a petroleum or chemical spill at the Northstar Development, all fluids collected in the deck drainage sumps will be evaluated for disposal. Marine discharge will be allowed under the following conditions:

- Deck drainage has not been in contact with contaminated materials (the spill site is contained, isolated, or remediated)
- There is no observable sheen on the surface water in the sumps

- If deck drainage has been in contact with contaminated material at the spill site, sump fluids will be tested in a laboratory to determine chemical or hydrocarbon concentrations. If sump fluids meet applicable water quality criteria, they will be discharged through the marine outfall.

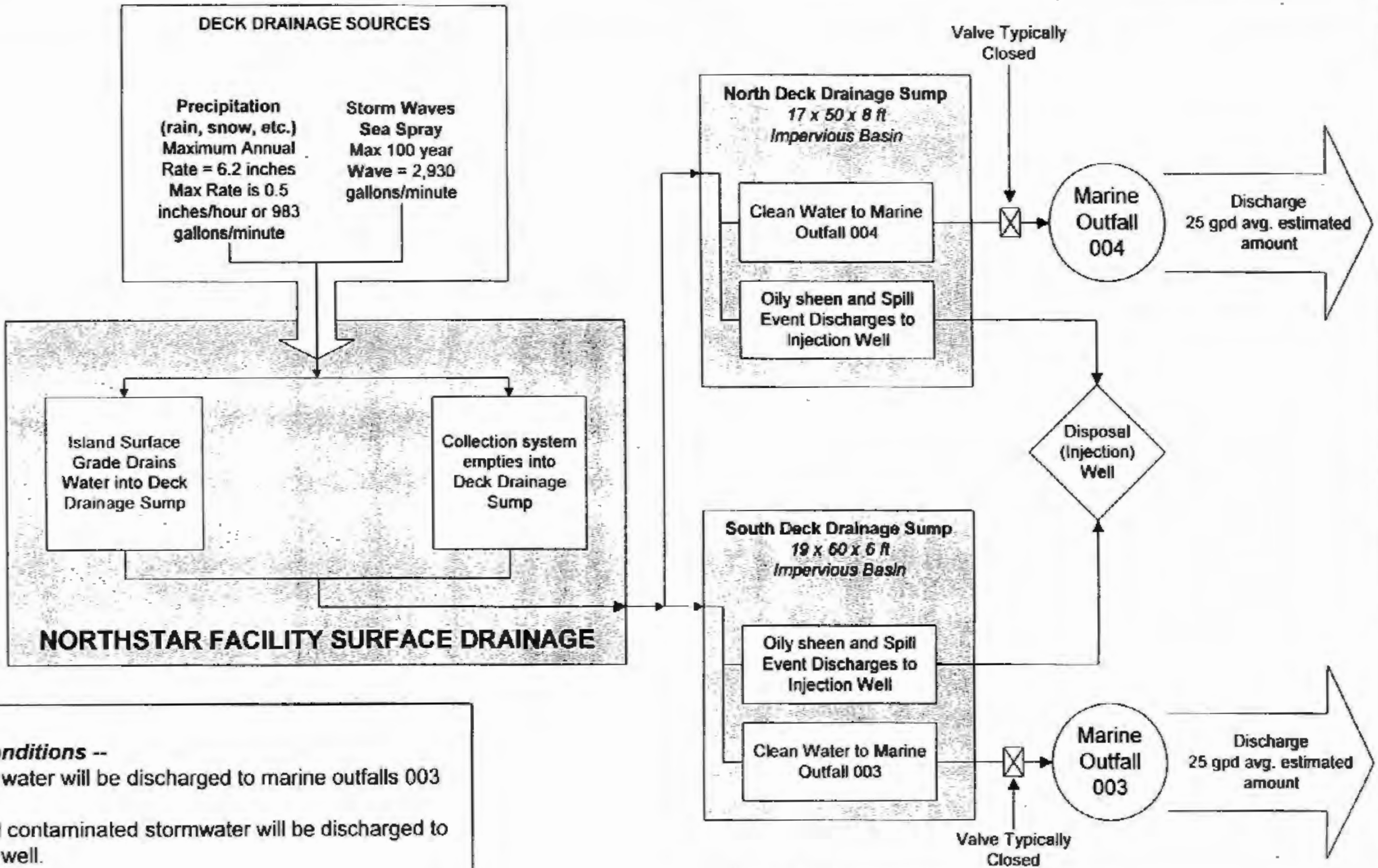
The onsite injection well will be permitted as a UIC Class I industrial disposal well for non-hazardous and RCRA-exempt fluids. If sump fluids do not meet water quality criteria for marine discharge, they will be injected in the disposal well if they are non-hazardous or RCRA-exempt. Any fluids classified as RCRA-hazardous waste will be managed at a designated storage area pending shipment to an approved hazardous waste disposal facility.

In the event of a large flow (upset condition), such as that caused by heavy rains or by waves overtopping the island during a 100 year storm, the sumps will not have adequate capacity to collect, store for inspection, and discharge the water on a batch basis (Exhibit 11). In these cases, which are expected to be very rare occurrences, the sumps will overflow to the ocean through the 10 or 12 inch overflow line. Any water discharged through the overflow lines must cross the underflow baffle which is designed to separate and contain any floating oil in the sumps (see Form 1, Exhibit XI-3). At the end of the storm event, the sumps will be inspected for oil sheen. If no oil sheens are observed, the sump water will be discharged through the manual marine outfall line (e.g., Outfalls 003 and 004). If oil sheen is observed, the sump water will be disposed of through the Class I injection well. Following a sheen event, the sumps will be cleaned in accordance with the procedures described in the BMP.

Best Management Practices (BMP)

Under the Site Specific NPDES permit, a BMP plan will be developed for the Northstar Development facility. It should be noted that no process water waste streams are designed to mix with deck drainage runoff at this facility.

The BMP plan will include provisions for regular visual inspections throughout the facility. Potential sources of pollution will be identified, and mitigative actions will be taken to prevent runoff of contaminated snow melt or deck drainage. Inspection records will be maintained as specified in the BMP plan. If there is evidence of pad contamination that has not previously been reported (such as an undetected spill), runoff collected in the deck drainage sumps will be evaluated for discharge or disposal as described in the previous section ("Sump and Outfall Operation").



Notes:

Summer Conditions --

Clean sump water will be discharged to marine outfalls 003 and 004.

Oily and spill contaminated stormwater will be discharged to the injection well.

Winter Conditions --

Uncontaminated snow will be moved onto Beaufort Sea ice. Contaminated snow and snow from drilling areas will be collected, melted, and disposed in an approved manner.

BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Seal Island Deck Drainage Line Diagram

Exhibit 11

CONTINUED FROM THE FRONT	EPA ID Number *(copy from item 1 of Form 1)*	Outfall Number **003 and 004 deck drainage**

V. Effluent Characteristics

A. and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instructions for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See table 2D-2 for Pollutants)*
Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

Deck Drainage Sump Outfall 1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
Flow (gallons per day)	***3000 gpd/outfall***	***25 gpd/outfall***	***1 (BPX Northstar Alliance Design)***
Temperature (winter)	***ambient sea & air***	***ambient ground***	***1 (BPX Northstar Alliance Design)***
Temperature (summer)	***ambient***	***ambient***	***1 (BPX Northstar Alliance Design)***
pH	***ambient seawater***	***ambient precipitation***	***1 (BPX Northstar Alliance Design)***

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	***Outfalls 003 and 004 deck drainage***

C. Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

1. Pollutant	2. Reason for Discharge
Not Applicable	

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
No arctic analog facility was identified.	

EPA FORM 2D

CONSTRUCTION DEWATERING (OUTFALL 005)

Exhibit 12 Outfall 005
Construction Dewatering

The Northstar Development Project is a stand-alone, self-contained, offshore drilling and production facility located on a gravel island which will include all support infrastructure and necessary facilities. The island will be built over the existing Seal Island.

Additional gravel fill will be required to expand and shape Seal Island into the proposed production facility. When sufficient gravel fill is available, the south side of the island will be expanded to the planned dockface. The gravel will be graded to an elevation of +7 ft mean lower low water (MLLW) and sheetpile will be installed along the perimeter to form the dockface. As in the Best Management Practices (Attachment 7), the Seawater Intake System (SWIS) will be installed below water in the dockface on the southern end of the island, adjacent to the helipad; Outfalls 001 and 006 will be located on the south side of the island through the dockface at an elevation of about -16 ft MLLW. Construction and installation of the SWIS and outfalls will occur sequentially.

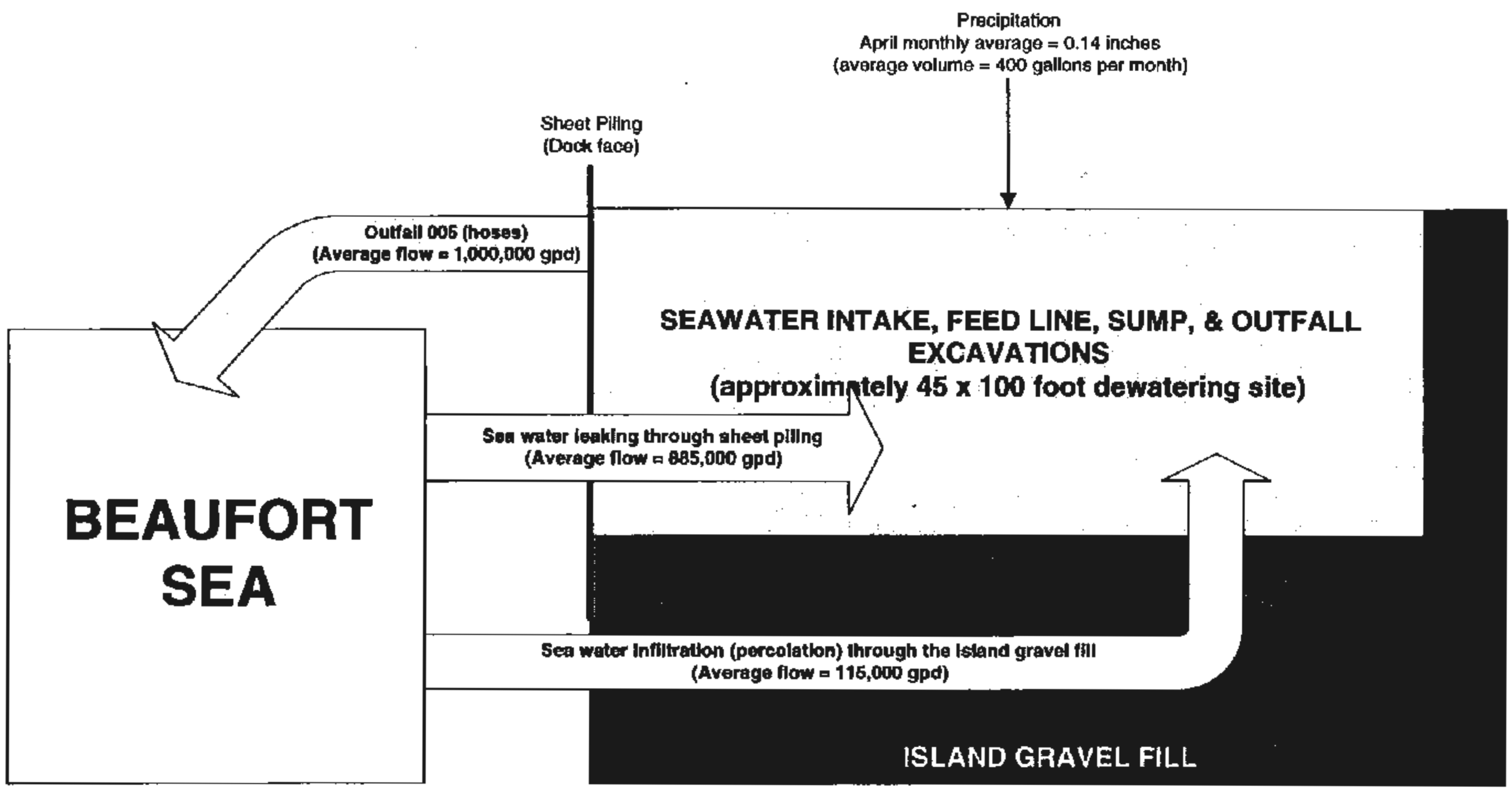
In order to minimize the infiltration of seawater into the SWIS excavation, the work will proceed in two sections. First, the excavation and feedline installation will occur in the section closest to the intake where seawater infiltration may be encountered. Second, a ditch plug will be installed at the northern end of the excavation to allow dry excavation of the section from the ditch plug to the coffer dam. Information from a site investigation (by backhoe, March 1997) revealed a dry excavation to -23 ft in this area, thus, this section is expected to remain dry. Discharge lines for Outfalls 001 and 006 will be installed in a similar fashion as described above.

Temporary dewatering activities are likely to be required during construction and installation of both the (SWIS) and Outfalls 001 and 006. It is anticipated that the dewatering operations will be required discontinuously over a two to four week period during early spring (April - May). A Best Management Practice Plan and Pollution Prevention Plan has been prepared for this discharge is provided as Attachment 7.

Water discharged during construction dewatering will consist of Beaufort Sea water that has leaked through the sheetpiles or dockface or has percolated through the clean gravel fill to collect in the excavations. It is anticipated that an insignificant amount of storm water will be incorporated into the construction dewatering discharge. Clean gravel fill used to construct the island will contain fines which will be subsequently discharged with the excavation water. Fine-grained material discharged will be of the same composition as that which leaches from the perimeter of the island both during and after construction. Pumps rated at no greater than 650 gallons per minute will be used as required to dewater the construction trenches. The discharge hose will be placed into the slot in the ice at the location of the trenching activities or into water adjacent to the island in accordance with the NPDES permit stipulations.

Discharge will be into the waters of the Beaufort Sea in Stefansson Sound, either directly into the trench location where trenching activities for pipeline placement will be occurring concurrently or into other waters adjacent to the island. The disturbance caused by the trenching activities will require a water quality variance from the State of Alaska under Section 404 of the Clean Water Act. The variance will cover all non-point source discharges that may occur during construction activities.

The average daily flow rate into the SWIS and Outfall 001 and 006 excavations is estimated to be approximately 1,000,000 gallons per day (GPD) [650 gal/min x 60 min/hr x 24 hrs/day= 936,000 gal]. A single pump is expected to be able to handle this discharge volume. However, should the average flow rate into either excavation exceed 1,000,000 GPD, an additional pump will be required. No more than two pumps will be used, each with its own separate hose. The discharge location into waters above the construction trench or into water adjacent to the island will be designated as Outfall 005. In summary, the approximate maximum daily discharge from Outfall 005 is 2,000,000 GPD with an approximate average of 1,000,000 GPD.



Notes:
gpm= gallons per minute

BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Seal Island Construction Dewatering Line Diagram

Exhibit 13

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	Outfall Number *005 construction dewatering*

V. Effluent Characteristics

A, and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instructions for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See table 2D-2 for Pollutants)*
Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

Construction Dewatering Outfall 1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
Flow (gallons per day)	*2,000,000 gpd*	*1,000,000 gpd*	*1 (BPX Northstar Alliance Design)*
Temperature (winter)	*ambient*	*ambient*	*1 (BPX Northstar Alliance Design)*
Temperature (summer)	*not applicable*	*not applicable*	*No discharge, winter construction only*
pH	*ambient*	*ambient*	*1 (BPX Northstar Alliance Design)*

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	***Outfall 005*** ***construction dewatering***

C. Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

1. Pollutant	2. Reason for Discharge
Not Applicable	

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
No arctic analog facility was identified.	

ATTACHMENT 7

CONSTRUCTION DEWATERING
BEST MANAGEMENT PRACTICE
AND
POLLUTION PREVENTION PLAN

BP Exploration (Alaska) Inc.

Northstar Development Project

NPDES Outfall 005
Construction Dewatering

Best Management Practices

and

Pollution Prevention Plan

September 5, 1997

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MANAGMENT APPROVAL

This combined Best Management Practices Plan and Pollution Prevention Plan is approved for dewatering activities during construction of the Seawater Intake System and Outfalls 001 and 006 at Seal Island, Northstar Unit. The discharge has been designated as Outfall 005 in the NPDES permit application submitted for the facility on May 7, 1997. As required by the permit, the plan has been reviewed and endorsed by the Best Management Practices Committee indicated below.

BPXA Northstar Project Manager — Date: 9/5/97

BPXA Alaska Exploration and Development (AED) HSE Assurance Manager — Date: 9/5/97

Alaska Interstate Construction (AIC) Project Manager — Date: 9/5/97

BPXA Health, Safety, & Environmental (HSE) Business Manager — Date: 9/5/97

BEST MANAGEMENT PRACTICES

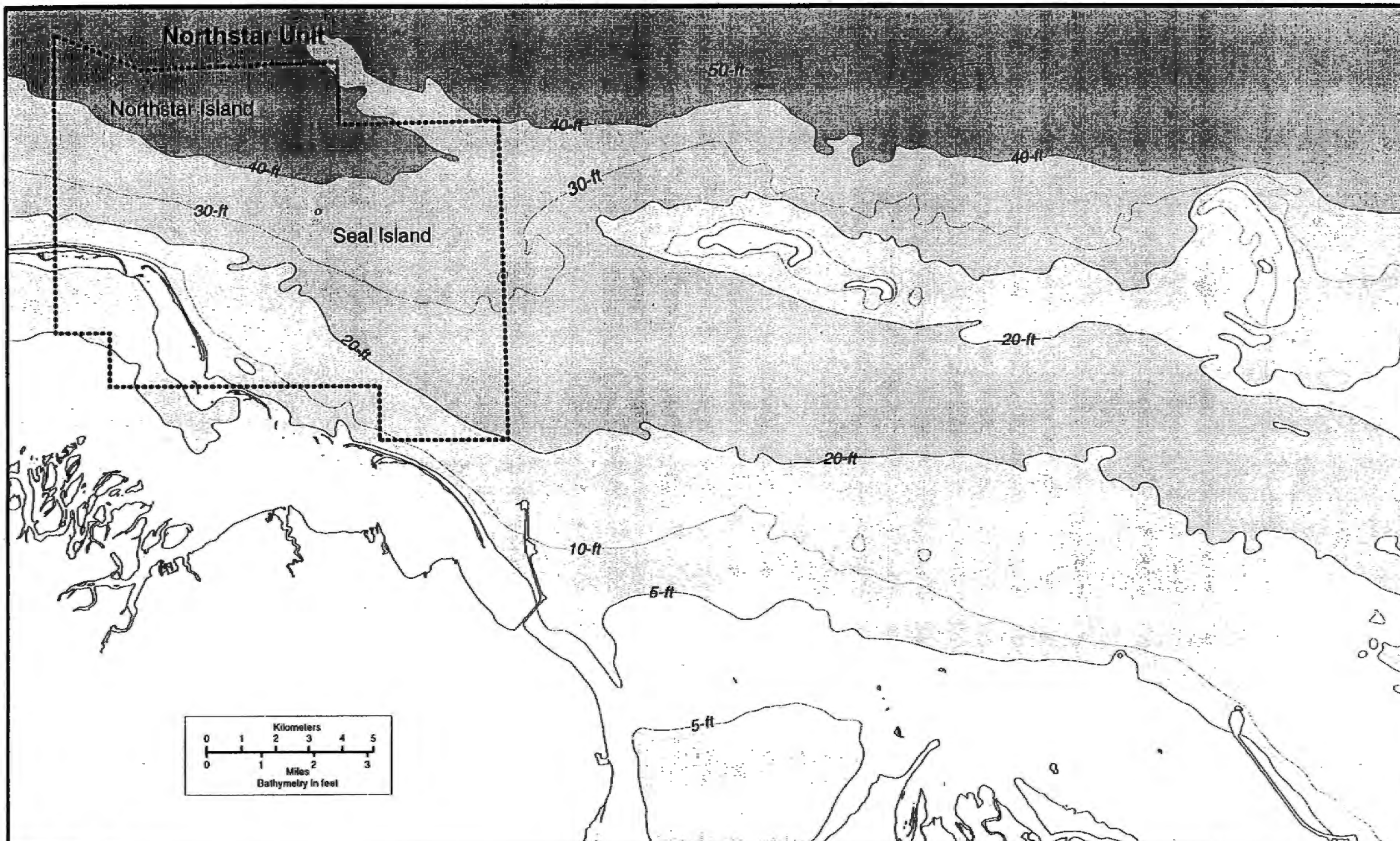
The primary pollutant expected in discharge from Outfall 005 will consist of fine sediments washed from the clean gravel fill used to construct the island. Therefore, the goal of this Best Management Practices (BMP) and Pollution Prevention (PP) Plan is to prevent the introduction of any other pollutants and to minimize the amount of sediment that may be contained in the discharge. The discharge from Outfall 005 will be placed either into waters above the offshore trench being excavated for placement of the oil and gas pipelines or into waters adjacent to the island. The sediment discharged through Outfall 005 is the same as that expected to be leached from the outer perimeter of the island both during and after fill placement. The receiving water will already contain both sediment from the island perimeter and sediment that is disturbed from the seafloor during trenching and pipe placement activities. Discharge from Outfall 005 (described in Section 1.3 of this document), is considered to be a point-source, and therefore must be covered under the NPDES permitting process.

1.0 GENERAL REQUIREMENTS

1.1 Name and Location of Facility

The offshore oil production facility for the Northstar Development Project will be located on Seal Island in the Beaufort Sea (Figure 1). The lease area is located northwest of the West Dock Causeway and offshore of the Return Islands. The southeast corner of the Northstar Unit reaches to Gwydyr Bay, north of the Kuparuk River delta. The unit extends seaward through the 3-mile territorial waters of Alaska and into the U.S. Federal outer continental shelf (OCS) lease area. Seal Island is situated about 9.6 km (6 miles) offshore in about 12 m (40 ft) of water.

The current design for the offshore production facility includes plans for marine discharge of process wastewater (001), fire water testing (002) controlled discharge of deck drainage (003, 004), construction dewatering.(005) and seawater treatment plant backwash (006). An NPDES permit application has been submitted for these discharges. This document serves as a BMP and PP Plan for temporary discharges from Outfall 005, Construction Dewatering, as defined in the NPDES permit application.



NORTHSTAR UNIT AND THE PRUDHOE BAY AREA

Figure 1

1.2 Nature of Construction Activity

The Northstar Development Project is a stand-alone, self-contained, offshore drilling and production facility located on a gravel island which will include all support infrastructure and necessary facilities. The island will be built over the existing Seal Island (Figure 1).

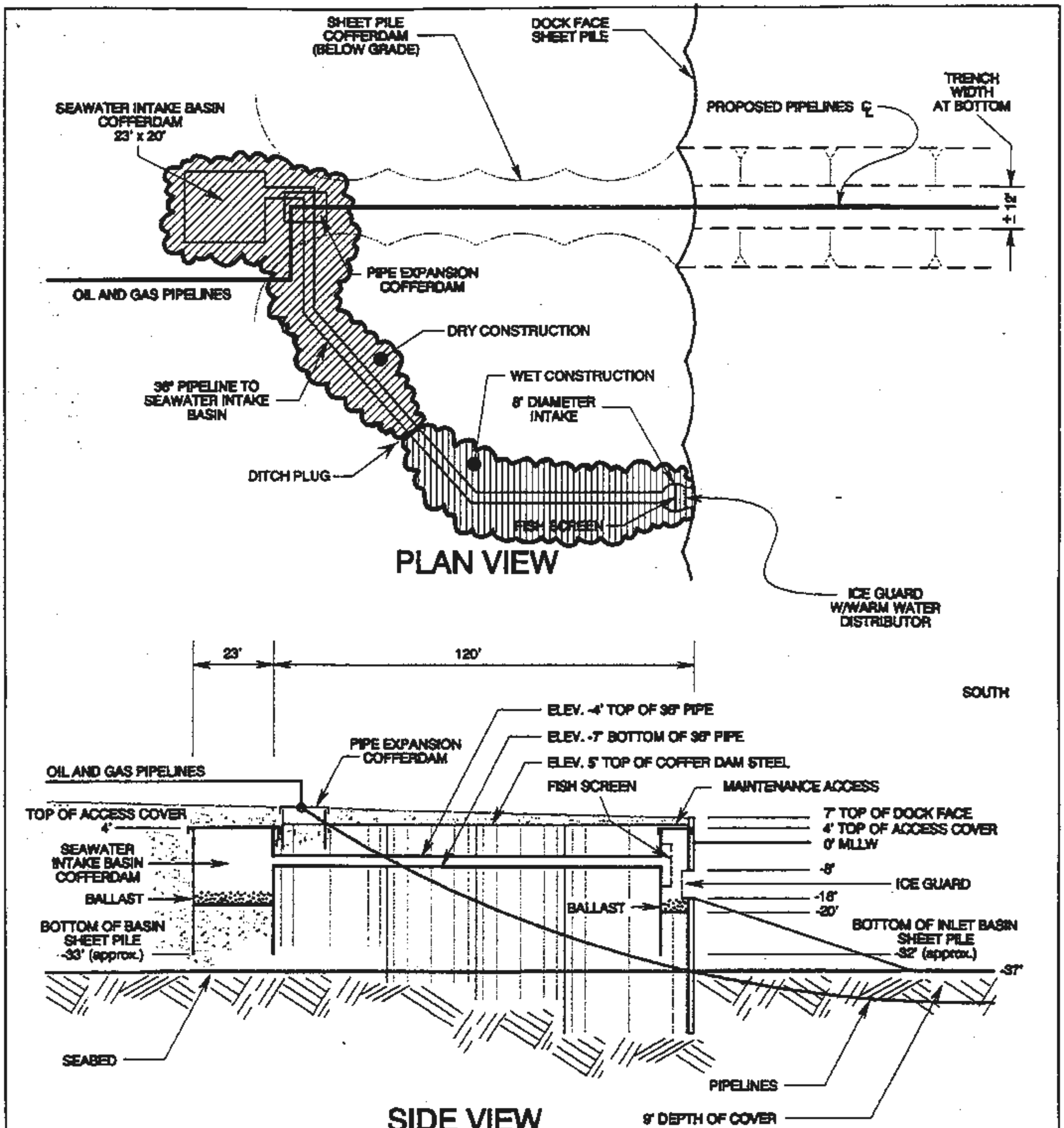
Additional gravel fill will be required to expand and shape Seal Island into the proposed production facility. When sufficient gravel fill is available, the south side of the island will be expanded to the planned dockface. The gravel will be graded to an elevation of +7 ft mean lower low water (MLLW) and sheetpile will be installed along the perimeter to form the dockface. As shown on Figures 2 and 3, the Seawater Intake System (SWIS) will be installed below water in the dockface on the southern end of the island, adjacent to the helipad; Outfalls 001 and 006 will be located on the south side of the island through the dockface at an elevation of about -16 ft MLLW. Construction and installation of the SWIS and outfalls will occur sequentially.

In order to minimize the infiltration of seawater into the SWIS excavation, the work will proceed in two sections. First, the excavation and feedline installation will occur in the section closest to the intake where seawater infiltration may be encountered (see figure 2). Second, a ditch plug will be installed at the northern end of the excavation to allow dry excavation of the section from the ditch plug to the coffer dam. Information from a site investigation (by backhoe, March 1997) revealed a dry excavation to -23 ft. in this area, thus this section is expected to remain dry. The ditch plug will be installed at a location in the trench where original frozen gravel is encountered and the work can be conducted in a safe manner.

Discharges lines for Outfalls 001 and 006 will be installed in a similar fashion as described above (see figure 3).

1.3 Description of Discharge Activity

Temporary dewatering activities are likely to be required during construction and installation of both the (SWIS) (Figure 2) and Outfalls 001 and 006 (Figure 3). It is anticipated that the dewatering operations will be required discontinuously over a two to four week period during early spring (April - May). Water discharged during construction dewatering will consist of Beaufort Sea water that has leaked through the sheetpiles or dockface or has percolated through the clean gravel fill to collect in the excavations. It is anticipated that an insignificant amount of storm water will be incorporated into the construction dewatering discharge. Clean gravel fill used to construct the island will contain fines which will be subsequently discharged with the excavation water.



BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT SEAWATER INTAKE PLAN AND ELEVATION VIEWS		
DATE: 05Sep97	SCALE: N/A	FIGURE: 2

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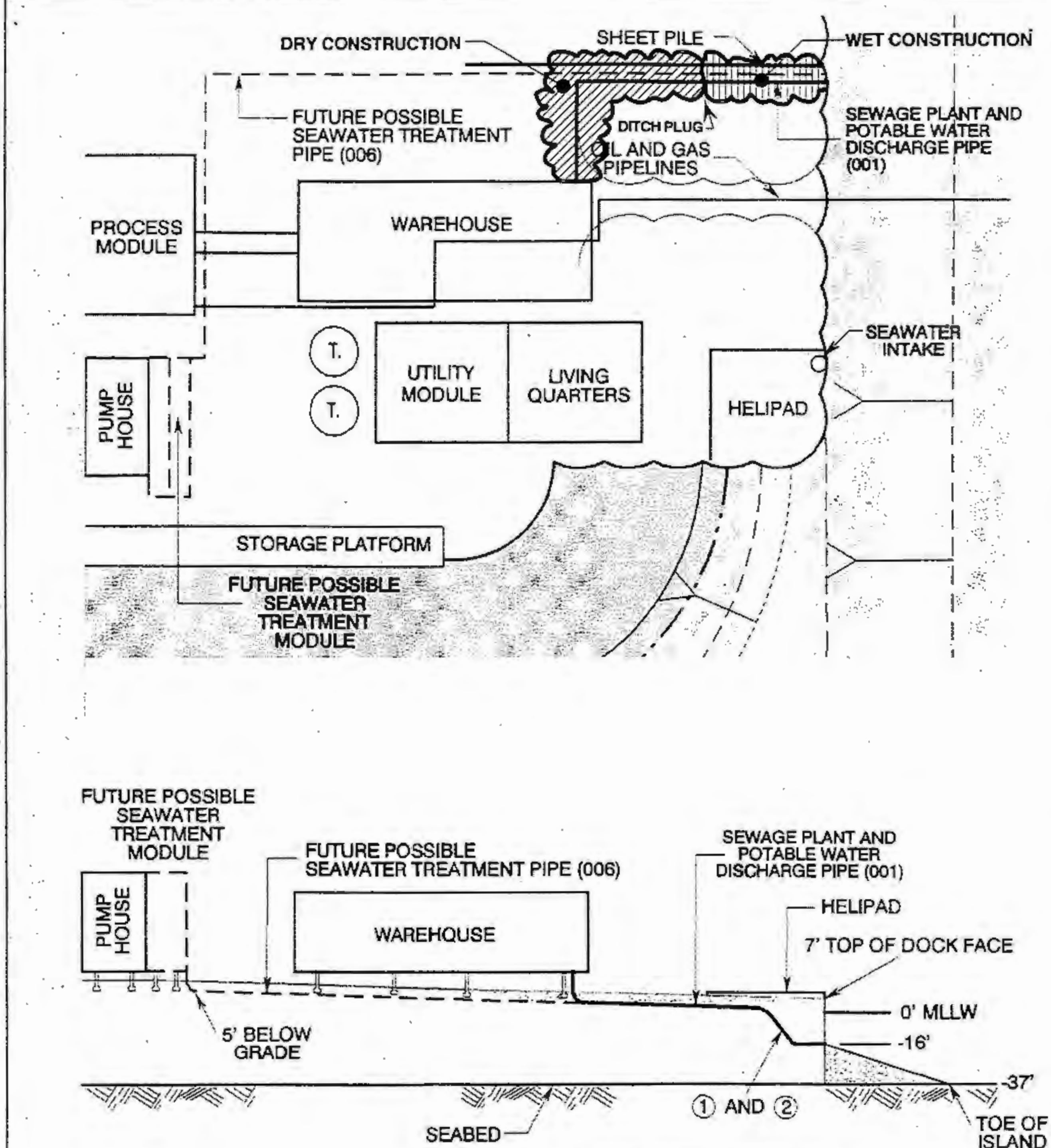


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND
EFFLUENT OUTFALL Nos. 001 AND 006
PLAN AND ELEVATION VIEWS

DATE:	SCALE:	FIGURE:
05Sep97	N/A	3

— — (1) FUTURE POSSIBLE SEAWATER TREATMENT PLANT OUTFALL DISCHARGING THRU 4" NOZZLE IN DOCK FACE @ -16' MLLW

—— (2) SEWAGE PLANT AND POTABLE WATER PLANT OUTFALL DISCHARGING THRU 2" NOZZLE IN DOCK FACE @ -16' MLLW

Fines material discharged will be of the same composition as that which leaches from the perimeter of the island both during and after construction. Pumps rated at no greater than 650 gallons per minute will be used as required to dewater the construction trenches. The discharge hose will be placed into the slot in the ice at the location of the trenching activities or into water adjacent to the island.

1.3.1 Name of Receiving Water

Discharge will be into the waters of the Beaufort Sea in Stefansson Sound, either directly into the trench location where trenching activities for pipeline placement will be occurring concurrently or into other waters adjacent to the island. The disturbance caused by the trenching activities will require a water quality variance from the State of Alaska under Section 404 of the Clean Water Act. The variance will cover all non-point source discharges that may occur during construction activities.

1.3.2 Anticipated Volume of Water to be Discharged

The maximum daily flow rate into the SWIS and Outfall 001 and 006 excavations is estimated to be approximately 1,000,000 gallons per day (GPD) [650 gal/min x 60 min/hr x 24 hrs/day= 936,000 gal]. A single pump is expected to be able to handle this discharge volume. However, should the maximum flow rate into either excavation exceed 1,000,000 GPD, an additional pump will be required. No more than two pumps will be used, each with its own separate hose. The discharge location into waters above the construction trench or into water adjacent to the island will be designated as Outfall 005. In summary, the approximate maximum daily discharge from Outfall 005 is 2,000,000 GPD with an approximate maximum of 1,000,000 GPD from each of two discharge hoses into one discharge location.

1.4 Statement of BMP Policy and Objectives

The purpose of the BMP plan is to "prevent or minimize the generation and the potential for the release of pollutants from the facility to the waters of the United States through normal operations and ancillary activities".

It is BPXA policy to promote full compliance with this BMP plan. Specific objectives of the BMP program include:

- Managing any influent wastes in the most appropriate manner, and
- Minimizing the number and quantity of pollutants and the toxicity of effluent discharged or potentially discharged.

2.0 SPECIFIC REQUIREMENTS

2.1 Best Management Practices Committee

As required by the NPDES permit, this plan has been prepared by a Best Management Practices Committee, whose responsibilities are:

- BPXA Northstar Project Manager - Responsible for overall regulatory compliance during all phases of construction

- BPXA Alaska Exploration and Development (AED) HSE Assurance Manager - Responsible for BMP Plan approval and implementation. Schedules training for field staff and contractors. Maintains BMP and other permit documents.

- Alaska Interstate Construction (AIC) Project Manager - Advises contractor supervision and employees of their responsibilities under the BMP program.

- BPXA Health, Safety, & Environmental (HSE) Business Manager - Advise the engineering and construction staffs on permitting requirements and regulatory issues. Assists in preparation and review of the BMP.

2.2 Risk Identification and Assessment

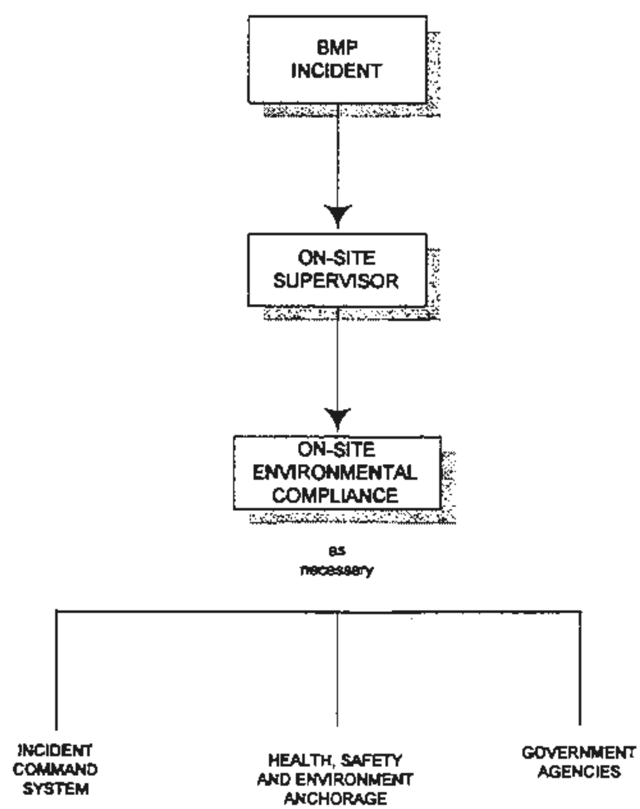
Water accumulated into the excavations during construction activities will consist of Beaufort Sea water that has leaked through the sheetpiles or dockface and has percolated through the clean gravel island fill to collect in the excavations. It is anticipated that an insignificant amount of storm water will be incorporated into the construction dewatering discharge.

The collected water itself is not considered to be a pollutant; the expected increase in suspended solids concentration in the discharge will be introduced only from clean gravel fill that has been placed and permitted as required. However, water in the excavation may be exposed to equipment and vehicles located in the vicinity and conducting the work. In addition, a diesel powered pump will be used to remove the collected water from the excavation. Potential pollutants from these sources include diesel fuel, lubricants, and hydraulic fluids. Good housekeeping practices (discussed in Section 3.5) will minimize the risk of these pollutants entering the discharge.

2.3 Incident Reporting Procedures

BMP incidents include spills, improper implementation of procedures, un-permitted discharges, and situations that may result in permit violations or environmental damage. BPXA reports all spills in accordance with local, state, and federal requirements. Spill reporting procedures are provided in detail in the Oil Discharge Prevention and Contingency Plan.

General procedures for BMP incident reporting are:



2.4 Recordkeeping

BMP-related records will be maintained as follows:

TYPE OF RECORD	LOCATION/RESPONSIBLE PARTY
BMP Plan	• BPXA Northstar Project Manager • BPXA AED HSE Assurance Manager • AIC Project Manager • BPXA Health, Safety, & Environment
NPDES Permit	• BPXA AED HSE Assurance Manager • AIC Project Manager • BPXA Health, Safety, & Environment
NPDES Discharge Monitoring Reports	• AIC Project Manager • BPXA Health, Safety, & Environment
BMP Incident Reports	• On-site Environmental Compliance • BPXA Health, Safety, & Environment
Daily Job Reports	• Site Foreman/AIC Project Manager
Routine Environmental Inspection Reports	• On-site Environmental Compliance

POLLUTION PREVENTION

3.0 MEASURES AND CONTROLS

3.1 Practices to Reduce Discharge Volume

The use of ditch plugs during excavation and installation of the SWIS and feedlines for Outfalls 001 and 006 will significantly reduce seawater seepage and the subsequent need for trench dewatering. The ditch plugs can be used to isolate a wetter area, possibly located closer to the dockface, from drier areas located towards the middle of the island.

The introduction of stormwater or sea spray runoff (expected to be nil during the expected time of construction) into either excavation can be minimized by the use of a small berm or dike around the perimeter of the open excavation. The dike can be periodically inspected to ensure integrity.

3.2 Timing

Since construction of the SWIS and outfall feedlines will not happen simultaneously, discharge of construction dewatering fluids will occur from only one excavation at a time. Therefore, the total volume of discharge is not expected to exceed 2,000,000 GPD (maximum of 1,000,000 GPD from each of two pumps with separate discharge hoses into one location).

3.3 Equipment

The pumps intended for dewatering purposes will be powered by diesel fuel. The equipment will be placed in large drip pans to eliminate leaking of fuel, hydraulic fluids, and other liquids from the pumps into the excavation and subsequent dewatering stream. Water in the excavation prior to discharge and the discharge area will be periodically monitored to ensure no visible pollutants or oily sheen (see Section 3.8). Hoses with sufficient length to reach to the ice slot for the construction trench or other waters adjacent to the island will be used to drain the water.

3.4 Sediment Input Control

The pump suction hose will be placed in the excavation to minimize the amount of sediment entrained in the dewatering discharge. At a minimum, the hoses will be kept off of the bottom of the excavation and away from the excavation sidewalls with the use of floats. The pump intakes will also be covered with a coarse screen to further eliminate coarser sediment materials from fouling the pumps or being discharged through the lines.

3.5 Good Housekeeping

General housekeeping guidelines are provided in the BPXA/ARCO Alaska Safety Handbook and the BPXA/ARCO Alaska North Slope Environmental Field Handbook, and are reinforced by training, regular meetings, and routine inspections. No chemicals, fuels, or lubricants will be stored in or around the excavation site. Any equipment that could potentially come into contact with the effluent will be kept clean and free of contaminants. Equipment will be removed from the excavation prior to all significant servicing needs.

Other good housekeeping practices include:

- Surface liners and/or catch pans during all fueling and fluid transfers
- Surface liners under parked vehicles and other engines, pumps etc. that potentially drip engine oil, antifreeze, or hydraulic fluid.
- Liners or secondary containment under fuel tanks
- Accurate labeling of all drums and containers
- Inventory control to avoid accumulating surplus materials

- Routine pickup and disposal of waste and/or surplus materials.

3.6 Preventive Maintenance

Construction equipment and pumps used in the dewatering process will be properly maintained to prevent loss of fuels, lubricants, antifreeze and hydraulic fluids. All contractor equipment is subject to inspection before it will be allowed to be used for the construction operations. Contractors are required to repair and/or replaces equipment that is leaking, or is susceptible to leakage due to worn or damaged parts. The site will be maintained to minimize or eliminate additional input or runoff of water into the excavation.

A spill response kit will be available in the immediate vicinity of excavation activities. The kit will contain absorbent squares, sorbent boom, shovels, and other absorbent and spill-response related equipment.

3.7 Training

Safety and environmental training is mandatory for BPXA workers and contractors assigned to this project. Training requirements and schedules will be established by BPXA AED Assurance. Relevant training topics include:

- Environmental Awareness Training
- BPXA/ARCO Alaska Safety Handbook
- BPXA/ARCO North Slope Environmental Field Handbook
- Hazard Communication and Material Safety Data Sheets (MSDS)
- Overall Safety Orientation
- Spill Response.

3.8 Inspections

During construction dewatering operations, inspections will include:

- Receiving waters - daily inspections for visible pollutants and oily sheen

- Excavation water - daily inspections for visible pollutants and oily sheen

- Equipment and Vehicles - periodic inspections for leaks or spills

- Pumps and Discharge Lines - daily inspections for proper positioning and operation. Verify that permitted flow rate is not exceeded.

- Berms or dikes - check for integrity if placed around the excavation to prevent infiltration of water.

Inspections will be conducted as appropriate by the site foreman or other designated staff. BPXA On-site Environmental Compliance personnel will make periodic inspections during construction. Their duties include spill detection and response, waste management, and general compliance with BPXA environmental and safety policies.

3.9 Security

The construction site is located on a remote man-made island situated about 9.6 km (6 miles) offshore in 12 m (40 ft) of water. Access to the island will be by ice road and helicopter and will be strictly controlled and limited to construction and other authorized personnel. Unauthorized personnel will not be allowed access and the site supervisor is responsible for all personnel present during construction activities.

EPA FORM 2D

SEAWATER TREATMENT PLANT BACKWASH
(OUTFALL 006)

Exhibit 14 Outfall 006
Seawater Treatment Plant Backwash

The preferred alternative for enhanced oil recovery (EOR) at the Northstar Development is natural gas injection. However, waterflood EOR is an alternative that results in the injection of treated seawater into the petroleum reservoir to maintain formation pressures and allow secondary oil recovery from production wells. Seawater is used for the waterflood EOR process in several North Slope production fields, including the BPXA Endicott facility.

In the event that the waterflood EOR process is selected for the Northstar Development, the average intake through the sump will be 2,591,796 gpd will be diverted to the Seawater Treatment Plant (STP). This seawater will be treated and injected into the petroleum reservoir. The seawater treatment process includes screening, straining, de-aeration, and granular media filtration (Exhibit 15). Two cartridge type mechanical coarse strainers will intercept coarse particles as the water enters the STP, and designed such that one strainer will be in service at all times. Trash collected from the strainers will be slurried and disposed in the onsite Class I/II injection well. There will be three media filters, two of which will be in service at all times, and the third unit being backwashed. Polyelectrolyte (MSDS provided in Attachment 9) will be injected into the water upstream of the media filters at a maximum concentration of 2 parts per million (ppm), and a designed average concentration of 1 ppm with a 10% solution.

A biocide, antifoam agent, oxygen scavenger, corrosion inhibitor, and scale inhibitor will be added to the water **downstream** of the backwash flow. These additives will be injected into the geologic formation along with the injected seawater, and thus, these chemicals will not be discharged into the marine environment.

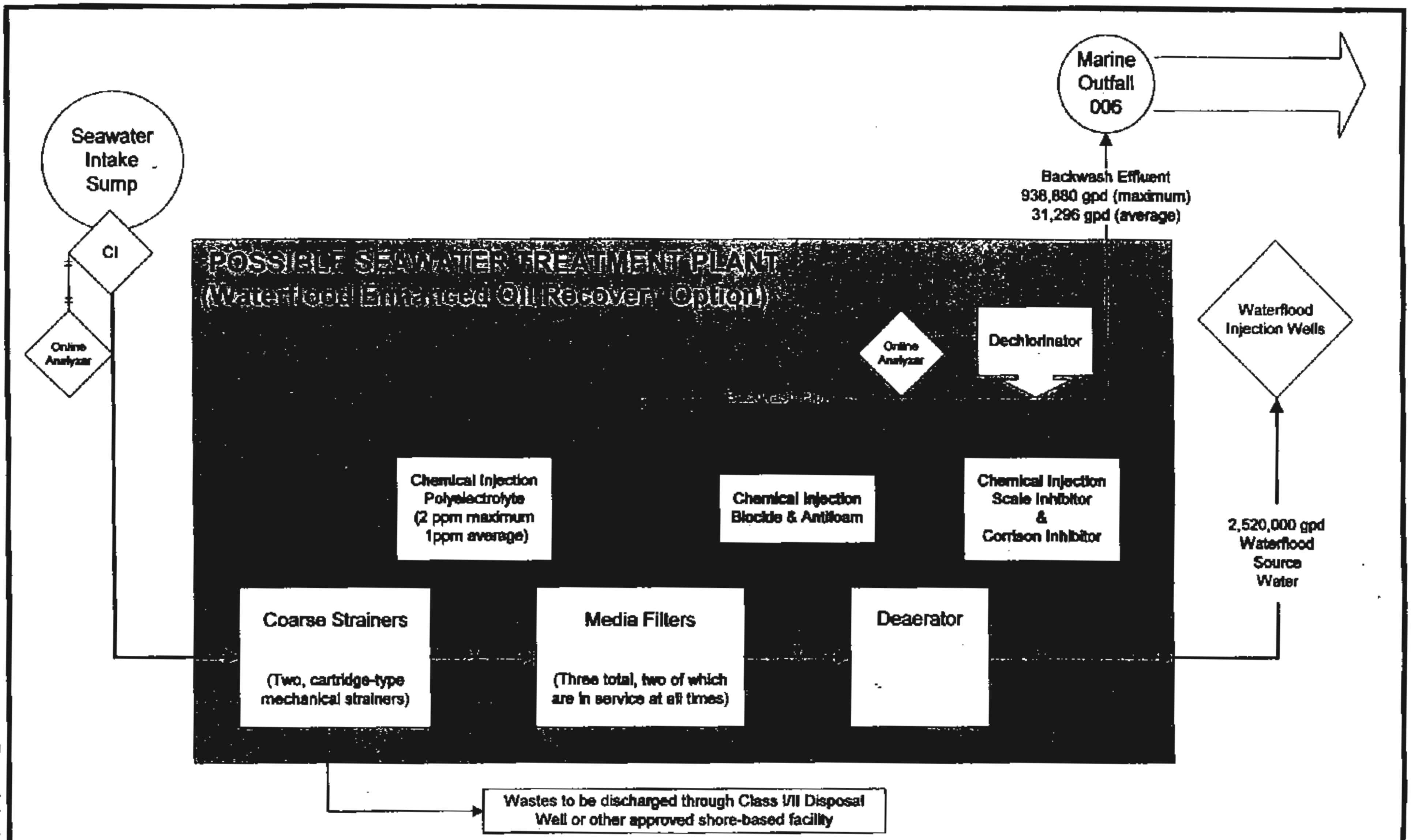
Some of the polyelectrolyte added upstream of the media filters is expected to be discharged with the filter backwash. Together, the strainer and media filter backwash is designated as the STP Backwash waste stream, with an anticipated average flow of 31,296 gpd and a maximum flow of 938,880 gpd. The STP Backwash waste stream will be discharged through outfall 006 after passing through a dechlorinator with a similar design as the dechlorinator described for outfall 001 (see Exhibit 2).

The Seawater Treatment Plant (STP) backwash (Outfall 006) will use seawater supplied from the seawater intake. Engineering estimates for temperature rise due to process equipment (e.g., pumps, piping, filters) is <0.1°C above ambient conditions in the summer. In winter, the heat gain is 0.4°C reflecting input from warm water recirculation. Heat tracing and insulation will maintain a discharge temperature of 4°C.

The STP filter backwash will be discharged via a 6-inch feed line at a flow rate of 652 gallons per minute (gpm). An average daily flow of 31,296 gallons per day (gpd) is anticipated for eight backwash events, each lasting 6 minutes. The Outfall

006 discharge nozzle (4-inch diameter) will be located at a depth of -5 m (-16 ft) mean lower low water (MLLW) with a horizontal orientation. Since the backwash is composed of seawater with only minor temperature increase over ambient conditions, the discharge will behave essentially as a submerged neutrally buoyant turbulent jet.

Assuming an ambient TSS concentration of 5 milligrams per liter (mg/l) in the receiving water around Seal Island, the total TSS load ingested by the STP process water was computed to be 48.33 kilogram per day (kg/day) or 106 pounds per day (lb/day) [Attachment 8]. Eight backwash cycles per day imply that one-eighth of this load will be discharged with each backwash, such that the average TSS concentration during the backwash will be 406 mg/l.



Notes:

gpd = gallons per day
ppm = parts per million
Cl = system chlorinator using $Ca(OCl)_2$

BP Exploration (Alaska) Inc.

Northstar Development NPDES Permit Application
Seal Island Seawater Treatment Plant Line Diagram

Exhibit 15

EPA ID Number *(copy from Item 1 of Form 1)*	Outfall Number 006 waterflood STP

V. Effluent Characteristics

A. and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instructions for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See table 2D-2 for Pollutants)*
Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

Waterflood Seawater Treatment Plant 1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
Flow (gallons per day)	938,880 gpd	31,296 gpd	1 (BPX Northstar Alliance Design)
Temperature (summer)	Ambient + 0.1°C	Ambient	1 (BPX Northstar Alliance Design)
Temperature (winter)	4°C	4°C	1 (BPX Northstar Alliance Design)
pH	ambient ± 0.1 pH	ambient ± 0.1 pH	3 (Endicott Seawater Treatment Backwash)
Total Suspended Solids (concentration)	406 mg/l	406 mg/l	1 (BPX Northstar Alliance Design) based on maximum ambient TSS of 5 mg/l
Total Suspended Solids (mass)	48.33 kg	48.33 kg	1 (BPX Northstar Alliance Design) based on maximum ambient TSS of 5 mg/l
Salinity	Ambient	Ambient	1 (BPX Northstar Alliance Design)
Backwash Events	8	8	1 (BPX Northstar Alliance Design)
Total Residual Chlorine	≤ 2ppb	≤ 2 ppb	1 (BPX Northstar Alliance Design)

CONTINUED FROM THE FRONT	EPA ID Number *(copy from Item 1 of Form 1)*	***Outfall 006** waterflood STP*

V. Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

1. Pollutant	2. Reason for Discharge
Not Applicable	

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
Endicott Development (Seawater Treatment Plant)	***Duck Island Unit Beaufort Sea, Stefansson Sound, Alaska (offshore of the Sagavanirktok River delta)***

ATTACHMENT 8

SEAWATER TREATMENT PLANT
TOTAL SUSPENDED SOLIDS
COMPUTATIONS

TOTAL SUSPENDED SOLIDS COMPUTATION -- OUTFALL 006

Seawater Treatment Plant Inflow	=	**2,543,472 gallons per day (gpd)**
	=	**9,628,089 liters per day**

where	
1 liter (l) =	0.26 gallons
1 gallon (gal) =	3.79 liters

If ambient TSS =	5 milligrams per liter (mg/l)
then	
TSS load =	**48,140,447 milligrams per day**

FOR EIGHT (8) BACKWASH CYCLES PER DAY WITH DURATIONS OF SIX MINUTES EACH

8 cycles per day where	6,017,556	mg per cycle
Backwash flow rate =	652	gallons per minute (gpm)
=	2,468	liters per minute
Backwash Volume per cycle =	(backwash flow rate) x (length of cycle)	
=	2,468	liters per minute x 6 minutes
=	14,809	liters per cycle

Then

AVERAGE TSS CONCENTRATION = $\dfrac{6{,}017{,}556 \text{ mg per cycle}}{14{,}809 \text{ liters per cycle}}$

= 406 mg/l

ATTACHMENT 9

MATERIAL SAFETY DATA SHEETS

Calcium Hypochlorite

Sodium Hypochlorite

M-104 Scale Remover

M-210 Scale Remover

M-236 Foamer

M-237 Scale Control Additive

M-239 Remineralization

Sodium Metabisulfite

MATERIAL SAFETY DATA SHEETS

CALCIUM HYPOCHLORITE

PRODUCT NAME:
CALCIUM HYPOCHLORITE GRANULAR 70%

MSDS #: PG0461

\- - - CALCIUM HYPOCHLORITE GRANULAR 70%

DATE:	05/20/96
EDITION:	002
TRADE NAME:	CALCIUM HYPOCHLORITE GRANULAR 70%
CHEM NAME/SYN:	CAL HYPO, INDUCLOR(R) 70, PPG 70

CHEMICAL FAMILY:	HYPOCHLORITE
FORMULA:	CA(OCL)2
CAS NUMBER:	007778-54-3
U.S. DOT SHIPPING NAME:	CALCIUM HYPOCHLORITE, HYDRATED
U.S. DOT HAZARD CLASS:	5.1 (OXIDIZER)
SUBSIDIARY RISK:	N/A
I.D. NUMBER:	UN2880
PACKING GROUP:	II
REPORTABLE QUANTITY:	10 LBS/4.5 KG

IMO DESCRIPTION: CALCIUM HYPOCHLORITE, HYDRATED, CLASS 5.1, UN2880, PACKING GROUP II, RQ.

SECTION 1 - PHYSICAL DATA

BOILING POINT @ 760 MM HG:	DECOMPOSES @ 180 C
VAPOR DENSITY (AIR=1):	N/A
SPECIFIC GRAVITY (H2O=1):	N/A
PH OF SOLUTIONS:	ALKALINE
FREEZING/MELTING POINT:	N/A
SOLUBILITY (WEIGHT % IN WATER):	217 G/L @ 27 C
BULK DENSITY:	65-67 LBS/CU.FT.
VOLUME % VOLATILE:	N/A
VAPOR PRESSURE:	N/A
EVAPORATION RATE:	N/A
HEAT OF SOLUTION:	SLIGHTLY EXOTHERMIC

APPEARANCE AND ODOR:
WHITE POWDER WITH SLIGHT CHLORINE ODOR

SECTION 2 - INGREDIENTS

MATERIAL	PERCENT
CALCIUM HYPOCHLORITE (70% AVAILABLE CHLORINE)	70
INERT (INCLUDES 5.5 - 10% MOISTURE)	30

SECTION 3 - FIRE/EXPLOSION HAZARD DATA

FLASH POINT (METHOD USED):
NONE

FLAMMABLE LIMITS IN AIR (% BY VOLUME)
LEL: N/A
UEL: N/A

EXTINGUISHING MEDIA:

WATER ONLY. SMOTHERING INEFFECTIVE-PRODUCT SUPPLIES OWN OXYGEN

SPECIAL FIRE FIGHTING PROCEDURES:
FIRE FIGHTERS MUST WEAR NIOSH/MSHA APPROVED, PRESSURE DEMAND SELF-CONTAINED BREATHING APPARATUS WITH FULL FACE PIECE FOR POSSIBLE EXPOSURE TO HAZARDOUS GASES.

UNUSUAL FIRE AND EXPLOSION HAZARDS:
DECOMPOSES AT 180 C RELEASING OXYGEN GAS; CONTAINERS MAY RUPTURE.

SECTION 4 - HEALTH HAZARD DATA

TOXICITY DATA:

LC50 INHALATION:	(RAT) NO MORTALITY @ 3.5 MG/L (1 HR)
LD50 DERMAL:	(RABBIT) >1000 MG/KG
SKIN/EYE IRRITATION:	SEE SECTION 5
LD50 INGESTION:	SEE SECTION 5
FISH,LC50 (LETHAL CONCENTRATION):	TLM 96 HR.: 10-1 PPM

CLASSIFICATION:

INHALATION:	IRRITATING
SKIN:	SLIGHTLY TOXIC
SKIN/EYE:	CORROSIVE
INGESTION:	SLIGHTLY TOXIC
AQUATIC:	HIGHLY TOXIC

SECTION 5 - EFFECTS OF OVEREXPOSURE

IS CHEMICAL LISTED AS A CARCINOGEN OR POTENTIAL CARCINOGEN?
NTP - NO IARC - NO OSHA - NO

MEDICAL CONDITIONS GENERALLY AGGRAVATED BY EXPOSURE:
NONE KNOWN

PERMISSIBLE EXPOSURE LIMITS:
NONE ESTABLISHED BY OSHA OR ACGIH FOR THIS PRODUCT.
PPG INTERNAL PERMISSIBLE EXPOSURE LIMIT (IPEL): 1 MG/CU.M., 8-HOUR TWA (TIME WEIGHTED AVERAGE); 2 MG/CU.M. STEL (SHORT-TERM EXPOSURE LIMIT).

ACUTE:

INHALATION: INHALATION OF CALCIUM HYPOCHLORITE DUST AND DEPOSITION OF PARTICLES IN THE RESPIRATORY TRACT CAN LEAD TO IRRITATION OF THE TISSUE AND CAUSE A VARIETY OF EFFECTS. THESE EFFECTS ARE DEPENDENT ON CONCENTRATION AND INCLUDE: UPPER RESPIRATORY TRACT IRRITATION, NASAL CONGESTION, COUGHING, SORE THROAT, LARYNGITIS AND SHORTNESS OF BREATH. IN OPERATIONS WHERE THERE ARE HIGH CONCENTRATIONS OF RESPIRABLE PARTICULATES, PULMONARY EDEMA (FLUID IN THE LUNG) MAY BE PRODUCED. IF NOT TREATED IMMEDIATELY, PULMONARY EDEMA CAN BE LIFE THREATENING. SINCE THIS PRODUCT IS IN GRANULAR FORM, PARTICLES OF RESPIRABLE SIZE ARE NOT GENERALLY ENCOUNTERED.

EYE/SKIN: CALCIUM HYPOCHLORITE IS CORROSIVE TO THE EYES. CONTACT OF CALCIUM HYPOCHLORITE DUST WITH THE EYES, EVEN A MINUTE AMOUNT FOR A SHORT DURATION, CAN CAUSE SEVERE IRRITATION AND EVEN BLINDNESS. CONTACT WITH THE SKIN MAY CAUSE SEVERE IRRITATION, BURNS, OR TISSUE DESTRUCTION.

IN STUDIES UTILIZING RABBITS, THE SKIN IRRITATION SCORE WAS 8/8 AND THE EYE IRRITATION SCORE WAS 98.5/110. THE CLASSIFICATION FOR BOTH OF THESE IS CORROSIVE.

INGESTION: CALCIUM HYPOCHLORITE, IF SWALLOWED, CAUSES SEVERE BURNS TO THE DIGESTIVE TRACT AND CAN BE FATAL.

CHRONIC:
GENOTOXICITY: CALCIUM HYPOCHLORITE PRODUCED POSITIVE RESPONSES IN IN-VITRO ASSAYS USING BACTERIAL SYSTEMS (THE AMES TEST) AND CHROMOSOMAL ABERRATIONS IN CHINESE HAMSTER FIBROBLASTS. IN A WHOLE ANIMAL EXPERIMENT (MOUSE MICRONUCLEUS TEST), EXPOSURES RANGING FROM 20 TO 160 MG/KG PRODUCED NO COMPOUND RELATED CHROMOSOMAL ABNORMALITIES.

CARCINOGENISIS: ALTHOUGH NO STUDY HAS BEEN CONDUCTED WITH CALCIUM HYPOCHLORITE, THE CARCINOGENIC POTENTIAL OF SODIUM HYPOCHLORITE WAS STUDIED IN F344 RATS. AFTER 104 WEEKS OF DRINKING WATER CONTAINING UP TO 2000 PPM SODIUM HYPOCHLORITE, THERE WAS NO EVIDENCE THAT THIS CHEMICAL PRODUCED ANY CARCINOGENIC RESPONSE. IN ADDITION, THIS EXPOSURE DID NOT RESULT IN ANY ADVERSE EFFECTS IN BLOOD, CLINICAL CHEMISTRY, OR OTHER TARGET ORGANS.

ONE OF THE MAJOR USES OF CALCIUM HYPOCHLORITE IS AS A SOURCE OF CHLORINE FOR WATER SANITIZATION IN DRINKING AND RECREATIONAL WATER. STUDIES HAVE BEEN CONDUCTED TO DETERMINE THE LONG-TERM EFFECTS OF CHLORINATED DRINKING WATER. SEVEN GENERATIONS OF RATS WERE GIVEN 100 PPM CHLORINE IN THEIR DRINKING WATER. NO DIFFERENCE IN FERTILITY, GROWTH, BLOOD PARAMETERS, OR SPECIFIC ORGAN TOXICITY WAS OBSERVED BETWEEN CONTROL AND EXPOSED ANIMALS. TWO SEPARATE ANIMAL STUDIES CONDUCTED BY DIFFERENT GOVERNMENT AGENCIES DETERMINED THAT THE CHLORINATION OF MUNICIPAL DRINKING WATER DID NOT RESULT IN TOXICITY TO THE DEVELOPING MOUSE FETUS.

SAFE HANDLING OF THIS MATERIAL ON A LONG-TERM BASIS SHOULD EMPHASIZE MINIMIZING REPEATED ACUTE EXPOSURES.

EMERGENCY AND FIRST AID PROCEDURES

INHALATION:
REMOVE TO FRESH AIR. IF NOT BREATHING, GIVE ARTIFICIAL RESPIRATION, PREFERABLY MOUTH-TO-MOUTH. IF BREATHING IS DIFFICULT, GIVE OXYGEN. CALL A PHYSICIAN.

EYE OR SKIN CONTACT:
FLUSH WITH PLENTY OF WATER FOR AT LEAST 15 MINUTES, WHILE REMOVING CONTAMINATED CLOTHING AND SHOES. FOR EYE CONTACT, GET IMMEDIATE MEDICAL ATTENTION. IF SKIN IRRITATION OCCURS, GET MEDICAL ATTENTION.

INGESTION:
IF CONSCIOUS, DRINK LARGE QUANTITIES OF WATER AND ANY COMMON COOKING (VEGETABLE) OIL, IF AVAILABLE. DO NOT INDUCE VOMITING. TAKE IMMEDIATELY TO A HOSPITAL OR PHYSICIAN. IF UNCONSCIOUS, OR IN CONVULSIONS, TAKE IMMEDIATELY TO A HOSPITAL. DO NOT ATTEMPT TO INDUCE VOMITING OR GIVE ANYTHING BY MOUTH TO AN UNCONSCIOUS PERSON.

NOTES TO PHYSICIAN (INCLUDING ANTIDOTES):
TREAT SYMPTOMATICALLY.

SECTION 6 - REACTIVITY DATA

STABILITY:
UNSTABLE
CONDITIONS TO AVOID:
CONTAMINATION OR EXCESSIVE HEAT ABOVE 177 C

HAZARDOUS POLYMERIZATION: WILL NOT OCCUR
CONDITIONS TO AVOID: NONE-WILL NOT POLYMERIZE

INCOMPATIBILITY (MATERIALS TO AVOID):
ACIDS, COMBUSTIBLE MATERIALS, ORGANICS, REDUCING AGENTS

HAZARDOUS DECOMPOSITION PRODUCTS:
ACIDS OR AMMONIA CONTAMINATION WILL RELEASE TOXIC GASES. EXCESSIVE HEAT WILL CAUSE DECOMPOSITION RESULTING IN THE RELEASE OF OXYGEN AND CHLORINE GAS.

SECTION 7 - SPILL OR LEAK PROCEDURES

STEPS TO BE TAKEN IF MATERIAL IS SPILLED OR RELEASED:
NOTE: USE EXTREME CAUTION IN HANDLING SPILLED MATERIAL. CONTAMINATION WITH ORGANIC OR COMBUSTIBLE MATERIAL MAY CAUSE FIRE OR VIOLENT DECOMPOSITION. IF FIRE OR DECOMPOSITION OCCURS IN AREA OF SPILL, IMMEDIATELY DOUSE WITH PLENTY OF WATER. OTHERWISE, SWEEP UP ALL VISIBLE MATERIAL USING A CLEAN, DRY SHOVEL AND BROOM AND DISSOLVE MATERIAL IN WATER. DISPOSE OF WASTE MATERIAL AS OUTLINED BELOW.

WASTE DISPOSAL METHOD:
SPILLED MATERIAL THAT HAS BEEN SWEPT UP AND DISSOLVED IN WATER SHOULD BE USED IMMEDIATELY IN THE NORMAL APPLICATION FOR WHICH CALCIUM HYPOCHLORITE IS BEING CONSUMED. IF THIS IS NOT POSSIBLE, CAREFULLY NEUTRALIZE DISSOLVED MATERIAL BY ADDING HYDROGEN PEROXIDE (ONE PINT OF 35% HYDROGEN PEROXIDE SOLUTION PER POUND OF CALCIUM HYPOCHLORITE TO BE NEUTRALIZED) THEN DILUTE THE NEUTRALIZED MATERIAL WITH PLENTY OF WATER AND FLUSH TO SEWER. NOTE: ONLY PROPERLY NEUTRALIZED MATERIAL SHOULD BE FLUSHED TO SEWER. UNNEUTRALIZED MATERIAL CAN CAUSE ENVIRONMENTAL DAMAGE TO RECEIVING WATER OR CAN INTERFERE WITH TREATMENT PLANT OPERATION.
FOR ON-SITE NEUTRALIZATION, CAREFULLY AND SLOWLY POUR THE APPROPRIATE QUANTITY OF 35% HYDROGEN PEROXIDE SOLUTION OVER ALL SPILLED MATERIAL THEN FLUSH AREA WITH PLENTY OF WATER.
COMMENTS: CARE MUST BE TAKEN WHEN USING OR DISPOSING OF CHEMICAL MATERIALS AND/OR THEIR CONTAINERS TO PREVENT ENVIRONMENTAL CONTAMINATION. IT IS YOUR DUTY TO DISPOSE OF THE CHEMICAL MATERIALS AND/OR THEIR CONTAINERS IN ACCORDANCE WITH THE CLEAN AIR ACT, THE CLEAN WATER ACT, THE RESOURCE CONSERVATION AND RECOVERY ACT, FIFRA, AS WELL AS ANY OTHER RELEVANT FEDERAL, STATE, OR LOCAL LAWS/REGULATIONS REGARDING DISPOSAL.

SECTION 8 - SPECIAL PROTECTION INFORMATION

RESPIRATORY PROTECTION:
IF DUSTY CONDITIONS ARE ENCOUNTERED, USE NIOSH/MSHA APPROVED RESPIRATOR WITH ACID GAS CARTRIDGE AND DUST PREFILTER. THE RESPIRATOR USE LIMITATIONS SPECIFIED BY NIOSH/MSHA OR THE MANUFACTURER MUST BE OBSERVED. RESPIRATORY PROTECTION PROGRAMS MUST BE IN ACCORDANCE WITH 29 CFR 1910.134.

VENTILATION(TYPE):
NONE, UNLESS DUSTY CONDITIONS ARE ENCOUNTERED.

EYE PROTECTION:
CHEMICAL SAFETY GOGGLES

GLOVES:
NATURAL OR SYNTHETIC RUBBER

OTHER PROTECTIVE EQUIPMENT:
BOOTS, APRONS, OR CHEMICAL SUITS SHOULD BE USED WHEN NECESSARY TO PREVENT SKIN CONTACT. PERSONAL PROTECTIVE CLOTHING AND USE OF EQUIPMENT MUST BE IN ACCORDANCE WITH 29 CFR 1910.132 (GENERAL REQUIREMENTS), .133 (EYE & FACE PROTECTION) AND .138 (HAND PROTECTION).

SECTION 9 - SPECIAL PRECAUTIONS

PRECAUTIONS TO BE TAKEN DURING HANDLING AND STORING:
- DO NOT GET IN EYES, ON SKIN OR ON CLOTHING.
- KEEP IN ORIGINAL CONTAINER IN A COOL, DRY PLACE.
- KEEP CONTAINER CLOSED WHEN NOT IN USE.
- KEEP AWAY FROM HEAT SOURCES, SPARKS, OPEN FLAMES AND LIGHTED TOBACCO PRODUCTS.
- USE ONLY A CLEAN, DRY SCOOP MADE OF METAL OR PLASTIC EACH TIME THIS PRODUCT IS TAKEN FROM CONTAINER.
- DO NOT ADD THIS PRODUCT TO ANY DISPENSING DEVICE CONTAINING REMNANTS OF ANY OTHER PRODUCT. SUCH USE MAY CAUSE VIOLENT REACTION LEADING TO FIRE OR EXPLOSION.
- ADD THIS PRODUCT ONLY TO WATER.
- MAY CAUSE FIRE OR EXPLOSION IF MIXED WITH OTHER CHEMICALS.
- FIRE MAY RESULT IF CONTAMINATED WITH ACIDS OR EASILY COMBUSTIBLE MATERIAL SUCH AS OIL, KEROSENE, GASOLINE, PAINT PRODUCTS AND MOST OTHER ORGANIC MATERIALS.
- WASH HANDS AFTER HANDLING.
- DO NOT REUSE CONTAINER. RESIDUAL MATERIAL REMAINING IN EMPTY DRUM CAN REACT TO CAUSE FIRE. THOROUGHLY FLUSH EMPTY CONTAINER WITH WATER THEN DESTROY BY PLACING IN TRASH COLLECTION. DO NOT CONTAMINATE WATER, FOOD, OR FEED BY STORAGE OR DISPOSAL.

OTHER PRECAUTIONS:
- KEEP OUT OF REACH OF CHILDREN.
- STRONG OXIDIZER - FIRE MAY RESULT FROM CONTACT WITH HEAT, ACIDS, ORGANIC OR COMBUSTIBLE MATTER.
- MAY BE FATAL OR HARMFUL IF SWALLOWED.
- MAY CAUSE CHEMICAL BURNS.
- IRRITATING TO NOSE AND THROAT - AVOID BREATHING DUST.

COMMENTS:

TSCA - CALCIUM HYPOCHLORITE IS ON THE TSCA INVENTORY UNDER CAS #7778-54-3.

SARA TITLE III - A) 311/312 CATEGORIES - ACUTE AND REACTIVITY, B) NOT LISTED IN SECTION 313, C) NOT LISTED AS AN "EXTREMELY HAZARDOUS SUBSTANCE" IN SECTION 302.

CERCLA - LISTED IN TABLE 302.4 OF 40 CFR PART 302 AS A HAZARDOUS SUBSTANCE WITH A REPORTABLE QUANTITY OF 10 POUNDS. RELEASES TO AIR, LAND OR WATER WHICH EXCEED THE RQ MUST BE REPORTED TO THE NATIONAL RESPONSE CENTER, 800-424-8802.

RCRA - WASTE CALCIUM HYPOCHLORITE AND CONTAMINATED SOILS/MATERIALS FROM SPILL CLEANUP ARE D001 HAZARDOUS WASTE AS PER 40 CFR 261.21(A)(4) AND MUST BE DISPOSED OF ACCORDINGLY UNDER RCRA.

FIFRA - CALCIUM HYPOCHLORITE IS REGISTERED WITH EPA AS A PESTICIDE.

NSF - PPG CALCIUM HYPOCHLORITE IS CERTIFIED FOR MAXIMUM USE AT 46 MG/L UNDER ANSI/NSF STANDARD 60.

REVISIONS MADE TO 9/21/93, 1ST EDITION: DATE, EDITION, IMO DESCRIPTION UPDATED (PAGE 1), OTHER PROTECTIVE EQUIPMENT UPDATED (PAGE 6).

NOTICE

WITH RESPECT TO THE PRODUCT OR INFORMATION PROVIDED HEREIN, AND SHALL UNDER

NO CIRCUMSTANCES BE LIABLE FOR INCIDENTAL OR CONSEQUENTIAL DAMAGES.**

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*** END OF MSDS ***

MATERIAL SAFETY DATA SHEETS

SODIUM HYPOCHLORITE

004 07/11/96 SODIUM HYPOCHLORITE 7-15%

PRODUCT NAME:
SODIUM HYPOCHLORITE 7-15%

MSDS #: OX622680

I. PRODUCT IDENTIFICATION

PRODUCT NAME: SODIUM HYPOCHLORITE 7-15%
SYNONYMS: Liquid chlorine, liquid bleach, Pure Chlor, Sunny Sol 150, Liquichlor
CHEMICAL FAMILY: Hypochlorite
FORMULA: NaOCl in water
DESCRIPTION: Swimming pool chlorinator, Microbiocide
OSHA HAZARD CLASSIFICATION: Oxidizer, unstable (reactive), corrosive to skin and eyes, lung toxin

II. COMPONENT DATA

PRODUCT COMPOSITION
CAS or CHEMICAL NAME: Sodium hypochlorite
CAS NUMBER: 7681-52-9
PERCENTAGE RANGE: 7-15
HAZARDOUS PER 29 CFR 1910.1200: Yes
EXPOSURE STANDARDS: None Established
CAS or CHEMICAL NAME: Water
CAS NUMBER: 7732-18-5
PERCENTAGE RANGE: 73-87
HAZARDOUS PER 29 CFR 1910.1200: No
EXPOSURE STANDARDS: None Established
CAS or CHEMICAL NAME: Sodium hydroxide
CAS NUMBER: 1310-73-2
PERCENTAGE RANGE: 0.5-2.5
HAZARDOUS PER 29 CFR 1910.1200: Yes
EXPOSURE STANDARDS:

	OSHA(PEL)		ACGIH(TLV)	
	ppm	mg/cubic-meter	ppm	mg/cubic-meter
TWA:	None Established		None Established	
CEILING:		2		2
STEL:	None Established		None Established	

CAS or CHEMICAL NAME: Sodium chloride
CAS NUMBER: 7647-14-5
PERCENTAGE RANGE: 5.0-11.0
HAZARDOUS PER 29 CFR 1910.1200: No
EXPOSURE STANDARDS: None Established

III. PRECAUTIONS FOR SAFE HANDLING AND STORAGE

DO NOT TAKE INTERNALLY. AVOID CONTACT WITH SKIN OR EYES, UPON CONTACT WITH SKIN OR EYES, WASH OFF WITH WATER
STORAGE CONDITIONS: Store in a cool, dry, well-ventilated area. Avoid high temperatures and exposure to and direct sunlight.
DO NOT STORE AT TEMPERATURES ABOVE: 15-21 Deg.C (60-70 Deg.F)
OTHER: Store in the dark at the lowest possible temperature, but keep from freezing.
PRODUCT STABILITY AND COMPATIBILITY
SHELF LIFE LIMITATIONS: Up to 6 months at 60 Deg.F. or lower
INCOMPATIBLE MATERIALS FOR PACKAGING: Metal containers
INCOMPATIBLE MATERIALS FOR STORAGE OR TRANSPORT: Oxidizers, acids, nitrogen containing materials such as quaternary ammonium salts.

IV. PHYSICAL DATA

APPEARANCE: Greenish-yellow liquid
FREEZING POINT: No Data
BOILING POINT: Decomposes on heating
DECOMPOSITION TEMPERATURE: Decomposes as heated

SPECIFIC GRAVITY: 1.08-1.26
BULK DENSITY: Not Applicable
pH @ 25 DEG.C: > 11
VAPOR PRESSURE @ 25 DEG.C: No Data
SOLUBILITY IN WATER: Miscible
VOLATILES, PERCENT BY VOLUME: 87.5-94.5
EVAPORATION RATE: No Data
VAPOR DENSITY: No Data
MOLECULAR WEIGHT: 74.5 (active ingredient-NaOCl)
ODOR: Chlorine-like
COEFFICIENT OF OIL/WATER DISTRIBUTION: No Data

V. PERSONAL PROTECTIVE EQUIPMENT REQUIREMENTS

PERSONAL PROTECTION FOR ROUTINE USE OF PRODUCT:

RESPIRATORY PROTECTION: Respirator protection not normally needed since the volatility and toxicity are low. If vapors, mists, or aerosols are generated, wear a NIOSH/MSHA approved respirator.

VENTILATION: Local exhaust ventilation is recommended if vapors, mists or aerosols are generated. Otherwise, use general exhaust ventilation.

SKIN PROTECTIVE EQUIPMENT: Use chemical safety goggles and impermeable gloves.

EQUIPMENT SPECIFICATIONS:

RESPIRATOR TYPE:	NIOSH/MSHA approved respirator equipped with chemical cartridges for protection against chlorine gas and dust mist pre-filters.
GLOVE TYPE:	Neoprene
BOOT TYPE:	Not normally needed
APRON TYPE:	Not normally needed
PROTECTIVE SUIT:	Not normally needed

VI. FIRE AND EXPLOSION HAZARD INFORMATION

FLAMMABILITY DATA:

FLAMMABLE:	No
COMBUSTIBLE:	No
PYROPHORIC:	No
FLASH POINT:	Not Applicable

AUTOIGNITION TEMPERATURE : Not Applicable
FLAMMABLE LIMITS AT NORMAL ATMOSPHERIC TEMPERATURE AND PRESSURE (PERCENT VOLUME IN AIR): LEL - Not Applicable UEL - Not Applicable
NFPA RATINGS: Not Established
HMIS RATINGS:

Health:	3
Flammability:	0
Reactivity:	2

EXTINGUISHING MEDIA: Not applicable
FIRE FIGHTING TECHNIQUES AND COMMENTS: Use water to cool containers exposed to fire. On small fire, use dry chemical, Carbon dioxide or water spray. On large fires, use water in flooding quantities as fog. In case of fire, hazardous concentrations of chlorine may be formed. See Section XI for personal protective equipment for fire fighting.

VII. REACTIVITY INFORMATION

CONDITIONS UNDER WHICH THIS PRODUCT MAY BE UNSTABLE
TEMPERATURES ABOVE: Decomposes as it is heated
MECHANICAL SHOCK OR IMPACT: No
ELECTRICAL (STATIC) DISCHARGE: No
OTHER: Decomposition will result from contact with iron or copper
HAZARDOUS POLYMERIZATION: Will not occur
INCOMPATIBLE MATERIALS: Iron, copper, acids, ammonium compounds, organics, other oxidizers
HAZARDOUS DECOMPOSITION PRODUCTS: Chlorine gas
OTHER CONDITIONS TO AVOID: High heat, sunlight and ultra-violet light
SUMMARY OF REACTIVITY:
OXIDIZER: Yes

PYROPHORIC: No
ORGANIC PEROXIDE: No
WATER REACTIVE: No

VIII. FIRST AID

EYES: Immediately flush with large amounts of water for at least 15 minutes, occasionally lifting the upper and lower eyelids. Call a physician at once.

SKIN: Immediately flush with water for at least 15 minutes. Call a physician. If clothing comes in contact with the product, the clothing should be removed immediately and should be laundered before re-use.

INGESTION: Immediately drink large quantities of water. DO NOT induce vomiting. Call a physician at once. DO NOT give anything by mouth if the person is unconscious or if having convulsions.

INHALATION: If person experiences nausea, headache or dizziness, person should stop work immediately and move to fresh air until these symptoms disappear. If breathing is difficult, administer oxygen, keep the person warm and at rest. Call a physician. In the event that an individual inhales enough vapor to lose consciousness, person should be moved to fresh air at once and a physician should be called immediately. If breathing has stopped, artificial respiration should be given immediately. In all cases, ensure adequate ventilation and provide respiratory protection before the person returns to work.

IX. TOXICOLOGY AND HEALTH INFORMATION

ROUTES OF ABSORPTION

Inhalation, skin, eye, ingestion

WARNING STATEMENTS AND WARNING PROPERTIES

HARMFUL IN INHALED OR INGESTED. HARMFUL IF EXPOSED TO SKIN OR EYES.

HUMAN THRESHOLD RESPONSE DATA

ODOR THRESHOLD: Approximately 0.9 mg/m3 (0.3 ppm) based on odor of chlorine.

IRRITATION THRESHOLD: There is no data for irritation threshold. Sodium hypochlorite has the potential to be immediately dangerous to life or health.

SIGNS, SYMPTOMS, AND EFFECTS OF EXPOSURE

INHALATION

ACUTE:

Inhalation of this material is irritating to the nose, mouth, throat and lungs. It may also cause burns to the respiratory tract with the production of lung edema which can result in shortness of breath, wheezing, choking, chest pain, and impairment of lung function. Inhalation of high concentrations can result in permanent lung damage.

CHRONIC:

Repeated inhalation exposure may cause impairment of lung function and permanent lung damage.

EYE

Severe irritation and/or burns can occur following eye exposure. Contact may cause impairment of vision and corneal damage.

SKIN

ACUTE:

Dermal exposure can cause severe irritation and/or burns characterized by redness, swelling and scab formation. Prolonged skin exposure may cause destruction of the dermis with impairment of the skin at site of contact to regenerate.

CHRONIC:

Effects from chronic skin exposure would be similar to those from single exposure except for effects secondary to tissue destruction.

INGESTION

ACUTE:

Irritation and/or burns can occur to the entire gastrointestinal tract, including the stomach and intestines, characterized by nausea, vomiting, diarrhea, abdominal pain, bleeding, and/or tissue ulceration.

CHRONIC:
There are no known or reported effects from chronic exposure.

MEDICAL CONDITIONS AGGRAVATED BY EXPOSURE
Asthma and respiratory and cardiovascular disease

INTERACTIONS WITH OTHER CHEMICALS WHICH ENHANCE TOXICITY
None known or reported.

ANIMAL TOXICOLOGY
ACUTE TOXICITY:
INHALATION LC50: No available data
ORAL LD50: Approximately 3-5 g/kg (rat)
DERMAL LD50: > 2 g/kg (rabbit)
Causes burns to eyes and skin

AQUATIC TOXICITY:
Aquatic LC50 - approximately 0.6 mg/l (bluegill)
approximately 1 mg/l (daphnia, 48 hours)

CHRONIC TOXICITY:
There are no known or reported effects from repeated exposure.

REPRODUCTIVE TOXICITY:
There are no known or reported effects on reproductive function or fetal development.

CARCINOGENICITY:
This product has been shown not to be carcinogenic. It is not included as a carcinogen by IARC, OSHA, NTP, or EPA.

MUTAGENICITY:
Sodium hypochlorite has been shown to produce damage to genetic material when tested in vitro. Studies in vivo have shown no evidence of mutagenic potential for this material. Chemicals with potent biocidal activity, typical of hypochlorite compounds, may compromise the integrity of many of the treated cells which remain viable during an in vitro assay. This result would likely produce cellular changes giving rise to a response indicative of mutation. It is judged that the risk of genetic damage is insignificant for sodium hypochlorite because of its biocidal activity, lack of mutagenicity in vivo, and failure to produce a carcinogenic response.

X. TRANSPORTATION INFORMATION

THIS MATERIAL IS REGULATED AS A DOT HAZARDOUS MATERIAL.
DOT DESCRIPTION FROM THE HAZARDOUS MATERIALS TABLE 49 CFR 172.101:
LAND (U.S. DOT): HYPOCHLORITE SOLUTIONS, 8, UN1791, PG II
WATER (IMO): Same as above
AIR (IATA/ICAO): Same as above
HAZARD LABEL/PLACARD: CORROSIVE
REPORTABLE QUANTITY: 100 lbs. (Per 49 CFR 172.101, Appendix)
EMERGENCY GUIDE NO: 60

XI. SPILL AND LEAKAGE PROCEDURES

FOR ALL TRANSPORTATION ACCIDENTS, CALL CHEMTREC AT 800-424-9300
REPORTABLE QUANTITY(POUNDS): 100 lbs. (Per 40 CFR 302.4)
SPILL MITIGATION PROCEDURES:
Hazardous concentrations in air may be found in local spill area and immediately downwind.
AIR RELEASE: Vapors may be suppressed by the use of a water fog. Capture all run off water for treatment and disposal.
WATER RELEASE: This material is soluble in water. Dike or contain material via use of compatible absorbents. Remove material with use of vacuum or pump operation and treat before disposition. This material is harmful to aquatic life.
LAND SPILL: Compatible absorbents: Sand, clay soil, commercial absorbents

SPILL RESIDUES:
Dispose of per guidelines under Section XII, WASTE DISPOSAL.

PERSONAL PROTECTION FOR EMERGENCY SPILL AND FIRE-FIGHTING SITUATIONS:
Response to this material requires the use of self contained breathing apparatus (SCBA).
Additional protective clothing must be worn to prevent personal contact

with this material. these items include but are not limited to boots, gloves, hard hat, impervious clothing, i.e. chemically impermeable suit. Compatible materials for response to this material are neoprene, butyl rubber, viton and saranex.

XII. WASTE DISPOSAL

If this product becomes a waste, it DOES NOT meet the criteria of a hazardous waste as defined under 40 CFR 261, in that it does not exhibit the characteristics of hazardous waste of Subpart C, nor is it listed as a hazardous waste under Subpart D.
As a nonhazardous liquid waste, it should be disposed of in accordance with local, state and federal regulations by treatment in a wastewater treatment system.
CARE MUST BE TAKEN TO PREVENT ENVIRONMENTAL CONTAMINATION FROM THE USE OF THIS MATERIAL. THE USER OF THIS MATERIAL HAS THE RESPONSIBILITY TO DISPOSE OF UNUSED MATERIAL, RESIDUES AND CONTAINERS IN COMPLIANCE WITH ALL RELEVANT LOCAL, STATE AND FEDERAL LAWS AND REGULATIONS REGARDING TREATMENT, STORAGE AND DISPOSAL FOR HAZARDOUS AND NONHAZARDOUS WASTES.

XIII. ADDITIONAL REGULATORY STATUS INFORMATION

TOXIC SUBSTANCES CONTROL ACT: This substance is listed on the Toxic Substances Control Act inventory.
SUPERFUND AMENDMENTS AND REAUTHORIZATION ACT TITLE III: None Established
HAZARD CATEGORIES, PER 40 CFR 370.2:
HEALTH:
Immediate (Acute)
Delayed (Chronic)
PHYSICAL:
Fire
Reactivity
EMERGENCY PLANNING AND COMMUNITY RIGHT TO KNOW, PER 40 CFR 355, APP.A:
EXTREMELY HAZARDOUS SUBSTANCE - THRESHOLD PLANNING QUANTITY:
None Established
SUPPLIER NOTIFICATION REQUIREMENTS, PER 40 CFR 372.45:
None Established

XIV. ADDITIONAL INFORMATION

MSDS REVISION STATUS: Transportation information updated

NOTICE

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* * * END OF MSDS * * *

MATERIAL SAFETY DATA SHEETS

M-104

410 0104 000
REVISION "A" JUNE 2, 1989
ACID, SULFAMIC, GRANULAR
50 LB. CONTAINER

TRANS[illegible] INDUSTRIES, INC.
6101 Humphreys Street
Harahan, LA 70123
504-733-7865

CALABRIAN CORPORATION

Material Safety Data Sheet

SULFAMIC ACID

PRODUCT IDENTIFICATION

IMPORTED BY CALABRIAN CORPORATION, 1445 NORTH LOOP WEST, SUITE 800, HOUSTON, TX 77008 713-880-9982
EMERGENCY CONTACT: CHEMTREC: 1-800-424-9300

SUBSTANCE :	SULFAMIC ACID, CRYSTAL	CAS NUMBER: 5329-14-6	
TRADE NAMES/SYNONYMS:	AMIDOSULFONIC ACID; AMIDOSULFURIC ACID; AMINESULFONIC ACID; AMINOSULFONIC ACID; AMINOSULFURIC ACID; JUMBO; SULFAMIDIC ACID; SULPHAMIC ACID; UN2967; A-295; OHS22200		
CHEMICAL FAMILY:	INORGANIC ACID	MOLECULAR FORMULA: H3-N-O3-S	
MOLECULAR WEIGHT:	97.10		
CERCLA RATINGS (SCALE 0-3):	HEALTH=2	FIRE=1	REACTIVITY=1 PERSISTENCE=0
NFPA RATINGS (SCALE 0-4):	HEALTH=2	FIRE=1	REACTIVITY=1

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410-0004-000
P.O. 137245

COMPONENTS AND CONTAMINANTS

COMPONENT:	SULFAMIC ACID	PERCENT: >99
OTHER CONTAMINANTS:	NONE	
EXPOSURE LIMITS:	NO OCCUPATIONAL EXPOSURE LIMITS ESTABLISHED BY OSHA, ACGIH, OR NIOSH.	

PHYSICAL DATA

DESCRIPTION:	COLORLESS, ODORLESS, NON-VOLATILE, NON- HYGROSCOPIC CRYSTALS	
BOILING POINT:	DECOMPOSES	MELTING POINT: 392 F (200 C) DEC.
SPECIFIC GRAVITY:	2.15	VOLATILITY: NIL
EVAPORATION RATE:	NOT AVAILABLE	SOLUBILITY IN WATER: 14.7% @ 0 C
SOLVENT SOLUBILITY:	SOLUBLE IN LIQUID AMMONIA, DIMETHYLFORMAMIDE, PYRIDINE, FORMAMIDE, NITROGEN CONTAINING ORGANIC SOLVENTS; SPARINGLY SOLUBLE IN ALCOHOL, METHANOL; SLIGHTLY SOLUBLE IN ACETONE; INSOLUBLE IN ETHER.	
pH:	1.18 @ 25 c (1% SOLUTION)	

FIRE AND EXPLOSION DATA

FIRE AND EXPLOSION HAZARDS: SLIGHT FIRE HAZARD WHEN EXPOSED TO HEAT OR FLAME.

FIREFIGHTING MEDIA: DRY CHEMICAL, CARBON DIOXIDE, HALON, WATER SPRAY OR STANDARD FOAM (1987 EMERGENCY RESPONSE GUIDEBOOK, DOT P 5800.4). FOR LARGER FIRES, USE WATER SPRAY, FOG OR STANDARD FOAM (1987 EMERGENCY RESPONSE GUIDEBOOK, DOT P 5800.4).

FIREFIGHTING: MOVE CONTAINERS FROM FIRE AREA IF POSSIBLE. COOL CONTAINERS EXPOSED TO FLAMES WITH WATER FROM SIDE UNTIL WELL AFTER FIRE IS OUT. STAY AWAY FROM STORAGE TANK ENDS (1987 EMERGENCY RESPONSE GUIDEBOOK, DOT P 5800.4, GUIDE PAGE 60). EXTINGUISH USING AGENT INDICATED; DO NOT USE WATER DIRECTLY ON MATERIAL. IF LARGE AMOUNTS OF COMBUSTIBLE MATERIALS ARE INVOLVED, USE WATER SPRAY OR FOG IN FLOODING AMOUNTS. AVOID BREATHING CORROSIVE DUSTS AND FUMES FROM BURNING MATERIAL, KEEP UPWIND.

TOXICITY

SULFAMIC ACID:
4% SOLUTION/5 DAYS-INTERMITTENT SKIN-HUMAN MILD IRRITATION; 500 MG/24 HOURS SKIN-RABBIT SEVERE IRRITATION; 250 UG/24 HOURS EYE-RABBIT SEVERE IRRITATION; 20 MG EYE-RABBIT MODERATE IRRITATION; 3160 MG/KG ORAL-RAT LD50; 100 MG/KG INTRAPERITONEAL-RAT LDLO; CARCINOGEN STATUS: NONE.
SULFAMIC ACID IS A SEVERE EYE, SKIN, AND MUCOUS MEMBRANE IRRITANT.

HEALTH EFFECTS AND FIRST AID

INHALATION: CORROSIVE.

ACUTE EXPOSURE - INHALATION OF FUMES OR MIST FROM ACIDS MAY CAUSE COUGHING, CHOKING, HEADACHE, DIZZINESS, WEAKNESS, HYPOTENSION, AND DELAYED PULMONARY EDEMA WITH CHEST TIGHTNESS, APNEA, FROTHY SPUTUM, AND CYANOSIS. AFTER INHALATION OF CORROSIVE ATMOSPHERES, CONVALESCENCE MAY BE PROLONGED AND FREQUENT RELAPSES MAY OCCUR.

CHRONIC EXPOSURE - REPEATED OR PROLONGED EXPOSURE TO ACIDIC FUMES MAY CAUSE EROSION OF TEETH FOLLOWED BY JAW NECROSIS. BRONCHIAL IRRITATION WITH COUGH AND FREQUENT ATTACKS OF BRONCHIAL PNEUMONIA MAY OCCUR. GASTROINTESTINAL DISTURBANCES ARE ALSO POSSIBLE.

FIRST AID - REMOVE FROM EXPOSURE AREA TO FRESH AIR IMMEDIATELY. IF BREATHING HAS STOPPED, GIVE ARTIFICIAL RESPIRATION. MAINTAIN AIRWAY AND BLOOD PRESSURE AND ADMINISTER OXYGEN IF AVAILABLE. KEEP AFFECTED PERSON WARM AND AT REST. TREAT SYMPTOMATICALLY AND SUPPORTIVELY. ADMINISTRATION OF OXYGEN SHOULD BE PERFORMED BY QUALIFIED PERSONNEL. GET MEDICAL ATTENTION IMMEDIATELY.

SKIN CONTACT: CORROSIVE.

ACUTE EXPOSURE - DIRECT CONTACT WITH ACIDS MAY CAUSE SEVERE PAIN, BURNS AND STAINS. EXTENSIVE SCARRING MAY OCCUR FROM THE BURNS PENETRATING DEEP INTO THE SKIN LAYERS REQUIRING A LONG PERIOD TO HEAL. CONCENTRATIONS OF GREATER THAN 20% OF SULFAMIC ACID MAY INJURE THE SKIN.

CHRONIC EXPOSURE - REPEATED APPLICATION OF A 4% SOLUTION OF SULFAMIC ACID SEVERAL TIMES A DAY FOR 5 DAYS ON THE SKIN OF 5 HUMAN SUBJECTS PRODUCED MILD IRRITATION.

FIRST AID - REMOVE CONTAMINATED CLOTHING AND SHOES IMMEDIATELY. WASH AFFECTED AREA WITH SOAP OR MILD DETERGENT

AND LARGE AMOUNTS OF WATER UNTIL NO EVIDENCE OF CHEMICAL REMAINS (AT LEAST 15-20 MINUTES). IN CASE OF CHEMICAL BURNS, COVER AREA WITH STERILE, DRY DRESSING. BANDAGE SECURELY, BUT NOT TOO TIGHTLY. GET MEDICAL ATTENTION IMMEDIATELY.

EYE CONTACT: CORROSIVE.

ACUTE EXPOSURE - CONTACT WITH DILUTE ACIDS WILL CAUSE IMMEDIATE PAIN, CONJUNCTIVAL HYPEREMIA AND SOMETIMES INJURY OF THE CORNEAL EPITHELIUM WITH SYMPTOMS OF PAIN, TEARING, AND PHOTOPHOBIA. USUALLY THE CORNEAL EPITHELIUM WILL REGENERATE PROMPTLY AND WITHOUT ANY CORNEAL OPACITIES. CONTACT WITH CONCENTRATED ACIDS MAY CAUSE EXTENSIVE NECROSIS OF THE CONJUNCTIVA AND CORNEAL EPITHELIUM WITH POSSIBLE PENETRATION AND DAMAGE TO THE STROMA OF THE CORNEA. CORNEAL DAMAGE FREQUENTLY RESULTS IN BLINDNESS. THE INSTILLATION OF 0.5 CC OF 4 PERCENT SOLUTION WITH A pH OF 0.82 INTO THE CONJUNCTIVAL SAC OF 5 RABBITS PRODUCED A MODERATE DEGREE OF CONJUNCTIVITIS AND EDEMA. SUBSTANCES WITH A pH OF LESS THAN 2.0 ARE CONSIDERED CORROSIVE TO THE EYES.

CHRONIC EXPOSURE - PROLONGED OR REPEATED EXPOSURE TO THE DUST OR MISTS MAY CAUSE EFFECTS AS DESCRIBED IN ACUTE EXPOSURE.

FIRST AID.- WASH EYES IMMEDIATELY WITH LARGE AMOUNTS OF WATER, OCCASIONALLY LIFTING UPPER AND LOWER LIDS, UNTIL NO EVIDENCE OF CHEMICAL REMAINS (AT LEAST 15-20 MINUTES). CONTINUE IRRIGATING WITH NORMAL SALINE UNTIL THE pH HAS RETURNED TO NORMAL (30-60 MINUTES). COVER WITH STERILE BANDAGES. GET MEDICAL ATTENTION IMMEDIATELY.

INGESTION: CORROSIVE.

ACUTE EXPOSURE - INGESTION OF ACIDS MAY CAUSE SEVERE BURNING PAIN IN MOUTH, PHARYNX, AND ABDOMEN, FOLLOWED BY VOMITING, DIARRHEA OF DARK

PRECIPITATED BLOOD AND A DROP IN THE BLOOD PRESSURE. DISCOLORATION MAY BE FOUND AROUND THE MOUTH AND THROAT. ASPHYXIA MAY OCCUR FROM EDEMA OF THE GLOTTIS. AFTER INITIAL RECOVERY, ONSET OF FEVER INDICATES MEDIASTINITIS OR PERITONITIS FROM PERFORATION OF THE ESOPHAGUS OR STOMACH. THE PATIENT MAY HAVE A RIGID ABDOMEN WITHOUT PERFORATION. IF THE PATIENT RECOVERS, SCAR FORMATION IS MORE APT TO PRODUCT STRICTURE OF THE PYLORUS THAN STRICTURE OF THE ESOPHAGUS. INGESTION OF GREATER THAN 10% OF SULFAMIC ACID SOLUTIONS WILL CAUSE LESIONS OF THE STOMACH.

CHRONIC EXPOSURE - CHRONIC INGESTION OF A 2% CONCENTRATION IN THE DIET OF RATS FOR 105 DAYS PRODUCED A DECLINE IN THE GROWTH RATE; A 1% CONCENTRATION IN THE DIET DID NOT PRODUCE ANY ADVERSE EFFECTS.

FIRST AID - DO NOT USE GASTRIC LAVAGE OR EMESIS. DILUTE THE ACID IMMEDIATELY BY DRINKING LARGE QUANTITIES OF WATER OR MILK. IF VOMITING PERSISTS, ADMINISTER FLUIDS REPEATEDLY. INGESTED ACID MUST BE DILUTES APPROXIMATELY 100 TIMES TO RENDER IT HARMLESS TO TISSUES. IF SYMPTOMS ARE SEVERE AND PERFORATION OF THE STOMACH OR ESOPHAGUS IS SUSPECTED, GIVE NOTHING BY MOUTH UNTIL ENDOSCOPIC EXAMINATION HAS BEEN DONE. (DREISBACH, HANDBOOK OF POISONING, 11TH EDITION) GET MEDICAL ATTENTION IMMEDIATELY. TREATMENT SHOULD BE ADMINISTERED BY QUALIFIED MEDICAL PERSONNEL.

REACTIVITY

REACTIVITY: THE SUBSTANCE IS HIGHLY STABLE AS A DRY, CRYSTALLINE SOLID, BUT IN WATER SOLUTION IT SLOWLY HYDROLYZES TO FORM AMMONIUM SULFATE AND BISULFATE. WHEN DISSOLVED IN WATER, IT IS A STRONG ACID.

INCOMPATIBILITIES: :

CHLORINE:	FORMATION OF A VERY SENSITIVE, EXPLOSIVE NITROGEN TRICHLORIDE.
POTASSIUM CHLORATE:	OXIDIZES TO SULFURIC ACID AND NITROGEN GAS.
NITRIC ACID:	FUMING NITRIC ACID COMBINED WITH SULFAMIC ACID CAUSES VIOLENT RELEASE OF NITROUS OXIDE.
METAL NITRATES AND NITRITES:	HEATING MAY RESULT IN A VIOLENT REACTION.
WATER:	SLOWLY HYDROLYZES SULFAMIC ACID TO AMMONIUM SULFATE AND BISULFATE.
BASES:	VIOLENT REACTION.
BROMINE GAS:	OXIDIZES TO SULFURIC ACID AND NITROGEN GAS.
DECOMPOSITION:	THERMAL DECOMPOSITION MAY RELEASE TOXIC AND HAZARDOUS FUMES OF AMMONIA, AND OXIDES OF NITROGEN AND SULFUR.
POLYMERIZATION:	HAZARDOUS POLYMERIZATION HAS NOT BEEN REPORTED TO OCCUR UNDER NORMAL TEMPERATURES AND PRESSURES.

CONDITIONS TO AVOID

MAY BURN BUT DOES NOT IGNITE READILY. FLAMMABLE, POISONOUS GASES MAY ACCUMULATE IN TANKS AND HOPPER CARS. MAY IGNITE COMBUSTIBLES (WOOD, PAPER, OIL, ETC.).

SPILL AND LEAK PROCEDURES

OCCUPATIONAL SPILL:

DO NOT TOUCH SPILLED MATERIAL. STOP LEAK IF YOU CAN DO IT WITHOUT RISK. FOR SMALL SPILLS, TAKE UP WITH SAND OR OTHER ABSORBENT MATERIAL AND PLACE INTO CONTAINERS FOR LATER DISPOSAL. FOR SMALL DRY SPILLS, WITH CLEAN SHOVEL PLACE MATERIAL INTO CLEAN, DRY CONTAINER AND COVER. MOVE CONTAINERS FROM SPILL AREA. FOR LARGER SPILLS, DIKE FAR AHEAD OF SPILL FOR LATER DISPOSAL. KEEP UNNECESSARY PEOPLE AWAY. ISOLATE HAZARD AREA AND DENY ENTRY.

PROTECTIVE EQUIPMENT

VENTILATION: PROVIDE LOCAL EXHAUST OR GENERAL DILUTION VENTILATION SYSTEM.

RESPIRATOR: THE SPECIFIC RESPIRATOR SELECTED MUST BE BASED ON THE CONTAMINATION LEVELS FOUND IN THE WORK PLACE, MUST NOT EXCEED THE WORKING LIMITS OF THE RESPIRATOR AND BE JOINTLY APPROVED BY THE NATIONAL INSTITUTE FOR OCCUPATIONAL SAFETY AND HEALTH AND THE MINE SAFETY AND HEALTH ADMINISTRATION.

THE FOLLOWING RESPIRATORS ARE RECOMMENDED BASED ON THE DATA FOUND IN THE PHYSICAL DATA, HEALTH EFFECTS AND TOXICITY SECTIONS. THEY ARE RANKED IN ORDER FROM MINIMUM TO MAXIMUM RESPIRATORY PROTECTION:

DUST AND MIST RESPIRATOR WITH A FULL FACEPIECE.
AIR-PURIFYING FULL FACEPIECE RESPIRATOR WITH A HIGH-EFFICIENCY PARTICULATE FILTER.
POWERED AIR-PURIFYING RESPIRATOR WITH A TIGHT-FITTING FACEPIECE AND HIGH-EFFICIENCY PARTICULATE FILTER.
TYPE "C" SUPPLIED-AIR RESPIRATOR WITH A FULL FACEPIECE OPERATED IN PRESSURE-DEMAND OR OTHER POSITIVE PRESSURE MODE OR WITH A FULL FACEPIECE, HELMET OR HOOD OPERATED IN CONTINUOUS-FLOW MODE.

CALABRIAN CORPORATION

Material Safety Data Sheet

SULFAMIC ACID, CONT.

SELF-CONTAINED BREATHING APPARATUS WITH A FULL FACEPIECE OPERATED IN PRESSURE-DEMAND OR OTHER POSITIVE PRESSURE MODE.

FOR FIREFIGHTING AND OTHER IMMEDIATELY DANGEROUS TO LIFE OR HEALTH CONDITIONS:

SELF-CONTAINED CONTAINED BREATHING APPARATUS WITH FULL FACEPIECE OPERATED IN PRESSURE DEMAND OR OTHER POSITIVE PRESSURE MODE.

SUPPLIED-AIR RESPIRATOR WITH FULL FACEPIECE AND OPERATED IN PRESSURE-DEMAND OR OTHER POSITIVE PRESSURE MODE IN COMBINATION WITH AN AUXILIARY SELF-CONTAINED BREATHING APPARATUS OPERATED IN PRESSURE-DEMAND OR OTHER POSITIVE PRESSURE MODE.

CLOTHING: EMPLOYEE MUST WEAR APPROPRIATE PROTECTIVE (IMPERVIOUS) CLOTHING AND EQUIPMENT TO PREVENT ANY POSSIBILITY OF SKIN CONTACT WITH THIS SUBSTANCE.

GLOVES: EMPLOYEE MUST WEAR APPROPRIATE PROTECTIVE GLOVES TO PREVENT CONTACT WITH THIS SUBSTANCE.

EYE PROTECTION: EMPLOYEE MUST WEAR SPLASH-PROOF OR DUST-RESISTANT SAFETY GOGGLES AND A FACESHIELD TO PREVENT CONTACT WITH THIS SUBSTANCE. CONTACT LENSES SHOULD NOT BE WORN.

EMERGENCY WASH FACILITIES: WHERE THERE IS ANY POSSIBILITY THAT AN EMPLOYEE'S EYES AND/OR SKIN MAY BE EXPOSED TO THIS SUBSTANCE, THE EMPLOYER SHOULD PROVIDE AN EYE WASH FOUNTAIN AND QUICK DRENCH SHOWER WITHIN THE IMMEDIATE WORK AREA FOR EMERGENCY USE.

CALABRIAN CORPORATION 6/2/89

This is the most current Material Safety Data Sheet available on this product 12/13/93

J Wild

MATERIAL SAFETY DATA SHEETS

M-210

EDTA TETRASODIUM

M210

Akzo Nobel Chemicals Inc.

MATERIAL SAFETY DATA SHEET

DATE PRINTED: 12/13/1995

PAGE 1
MSDS NO. 16-075348

Dissolvine NA-X

SECTION 1. CHEMICAL PRODUCT AND COMPANY INFORMATION

PRODUCT NAME
Dissolvine NA-X

SYNONYM
Tetrasodium EDTA

CAS #
64-02-8

MANUFACTURERS NAME
Akzo Nobel Chemicals Inc.

ADDRESS
5 Livingstone Avenue
Dobbs Ferry, NY 10522

COUNTRY
USA

PRODUCT USE
Sequestering agent

ISSUE DATE
8/20/1995

CHEMICAL NAME
Ethylenediaminetetraacetic acid, tetrasodium

CHEMICAL FORMULA
C10H12N2O8Na4x4H2O

CHEMICAL FAMILY
Aminocarboxylic acid salt

PRODUCT/TECHNICAL INFORMATION
1-800-666-1200

MEDICAL/HANDLING EMERGENCY
1-914-693-6946

TRANSPORTATION EMERGENCY
CHEMTREC 1-800-424-9300

REVISION DATE
8/20/1995

REVISION NO.
004

SECTION 2. COMPOSITION/INFORMATION ON INGREDIENTS

SUBSTANCE DESCRIPTION	PERCENT	CAS#
Tetrasodium EDTA	86.000	64-02-8
Water	14.000	7732-18-5
Nitrilotriacetic acid	0.200	139-13-9

SECTION 3. HAZARDS IDENTIFICATION

Appearance & Odor
Appearance: Crystalline (25C)
Color: white
Odor: odorless

STATEMENT OF HAZARDS
ATTENTION: CONTAINS MATERIAL WHICH MAY CAUSE KIDNEY DAMAGE BASED ON ANIMAL DATA.
POSSIBLE BIRTH DEFECT HAZARD-CONTAINS MATERIAL WHICH MAY CAUSE BIRTH DEFECTS BASED ON ANIMAL DATA.
POSSIBLE CANCER HAZARD-CONTAINS MATERIAL WHICH MAY CAUSE CANCER BASED ON ANIMAL DATA.
Risk of cancer depends on duration and level of exposure.
HANDLE IN ACCORDANCE WITH GOOD INDUSTRIAL HYGIENE PRACTICES.
AVOID UNNECESSARY EXPOSURE.
REMOVE MATERIAL FROM EYES, SKIN AND CLOTHING.
USE WITH ADEQUATE VENTILATION.
WASH THOROUGHLY AFTER HANDLING.

Fire & Explosion Hazards
Not considered a fire hazard. When involved in a fire, may produce irritating fumes and/or gasses if heated to 600 C.or above.

SECTION 3. HAZARDS IDENTIFICATION (CONTINUED)

Primary Route of Exposure
Skin and eye contact are the principal routes of exposure to this product.

Inhalation Acute Exposure
Inhalation of dust may be irritating to mucous membranes and may cause upper respiratory tract irritation.

Skin Contact - ACUTE
Skin contact is not expected to cause irritation.

Eye contact - ACUTE
Eye contact may cause mild irritation.

Ingestion - ACUTE
This product has a low order of toxicity. No significant toxic effects are expected.

CARCINOGENICITY

IARC	....YES	OSHA	....NO
NTP	....YES	ACGIH	....NO

SECTION 4. FIRST AID MEASURES

Inhalation First Aid
Remove victim to fresh air. If respiratory irritation occurs or if breathing becomes difficult, get medical attention.

Skin Contact - First Aid
Remove contaminated clothing and equipment. Wash all affected areas thoroughly with plenty of soap and water. Wash any contaminated clothing and shoes before reuse. Obtain medical attention if irritation occurs.

Eye Contact - First Aid
Immediately flush eyes with plenty of running water. If victim is wearing contact lenses, remove them. Hold the eyelids apart during the flushing to ensure rinsing of the entire surface of the eye and lids with water. Get medical attention if irritation persists.

Ingestion - First Aid
Give several glasses of water. If vomiting occurs, keep head below hips to reduce risk of aspiration. Give fluids again. Seek medical attention if health effects occur.

Medical conditions aggravated
There are no data available which address medical conditions that are generally recognized as being aggravated by exposure to this product.

Note to Physician
No specific antidote is known. Based on the individual reactions of the patient, the physician's judgement should be used to control symptoms and clinical conditions.

Akzo Nobel Chemicals Inc.

MATERIAL SAFETY DATA SHEET

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Dissolvine NA-X

SECTION 5. FIRE FIGHTING MEASURES

FLASH POINT
N/D F N/D C

FLASH METHOD
N/D

AUTO IGNITION TEMPERATURE
N/D F N/D C

UPPER EXPLOSION LIMIT
NA

LOWER EXPLOSION LIMIT
NA

Extinguishing Media
Use water fog, dry powder, foam or carbon dioxide extinguishing agents.

Fire Fighting Procedures
As in any fire, prevent human exposure to fire, smoke, fumes or products of combustion. Evacuate non-essential personnel from the fire area. Firefighters should wear full-face, self-contained breathing apparatus and impervious protective clothing. If possible, move containers from the fire area. If not leaking, keep fire exposed containers cool with a water fog or spray to prevent rupture due to excessive heat. High pressure water may spread product from broken containers increasing contamination or fire hazard.

Contaminated buildings, areas and equipment must not be used until they are properly decontaminated. Dike fire water for later disposal. Do not allow contaminated water to enter waterways.

Fire & Explosion Hazards
Not considered a fire hazard. When involved in a fire, may produce irritating fumes and/or gasses if heated to 600 C.or above.

Other Fire + Explosion Hazards
No other explosion hazards of this product are known.

Hazardous Products/Combustion
Oxides of carbon and nitrogen are produced by the combustion of this product.

NFPA HEALTH RATING
1

NFPA FLAMMABILITY RATING
1

NFPA REACTIVITY RATING
0

NFPA OTHER
NA

SECTION 6. ACCIDENTAL RELEASE MEASURES

Cleanup
Stop source of spill. Sweep up spilled solid material, being careful not to create dust. Return sweepings to stock or, if contaminated, place into a chemical waste container for disposal. Contaminated areas, buildings and equipment must not be used until they are properly decontaminated. Generously cover contaminated area with a slurry of common household, powdered laundry detergent and water. Using a stiff brush, work the slurry into cracks and crevices. Allow to stand for 2-3 minutes. Then flush with water. Repeat if necessary. Dike water for later disposal. Do not allow contaminated water to enter waterways.

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Dissolvine NA-X

SECTION 7. HANDLING AND STORAGE

Handling
Avoid prolonged and/or repeated skin and eye contact and inhalation. Minimize the generation of dust when handling this product.

Storage
Keep container closed and dry.

MAXIMUM STORAGE TEMPERATURE
N/D F N/D C

General Comments
No specific comments.

SECTION 8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Respiratory protection
If handling operations lead to dusting, wear a NIOSH-approved half-mask, air purifying respirator with dust, mist and fume filters

When using respirator cartridges or canisters, they must be changed frequently (following each use or at the end of the workshift) to assure breakthrough exposure does not occur.

Skin Protection
Skin contact with this product should be prevented through the use of suitable protective clothing, gloves, and footwear selected with regard for use condition exposure potential.

Eye Protection
Dust-tight goggles are recommended when handling this product.

Ventilation protection
Special ventilation is usually not required under normal use conditions. General plant ventilation should be adequate in most cases.

Other Protection
All food and smoking materials should be kept in a separate area away from the storage/use location. Eating, drinking and smoking should be prohibited in areas where there is a potential for significant exposure to this material. Before eating, drinking or smoking, hands and face should be thoroughly washed.

Eye wash fountains, or other means of washing the eyes with a gentle flow of cool to tepid tap water, should be readily available in all areas where this material is handled or stored. Water should be supplied through insulated and heat-traced lines to prevent freeze-ups in cold weather.

APPLICABLE EXPOSURE LIMITS
In addition to any exposure limits displayed in Section 8, exposures to this product should be controlled below limits established for "Particulates Not Otherwise Classified (PNOC):"
10 mg/m3 - ACGIH
15 mg/m3 (total dust); 5 mg/m3 (respirable fraction) - OSHA

EXPOSURE LIMITS/REGULATORY INFORMATION
(IN MG/M3)

SUBSTANCE DESCRIPTION	REG. AGCY	PEL	TLV	TWA	STEL	CEL

SECTION 8. EXPOSURE CONTROLS/PERSONAL PROTECTION (CONTINUED)

Tetrasodium EDTA	OSHA	N/D	N/D	N/D	N/D	N/D
	ACGIH	N/D	N/D	N/D	N/D	N/D
	NIOSH	N/D	N/D	N/D	N/D	N/D
	SUPPLIER	N/D	N/D	N/D	N/D	N/D
Water	OSHA	N/D	N/D	N/D	N/D	N/D
	ACGIH	N/D	N/D	N/D	N/D	N/D
	NIOSH	N/D	N/D	N/D	N/D	N/D
	SUPPLIER	N/D	N/D	N/D	N/D	N/D
Nitrilotriacetic acid	OSHA	N/D	N/D	N/D	N/D	N/D
	ACGIH	N/D	N/D	N/D	N/D	N/D
	NIOSH	N/D	N/D	N/D	N/D	N/D
	SUPPLIER	N/D	N/D	N/D	N/D	N/D

LEGEND:

EXPOSURE LIMIT DESCRIPTIONS

- CEIL Ceiling Exposure Limit
- PEL Permissible Exposure Limit
- STEL Short Term Exposure Limit
- TLV Threshold Limit Value
- TWA Time Weighted Average
- N/D = Not Determined

SECTION 9. PHYSICAL AND CHEMICAL PROPERTIES

VAPOR PRESSURE (mm Hg)
N/D

VAPOR DENSITY (Air = 1.0)
N/D

EVAPORATION RATE
N/D

VOLATILE %
N/D

BOILING POINT
N/D F N/D C

ODOR THRESHOLD (ppm)
N/D

SPECIFIC GRAVITY
N/D

BULK DENSITY
AP - 650 kg/m3

SOLUBILITY IN WATER
- 1100 g/l (20C), 1500 g/l (80C) N/D

SOLUBILITY IN OTHER SOLVENTS

COEFFICIENT OF OIL/WATER
N/D

POUR POINT
N/D F N/D C

MELTING POINT
N/D F N/D C

pH FACTOR
AP - 11 (1% solution)

CLOUD POINT
N/D F N/D C

FLASH POINT
N/D F N/D C

FLASH METHOD
N/D

UPPER EXPLOSION LIMIT
NA

Akzo Nobel Chemicals Inc.

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SECTION 9. PHYSICAL AND CHEMICAL PROPERTIES (CONTINUED)

LOWER EXPLOSION LIMIT
NA

AUTO IGNITION TEMPERATURE
N/D F N/D C

Other
None.

SECTION 10. STABILITY AND REACTIVITY

Stability
Decomposition temperature: >200C

Incompatibilities
Avoid contact with aluminium, nickel, zinc, copper, and copper alloys

Polymerization
Hazardous polymerization is not expected to occur.

Decomposition
Decomposition products are carbon dioxide, carbon monoxide and nitrogen oxides.

Conditions to Avoid
Contact with strong oxidizers should be avoided.

SECTION 11. TOXICOLOGICAL INFORMATION

Toxicological - Inhalation
Inhalation toxicity data are not available for this product.

Inhalation Chronic Exposure
Chronic inhalation exposure effects for this product are not known. (see Section 5 "Note to Physician" for additional information).

Toxicological - Dermal
Dermal toxicity data are not available for this product.

Skin Contact - CHRONIC
Chronic dermal exposure effects for this product are not known.

Toxicological - Eye
This product is a mild irritant to the eyes.

Toxicological - Ingestion
The oral LD50 for this material is > 2000 mg/kg in rats.

Ingestion - CHRONIC
Chronic ingestion of NTA has been shown to cause kidney toxicity.

CARCINOGENICITY/MUTAGENICITY
Nitrilotriacetic acid (NTA) and its salts were determined to be "possibly carcinogenic to humans" (Group 2B), by the International Agency for Research on Cancer (IARC) and a compound which "may resonably be anticipated to be a carcinogen" by the National Toxicology Program (NTP).

REPRODUCTIVE EFFECTS
EDTA and its sodium salts have been reported, in some studies, to cause birth defects in laboratory animals only at exaggerated doses that were toxic to the mother. These effects are likely associated with zinc deficiency due to chelation. Exposures having no effect on the mother should have no effect on the fetus.

Akzo Nobel Chemicals Inc.

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Dissolvine NA-X

SECTION 11. TOXICOLOGICAL INFORMATION (CONTINUED)

NTA is not teratogenic and did not induce reproductive toxicity.

NEUROTOXICITY
The neurotoxic effects of this product are not known.

Other Toxicological Effects
No other toxic effects for this product are known.

Target Organs
The kidney and bladder appear to be target organs.

SECTION 12. ECOLOGICAL INFORMATION

ECOTOXICOLOGICAL INFORMATION
24h-EC50, Daphnia magna: 1033 mg/l (Lit.)

DISTRIBUTION
Other ecological information on this product is not known.

CHEMICAL FATE
This product is not readily biodegradable.

SECTION 13. DISPOSAL CONSIDERATIONS

Waste Disposal
Dispose of waste in accord with local, state, and federal regulations. (NOTE: State and local regulations may be more stringent than federal regulations.)

CONTAINER DISPOSAL
Containers should be cleaned of residual product before disposal. Empty containers should be disposed of in accordance with all applicable laws and regulations.

SECTION 14. TRANSPORT INFORMATION

SHIPPING DESCRIPTION
Not regulated as hazardous by DOT, see exception for material corrosive to aluminum 49CFR 173.154 (d).
For air, water and international shipments this product is regulated as: Corrosive solid, n.o.s. (aminocarboxylic acid),
CLASS 8, UN1759, PACKING GROUP III
DOT EMERGENCY GUIDE NO.60
TDG EMERGENCY GUIDE NO.39
(corrosive to aluminum)

REQUIRED LABELS
None required for domestic land shipment.
For air, water and international shipment, corrosive labels are required.

ENVIRON. HAZARDOUS SUBSTANCE
This product does not contain an environmentally hazardous substance per 49 CFR 172.101, Appendix.

Akzo Nobel Chemicals Inc.

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Dissolvine NA-X

SECTION 15. REGULATORY INFORMATION

Component Tetrasodium EDTA is subject to the following

Enviromental List

DSL	Domestic Substance List-Canada
TSCA	Toxic Subst. Cont. Act -listed

Component Water is subject to the following

Enviromental List

DSL	Domestic Substance List-Canada
TSCA	Toxic Subst. Cont. Act -listed

Component Nitrilotriacetic acid is subject to the following

Enviromental List

DSL	Domestic Substance List-Canada
IARC	IARC Carcinogens-Grps. 1,2A,2B
MA. LIST	Massachusetts Substance List
NJ R-T-K	New Jersey R-T-K Hazard. Sub.
PA. LIST	Penn. Hazardous Substance List
PROP 65	California Proposition 65
SARA 313	SARA Title III, Section 313
TSCA	Toxic Subst. Cont. Act -listed

OTHER REGULATORY INFORMATION
No other regulatory information is available on this product.

WHMIS HAZARD CLASS
D-2B

HAZARD RATING SOURCE
HMIS

HEALTH
1

REACTIVITY
0

FLAMMABILITY
1

OTHER

SECTION 16. OTHER INFORMATION

OTHER INFORMATION
No other information is available.

CREATED BY
Product Safety 914 674-5000

SECTION 16. OTHER INFORMATION (CONTINUED)

KEY TO ABBREVIATIONS:

EQ=EQual	LT=Less Than	GT=Greater Than
AP=APproximately	TR=TRace	ND=No Data available

MATERIAL SAFETY DATA SHEETS

M-236

WA PASTE SURFACTANT

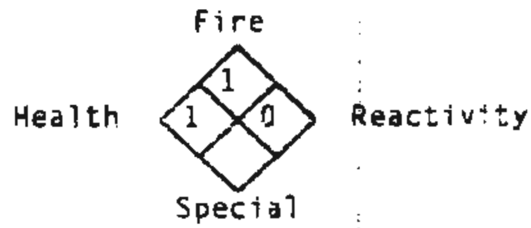
WITCO MATERIAL SAFETY DATA SHEET

Supralate WAQE

Product Code: 074 5788

CAS NO:73296-89-6

NFPA HAZARD RATING
4 - Extreme
3 - High
2 - Moderate
1 - Slight
0 - Insignificant



HMIS HAZARD INDEX		HMIS RATINGS
Hazardous	4 - Severe	Health..................1
Materials	3 - Serious	Flammability............1
Identification	2 - Moderate	Reactivity..............0
System	1 - Slight	Personal protection.....C*
	0 - Minimal	*See last page for Code Table.

DIVISION AND LOCATION---SECTION I

Division: ORGANICS
Location: HOUSTON PLANT, TX
3230 BROOKFIELD ST.,HOUSTON,TX.77045
Emergency Telephone Number: (713) 433-7281
Transportation Emergency: CHEMTREC 1-(800) 424-9300 (U.S. and Canada)

CHEMICAL AND PHYSICAL PROPERTIES---SECTION II

Chemical Name:
sodium lauryl sulfate
Formula: not applicable
Hazardous Decomposition Products:
carbon monoxide and carbon dioxide from burning.
oxides of sulfur
Incompatibility (Keep away from):
strong oxidizers such as hydrogen peroxide, bromine, and chromic acid.
Toxic and Hazardous Ingredients:
none
Form: liquid **Odor**: bland
Appearance: clear liquid **Color**: water-white to lt. amber
Specific Gravity (water=1): 1.03
Boiling Point: 100°C (212°F)
Melting Point: no data available
Solubility in Water (by weight %): soluble at 25°C
Volatile (by weight %): 69-71
Evaporation Rate: not applicable
Vapor Pressure (mm Hg at 20°C): no data available
Vapor Density (air=1): no data available
pH(10%): 7.5 to 8.5
Stability: Product is stable under normal conditions
Viscosity SUS at 100°F: greater than 100

(Continued on next page)

WITCO MATERIAL SAFETY DATA SHEET

Supralate WAQE

Product Code: 074 5788

FIRE AND EXPLOSION DATA---SECTION III

Special Fire Fighting Procedures:
Firefighters must be equipped to prevent breathing of vapors or products of combustion. Wear an approved self-contained breathing apparatus and protective clothing.

Unusual Fire and Explosion Hazards:
none

Flashpoint: (Method Used) Pensky-Martens closed-cup greater than 200°F

Flammable limits %: not applicable

Extinguishing agents:
Drychemical or Waterspray or Waterfog or CO_2 or Foam or Sand/Earth

HEALTH HAZARD DATA---SECTION IV

Permissible concentrations (air):
not applicable

Chronic effects of overexposure:
no data available

Acute toxicological properties:
animal data on sodium lauryl sulfate: oral LD_{50} 1000 mg/kg (rats)
severe skin irritant and is corrosive to the eye in animals.

Emergency First Aid Procedures:

Eyes: Immediately flush with large quantities of water for at least 15 minutes and call a physician.

Skin Contact: Flush with large amounts of water for 15 minutes.

Inhalation: Remove victim to fresh air and call a physician immediately. If not breathing give mouth to mouth respiration. If breathing is difficult, give oxygen.

If Swallowed: Do NOT induce vomiting. If conscious, have victim rinse mouth, then drink large amounts of water. Never give anything by mouth to an unconscious person. Call a physician immediately.

SPECIAL PROTECTION INFORMATION---SECTION V

Ventilation Type Required (Local,mechanical,special):
mechanical

Respiratory Protection (Specify type):
not applicable

Protective Gloves:
rubber or plastic, solvent resistant

Eye Protection:
chemical safety goggles

Other Protective Equipment:
neoprene protective type apron.

(Continued on next page)

WITCO MATERIAL SAFETY DATA SHEET

HANDLING OF SPILLS OR LEAKS---SECTION VI

Procedures for Clean-Up:
Absorb with an inert material such as sand, soil or vermiculite; sweep up and dispose of in accordance with federal, state and local regulations.

Waste Disposal:
Dispose of in accordance with all applicable federal, state and local regulations.

SPECIAL PRECAUTIONS---SECTION VII

Precautions to be taken in handling and storage:
Store between 40½ F and 120½ F.

TRANSPORTATION DATA---SECTION VIII

D.O.T.: Not Regulated
Reportable Quantity: not applicable
Freight Classification: Cleaning compound
Special Transportation Notes:
none

ENVIRONMENTAL/SAFETY REGULATIONS---SECTION IX

Section 313 (Title III Superfund Amendment and Reauthorization Act):
This product does not contain any chemical subject to the reporting requirements of Section 313 of Title III of the Superfund Amendments and Reauthorization Act of 1986 and 40 CFR Part 372.

COMMENTS

PENNSYLVANIA WORKER AND COMMUNITY RIGHT TO KNOW ACT: This product does not contain any ingredient(s) listed in Appendix A Hazardous Substance List.
This product contains the following ingredients at 3% concentration or greater:
sulfuric acid, mono-C12-16-alkyl esters, sodium salts 73296-89-6
water 7732-18-5

(Continued on next page)

WITCO MATERIAL SAFETY DATA SHEET

Supralate WAQE

Product Code: 074 5788

(COMMENTS continued)

Prepared by: Charles Green
Title: Divisional Manager - Government Regs
Original Date: **Sent to**:
Revision Date: 07/06/94
Supersedes: 03/21/91
Date Sent:

We believe the statements, technical information and recommendations contained herein are reliable, but they are given without warranty or guarantee of any kind, express or implied, and we assume no responsibility for any loss, damage, or expense, direct or consequential, arising out of their use.

LETTER DESIGNATIONS OF PERSONAL PROTECTIVE EQUIPMENT	
Safety Glasses	A
Safety Glasses, Gloves	B
Safety Glasses, Gloves, Synthetic Apron	C
Face Shield, Gloves, Synthetic Apron	D
Safety Glasses, Gloves, Dust Respirator	E
Safety Glasses, Gloves, Synthetic Apron, Dust Respirator	F
Safety Glasses, Gloves, Vapor Respirator	G
Splash Goggles, Gloves, Synthetic Apron, Vapor Respirator	H
Safety Glasses, Gloves, Combination Dust and Vapor Respirator	I
Splash Goggles, Gloves, Synthetic Apron, Combination Dust and Vapor Respirator	J
Airline Hood or Mask, Gloves, Full Protective Suit, Boots	K
Situations Requiring Specialized Handling	X

MATERIAL SAFETY DATA SHEETS

410-0237-000

M-237

SCALE CONTROL ADDITIVE

(NAVY PART NUMBER - 411-0237-000 M-209)

UN NO: 1760
IMDG CLASS: 8
IMDG PAGE NO: 8147
LABLE: CORROSIVE

Material Safety Data Sheet
May be used to comply with OSHA's Hazard Communication Standard, 29 CFR 1910.1200. Standard must be consulted for specific requirements.

U.S. Department of Labor
Occupational Safety and Health Administration
(Non-Mandatory Form)
Form Approved
OMB No. 1218-0072

IDENTITY (As used on label and List)
M-237, Scale Control Additive

Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that.

Section 1

Manufacturer's Name: Mechanical Equipment Company, Inc.	Emergency Telephone Number: (504) 523-7271
Address (Number, Street, City, State and ZIP Code): 861 Carondelet St.	Telephone Number for Information: (504) 523-7271
New Orleans, LA 70130	Date Prepared: September 11, 1991
	Signature of Preparer

Section II - Hazardous Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Name(s))	OSHA PEL	ACGIH TLV	Other Limits Recommended	% (optional)
Sulfite modified polycarboxylic acid	None established.			28.3%
Hydroxy Ethylidene, 1-diphosphonic acid	None established.			18.7%
Phosphorous acid	None established.			0.9%

Section III - Physical/Chemical Characteristics

Boiling Point	212-220° F	Specific Gravity (H_2O=1)	1.30
Vapor Pressure (mm Hg)	Similar to Water	Melting Point	N/A
Vapor Density (AIR=1)	Similar to Water	Evaporation Rate (Butyl Acetate=1)	Similar to Water

Solubility in Water: Completely miscible

Appearance and Odor: Yellow liquid; odorless

Section IV - Fire and Explosion Hazard Data

Flash Point (Method Used)	Flammable Limits	LEL	UEL
200° F Closed cup	Not flammable		

Extinguishing Media
Water spray, carbon dioxide, dry chemicals.

Special Fire Fighting Procedures
If exposed to vapor or products of combustion, use protective clothing & selfcontained breathing apparatus.

Unusual Fire and Explosion Hazards
After water has evaporated, solids will burn in presence of strong ignition source.
Thermal decomposition products are CO_2, CO, phosphine SO_x, NO_x, NH_3.

Section V - Reactivity Data

Stability	Unstable		Conditions to Avoid N/A
	Stable	X	

Incompatibility (Materials to Avoid) Corrosive to ferrous metals, aluminum and copper

Hazardous Decomposition or Byproducts

Hazardous Polymerization	May Occur		Conditions to Avoid Fire - strong ignition source
	Will Not Occur	X	

Section VI - Health Hazard Data

Route(s) of Entry: Inhalation? X Skin? X Ingestion? X

Health Hazards (Acute and Chronic)

Skin - Practically non-toxic: Inhalation - may cause irritation; Ingestion - Slightly toxic; Eyes - may be corrosive

Carcinogenicity: N/A NTP? IARC Monographs? OSHA Regulated?

Signs and Symptoms of Exposure Skin: Mild irritation: Eyes: Corrosive Irritant; Inhalation: may cause irritation; Ingestion: Possible slight irritation.

Medical Conditions Generally Aggravated by Exposure Skin and lung disease.

Emergency and First Aid Procedures Ingestion: DO NOT INDUCE VOMITING. Immediately drink large amounts of water, call physician. Skin & Eyes: flush with large amounts of water: Eyes-call physician. Inhalation: exposure to uncontaminated air.

Section VII - Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled

Absorb with inert material, and wash area with water & scrub to remove residue.

Waste Disposal Method

Disposal must be in accordance with applicable government regulations.

Precautions to Be Taken in Handling and Storing

Avoid spills & splashes; Store in dry area and avoid excessive temperatures.

Other Precautions

Avoid repeated or continuous skin contact, eye contact, breathing vapor or mist.

Section VIII - Control Measures

Respiratory Protection (Specify Type) Use NIOSH/MSHA approved respiratory equipment when airborne exposure is likely (confined space & no exhaust).

Ventilation	Local Exhaust YES if used in confined space.	Special	N/A
	Mechanical (General) N/A	Other	N/A
Protective Gloves	Rubber Gloves	Eye Protection	Goggles or full face shield

Other Protective Clothing or Equipment Rubber apron (optional)

Work/Hygienic Practices Wash hands & protective equipment promptly after use & flush spills. Practice good general hygiene.

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MATERIAL SAFETY DATA SHEET

410-0239-000

M239

CALCITE

9

Section V — Reactivity Data

Stability			Conditions to Avoid
	Unstable		None
	Stable	X	

Incompatibility (Materials to Avoid) N.A.

Hazardous Decomposition or Byproducts No appreciable decomposition

Hazardous Polymerization			Conditions to Avoid
	May Occur		
	Will Not Occur	X	None

Section VI — Health Hazard Data

Route(s) of Entry: Inhalation? Skin? Ingestion?

Health Hazards (Acute and Chronic)

Carcinogenicity: NTP? IARC Monographs? OSHA Regulated?

Signs and Symptoms of Exposure Nuisance particulate

Medical Conditions Generally Aggravated by Exposure

Emergency and First Aid Procedures N A

Section VII — Precautions for Safe Handling and Use

Steps to Be Taken in Case Material Is Released or Spilled

None - Good housekeeping practices recommended.

Waste Disposal Method Bury in landfill

Precautions to Be Taken in Handling and Storing -None

Other Precautions

None

Section VIII — Control Measures

Respiratory Protection (Specify Type)

If excessive dustiness, wear NIOSH/MSHA approved respirator.

Ventilation	Local Exhaust: Preferable	Special: None
	Mechanical (General): Acceptable	Other: None

Protective Gloves Not required | Eye Protection Safety glasses or goggl

Other Protective Clothing or Equipment None

Work/Hygienic Practices

4100239000 CALCITE

Material Safety Data Sheet
May be used to comply with OSHA's Hazard Communication Standard, 29 CFR 1910.1200. Standard must be consulted for specific requirements.

U.S. Department of Labor
Occupational Safety and Health Administration
(Non-Mandatory Form)
Form Approved
OMB No. 1218-0072

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IDENTITY (As Used on Label and List) Calcite

Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that.

Section I

Manufacturer's Name [illegible]	Emergency Telephone Number (808) 846-5481
Clark Corporation	Telephone Number for Information (808) 281-3010
Address (Number, Street, City, State, and ZIP Code) 4400 [illegible] Lane	Date Prepared 8/8/87
[illegible], WI [illegible]-0800	Signature of Preparer (optional)

Section II — Hazardous Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Name(s))	OSHA PEL	ACGIH TLV	Other Limits Recommended	% (optional)
Calcium/Magnesium Carbonate/				
Calcium Carbonate				
Marble, Limestone, Dolomite				
$CaCO_3$, $CaCO_3.MgCO_3$				
		30 Mppcf:		
		10 Mg/m^3		
		(Respirable Dust)		

Section III — Physical/Chemical Characteristics

Boiling Point	N.A.	Specific Gravity (H_2O = 1)	2.71
Vapor Pressure (mm Hg.)	N.A.	Melting Point	N.A.
Vapor Density (AIR = 1)	N.A.	Evaporation Rate (Butyl Acetate = 1)	N.A.

Solubility in Water N.A.

Appearance and Odor Fine, white powder, mild, no odor

Section IV — Fire and Explosion Hazard Data

Flash Point (Method Used)	N.A.	Flammable Limits	N.A.	LEL	UEL

Extinguishing Media N.A.

Special Fire Fighting Procedures N.A.

Unusual Fire and Explosion Hazards N.A.

(Reproduce locally)

MATERIAL SAFETY DATA SHEET

SODIUM METABISULFITE

Material Safety Data Sheet

Product Name SODIUM METABISULFITE

ItemCode 0

Manufacturer ALLIED CORPORATION

BPXA MSDS No 3868

ALLIED

SODIUM METABISULFITE

PRODUCT SAFETY DATA SHEET

A. GENERAL INFORMATION

TRADE NAME (COMMON NAME)	X	C.A.S. NO.	ALLIED PRODUCT CODE
SODIUM METABISULFITE (anhydrous sodium bisulfite, ABS, sodium pyrosulfite)		7681-57-4	

CHEMICAL NAME AND/OR SYNONYM
Sodium Metabisulfite

FORMULA	MOLECULAR WEIGHT
$Na_2S_2O_5$	190.11

ADDRESS (No.,STREET,CITY,STATE AND ZIP CODE)
ALLIED CORPORATION
CHEMICAL SECTOR
P.O. Box 1139R
Morristown, N.J. 07960

CONTACT	PHONE NUMBER	PERVIOUS ISSUE
Director, Product Safety	(201) 455-4157	June, 1982

CURRENT ISSUE DATE
May, 1985

B. FIRST AID MEASURES

EMERGENCY PHONE NUMBER
(201) 455-2000

Eyes: Immediately flush with plenty of water, for at least 15 minutes. Get medical attention.
Skin: Promptly flush wit plenty of soap and water.
Inhalation: Promptly remove to fresh air. Get medical assistance for irritation or any other symptoms.
Ingestion: If conscious, give plenty of water or milk. Induce vomiting by touching finger to back of throat. Get medical attention.

C. HAZARDS INFORMATION
HEALTH
INHALATION
Inhalation of dust or mist may irritate respiratory tract.

INGESTION
May irritate gastrointestinal tract. Very large doses cause violent colic, diarrhea, depression, and death. -Reference (b).
May cause severe allergic reaction in some asthmatics.

Material Safety Data Sheet	Product Name	SODIUM METABISULFITE
	ItemCode	0
Manufacturer: ALLIED CORPORATION	BPXA MSDS No	3868

SKIN
Repeated or prolonged contact with dust may cause irritation.
Contact with solution will irritate. See pH, Section F.

EYES
Dust or mist contact may irritate or burn eyes.
Solution contact may irritate or burn eyes.

PERMISSIBLE CONCENTRATION: AIR (SEE SECTION J) — BIOLOGICAL

AIR	BIOLOGICAL
TLV: 5 mg/cu.m.	None

UNUSUAL CHRONIC TOXICITY
None known.

CC124-219 (11/84) ND=NOT DETERMINED

FIRE AND EXPLOSION

FLASH POINT DEG. C	AUTO IGNITION DEG. C TEMPERATURE	FLAMMABLE LIMITS IN AIR TEMPERATURE(% BY VOL.)
Not flammable	N.A.	LOWER - N.A
OPEN CUP CLOSED CUP		UPPER -

UNUSUAL FIRE AND EXPLOSION HAZARDS
See Hazardous Decomposition Products, Section G.

D. PRECAUTIONS/PROCEDURES
FIRE EXTINGUISHING AGENTS RECOMMENDED
N.A

FIRE EXTINGUISHING AGENTS TO AVOID
N.A.

SPECIAL FIRE FIGHTING PRECAUTIONS
Wear self-contained breathing apparatus approved by NIOSH.

VENTILATION
Local Exhaust if dusty or misty condition prevails. The TLV may be exceeded without visual warning.

NORMAL HANDLING
Avoid contact with skin, eyes, clothing. Avoid breathing dust or mist.
Use normal personal hygiene and housekeeping.
Keep away from water or acids or heat.

STORAGE
Cool, dry, well-ventilated space away from acids and oxidizing agents.
(Dry to avoid tendency of this product to cake).
(Releases sulfur dioxide gas slowly at ambient temperatures-see odor,

Section F.)

SPILL OR LEAK (ALWAYS WEAR PERSONAL PROTECTIVE EQUIPMENT - SECTION E)
Promptly sweep up with minimum dusting and shovel into an empty container and close. Cautiously spray residue with plenty of water. Provide ventilation to clear sulfur dioxide fumes which will be generated as a result of water contact. (See Section I for disposal methods.)

SPECIAL:PRECAUTIONS/PROCEDURES/LABEL INSTRUCTIONS SIGNAL WORD: WARNING!
Avoid contact with acid and oxidizers.

E. PERSONAL PROTECTIVE EQUIPMENT
RESPIRATORY PROTECTION
Where required, use a NIOSH-approved respirator for dust, mist, and/or sulfur dioxide gas, as conditions indicate. Some exposures may require NIOSH-approved self-contained breathing apparatus or supplied-air respirator.

EYES AND FACE
Wear hard hat (or other head covering) and chemical safety goggles. Do not wear contact lenses.

HANDS, ARMS, AND BODY
For handling dry material, wear cotton gloves and full work-clothing, including long-sleeved shirt and trousers. When handling solutions and there is prolonged or repeated contact, wear impervious gloves, clothing, and boots.

OTHER CLOTHING AND EQUIPMENT
Eye-wash facility.

F. PHYSICAL DATA
MATERIAL IS (AT NORMAL CONDITIONS): APPEARANCE AND ODOR
LIQUID X SOLID GAS Fine, white granular product. Pungent sulfur dioxide gas odor.

BOILING POINT DEG. C SPECIFIC GRAVITY VAPOR DENSITY
Decomposes above 150 Deg. C (H2O = 1) (AIR = 1)
1.48 N.A.
MELTING POINT DEG. C

SOLUBILITY IN WATER pH VAPOR PRESSURE
(% by Weight) (mm Hg at 20 Deg. C)
(PSIG)
39% at 16 Deg. C 1% solution; pH = 4.3 N.A

EVAPORATION RATE % VOLATILES BY VOLUME
(Butyl Acetate = 1) (Ether = 1) (At 20 Deg. C)
N.A. N.A.

Material Safety Data Sheet

Product Name SODIUM METABISULFITE

ItemCode 0

Manufacturer ALLIED CORPORATION

BPXA MSDS No 3868

G. REACTIVITY DATA

STABILITY — CONDITIONS TO AVOID

UNSTABLE X STABLE — Temperatures above 150 Deg. C: cause evolution of toxic and corrosive gas (sulfur dioxide).

INCOMPATIBILITY (MATERIALS TO AVOID)

Oxidizers may cause strong exothermic reaction.
Acids: yield sulfur dioxide gas, which is toxic and corrosive.
Water: increases the natural rate of yield of sulfur dioxide gas.

HAZARDOUS DECOMPOSITION PRODUCTS

Sulfur dioxide gas: see above comments.
Sodium sulfide residue formed at high temperatures or under reducing conditions. This is an explosive hazard and strongly alkaline in contact with water.

HAZARDOUS POLYMERIZATION — CONDITIONS TO AVOID

MAY OCCUR X WILL NOT OCCUR — N.A

H. HAZARDOUS INGREDIENTS (Mixtures Only)

MATERIAL OR COMPONENT/C.A.S. # WT.% HAZARD DATA (SEE SECT. J)

N.A.

DEGRADABILITY/AQUATIC TOXICITY — OCTANOL/WATER PARTITION COEFFICIENT

N.D.

Aquatic toxicity:

120 ppm/24, 48, & 96 hr/mosquito fish/TLm/fresh water-Reference (b)
(converting bisulfite figure to metabisulfite basis)

EPA HAZARDOUS SUBSTANCE X IF SO, REPORTABLE QUANTITY: 5000 *
(CLEAN WATER ACT SECT. 311) YES NO (At Sodium Bisulfite)

40 CFR
116-117

WASTE DISPOSAL METHODS (DISPOSER MUST COMPLY WITH FEDERAL, STATE AND LOCAL DISPOSAL OR DISCHARGE LAWS)

Neutralize with alkali and flush to sewer with plenty of water if permitted by applicable disposal regulations. Good ventilation is required during neutralization because of the release of SO2 gas. Oxidation to sodium sulfate solution is required prior to disposal. This may be done by adding a slight excess of dilute hydrogen peroxide carefully and with stirring. Neutralized or oxidized waste may have to be disposed of by an approved contractor.

RCRA STATUS OF UNUSED MATERIAL IF DISCARDED

Not a "hazardous waste".

HAZARDOUS WASTE NUMBER:(IF APPLICABLE)

Material Safety Data Sheet

Product Name SODIUM METABISULFITE

ItemCode 0

Manufacturer ALLIED CORPORATION

BPXA MSDS No 3868

40 CFR
261

J. REFERENCES
PERMISSIBLE CONCENTRATION REFERENCES
(1) "Threshold Limit Values for Chemical Substances", ACGIH, 1984/85.

REGULATORY STANDARDS
D.O.T. CLASSIFICATION: ORM-B 49 CFR 173
DOT ID No.: NA 2693

FDA regulations apply to use food and NF grades (21 CFR). Food use in meats or in food recognized as a source of vitamin B1 is prohibited (21 CFR 132.3766).

GENERAL
(a) ACGIH, Documentation of the Threshold Limit Value, 4th Ed., 1981, Am. Conf. of Governmental Industrial Hygienists, Cincinnati 45202-a review for this material with 4 references.
(b) Coast Guard CHRIS system form covering Sodium Bisulfite and Metabisulfite, "SBS", October, 1978.

K. ADDITIONAL INFORMATION
This product is not for food or drug use unless material is labeled "food grade" or "NF grade," as applicable.

FILE #814

THIS PRODUCT SAFETY DATA SHEET IS OFFERED SOLELY FOR YOUR INFORMATION CONSIDERATION AND INVESTIGATION.

ALLIED CORPORATION PROVIDES NO WARRANTIES EITHER EXPRESS OR IMPLIED AND ASSUMES NO RESPONSIBILITY FOR THE ACCURACY OR COMPLETENESS OF THE DATA CONTAINED HEREIN.

EPA UNDERGROUND INJECTION CONTROL CLASS I INDUSTRIAL WELL

BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

September 4, 1997

Northstar Project Distribution List

Final Project Description (FPD), Rev.1
Northstar Development Project
Transmittal of UIC Class 1 Disposal Well Permit Application Update
Revised August 1997

Dear Registered FPD Book Holder:

BP Exploration (Alaska) Inc. (BPXA) is enclosing this revised Underground Injection Control (UIC) application for a Class I Industrial well permit to replace the copy found in your "Northstar Development Project, Final Project Description" book. There are no substantive changes from a UIC perspective between the original application of June 1996 and this revised application. The revised application reflects the current project description, surface facilities, and project schedule being used in the Environmental Impact Statement.

This application revision also incorporates proposed changes subsequent to the June 1996 application that have been documented in written correspondence with the Environmental Protection Agency (EPA), Region 10. These changes and references to these changes within the application are summarized below:

- Injection zone usage and area-of-review: Section 3.2 describes how BPXA proposes to segregate subsurface disposal of drill mud/cuttings and relatively clean fluids. This has produced revised area-of-review criteria that is described in Section 5.0.
- Disposal well design: Section 7.0 and Appendix F have been changed to reflect discussions and correspondence with the EPA on casing design and cementing practices.
- Waste confinement during reservoir fracturing: Section 3.2.3 and Section 6.6 dealing with confinement and fracturing have been updated to reflect the information BPXA provided to the EPA in February 1997 at the Slurry Injection Technology Workshop.

This transmittal replaces the entire body of text and drawings found behind tab "EPA Underground Injection Control Class I Industrial Well." Please retain Exhibits C1 and C2 as they have not been revised and are not being reissued.

If you have any other questions, please contact me at (907) 564-5202 or Tom Barnes of my staff at (907) 564-5154.

Sincerely,

Peter T. Hanley, Permitting Supervisor
Environmental & Regulatory Affairs, Alaska

PTH/jag

Enclosure (1)
cc: see Controlled Distributions List 3 attached

Northstar Project

Final Project Description (Rev. 1) - Controlled Document Distribution

Control Number	Name	Group	Location	Control Number	Name	Group	Location
1	Tom Barnes (File)	BPXA	ANC	43	Richard Shirley	MEI	
2	Mike Skitmore	BPXA	ANC	44	Peter Gadd	CFC	Chwth, CA
3	Ian Livett	BPXA	ANC	45	George Valiuis	MMS	Hndn, VA
4	Peter Hanley	BPXA	ANC	46	Richard Pomeroy	MMS	ANC
5	Wayne Gum	BPXA	HOU	47	Jeff Walker	MMS	ANC
6	Gary Campbell	BPXA	ANC	48	Bob Brock	MMS	ANC
7	Chris Herlugson	BPXA	ANC	49	~~Ray~~ Emerson	MMS	ANC
8	Ken Gibson	BPXA	ANC	50	Scott Johnson	NMFS	JNU
9	John Conway	VCI	ANC	51	Steve Zimmerman	NMFS	JNU
10	Pat Egger	HCC	ANC	52	Cindy Bailey	BPXA	ANC
11	Dave Thomas	AIC	ANC	53	Anthony Braden	SPCO	ANC
12	Terry Carpenter	COE	ANC	54	Vic Manikian	SPCO	ANC
13	Paul Lowry	MMS	ANC	55	Dick Crosby	BPXA	ANC
14	Ted Rockwell	EPA	ANC	56	Joseph Gross	BPXA	ANC
15	Jeanne Hanson	NMFS	ANC	57	Bryan Trimm	W-C	ANC
16	Tom Lohman	NSB	ANC	58	Jon Dunham	NSB	Barrow
17	Eric Taylor	USFWS	FAI	59			
18	Gary Hayward	D & M	ANC	60			
19	Molly Birnbaum	DGC	ANC	61	Betty Haire	BPXA	ANC
20	Glenn Gray	DGC	JNU	62			
21	Bruce Webb	DNR/DOG	ANC	63			
22	Nancy Welch	DNR/DL	FAI	64			
23	Al Ott	ADFG	FAI	65			
24	Brad Fristoe	ADEC	FAI	66			
25	Jack Kerin	DNR/DMWM	FAI	67			
26	Cindi Godsey	ADEC	ANC	68			
27	Judy Kitagawa	ADEC	VAL	69			
28	Robert Watkins	ADEC	ANC	70			
29	Luke Franklin	Gateway	ANC	71			
30	Larry Foster	D & M	ANC	72			
31	Allen Gay	D & M	ANC	73			
32	Debby Vreeland	D & M	ANC	74			
33	Mike Foster	D & M	ANC	75			
34	Art LeMaster	Veco	ANC				
35	Richard Siira	BPXA	ANC				
36	Craig Heywood	Fluor Danial	ANC				
37	Richard Goff	BPXA	HOU				
38	Doug Rainwater	BPXA	ANC				
39	Jim Gilroy	BPXA	ANC				
40	Sam Foster	Intec	HOU				
41	Greg Swank	SPCO	ANC				
42	Craig Miller	VEI	ANC				

Pages changed 9/8/97 Paul

Northstar Development Project

North Slope — Alaska

Underground Injection Control Permit Application

Class I Industrial Wells

June 1996

Northstar Development Project

North Slope - Alaska

UIC Permit Application

Class I (Industrial)

(Revised)

August 1997

Prepared By:

BP Exploration (Alaska) Inc.
900 E. Benson Boulevard
P. O. Box 196612
Anchorage, Alaska 99519-6612

Class I UIC Application

Document Declaration

This Underground Injection Control (UIC) Application for a Class I Industrial well permit is submitted to the U. S. Environmental Protection Agency - Region 10 by BP Exploration (Alaska) Inc. (BPX). The proposed site is located at the Northstar oil development project, 15 miles northwest of Prudhoe Bay, on the North Slope of Alaska.

The Application has been prepared according to the U. S. Code of Federal Regulations, Title 40 - Protection of the Environment; Part 124 Subpart A which outlines procedures, Part 144 which lists general program requirements, and Part 146 that deals with specific program criteria and standards. It is formatted per instructions and guidance provided by the Region 10 office in their letter of September 14, 1994.

Official communication regarding the Application should be directed to: David A Wallace, Health, Safety, Environmental, Business Manager, BP Exploration (Alaska) Inc., P. O. Box 196612, Anchorage, Alaska 99519. Inquiries regarding clarification of facts may also be directed to Ms. Janet D. Platt or Ms. Alison D. Cooke at this office.

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J-2	EPA Letter on Aquifer Exemption

Executive Summary

In this revised Underground Injection Control (UIC) application, BP Exploration (Alaska) Inc. (BPX) requests approval to drill up to two Class I (Industrial) waste injection wells at the proposed Northstar development project, located 250 miles north of the Arctic Circle on Alaska's North Slope. The original application, submitted in June 1996, was deemed complete by EPA Region 10 in their letter dated March 27, 1997 (EPA letter included in Appendix J). The application has been revised to reflect the current project description, surface facilities, and project schedule being used in the Environmental Impact Statement. There are no substantive changes from the UIC perspective between the original application and this revised version.

Class I injection capability will be critical to Northstar development because it is remote and isolated from other North Slope infrastructure. With no year-round connecting road, waste transport is prohibitively expensive and introduces the added potential for spills. The Class I wells are a key component of the BPX overall environmental program and goal of zero surface discharge of wastes. The concept of blending and injecting all local non-hazardous wastes is consistent with the U. S. Environmental Protection Agency's (EPA) reported national directive (July 1994)[1] to focus on the overall impact of an industry rather than focus on an individual pollutant. This operation will provide an integrated approach to managing wastes from drilling, production, maintenance operations, and the camp sewage system.

The North Slope operators have developed an innovative technique that combines mechanical grinding and deep well injection to permanently dispose of waste streams from drilling and production activities. With this technology, BPX and its partners are working towards eliminating the traditional use of reserve pits for storage or disposal of drilling wastes. The Northstar facility will use the grind and inject method to handle muds and cuttings from drilling operations, as well as the smaller volumes of oily production sediments coming from well workover-stimulation operations and vessel-pipeline cleanouts. The waste disposal system will consist of a solids grinding plant; a pipeline network that collects routinely generated and consistent wastes from the slurry plant, process vessels, and camp sewage; manifolding hookups for intermittent disposal of batch loads; and an injection facility that consists of tankage, pumps, piping, controls, and a Class I injection well (Exhibit 2-3). If project life lasts 20 years, total waste disposal will consist of 900,000 barrels of Class II drilling and production wastes,

[1]EPA Administrator Carol M. Browner's address on the "Common Sense Initiative:...A New Generation of Environmental Protection", delivered at the Center for National Policy Newsmaker Luncheon, July 20, 1994, Washington DC.

600,000 barrels of Class I camp domestic waste waters, 40,000 barrels of Class I non-hazardous industrial wastes, and 60 to 118 million barrels of produced water from the oil reservoir.

BPX requests the option to drill up to two Class I wells from the central offshore island. Permitting two wells allows for necessary operational flexibility and redundancy in the event of unexpected down-hole mechanical problems in the first well. The wells are sited in an area where all aquifers below the approximately 1500-foot-thick permafrost interval qualify for an aquifer exemption. By letter dated May 12, 1997, EPA Region 10 stated that they were prepared to process an aquifer exemption at Northstar as part of the Class I well permitting process (EPA letter included in Appendix J).

The subsurface geology is very compatible with the proposed disposal process. The injection zones (sandstone intervals) are extensive, free of any influential faulting, and interbedded with thick shales that make up the confining intervals. Similar injectate has been successfully disposed of into these storage reservoirs for many years at Prudhoe Bay in the Class I and Class II UIC programs administered by the Environmental Protection Agency and the Alaska Oil and Gas Conservation Commission respectively.

Three waivers of UIC Program requirements are requested in this permit application. These waivers are consistent with 40 CFR 144.16, which allows the Director to waive program requirements when there are no recognized USDWs to protect. Firstly, in order to inject slurred muds and cuttings, BPX requests that the EPA waive the prohibition against fracturing the injection interval as required by 40 CFR 146.13(a). While it is hard to predict definitively what a fracture system will look like, the storage domain can be bounded based on years of large-volume slurry injection of drilling mud-cuttings, and extensive tiltmeter field tests, coupled with other field and laboratory data. Fracturing of the confining zone will not occur.

Secondly, the expense to collect additional rock and fluid samples while these wells are being drilled does not appear warranted since a large volume of data already exists at the nearby Prudhoe and Kuparuk River fields. This would also be applicable to short-term formation testing on a new borehole. Therefore, a waiver is requested from the 40 CFR 146.12(e) requirements to sample and characterize formation fluids and injection matrix.

Thirdly, ambient monitoring above the confining zone will be costly and is unlikely to provide any useful information. Neither long term North Slope experience or the Northstar waste confinement assessment has identified any significant concern for breaching the confining zone. Accordingly, a waiver is requested from the stipulations of

40 CFR 146.13(b) requiring ambient monitoring in the saline aquifers above the confining zone.

BPX is committed to proper well construction and operation. Systems are in place for proper monitoring and control of all surface equipment and to guarantee mechanical well integrity. The implementation of a Class I manifesting system and a Waste Analysis Plan, patterned after the ones used for years at the Prudhoe Bay Pad-3 Class I solids storage and injection facility, will insure proper waste handling. This is further backed up by a comprehensive Spill Prevention and Control Plan, operator training program, and relief well contingency plans should they be required. With these systems in place, contamination of surface waters will not occur from deep well injection. The combination of confining beds, the confining zone, overlying siltstone layers, and the 1500 foot permafrost interval should further guarantee that the surface will not be breached.

BPX, in this application, justifies technically that Class I injection is the most environmentally sound and cost effective method for permanent disposal of wastes, and one that meets the BPX goal of zero surface discharge and minimal storage. In addition, BPX has demonstrated the corporate commitment and financial resources necessary to implement a successful Class I injection program at Northstar. This commitment is to a long-term method of disposal for total field life, including proper well abandonments and final closure.

BPX requests the EPA authorize the drilling and operation of the two Class I wells as specified in the application as soon as the EIS has been completed.

1.0 Project Description

The Northstar project area is located approximately 250 miles north of the Arctic Circle on Alaska's North Slope, as shown in Exhibits 1-1 and 1-2. Surface production facilities will be situated on an existing gravel island six miles offshore in the Beaufort Sea. The project will be developed and operated as a single business unit with co-owners sharing the costs and the production. Since the Unit encompasses both state and federal leases, the operation of the field is governed by legal agreements executed between the lessees, the State of Alaska, and the Minerals Management Service. BP Exploration (Alaska) Inc. (BPX) is the operator and as such, is responsible for securing permits. Accordingly, the official Class I well UIC permit application form is included as Exhibit 1-3.

Northstar field is an undeveloped oil accumulation approximately six miles offshore in the Beaufort Sea, northwest of the Prudhoe Bay field. It was discovered in 1983 by Shell Oil Company and is fully delineated by five exploratory wells and 2D seismic data; however, 3D seismic data is currently being analyzed which may change the subsurface picture. Surface production facilities will be situated on an existing gravel island. Development will involve anticipated high rate wells (7000+ barrels per day each) and a high quality crude oil (42° API). Production is tentatively scheduled to begin in early 2000 and reach a peak of 65,000 barrels per day. Northstar would be the first joint (State and Federal) offshore Arctic development. This operation is expected to last 15 to 20 years and generate the normal type wastes associated with oil field activities.

New technologies were needed to address the waste-handling challenges facing the oil industry on the North Slope. Working together with State of Alaska regulatory agencies, the two North Slope operators, BPX and ARCO Alaska Inc. (ARCO), have developed innovative methods for waste reduction, recycling, and environmentally sound disposal. The operators have pioneered techniques that achieve environmental standards more stringent than existing regulatory requirements. As such, an integrated approach to managing waste from drilling rig activities, production operations, and maintenance work has been developed.

An example of this approach is combining the mechanical grinding of solids with deep well injection to permanently dispose of drilling wastes. With this technology, BPX is working towards eliminating the traditional use of reserve pits for storage or disposal of drilling wastes. The Northstar facility will use the grind and inject method to handle muds and cuttings from drilling operations, as well as the smaller volumes of oily production sediments coming from well workover-stimulation operations and vessel-pipeline cleanouts. Additional information on waste management practices is included in the North Slope Waste Management booklet in Appendix A.

Exhibit 1-4 illustrates the major oil production, gas re-injection, and produced water disposal processes. Exhibit 2-3 shows the waste disposal system which will consist of a solids grinding plant; a pipeline network that collects routinely generated and compositionally consistent wastes from the slurry plant, process vessels, and camp sewage; manifolding hookups for intermittent disposal of batch loads; and an injection facility that consists of tankage, pumps, screens, controls, and a Class I injection well . If project life lasts 20 years, total waste disposal will consist of 900,000 barrels of Class II exempt drilling and production wastes, 600,000 barrels of Class I camp domestic waste waters, 40,000 barrels of Class I non-hazardous industrial wastes, and 60 to 118 million barrels of produced water from the oil reservoir.

Class I injection capability will be critical to Northstar development because it is remote and isolated from other North Slope infrastructure. The disposal system itself is a key component of the overall BPX environmental program and goal of zero surface disposal of wastes. The disposal well will be the first well drilled when drilling rig activities begin, targeted for May 1999.

In this application, BPX requests the option to drill two Class I wells from the offshore island (Exhibit 1-5). Permitting two wells allows for necessary operational flexibility and redundancy in the event of mechanical well problems; however, it is not anticipated that the second well will be needed. The wells are sited in an area where all aquifers below the 1500-foot-thick permafrost interval qualify for exemption status. The subsurface geology is very compatible with the proposed disposal process. The receiving zones (sandstones) are extensive, free of any influential faulting in the area, and interbedded with thick shale-siltstones that make up the confining intervals. Similar injectate has been successfully disposed of into these storage reservoirs for many years at Prudhoe Bay in the Class I and Class II UIC programs administered by the EPA and Alaska Oil and Gas Conservation Commission respectively.

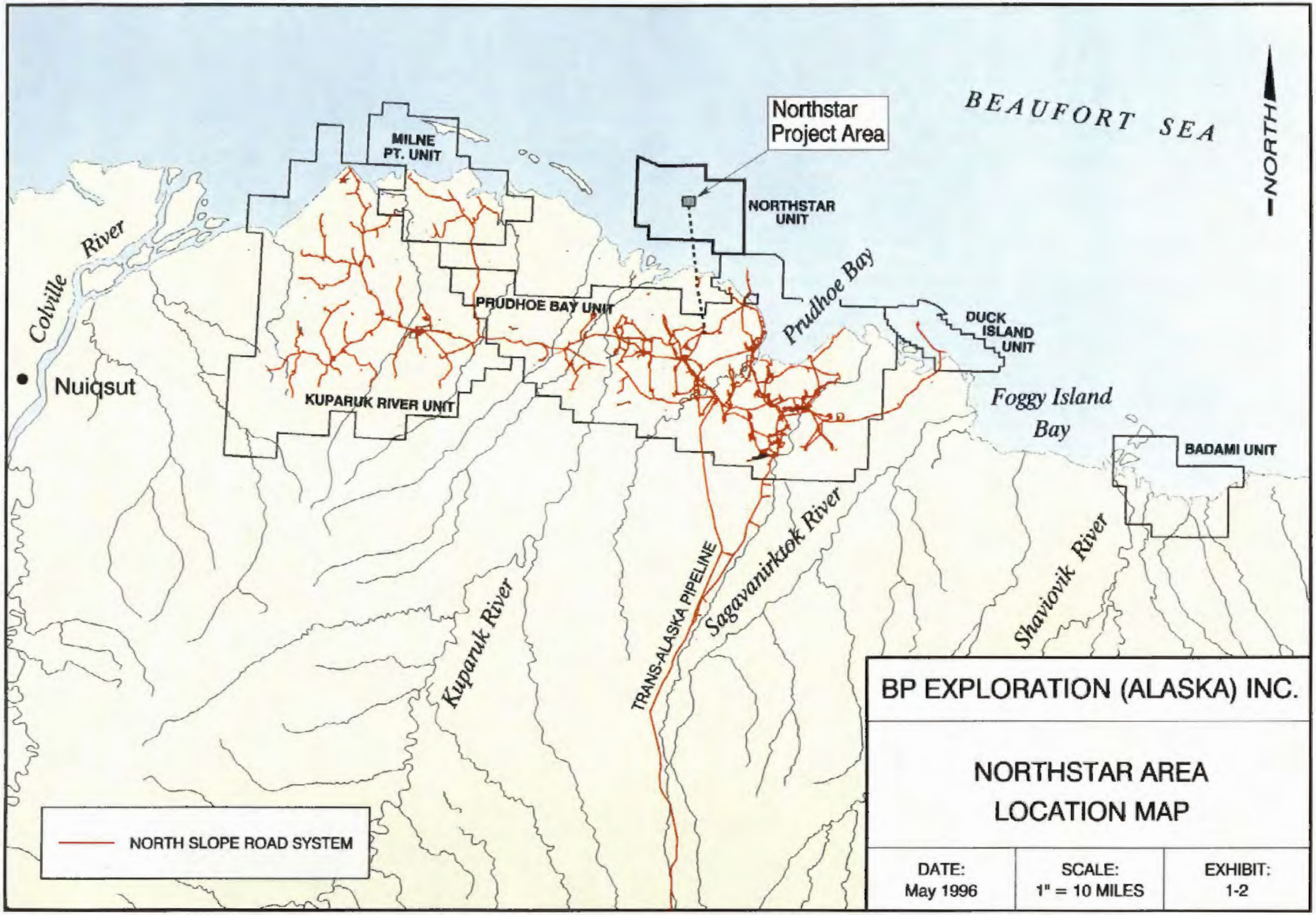
The surface distribution of oil reservoir development wells and their relationship to disposal wells WD-1 and WD-2 can be seen on Exhibit 1-6. Initially 21 development wells will be drilled which includes 7 gas injectors associated with the enhanced oil recovery process. How these wellbores affect the issue of waste confinement in the subsurface is addressed in Section 6.6 and in part in Appendix E.

An environmental analysis dealing with deep well waste confinement is addressed in Section 6.6. BPX is confident that with proper planning and monitoring, the environmental and safety risks are so low as to be virtually non-existent.

EXHIBIT 1-1

PROJECT LOCATION MAP - ALASKA

5/96 - Cartography - BS12386.dgn



BP EXPLORATION (ALASKA) INC.

NORTHSTAR AREA
LOCATION MAP

DATE:	SCALE:	EXHIBIT:
May 1996	1" = 10 MILES	1-2

bs13089.dgn

Exhibit 1-3

Form Approved. OMB No. 2040-0042. Expires 3-31-95

Form 4 UIC **EPA**

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL
PERMIT APPLICATION
(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID NUMBER

U		T/A	C

READ ATTACHED INSTRUCTIONS BEFORE STARTING
FOR OFFICIAL USE ONLY

Application approved (mo day year)	Date Received (mo day year)	Permit/Well Number	Comments

II. FACILITY NAME AND ADDRESS

Facility Name: Northstar Development Project
Street Address: Seal Island - Stefansson Sound (North Slope)
City: Deadhorse | State: AK | ZIP Code: 99734

III. OWNER/OPERATOR AND ADDRESS

Owner/Operator Name: ~~BP Exploration (Alaska) Inc.~~
Street Address: 900 E. Benson
City: Anchorage | State: AK | ZIP Code: 99508

IV. OWNERSHIP STATUS *(Mark 'x')*

☒ A. Federal ☒ B. State ☐ C. Private
☐ D. Public ☐ E. Other *(Explain)* Joint Ownership

V. SIC CODES

1311 2911

VI. WELL STATUS *(Mark 'x')*

☐ A. Operating — Date Started (mo day year): ☐ B. Modification/Conversion ☒ C. Proposed

VII. TYPE OF PERMIT REQUESTED *(Mark 'x' and specify if required)*

☒ A. Individual ☐ B. Area	Number of Existing wells	Number of Proposed wells	Name(s) of field(s) or project(s)
	-0-	2	Central Production Island - Northstar Unit

VIII. CLASS AND TYPE OF WELL *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
1	I		2 - (class 1 - Type I)

IX. LOCATION OF WELL(S) OR APPROXIMATE CENTER OF FIELD OR PROJECT

C	Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Twsp	Range	Sec	¼ Sec	Feet from	Line	Feet from	Line
I	70	29	29	148	41	46	13N	13E	11	SE	615	East	1360	South

X. INDIAN LANDS *(Mark 'x')*

☐ Yes ☒ No

XI. ATTACHMENTS

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

FOR CLASSES I, II, III (and other classes) complete and submit on separate sheet(s) Attachments A — U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application: A, B, C, D, F, H, I, J, K, L/M, O, P, Q, R, S, T, U

XII. CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

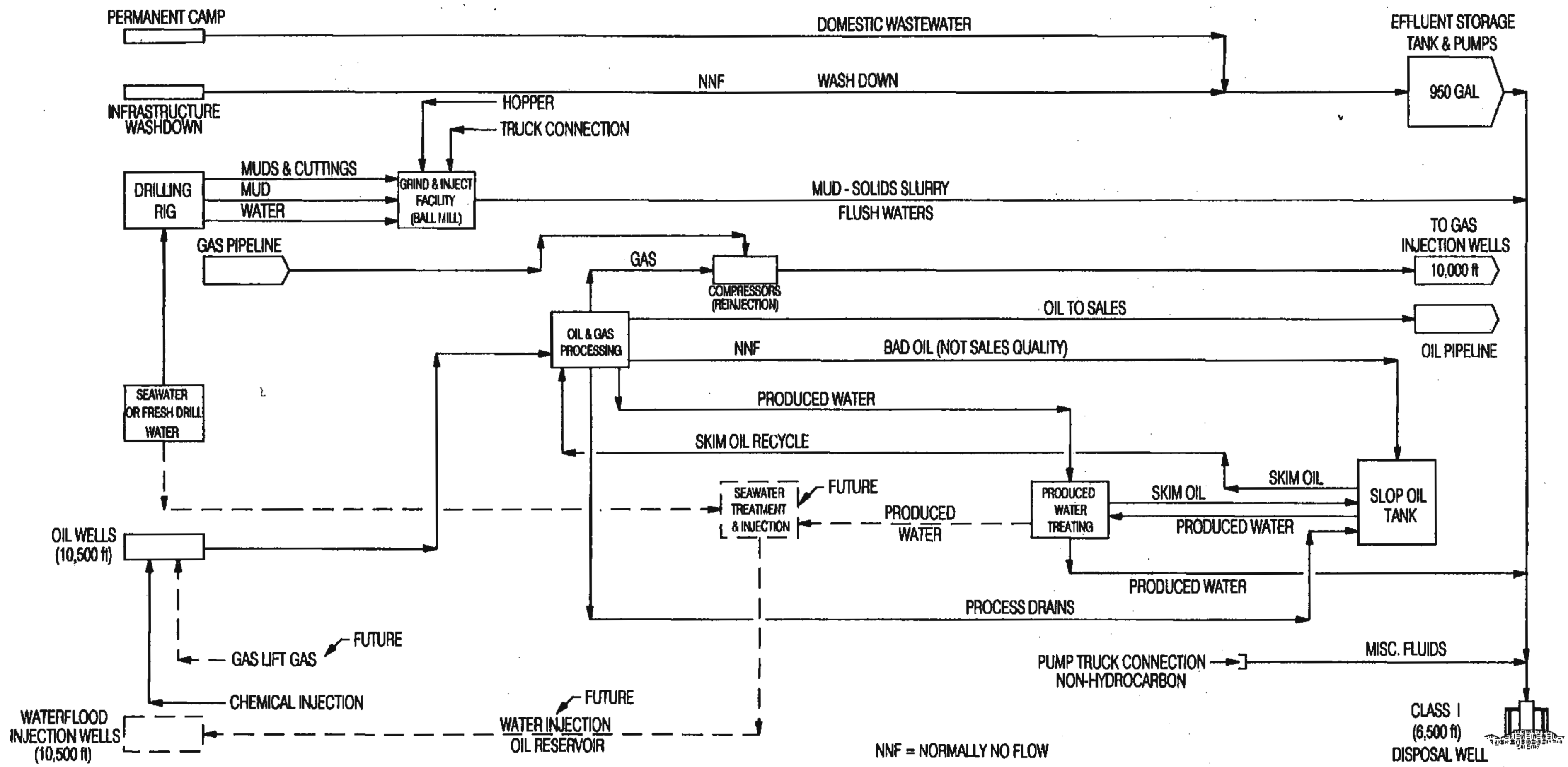
A. Name and Title *(Type or Print)*: Steven D. Taylor, Manager, Environmental & Regulatory Affairs

B. Phone No. *(Area Code and No.)*: (907) 564-4037

C. Signature: [signature]

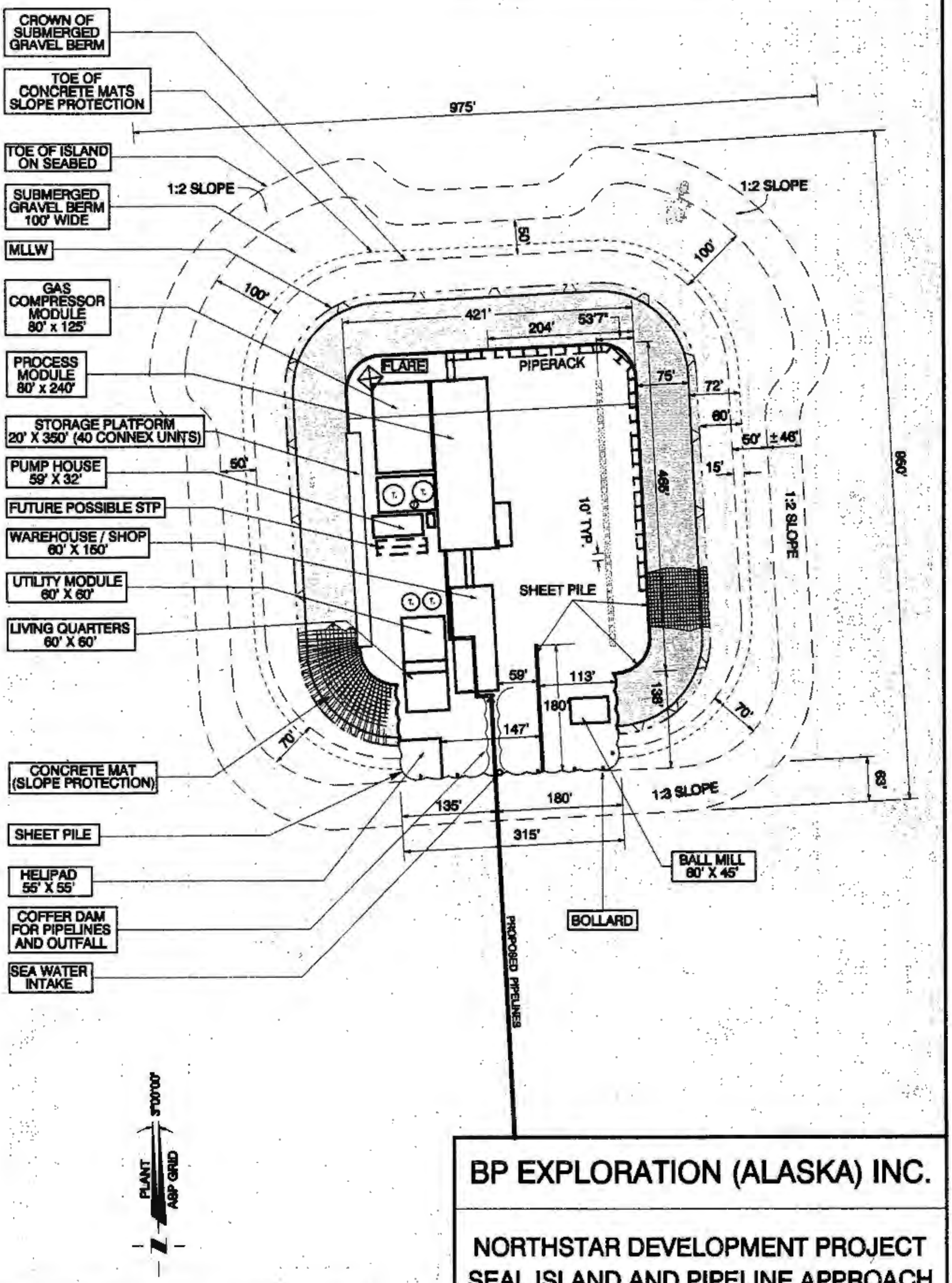
D. Date Signed: 6-24-96

EPA Form 7520-6 (2-84)



BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT BLOCK FLOW DIAGRAM ALL PROCESSES		
DATE: 8/14/97	SCALE: N/A	EXHIBIT: 1-4

nsv897.dgn



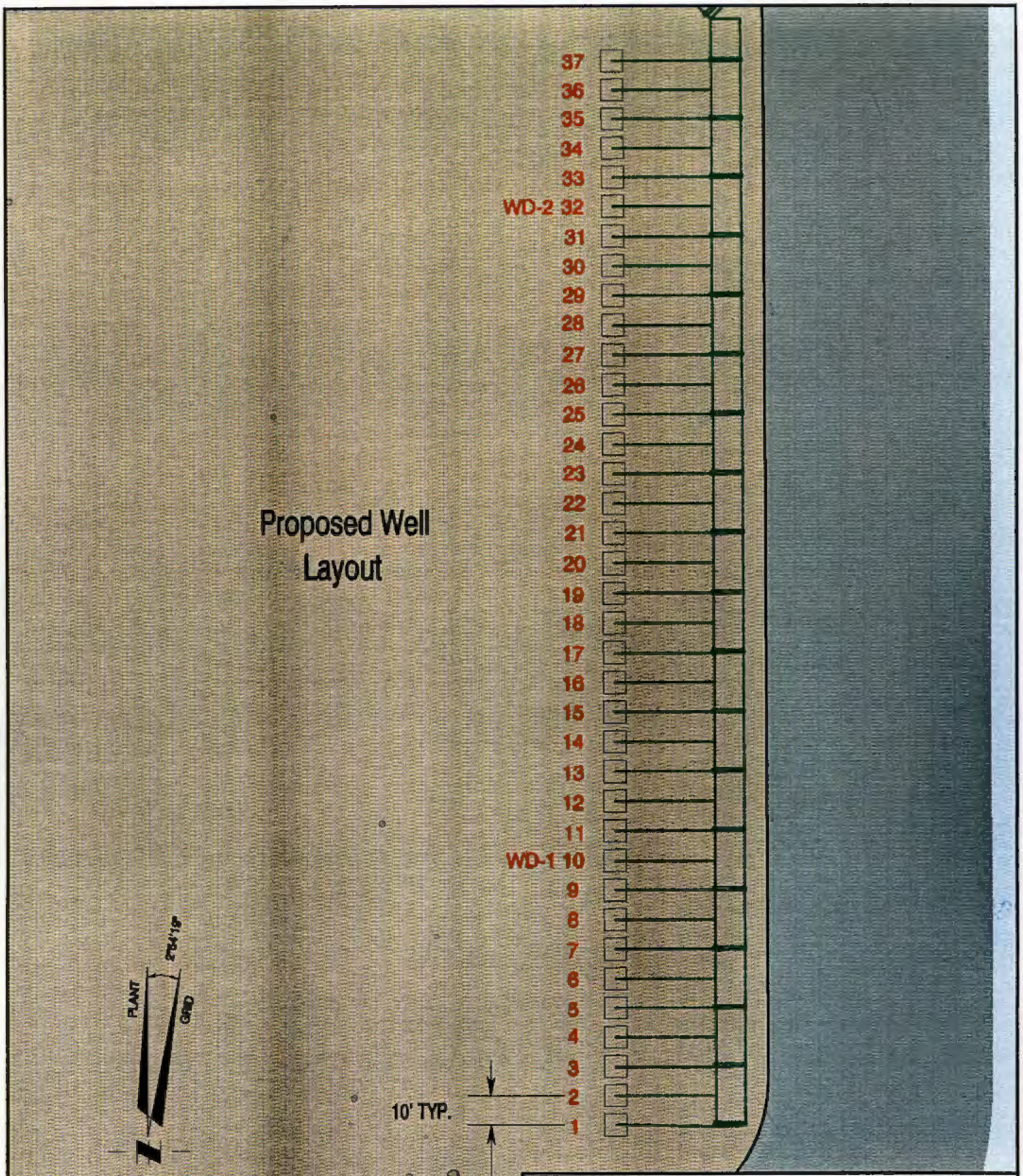
ISLAND SEABOTTOM FOOTPRINT = 18.1 ACRES
ISLAND WORKING SURFACE = 5.4 ACRES
ISLAND SURFACE ABOVE MLLW = 8.7 ACRES
ISLAND SURFACE BELOW MLLW = 9.4 ACRES

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND AND PIPELINE APPROACH
PLAN VIEW

DATE:	SCALE:	EXHIBIT:
7/22/97	NOT TO SCALE	1-5

nsv897.dgn



WD-1
EAST 659,962.78
NORTH 6,031,014.63

WD-2
EAST 659,951.26
NORTH 6,031,234.32

Coordinates are ASP4
NAD 1927

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
WELL SURFACE LOCATIONS

DATE:	SCALE:	EXHIBIT:
8/28/97	1" = 60'	1 - 6

bs13106.dgn

2.0 Waste Sources and Characteristics
and
Alternative Handling and Disposal Assessment

2.1 North Slope Oil Field Wastes

2.1.1 Types of Wastes

Exploring for and producing oil and natural gas are industrial operations which unavoidably generate some waste. However, the vast majority of these wastes are not hazardous. These non-hazardous wastes include drilling muds and cuttings, produced water not usable for enhanced oil recovery (EOR), and a class of waste termed "other associated waste."

Drilling muds are usually water-based mixtures of clays and weighting materials with small amounts of various additives. (Occasionally, an oil-based mud is used in special drilling applications such as highly deviated wells.) Muds serve to lubricate the drill bit, remove the cuttings from the well bore, and control the pressures in the underground formations. Cuttings are rock fragments removed from the well bore by the mud system.

Produced water that comes to the surface mixed with the oil and gas must be separated before the oil can be sent to the Trans-Alaska Pipeline. The majority of produced water handled each day is treated and then reinjected into the oil reservoir; a process that helps recover additional oil. The U.S. Environmental Protection Agency does not consider produced water that is recycled in this way to be a waste. At Northstar, produced water will not be returned to the oil reservoir unless experience shows that the EOR recovery mechanism will result in increased efficiency from its usage.

Other associated wastes specifically includes waste materials intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil and natural gas. "Intrinsically derived from primary field operations" is intended to distinguish exploration, development, and production wastes from wastes derived from transportation and manufacturing. With respect to crude oil, primary field operations include activities occurring at or near the wellhead and before the point where the oil is transferred from an individual field facility or a centrally located facility to a carrier for transport to a refinery or a refiner. It also includes the primary, secondary and tertiary production operations. Crude oil processing, such as water separation, de-emulsifying, degassing, and storage at tank batteries associated with a specific well or wells, are examples of primary field operations. In general, the exempt status of an exploration and production waste depends on how the material was used or generated as waste, not necessarily whether the material is hazardous or toxic. Some major associated wastes which are covered by the Resource Conservation and Recovery Act (RCRA) oil and gas exemption are:

- Tank bottoms and pit sludges
- Wastes from well workovers and stimulations
- Pipeline pigging wastes
- Gas dehydration wastes
- Truck/tank/cellar wastewaters
- Spill residues and contaminated soils
- Produced formation sand and hydrocarbon soils

In addition to the three major classes of exempt waste discussed above (muds/cuttings, produced water, and associated materials), oil field operations create some non-exempt wastes and a small volume of hazardous waste, typically from equipment and building maintenance. Wastes not intrinsically associated with the production of oil and gas are not exempt wastes and are regulated under Subtitle C of RCRA if they are hazardous. Finally, paper and other non-hazardous solid wastes are recycled as much as possible. When disposal is necessary, such wastes are incinerated or taken to the North Slope Borough landfill. Exhibit 2-1 is a simplified schematic illustrating sources, waste types, and disposal methods for the North Slope oil fields.

2.1.2 Overview of Current North Slope Injection Disposal Programs

Currently on the North Slope only one facility exists for injection of Class I non-hazardous industrial wastes which were not brought to the surface during production operations. The Pad-3 facility at Prudhoe Bay Field is operated by ARCO and includes three active Class I injection wells. Nine million barrels of fluid have been injected

Class I non-exempt solids, which typically result from spills of non-exempt liquids, are stored in lined pits at the pad-3 facility and in a pit at the Kuparuk River Field. Periodically these solids are thermally remediated for reuse.

Produced water from oil reservoirs is recycled for enhanced oil recovery. Approximately 85 percent is returned to them for EOR enhancement while15 percent goes to Class II disposal wells. Produced water disposal started on the North Slope in 1977 and has involved one billion barrels and 25 disposal wells located at the 12 major separation centers. There are currently 17 disposal wells in operation.

Class II solids resulting from drilling and production operations are injected at the Prudhoe Bay CC-2 Facility, or at four Class II disposal wells in the Kuparuk River field. (Over 9 million barrels have been injected.) In addition, drill cuttings and mud are pumped down well surface casing annuli in individual wells for disposal. This is occuring primarily in the Kuparuk River field.

2.2 Source and Analysis of Injection Fluids at Northstar

2.2.1 Typical Northstar Injection Stream

Exhibit 2-2 depicts the recent types and volumes of wastes disposed of by injection at the Prudhoe Bay facilities mentioned above. This profile was adjusted for differences between field development and operating schemes using the more typical Milne Point and Endicott production centers as models. The result is the following projected disposal volumes, assuming a maximum produced water disposal situation develops.

Rig muds and other liquids	360,000 Bbls
Rig drill cuttings and other solids	80,000 Bbls
Flush waters for cuttings disposal	60,000 Bbls
Camp sewage and gray water (Class I)	600,000 Bbls
Wells, process facilities, etc. waste	400,000 Bbls
Industrial non-hazardous wastes (Class I)	40,000 Bbls
Produced water (oil reservoir brine)	~118,500,000 Bbls
Total disposal volume	~120,000,000 Bbls

It is estimated that all but about 10,000 barrels will arrive at the injection facility (tanks - pumps) via pipeline from the camp, drilling rig, wells, or production complex. Most of this material will have been previously hauled to the Northstar site and inventoried, or alternately, it could have been generated on site but not piped to the disposal system because of its small volume or intermittent generation. Exhibit 2-3 shows the waste system piping network, external hookup points, and cumulative volumes moving through each collection conduit over the life of the project.

The following wastes are the major components of the injection stream. A short paragraph discusses the source and characteristics of each. They are divided into two major categories: Wastes requiring little or no grinding prior to injection and injectable wastes requiring grinding prior to injection.

2.2.2 Description of Wastes Requiring Little or no Grinding

1. Drilling Muds, Water-Based: Spent drilling muds have been used for cooling and flushing of cuttings during the drilling of wells. The muds consist of water, clay (usually bentonite), cuttings which include soil and rock fragments and small amounts of dissolved chemicals which enhance certain properties of the mud. The mud is typically dark gray in color, viscous and lacks a distinctive odor. The mud may carry a significant amount of solids. Muds are denser than water and may contain barium compounds. Spent drilling mud is used to suspend solids during the grinding and injection disposal process.

2. Drilling Muds, Oil-Based: Oil based drilling muds are used for cooling and for the flushing of cuttings during the well drilling process. Oil based mud is typically a mixture of a hydrocarbon fluid (usually mineral oil or diesel), clay or asphalt, some water, cuttings which will include soil and rock fragments and dissolved chemicals which enhance certain properties of the mud. The mud is dark gray in color, viscous and may carry a significant amount of solids. The odor is characterized by the hydrocarbon fluid. Drilling muds are denser than water and may contain significant amounts of barium compounds.

3. Workover Fluids: Workover fluids are wastes from the maintenance of a hydrocarbon production well. The fluid may contain small amounts of chemicals, crude oil and solids; however, the fluid is predominantly water. The workover fluids are about neutral in pH.

4. Stimulation Fluid: Stimulation fluids are chemical compounds which have been designed to enhance the productivity or the injectivity of a well. They are injected into producing or injection zones. The fluid is normally acidic and may contain various chemicals to enhance its properties. The fluid is usually non-viscous, low in pH and has a pale color except for the soil contaminants which will sometimes be present.

5. Clean-Up Fluids: Clean-up fluids, or washwaters, are predominantly water which has been contaminated in the process of washdown of an area, engine, etc. The fluid is normally turbid, has a moderate pH, contains some amount of hydrocarbon material and has a density very close to water.

6. Crude Oil: Contaminated crude oil is generated during spills of crude oil or as a waste from a well workover. The contaminants in the crude oil are normally water and some amounts of soil. Crude oil is basically a blend of many types of

hydrocarbons with some impurities. It is black in color, somewhat acidic, viscous and has an odor somewhat like refined motor oil. It may contain nitrogen and sulfur compounds, salts and trace metals.

7. Diesel: Diesel fuel wastes are generated from a variety of sources by workers who use diesel as a fuel, solvent, workover fluid or as a freeze prevention fluid. The diesel will normally be contaminated with small amounts of chemicals or water. It will be pale in color, fluid, near neutral in pH and have a characteristic hydrocarbon odor.

8. Condensate: These fluids can vary in composition since they are collected from drain sumps, blow case discharge, and knock-out pots. This is an effluent from normal process separation of oil, water, and gas. The specific gravity is less than 1.0 and pH is about neutral.

9. Natural Gas Liquids (NGL): Natural gas liquids are petroleum products (propane, butane, etc.) which are disposed of as wastes when they become contaminated with water, solids or some other hydrocarbon. NGL will normally be a contaminant in a waste of another classification; however, the NGL is ignitable and will usually be the waste constituent of most concern. Wastes containing NGL will not be accepted for disposal unless they are non-hazardous. NGL will be pale in color, near neutral in pH, less dense than water, fluid, have a distinctive chemical odor and will evaporate quickly.

10. Lubricating Oils and Hydraulic Fluids: Spent lubricating oils and hydraulic fluids are produced as wastes of engines and power transmission systems. They contain small amounts of metal and chemical additives to enhance their properties. Whereas some hydraulic fluids may be light in color, normally these materials will be dark in color, moderate in pH, of moderate viscosity and have a characteristic oil odor. They will be less dense than water.

11. Arctic Pack: Arctic Pack is a proprietary product which consists of diesel with some gel additives. It is used to prevent freezing of well facilities which are exposed to cold weather. It will be disposed as a result of contamination by water, soil, or hydrocarbons, or as a result of a well workover. It is pale in color, moderate in pH, fluid and has a characteristic hydrocarbon odor.

12. Solvents: Solvents typically consist of a wide range of hydrocarbon products. Spent solvents are normally contaminated with grease, solids and/or water. Solvent contaminated wastes will not be accepted for disposal unless they are

non-hazardous. The solvents often have a density less than water, have a low flash point and have distinctive hydrocarbon or chemical odors.

13. Spent Acid: Acids are used widely as cleaning fluids and in chemical reactions. Spent acids result from an acid being excess to needs, off specification, or contaminated with solids, water or some other chemical. Acids will be characterized by low pH and sometimes will have a biting odor. The acids will normally be fluid with moderate to low reactivity.

14. Caustic Fluid: Caustic fluids involve a wide range of materials which are characterized by high pH and corrosivity. These materials are normally generated by cleaning operations, as off-specification chemical compounds, or as the result of chemical combinations which are characterized as caustic because they are high in pH. These materials will be high in pH, fluid, and may have a biting odor. Color will often be pale and density will normally be greater than water.

15. Glycol: Glycol is an alcohol which is widely used in circulating fluid systems to prevent freezing. It will be disposed of when contaminated with water, hydrocarbons or solids. Glycol is pale in color, denser than water, moderate in pH, fluid and has a characteristic hydrocarbon odor.

16. Methanol: Methanol is a light alcohol which is widely used as a freeze prevention fluid. It is often used in combination with other materials, such as glycol, and will often be a contaminant in wastes of other characteristics. Because it is ignitable, it will often be the contaminant of concern in mixtures. Methanol is a pale fluid which is less dense than water, has a somewhat low pH and has a distinctive chemical odor.

17. Production Chemicals: This broad category includes chemicals used in the production or transportation of crude oil to achieve certain desirable effects. Examples are corrosion inhibitors, emulsion breakers and foam suppressants. Other production chemicals include proprietary compounds used in drilling fluids, muds and cleaning products.

18. Laboratory Waste: Laboratory waste will be similar to Production Chemicals in that it will contain various chemicals, products and contaminants in varying proportions. Normally laboratory waste will be spent and its potential for incompatibility with other wastes has already been exhausted. Laboratory

wastes will not be accepted for disposal unless they are non-hazardous. The volume will be minuscule.

19. Transformer Oil: This oil is used as a non-conducting medium in electrical power transformers and is discarded when the equipment is abandoned. It will not be accepted for disposal unless it is non-hazardous. The volume will be very small.

20. Source Water: This is subsurface water produced from the saline aquifers below the permafrost; however, its use is not planned at this time. If so, it would be used for making drilling mud and flushing the disposal well. It has a high dissolved solids content and is useful only for industrial purposes. The specific gravity is in the 1.034 range. This water is not considered a waste.

21. Miscellaneous Waters: This includes sea water, surface runoff to well cellars, snowmelt, and fresh water which is not considered as clean-up fluid. These wastes may contain small amounts of contaminates and the sea water will contain significant amounts of salt and dissolved solids. These waters will be clear in color, of moderate pH, fluid, lacking in characteristic odor and will be near or sligbtly above the density of pure laboratory water.

22. Produced Water: This is brine produced from the oil reservoir during the oil recovery process. It is separated from the oil and gas and must be disposed of or reused. It is moderate in pH and has a high dissolved solids content.

23. Boiler Blowdown Water: This is fresh water used in boilers, typically to make steam for drilling rigs. It is collected when the boiler is taken out of service for some reason. It will not be contaminated but will have some amount of cations/anion concentration reflective of the initial fresh water source. The volume will be small.

24. Domestic Waste Water: This waste stream was originally potable water used for human consumption. It comes from the kitchen, showers, lavatories, laundry, toilets, and any camp floor drains. It will have a gray turbid look and some associated odor. It typically has a suspended and dissolved solids content of less than one percent. If the raw stream is treated it is possible to concentrate and collect the solids as sludge which can be disposed of separately.

2.2.3 Description of Wastes Requiring Grinding Prior to Injection

25. Drill Cuttings: Drill cuttings are generated when the drill bit penetrates the rock formation. Drill cuttings are circulated to the surface with the drilling mud and are separated from the liquid mud with the use of a "shale shaker". Cuttings can be composed of sand, gravel, clay, shale, hydrocarbon bearing rock or other naturally occurring formation solids and are denser than water. Residual mud (water or oil base) can remain on the cuttings following the shale shaker. Water base mud is typically used to suspend cuttings during transport from the point of generation to the grinding and injection facility if it is not located adjacent to the drilling rig. Mud is also required to maintain suspension of solids during processing through the grinding and injection circuit.

26. Frac Sand: Certain well stimulations utilize proppant or "frac sand" to fill the producing formation fracture space created during a well stimulation. The stimulation objective involves keeping the frac sand in the formation fracture to increase well productivity. At the well head, "loose" frac sand can be backflowed to the surface as part of the frac job or later as part of a well clean-out. Frac sand can be transported from down hole to production facility separation vessels, where it will accumulate until removed during a vessel clean-out. In addition, small quantities of frac sand can be found in flow line pigging material. Frac sand is an inert ceramic material, and as a waste it is commonly accompanied with crude oil, fresh or sea water, formation solids, small amounts of chemicals and spent acid. Carbo-Lite is a common proppant used on the North Slope and is composed primarily of aluminum oxide and silicon oxide. As with drill cuttings, transportation to and processing of frac sand at the grinding and injection facility requires the use of mud to maintain solids in suspension.

27. Vessel Sludge/Sand: Fine solids particles from the oil producing formation, biomass, pipe scale, or frac sand can accumulate in test separators, tanks, production facility vessels, and heat exchangers. These solids are periodically removed and can be associated with crude oil, fresh or sea water, and production chemicals or solvents. The solids are denser than water, have a distinctive hydrocarbon odor, and usually assume the dark brown or black color of crude. Mud can be used to transport vessel solids to the grinding and injection facility and would be required to suspend solids during processing.

28. Contaminated Gravel: Contaminated gravel is the result of spills associated with various oil field operations. The major source of gravel contamination is

caused by fuel and crude spills; however, spills of the other injectable wastes can be the source of gravel contamination. The characteristics of the contaminated gravel will be dependent on the source and concentration of spilled material in the gravel. Gravel that is not readily treatable for reuse can be disposed of by grinding and injection. Pre-crushing of the gravel may be required before it enters the ball mill grinding process, and the addition of mud would be required to suspend the solids through the grinding process.

29. Line Pigging Material: Crude oil pipelines and produced water or sea water pipelines require pigging to remove materials which have built up on the pipe walls. Normally the pigging waste is pushed through the pipelines back to the production facilities and is deposited in facility vessels where it is later removed as vessel sludge/sand. Occasionally pigging waste will be removed directly from the pipelines at certain locations. The pigging waste composition can include crude, produced or sea water, biomass, paraffin, formation solids, frac sand, calcium scale, and iron sulfide. Pigging waste has a density greater than water, can be a thick viscous sludge, and typically has a very strong hydrocarbon or rotten egg odor.

30. Naturally Occurring Radioactive Material (NORM): NORM is a weakly radioactive natural material which sometimes forms as pipe scale or sludge in production pipelines, tubing, and separation vessels. This material has been approved for injection in Class II disposal wells in Alaska by the state agencies and the EPA. The material is below activity levels of concern by the NRC. The EPA UIC office has specifically referred to this material as "pipe scale" or "vessel sediments" which are cited in UIC regulations as material which can be injected in Class II wells. The material is typically found as barium sulfate scale with some radium 226 or 228 co-precipitating with barium to provide radiation levels of 1 to 2 millirems per hour.

31. Incinerator Ash: This is the result of burning paper, wood products, rags, etc. in an incinerator. The residue is typically gray in color. It can be disposed of by slurry injection if it tests non-hazardous.

32. Waste Water Treatment Plant sludge: This is a semi-solid material that is the residue from treating camp domestic waste water. It is grey in color and has a rotten egg odor. It can be disposed of by slurry injection.

33. Diatomaceous Earth: This is a filter media used to clean up returned sea water, brines, and produced water. When back washed or physically removed it is dark

in color and contains contaminates removed from the process stream. It has a specific gravity greater than 1.0 and should have a pH about neutral.

34. Cement and Cement Rinsate: This can be composed of many variations of the standard Portland cements. They are manufactured by combining limestone (calcium carbonate) and clay (silicon dioxide plus iron oxides) in a ratio of about 2:1. When heated, with time, one of four crystalline states can result. Other additives are used such as accelerators, retarders, fluid loss additives, etc. The specific gravity ranges from 1.3 to 2.2. The rinsate come from cleaning tanks, pumps, and associated equipment.

2.3 Alternative Handling and Disposal Options of Non-exempt Wastes

2.3.1 Class I Industrial Solids

Spills of non-exempt liquids (diesel, hydraulic oil, lube oil, glycol, unused production chemicals, etc.) on gravel roads and pads are the primary source of non-exempt solid wastes on the North Slope. Minor volumes of non-exempt solids are generated from non-exempt spills on tundra, clean out of auto shop sump solids, and other miscellaneous non-production related waste generation activities. Depending on the spill statistics for a given year, Class I solids can represent from 5 to 35 percent of the total annual solids manifested into the Prudhoe Bay Pad-3 Class I facility. In recent years, 1000 to 1500 cu. yds./year of contaminated gravel have been stockpiled at Pad-3 and undergone thermal remediation for reuse as road and pad maintenance gravel. Class I non-exempt solids which have not been thermally remediated for reuse have been placed in Pad-3 Cell 2 for temporary storage and future remediation and/or disposal.

The following discussion summarizes the various options, associated costs and potential risks for disposition of Class I Northstar solids.

Grind and Inject Non-exempt Solids at the Northstar Class I Well

The grinding facility may not be designed to receive and process bulk gravel deliveries, which are the major source of Class I solids routinely generated in oil field operations. However, smaller volumes of Class I solids (finer rock and sand) could be processed. Many of these solids contain low levels of hydrocarbon contamination and can be processed; however, highly saturated soils would probably require thermal remediation on site or at a commercial facility. For Class I solids determined to be safe for processing, the average disposal cost is projected to be less than $10 per barrel.

Experience at the Prudhoe CC-2 facility suggests that there is no environmental risk from this disposal option. The Northstar risk assessment included in Section 6.6 also determined that environmental risks were almost non-existent.

Thermal Remediation and Reuse of Non-exempt Solids

Hydrocarbon contaminated gravel has been routinely treated using thermal remediation systems. For lightly contaminated gravel, thermal treatment has successfully generated gravel suitable for reuse in road and pad maintenance at a cost of $25-30 per barrel. Hauling from Northstar to the commercial Deadhorse incinerator will increase this cost. Heavily contaminated gravel may require multiple treatments or increased residence time, both of which can substantially increase treatment costs. In some limited circumstances, reuse of treated solids could require monitoring to ensure contamination of surface water does not occur. This would result in additional cost for this option.

Experience to date suggests that there is limited environmental risk with this treatment and reuse option. However, future changes to gravel reuse criteria or air permit limits on a thermal treatment unit could limit the use of this option and/or impact the treatment costs.

Disposal of Untreated Non-exempt Solids in Lined or Unlined Pits

This technique relies on the ability of permafrost to maintain buried waste in a continually frozen state which immobilizes the waste. Disposal pit excavation and closure costs for large scale (100,000+ cu. yds) burial and capping in unlined pits is expected to be less than $10 per barrel (excluding waste excavation, loading, testing, and transportation to the burial site). Use of lined waste pits for smaller scale (15,000 cu. yds.) solid waste burial and capping is expected to cost less than $40 per barrel. Monitoring of buried waste to verify that it remains frozen is an additional cost under this option.

Past experience indicates that waste buried significantly below the active permafrost layer (the top 2-3 feet which thaws annually) will remain confined and not present an environmental risk. However, untreated wastes currently acceptable for burial in unlined pits may present a risk if future regulatory changes resulted in reclassification of the buried waste. This could potentially result in a requirement for additional monitoring or for excavating and treating the waste, followed by reburial. This would substantially increase ultimate disposal costs.

Disposal of Treated Non-exempt Solids in Unlined Pits

This option is the same as above except that wastes are treated prior to placement in unlined pits. It is unlikely that a treated waste would require use of lined pits in permafrost. However, this would depend on characteristics of the waste and the effectiveness of a given treatment technology (incineration, fixation, soil washing, etc.). Treatment costs could range from $25 to over $50 per barrel and would be in addition to the cost of burial.

The treatment burial option would minimize the risks associated with potential future changes in regulations.

2.3.2 Class I Industrial Liquids

Major sources of non-exempt liquids on the North Slope are contaminated snow melt, auto shop sumps, other non-production related sumps, and unused well stimulation fluids. Prudhoe area spills of non-exempt liquids on snow are cleaned up and stock piled for periodic melting and subsequent Class I disposal at the Prudhoe Pad-3 facility. Other fluids and minor volumes of other non-exempt liquids (film processor fluids, etc.) are disposed of directly at Pad-3. Based on past experience, the projected total volume of non-exempt liquids expected to be disposed at the Prudhoe Bay facility is over 100,000 barrels per year. The Northstar project could add an additional 40,000 barrels during its 20 year life.

The following discussion summarizes the various options, associated costs and potential risks for disposition of non-exempt Northstar liquids .

Disposal at a Northstar Class I Well

Direct operating costs for disposal of Class I liquids are expected to be in the $1 to $3 per barrel range. Based on many years of injection experience with numerous Class II disposal wells and the Prudhoe Bay Pad-3 Class I wells, there is minimal environmental risk anticipated with using Class I disposal at Northstar. The risk assessment included in Section 6.6 did not identify any potential for concern about environmental damage.

Future potential changes in regulations could result in facility modifications or changes in operating practices which could increase unit costs and/or restrict disposal activities.

Continued Use of Existing Prudhoe Pad-3 Class I Disposal Wells

Pad-3 wells are currently used for disposal of all Class I liquid wastes as well as some Class II fluids. Direct operating costs have historically ranged from $2-6 per barrel. Use of this facility is feasible; however, storage and hauling costs would probably make disposal of Northstar wastes increase to $8 per barrel or more. In addition, funding and proration of abandonment costs for the Pad-3 wells based on usage could push this cost even higher.

As previously noted, limited environmental risk is expected with continued use of the Pad-3 Class I wells. However, long distance hauling would introduce some spill risk. Future potential changes in regulations could restrict operations and increase unit disposal costs.

Recycling of Non-exempt Fluids Through Production Facilities

Since a large portion of Class I wastes consist of water containing low levels of hydrocarbons and other contaminants, it may be physically possible to treat a portion of the Class I liquid waste stream to recover hydrocarbons and create water suitable for use in a waterflood operation to augment enhance subsurface recovery of oil. The cost of this operation is expected to be significantly greater than disposal via injection and would require construction of additional facilities to store, treat, separate, filter and recover Class I liquid. Given the small volumes of potentially recoverable hydrocarbons and the high unit cost of operating a small-scale water treatment operation, this is not considered an economically viable option. Capital investments over the life of the project are estimated to be over $50 per barrel. Direct operating costs would also be incurred. In addition, unless the treatment standards are very high, there is a risk of incurring a negative production impact.

Certain Class I wastes may be suitable for treatment using existing facilities; however, the additional cost of special handling of these small volumes would not likely justify this option. Not all Class I liquid wastes would be suitable for treatment and recycling. Therefore, separate Class I facilities would still need to be maintained for disposal of these wastes. It is likely that the unit cost of Class I disposal would increase due to the total volume reduction created by shifting a portion to a different facility for recycling.

Minimal environmental risk would be expected with this option.

Treatment of Non-exempt Liquids for Surface Discharge

Since a large portion of Class I wastes consist of water containing low levels of hydrocarbons and other contaminants, it may be physically possible to treat a portion of the stream to allow surface discharge of the water. The water quality standards for surface discharge would be more stringent than those required for reuse. The cost of building and operating new treatment facilities and the required monitoring would be greater than for recycling and significantly greater than Class I injection. Therefore, this is not considered a viable option.

According to EPA pollution prevention guidelines, surface discharge is less environmentally sound than underground injection. In addition, this option does not meet the BPX goal of zero surface discharge.

2.3.3 Class I Camp Domestic Waste Waters

There are no plans to treat the domestic waste water stream and concentrate solids into a sludge effluent at the present time. However, should this occur, the sludge would have to be collected, stored, and incinerated onsite or hauled to the Prudhoe Bay area for commercial incineration. Commercial incineration would cost $13 per barrel plus hauling. There is small environmental risk to incineration; however, transportation and additional handling would introduce the possibility for spills.

The liquids from a treatment plant could either go to a Class I disposal well, the EOR waterflood system, or be discharged to the Beaufort Sea through a NPDES permit. Since it is BPX policy to eliminate surface discharges whenever possible, permanent use of a NPDES permit is not viewed as a desirable option.

Disposal at a Northstar Class I well

Since the dissolved solids content of domestic waste water is low and there is no requirement to treat the raw stream, the camp effluent can be directly injected as received at the injection facility. Direct operating costs are expected to be less than $3 per barrel. There is minimal environmental risk associated with deep well disposal.

Recycle Through the EOR Waterflood System

Camp waste waters could be filtered, deoxygenated, treated, and made suitable for inclusion in an EOR waterflood system if one existed. This is estimated to cost less than $3 per barrel; however, there are no present plans to inject water into the oil reservoir since pressure maintence by gas cycling offers a more efficent oil recovery mechanism. Therefore, this option does not really exist. No environmental risk is associated with this reuse option should it be reevaluated as beneficial to ultimate oil recovery.

Sources, Types, and Disposal Methods for North Slope Oil Field Wastes

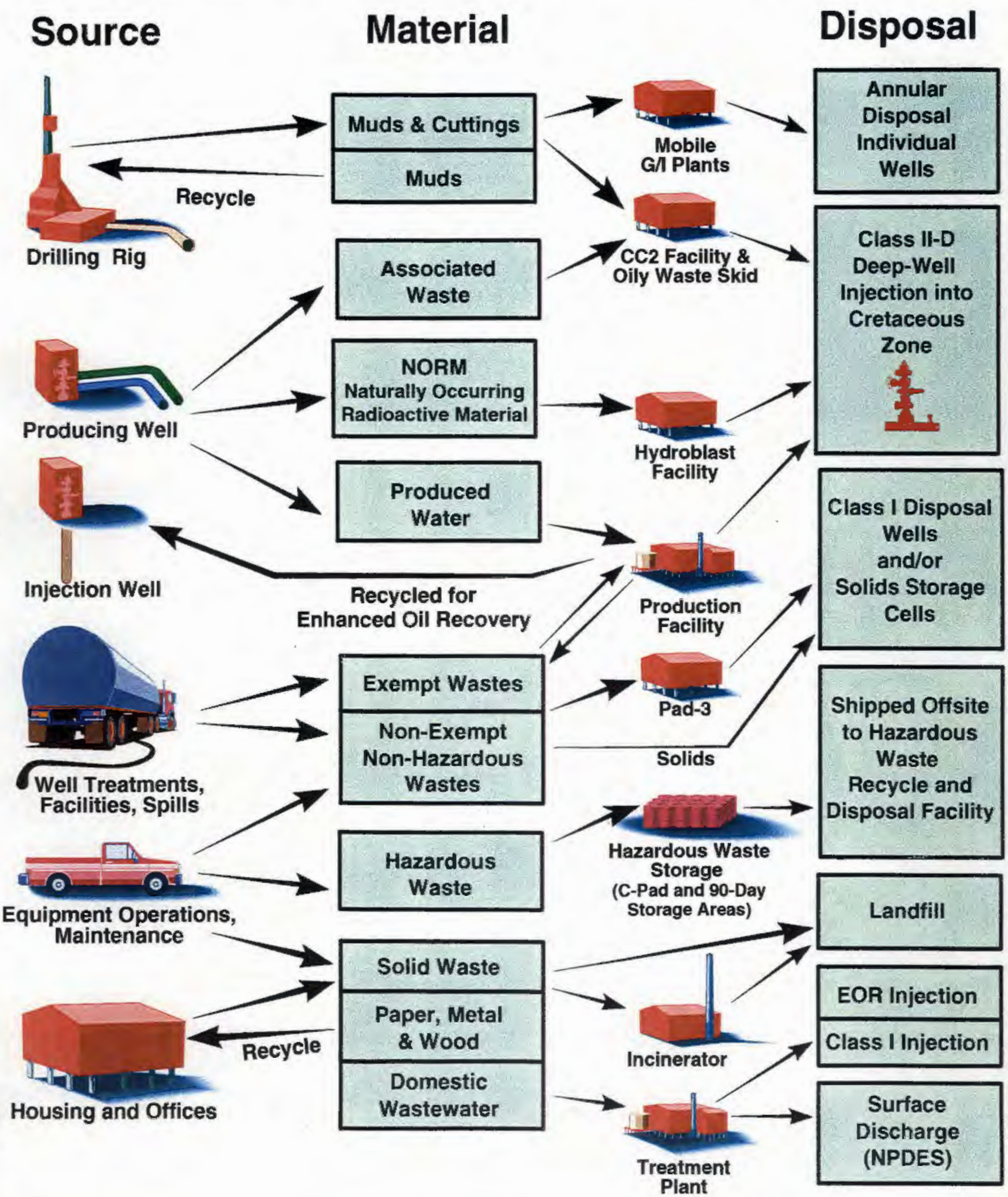
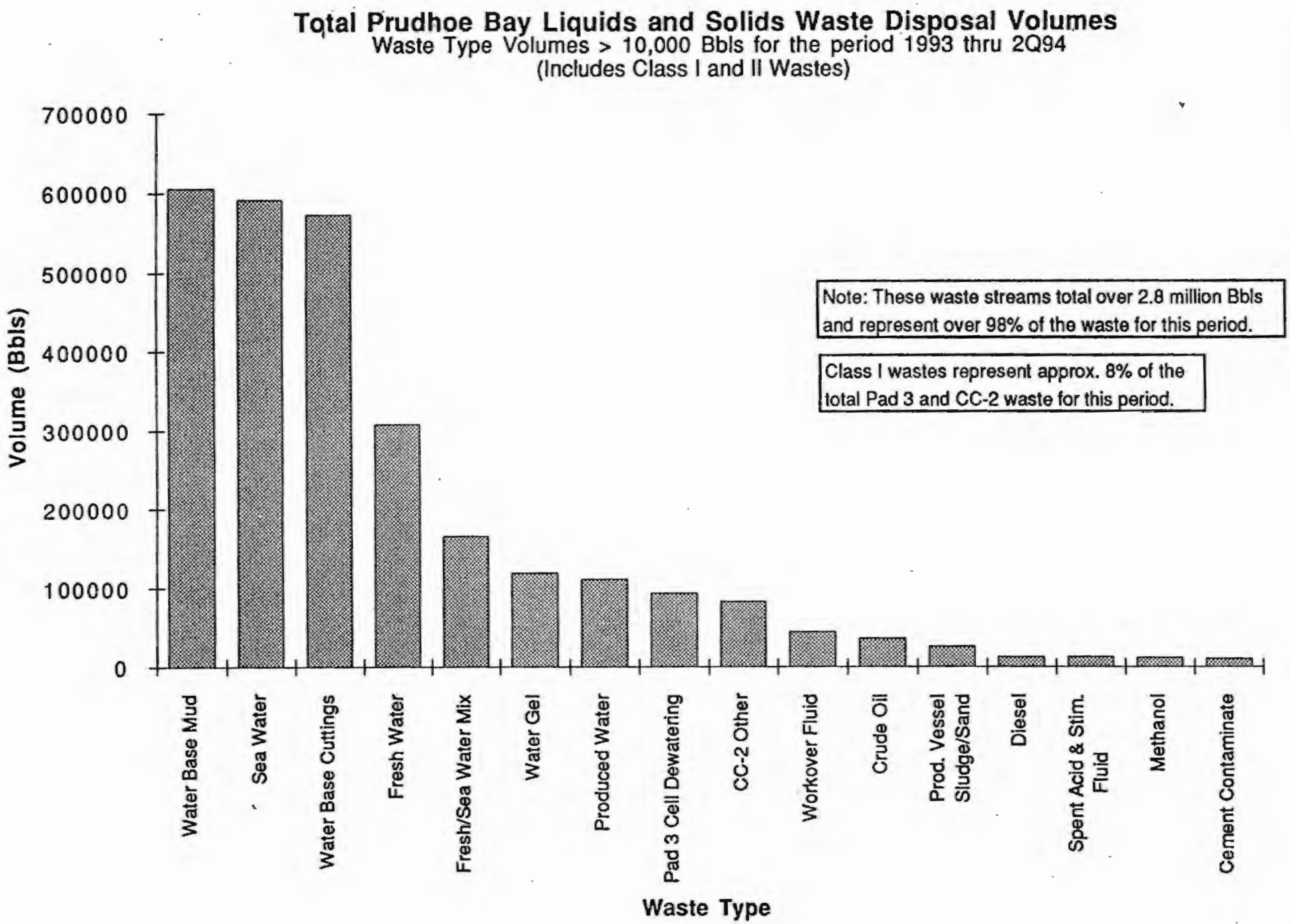
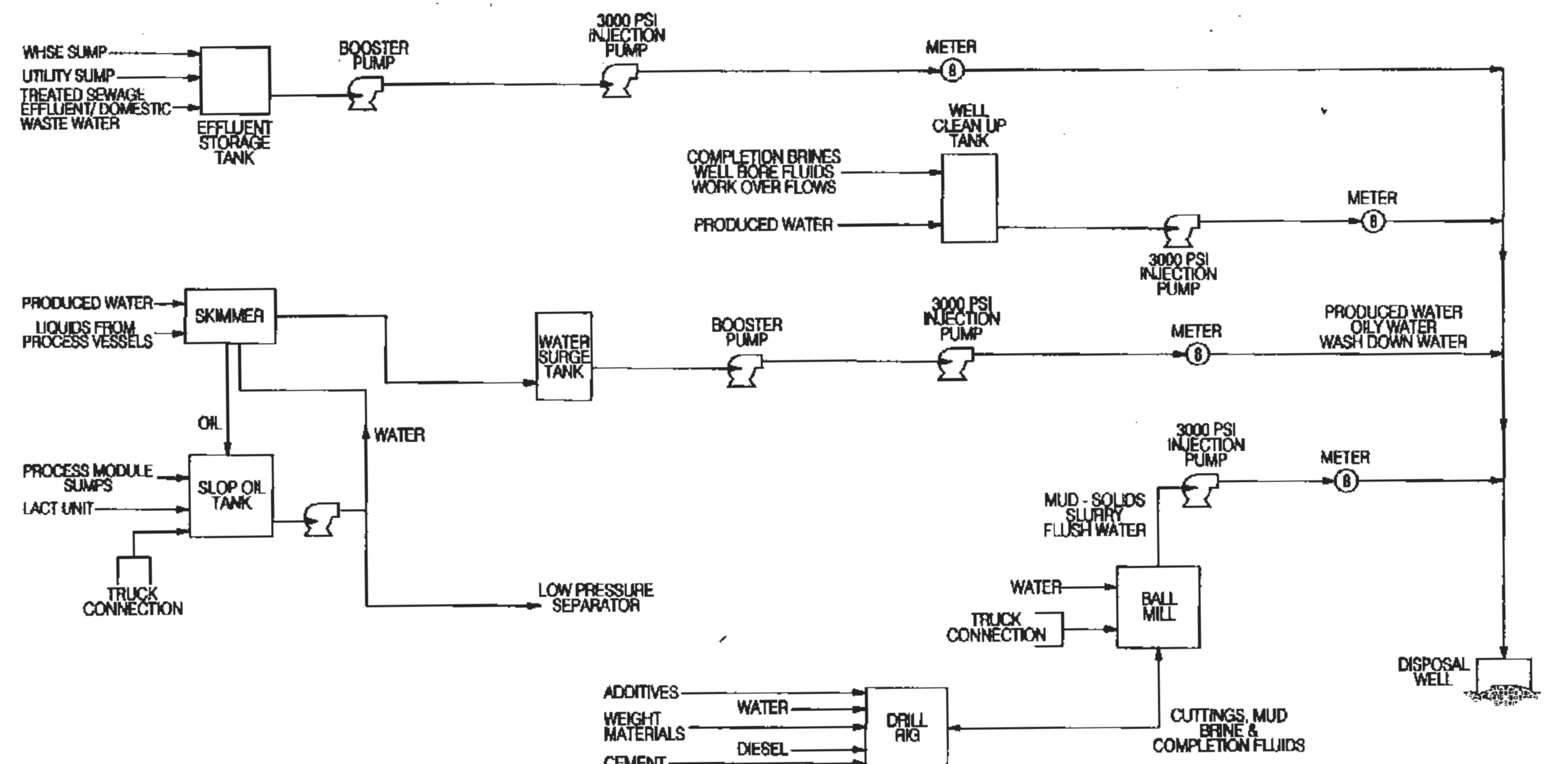


Exhibit 2-1

Exhibit 2-2


Total Prudhoe Bay Liquids and Solids Waste Disposal Volumes
Waste Type Volumes > 10,000 Bbls for the period 1993 thru 2Q94
(Includes Class I and II Wastes)
700000
600000
500000
400000
300000
200000
100000
0
Volume (Bbls)
Note: These waste streams total over 2.8 million Bbls and represent over 98% of the waste for this period.
Class I wastes represent approx. 8% of the total Pad 3 and CC-2 waste for this period.
Water Base Mud
Sea Water
Water Base Cuttings
Fresh Water
Fresh/Sea Water Mix
Water Gel
Produced Water
Pad 3 Cell Dewatering
CC-2 Other
Workover Fluid
Crude Oil
Prod. Vessel Sludge/Sand
Diesel
Spent Acid & Stim. Fluid
Methanol
Cement Contaminate
Waste Type



BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT WASTE DISPOSAL FLOW SCHEMATIC CLASS 1 INJECTION WELL		
DATE: 8/14/97	SCALE: N/A	EXHIBIT: 2-3

nsv897.dgn

3.0 Geologic Setting and Operating Characteristics

3.1 Geology

3.1.1 Deposition/Lithology/Stratigraphy

The confining and injection zones at the Northstar development project are composed of sedimentary strata of Cretaceous and Tertiary age. These strata are assigned to the Colville Mud/Seabee, Schrader Bluff/West Sak, Prince Creek/Ugnu and Sagavanirktok formations (in ascending order) based on lithologic sequence correlations to strata at the Milne Point and Prudhoe Bay Fields to the south and west. The Colville, Schrader Bluff, and Prince Creek strata comprise the final regressive marine sequence in the Middle Brookian section of Late Cretaceous to Early Tertiary time. The overlying Sagavanirktok strata comprise at least two cycles of marine transgression-regression in the Upper Brookian section of Tertiary time (Upper Eocene to Miocene). The general stratigraphic scheme and local log character are illustrated in Exhibit 3-1.

The Middle Brookian sequence shows an upward shallowing cycle starting with deep water marine shales (Colville Mud/Seabee Formation) followed by shelf shales, siltstones and very fine to fine, with occasionally coarse grained sandstone (Schrader Bluff/West Sak Formation) capped by fluvial and deltaic, fine to coarse grained, sandstone (Prince Creek/Ugnu Formation).

The Upper Brookian sequences (Sagavanirktok Formation) begin with a major shale unit which is the result of a depositional transgression that created a subsiding muddy shelf. This shale is overlain by a series of six coarsening up sequences of shales, silt and fine to very coarse sands (Exhibit 3-1). These coarsening upward sequences were deposited in a deltaic to shoreline environment. Another transgression resulted in shelf mud deposition creating a thick shale unit which is overlain by 3000 feet of largely coarse sand and gravel that resulted from the final regressive phase of the Sagavanirktok Formation. Some interpreters refer to the gravels in the shallowest part of the section as the Gubik Formation. The transition into permafrost is wholly contained within the upper coarse interval in the Northstar area. A detailed discussion of the geology, a type log, a regional cross section, and horizon maps are contained in Appendix C.

A series of geological markers have been defined from wireline log data and cutting samples. The continuity of the stratigraphic units is shown in the log cross section (Appendix C), the generalized cross section (Exhibit 3-2), and in the seismic cross section (Exhibit 3-3).

The general structure of the stratigraphic sequence is dominated by dips of 1 to 2 degrees toward the northeast and east. This is shown on the structure map of Exhibit 3-4 with the approximate locations of disposal wells WD-1 and WD-2. An expanded discussion and maps of marker horizons are contained in Appendix C. There are no significant faults apparent within this stratigraphic sequence in the Northstar development area, as indicated by the seismic cross section.

The relationship of the proposed waste injection, arresting and confining zones to the stratigraphy is shown on Exhibits 3-1 and 3-2. None of these formations outcrop in the local area. The upper confining zone is projected to intercept a 2000-foot-thick permafrost zone 10 to 15 miles southwest. The permafrost (generally 2000 feet in the onshore areas) is considered a barrier to recharge. The permafrost becomes shallower and less consistent offshore in the direction of Northstar. There is still significant permafrost present at Northstar, and the base of the permafrost is projected to be 1400-1600 feet in depth. The base-permafrost structural trend is discussed further in Appendix C.

3.1.2 Injection and Confining Zones

The proposed injection, arresting, and confining zones at Northstar are within the same formations as those successfully utilized for waste disposal and confinement at the Prudhoe Bay and Duck Island Units. In all three field areas the lower confining zone is the Seabee shale (equivalent to the Colville mudstone and the Canning Formation). The injection zones in all three areas contain the Ugnu (Prince Creek) sands and the basal sands of the Sagavanirktok. The only difference is that at Northstar, a major shale barrier between the upper and lower injection zones is somewhat better developed than at Prudhoe Bay. This shale improves the confinement between the upper and lower injection zones. The upper confining and arresting zones are also positioned in the same stratigraphic interval as seen at Prudhoe Bay, in the mud dominated unit of the Sagavanirktok formation that lies above the basal Sagavanirktok sands and below the massive surficial gravels and sands which extend upward into the permafrost.

3.1.3 Reservoir Properties

There are no hydrocarbon accumulations within the waste disposal intervals in the Northstar Unit. Extremely faint residual oil shows are present in some of the up-dip wells in the Prince Creek/Ugnu and Schrader Bluff/West Sak Formations. This is to be expected as these beds probably acted as minor migratory routes long ago for hydrocarbons that are now accumulated southwest and far up dip in the Schrader

Bluff/West Sak and Ugnu Formations above the Milne Point and Kuparuk Fields. Mud logs from the area show some methane gas below 3600 feet in the Sagavanirktok Formation. This gas is in a water wet zone, is probably locally derived by biogenic activity, and is not associated with any oil accumulation. The methane is not significant, it appears to be dissolved in water, and bears no possible economic value. Although the possibility exists for gas hydrates to be trapped at the permafrost base, there is no indication of this occurrence at Northstar.

Average rock and reservoir properties for the two injection intervals are summarized in Exhibit 3-5. They have been estimated from wireline log interpretations. To summarize, the Sagavanirktok sands have excellent porosity and permeability while the deeper Prince Creek/Ugnu sands have good to very good characteristics. The sands in the lower Prince Creek/Ugnu and Schrader Bluff/West Sak intervals are somewhat poorer because they are generally the finest grained sands and are buried the deepest; however, their properties are still acceptable for waste disposal purposes.

3.2 <u>Operating Characteristics</u>

3.2.1 Injection Volumes and Injection Zone Usage

Exhibit 3-6 lists the volumes of liquids and solids to be injected. Initially, while both the drilling rig and plant are operating, the average monthly injection is expected to be 28,000 barrels. A maximum disposal situation could require injecting up to 60,000 barrels in any given month during the early production phase. Following the initial drilling program of 23 months, the rig will operate infrequently; however, formation water within the oil reservoir is expected to start encroaching and the produced water rate will begin increasing. From a low value it is anticipated to reach 16,000 BPD by the end of year four. If it holds at this average level, approximately 118,500,000 barrels will be produced and must be disposed of during a 20 year project life.

Major plant upsets, scheduled yearly shut downs, well treatments and workovers generate large volumes in short periods. These events can sometimes push the disposal rate from 16,000 to 30,000 barrels per day, or 900,000 barrels per month if these activities were occurring for an extended period. Accordingly, this permit request is for the following condition:

- Maximum Monthly Volume ....900,000 Barrels
- Maximum Total Disposal Volume ....120,000,000 Barrels

To address concerns that the upper confining zone not be penetrated, BPX proposes to permit for injection the interval bounded by the Seabee shale and the SV2 marker as shown in the original application, with the following stipulations:

- Drill cuttings generated during the initial drilling phase, which is currently estimated to involve 22 development wells and one disposal well, will be injected only into the lower injection zone (below the TMBK marker). This period is estimated to last 20-24 months. With a cuttings/solids disposal volume of 45,000-50,000 barrels (approximately 10,000 cubic yards) coupled with an estimated 500,000 barrels of liquids, the injection slurry will average a solids content of 9-10 percent. Injection will be initiated in the deeper part of the lower injection zone (approximately 6500 feet subsea) with perforations only added uphole as needed. Recent experience from the DS4-19 solids waste disposal well suggests that it is unlikely that perforations will need to be repeatedly added uphole. In a situation with perforations just below TMBK, there would still be numerous shale bodies and 1500 feet between the injection point and the base of the confining zone.

- Waste injection will remain below the TMBK marker as long as the lower injection zone is useful from a reservoir and well completion standpoint. It is expected that with routine flushing, wellbore stimulation exercises, and cleanouts as required, that disposal will be maintained at this level through the life of the project.

- Should the lower zone become plugged or otherwise useless, the upper zone would be perforated, preferentially in the basal sand package. This zone would only be used for waste streams with a low solids content (produced water, camp sewage, well stimulation acids-fluids, produced sand from a wellbore clean out, etc.) and well cuttings from an occasional new well. The zone would not be used for routine disposal of drill cuttings should an extended drilling program be reinitiated. Injection between years 3-18 is estimated to have a maximum solids content considerably below 0.5 percent. Any fracturing that occurred would be on a completely different scale from what will be occurring in the lower zone as described above. With approximately 1100 feet between the proposed perforations and the base of the upper confining zone, BPX feels confident that the confining zone will not be penetrated.

3.2.2 Injection Pressures

Field experience from three Prudhoe Bay solids disposal projects provides the basis to estimate pressure trends that will occur as the disposal process proceeds. The tabulation in Exhibit 3-6 shows the range of injection pressures that are estimated to occur through the life of a single well. This includes the time from when it is initially completed in the deeper sands, through abandonment of that interval if it becomes plugged with solids, and further through the well life as a successively shallower interval is used for storage. The intent is to use any given interval as long as solids can be transported into and through the formation. However, progressive plugging is expected to occur, ultimately further stimulations will be ineffective, and a lockup situation will evolve. That interval will then be abandoned. The range of injection pressures are relatively high, well above the fracture gradient for the receiving sands (0.65 psi/foot of depth). By necessity, the pressures must be at these levels since the receiving reservoirs must be fractured for the solids placement process to work.

It should also be emphasized that the expected pressures, as shown, reflect operation of a well when no major plugging of the wellbore or region adjacent to it has occurred. Periodically, the solids being transported and the filter cake additives in the mud will combine to begin a gradual plugging of the then-existing fracture faces and matrix porosity. When this occurs, if injection operations cease and the wellbore is not flushed adequately with clear fluid, the pore throats and flow channels will become plugged. To re-initiate communication with the reservoir, surface pressure may sometimes have to be temporarily surged above those pressures listed in Exhibit 3-6. This temporary surge, which could reach 4800 psi, acts the same as a stimulation procedure and flow can once again be established. This type of operation is typically done with clean brine. Except for these infrequent and brief stimulation exercises, it is expected that injection pressures would generally be at or below the indicated levels, which are viewed as maximum levels that would occur as lockup of a completion interval progressed. Accordingly, this permit request is for the following condition:

- Maximum operating pressure .... 3000 psi.

Waiver Request: BPX requests that the EPA waive the performance standard of 40 CFR 146.13 (a) which prohibits fracturing the injection zone. We request that the EPA permit the wells to operate at a maximum injection pressure of 3000 psi. This waiver is requested based on the facts detailed in Section 4.4, which demonstrates that the Northstar area aquifers below the permafrost meet the criteria by which an aquifer can be exempted by the EPA. Injection operations will conform to 40 CFR 146.13 (a), which prohibits fracturing the confining zone, as discussed in Sections 3.2.1 and 6.6. This request is consistent with 40 CFR 144.16 which allows the Director to waive requirements when injection does not occur into, through, or above a USDW.

3.2.3 Reservoir Fracturing/Solids Storage

The sandstone intervals that will be subjected to fluid and solids injection will initially fracture at a gradient of 0.65 psi/foot of depth. With injection pressures that may reach 1.0 psi/foot, fractures will occur. Maintenance of an open system will require an internal pressure greater than the fracture gradient and thus the pore pressure of adjacent reservoir rock.

In the deeper sands, solids storage is expected to occur predominantly between the faces of a conventional planar fracture. When that fracture becomes filled and/or plugged, a second major fracture should occur with a somewhat different directional orientation. These fractures should all propagate in the vertical plane. Progressively, that completion interval may ultimately reach a lockup point and become useless.

In the intermediate sands, it is conceivable that a dendritic system would develop in which multi-conjugate fractures develop as appendages of a main single fracture. Alternately, secondary systems might also originate near the wellbore.

Should the upper disposal interval be required, it would be perforated in its basal few feet as discussed in Section 3.2.1, and would only be used for waste streams with a low solids content. Fracturing would be significantly different from fracturing which occurs from a slurry with 9-10 percent solids. Because this sand is more loosely consolidated, if some solids disposal was required, a dendritic variation may develop which would also involve rock solidification and movement along the fracture faces. This would further enhance solids storage and limit fracture growth.

The mechanisms of solids transport and placement will vary with depth because of the different rock properties controlling mechanical behavior in the different injection intervals. Exactly how storage will occur at the deeper depth, with attendant pressures and injection rate requirements, is something that can be verified only after the process is initiated and some history obtained. While it is hard to predict definitively what a fracture system will look like, the storage domain can be bounded based on years of slurry injection and extensive tiltmeter field tests, coupled with other field and laboratory experiments.

Comparing the Northstar disposal operation with other projects indicates vertical fracture growth might be in the 250 foot range. A maximum case might be 500 feet. The relationship of the Northstar project with others can be seen on the following table and in Exhibit 6-6.

Project	Average Injection Rate (BPD)	Total Solids Volume (Cu Yds)	Maximum Fracture Length (Feet)	Fracture Height (Feet)
Prudhoe DS4-19	20	400,000	2000	1600
Jasper County (Texas)	10-15	1500	1200	confined by shales
Prudhoe CC-2	2.5	130,000	800	300
Northstar	1	10,000	----	----

With the confining zone 1400 feet above the lower injection zone, the estimated fracture height generates a safety factor between 2-5. Fracturing of the confining zone should not occur. Further discussion on fracturing and waste confinement is included in Section 6.6.

3.2.4 Well Stimulation

The objective of any injection well stimulation program is to achieve and maintain the required injection rate at minimum pressure. These sands are very permeable and under normal conditions do not need the typical chemical stimulation treatments conducted in other formations. Nevertheless, they have been known to become damaged and flow restricted due to suspended solids and occasional emulsions in the injectant, and other factors. It is conceivable but not probable that a xylene or acid treatment would be employed to restore injectivity. In such an instance the chemicals would be displaced into the formation and not back-flowed or recirculated to the surface.

With formation fracturing occurring when a drilling mud or solids laden slurry is being continually injected, we assume solids will be transported through the wellbore and adjacent reservoir area successfully. However we know this will not always occur. On occasion the gradual bridging and plugging of settled solids in the near-wellbore region causes the injection pressure to increase. At these times, if a plant shutdown occurs and the wellbore can not be flushed adequately with brine, the solids can effectively settle out and restrict flow. Two options exist. A wellbore cleanout can restore injectivity or a high pressure surge of short duration can re-establish communication with the reservoir. These surges, which could reach 4800 psi, are typically done with clean fluids which flush the solids away re-establishing communication. Surging will be tried prior to initiating a mechanical cleanout.

- Maximum Pressure During Stimulation.............. 5000 psi

Stimulation might also involve reperforating an already open disposal interval if it is concluded that increased injection pressure is the result of too low a perforation density or other perforation restrictions.

3.2.5 Tubing-Annulus Corrosion

While some of the injected fluids will be corrosive relative to bare steel, serious degradation should not occur since most fluids are virtually non-reactive. Prior to injection, acids, caustics, and chemicals have been used, processed, handled, and are spent and virtually dead. These same wastes have been injected at the Prudhoe Bay Pad-3 Class I disposal facility for over 18 years and no corrosive tubing failure has occurred on any of those three wells. The critical subsurface tubulars are protected by tubing/packer/seal isolation and a non-reactive fluid placed in the tubing/casing annulus. The annulus fluid placed in these wells will consist of 8.6 #/gallon inhibited sea water with a diesel cap across the permafrost.

Corrosion control is a subjective term since corrosion can rarely be eliminated, even at great cost. The function of well tubing and packers is to protect the casing strings from internal corrosion, stress, and abrasion. When the tubing deteriorates it is replaced. Should corrosive action weaken any internal down hole component or the surface piping, that part will be replaced.

3.2.6 Compatibility of Fluids and Formation Lithology

A fluid sensitivity and mineralogy analysis was performed on Tertiary core samples from Prudhoe well GC-2B. The laboratory study was done in 1977 by Dowell Schlumberger, Inc. Results are summarized below.

- Rock Mineralogy:

Analysis from X-ray diffraction showed the sand to contain predominantly silica in the form of quartz (chemically a very stable mineral), with low percentages (1-15%) of feldspar, halite, pyrite, and muscovite. The clay minerals illite, chlorite, kaolinite, and montmorillinite also occurred in low percentages. However, clay content based on mud acid solubility tests showed significantly higher percentages in the 30 percent range. No calcium carbonate is present to react with acidic fluids.

- Fluid Sensitivity:

Lab testing determined that fluid movement through the formation will cause some fine particle migration, and thus a permeability reduction. Tests on the sand also showed a sensitivity to fresh water caused primarily by unstable clay minerals, reducing the permeability. However, tests using brine solutions showed no formation sensitivity, and an enhancement of permeability was seen following treatment with stimulation fluids such as mud acid.

The injection fluids will consist primarily of produced water, brines, fresh waters, hydrocarbon-based oily wastes, and drilling wastes in the range of pH 6 to 9. From the Dowell study, we can conclude that the brine wastes will be non-reactive with the injection zone, except for causing fines migration. Since oil based muds are commonly used when drilling in unstable shale environments, we can conclude that the clay minerals present will be non-reactive with the oil wastes. Further evidence can be derived from the Prudhoe CC-2A and Pad-3 disposal wells, which have been injecting these types of wastes for years and have experienced no downhole compatibility problems, either with formation waters or rock matrix.

The confining shales and siltstones may contain significant amounts of smectite clay which, depending upon the water salinity, could swell upon contact with injected waters. This reaction would only serve to enhance the confining characteristics of the zone, without affecting the structural integrity of the formation.

Waiver Request: A waiver is requested from the requirements of 40 CFR 146.12 (e) and 146.14 (a) that requires (1) sampling and physical/chemical characterization of formation fluids, and requests proof that the injectant is compatible with formation waters and; (2) sampling and physical/chemical characterization of the injection matrix. In support of this request, it is pointed out that over 8 million barrels of exempt waste and solids have been injected at the Class II Prudhoe CC-2 facility, 9 million barrels of waste at the Class I Pad-3 wells, and 6 million barrels of exempt waste at the Endicott field in these same sands. (Injection plots are included in Section 6.0). In addition,1 billion barrels of produced water have been injected into the Tertiary sands in the Class II disposal wells at the other major oil production centers on the North Slope. Thus, the blending of these wastes with formation waters has been occurring successfully for many years. Additional justification for the request to waive matrix testing is included in Section 6.1.

NORTHSTAR TYPE LOG (SEAL-A-01)

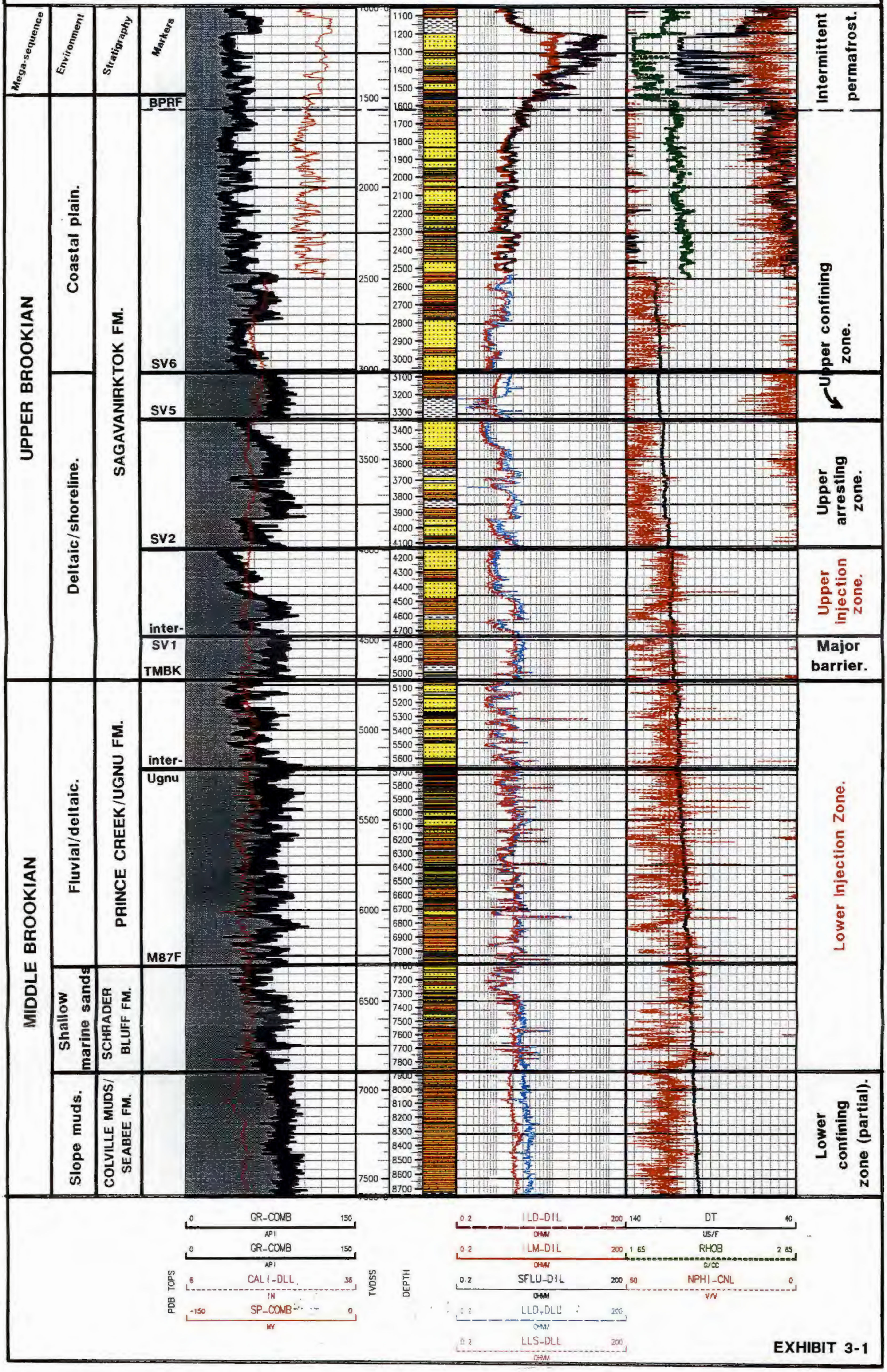
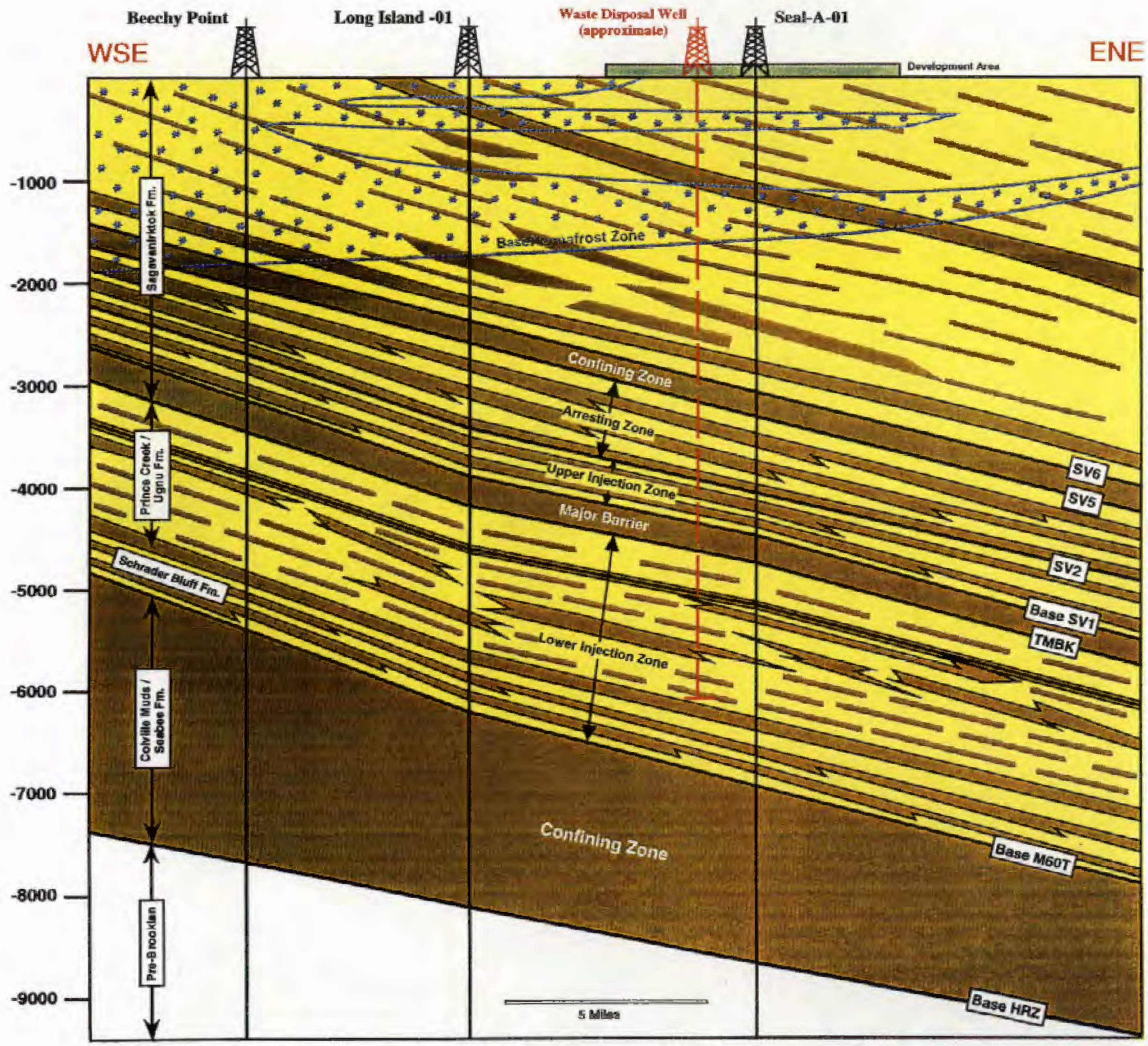
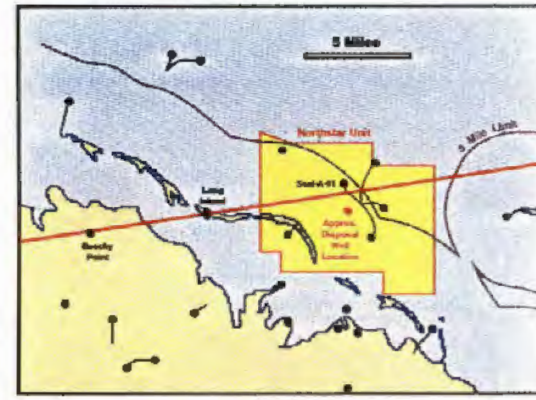


EXHIBIT 3-1



Northstar Area Index Map



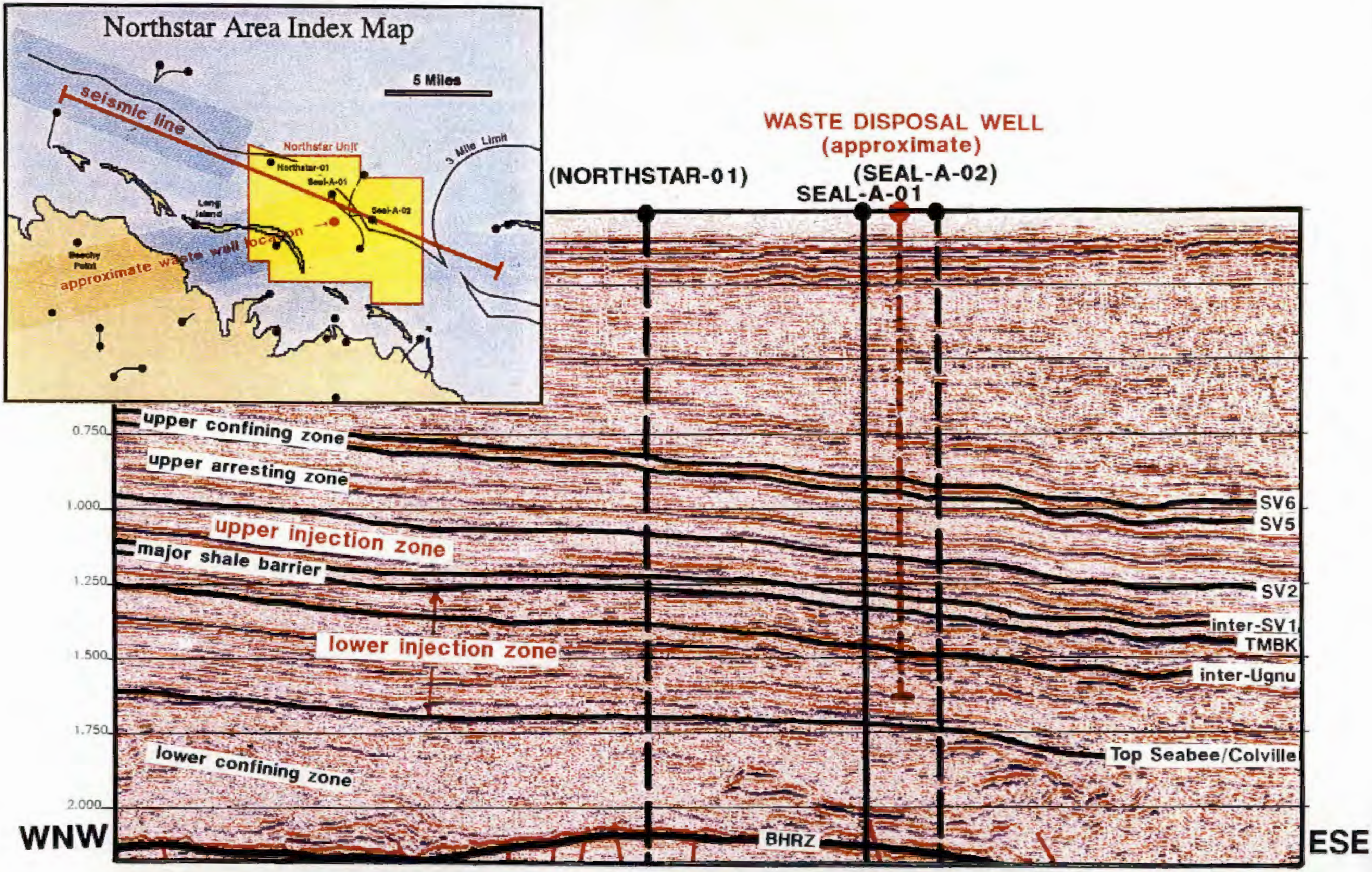
Legend

(yellow)	Sands and Gravels
(brown)	Shales and Silts
SV6	Marker - with structure map in Appendix C

Ra Eldredge / ljl (June 1, 1996)

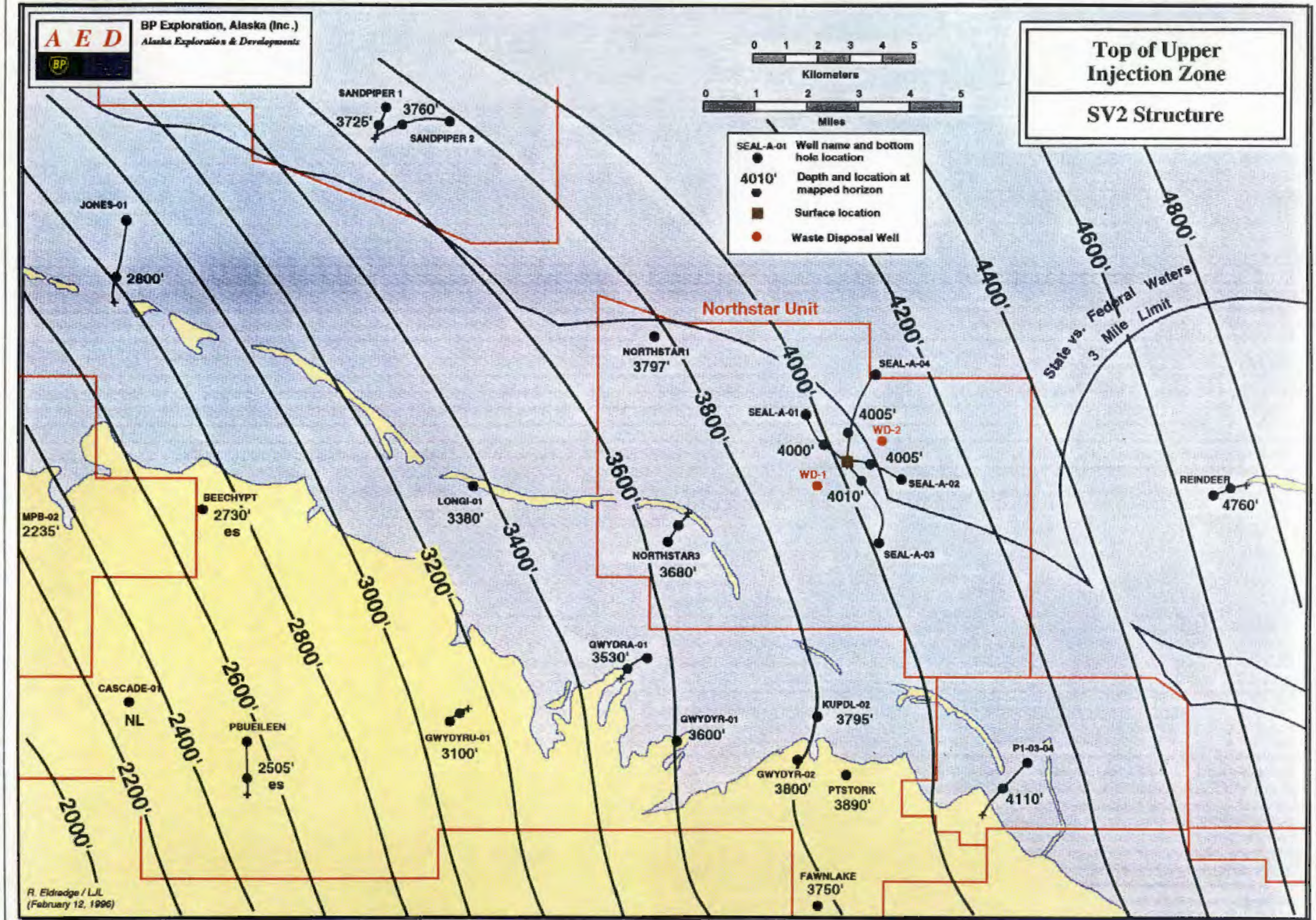
Generalized Cross-Section across Northstar Unit

Exhibit 3-2



2D SEISMIC LINE ACROSS NORTHSTAR AREA

EXHIBIT 3-3



A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Development
Top of Upper Injection Zone
SV2 Structure
Kilometers
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters
3 Mile Limit
SANDPIPER 1
3760'
3725'
SANDPIPER 2
JONES-01
2800'
NORTHSTAR1
3797'
SEAL-A-04
SEAL-A-01
4005'
WD-2
4000'
4005'
WD-1
SEAL-A-02
4010'
SEAL-A-03
REINDEER
4760'
BEECHYPT
2730'
es
MPB-02
2235'
LONGI-01
3380'
NORTHSTAR3
3680'
GWYDRA-01
3530'
CASCADE-01
NL
PBUEILEEN
2505'
es
GWYDYRU-01
3100'
GWYDYR-01
3600'
KUPDL-02
3795'
GWYDYR-02
3800'
PTSTORK
3890'
P1-03-04
4110'
FAWNLAKE
3750'
2000'
2200'
2400'
2600'
2800'
3000'
3200'
3400'
3600'
3800'
4000'
4200'
4400'
4600'
4800'
R. Eldredge / LJL
(February 12, 1996)

Exhibit 3-4

Exhibit 3-5

Reservoir Properties

Pressure and Temperature Gradients

The pressure gradient is estimated to be 0.45 psi/ft of depth from the surface to the Seabee Shale. The temperature gradient below the permafrost is estimated to be 50 feet/degree.

Original Reservoir Fluid

There are no actual water samples taken near the Northstar Unit. Brine with an average total dissolved solids content of 21,000 mg/l or greater, and a gas solubability of 7 standard cubic feet of gas per barrel of brine exists in the injection zone. The salinity values are calculated from nearby well logs and the gas content is from tests at Prudhoe.

Aquifer Flow Characteristics

With a uniform, natural pressure gradient from the surface and some dissolved gas present, all the Tertiary sands above the Colville Mud/Seabee Shale will act as artesian sources and most probably flow to the surface if completely unrestricted.

Areal pressure data ties with what has been measured across the Prudhoe Bay area and indicates that originally a flat piezometric surface existed in all zones. Therefore, no natural aquifer movement exists. Since reservoir fluids were originally static, the only lateral movement that occurs is caused by injection or production.

Fracture Gradient

The sand intervals have an anticipated fracture gradient of 0.65 psi/foot of depth. The shale gradient has not been defined.

Average Reservoir Properties

Based on Seal A-1, which was compared with Northstar #1 and Long Island #1 wells.	Disposal Interval Lower	Disposal Interval Upper
Net Sand Thickness (feet)	650	340
Porosity (%)	26-28	29-31
Permeability (md)	100-600	600-1000

Exhibit 3-6

Injection Volumes and Pressures

Drilling and Early Production Period	**Injection Volumes - Barrels per Month**		
Drilling Rig and Camp Operating	Liquid	Solids	Total
Normal Operation	16,400	3,600	20,000
Maximum Disposal Rate	26,000	7,000	33,000
Rig/Camp and Process Facilities Operating			
Normal Operation	24,400	3,600	28,000
Maximum Disposal Rate	53,000	7,000	60,000

Expected Produced Water Volume

Produced water disposal is anticipated to increase from an initial low value to approximately 16,000 barrels per day by the end of year four, and to hold at this level. This averages to 500,000 barrels per month, and generates a cumulative disposal volume of approximately 118,500,000 barrels over a 20 year period.

Maximum Produced Water Injection Rate

Major plant upsets, scheduled yearly shutdowns, well treatments and workovers generate large volumes in short periods. These events can sometimes push the disposal rate from 16,000 to 30,000 barrels per day, or 900,000 barrels per month if these activities were occurring for an extended period.

Expected Project Disposal Volumes by Major Category (20 years)

Rig muds and other liquids	420,000 Bbls
Rig drill cuttings and other solids	80,000 Bbls
Camp sewage and gray water (Class I)	600,000 Bbls
Wells, process facilities, etc. waste	400,000 Bbls
Industrial non-hazardous wastes (Class I)	40,000 Bbls
Produced water (oil reservoir brine)	~118,500,000 Bbls
Total disposal volume	~120,000,000 Bbls

	Operational Injection Pressures (psi)	
	Water (S.G.=1.0)	Mud/Solids (S.G.=1.3)
Upper Sands (+/- 4300 ft)		
Expected Maximum Bottom Hole Pressures New Completions	3,200	3,200
Old Completions	4,650	4,650-Lockup
Injection Gradient (psi/ft)	1.08	1.08
Expected Maximum Surface Pressures New Completions	1,400	700-1,300
Old Completions	2,800	2,400-Lockup
Lower Sands (+/- 6300 ft)		
Expected Maximum Bottom Hole Pressures New Completions	4,700	4,700
Old Completions	6,300	6,300-Lockup
Injection Gradient (psi/ft)	1.0	1.0
Expected Maximum Surface Pressures New Completions	1,800	900-1,800
Old Completions	3,300	2,400-Lockup
Type of Fluid Behavior	**Newtonian**	**Non-Newtonian**

Maximum Pressure During Well Stimulation 5000 psi

4.0 Subsurface Aquifers

The North Slope of Alaska, consisting of the Arctic coastal plain and Arctic foothills, is unique as reflected by the fact that jurisdictionally nearly the entire 88,000 square miles are classified as wetlands by the U.S. Army Corp. of Engineers. In addition, according to the U.S. Fish and Wildlife Service (USFWS), approximately 83 percent of the Arctic coastal plain is a wetland. These wetlands in northern Alaska are underlain and maintained by perennially frozen ground, or permafrost. During the brief Arctic summer, spring snow melt and summer rain are trapped by the frozen layer at or near the surface. The approximate 2,000 foot thick permafrost layer is a barrier to water. Therefore, unlike the rest of the United States, there is no continuous cycle of aquifer discharge and recharge between the surface and underground aquifers. The areal extent of the permafrost and depth to the base in the offshore Northstar area is discussed in Section 3.0 and shown in map and cross section form in Appendix C. For reference purposes two documents on Alaska wetlands are included in Appendix D. The first was published by BPX and the second by the USFWS.

4.1 North Slope Resident Water Supplies

The North Slope of Alaska is very sparsely populated. Approximately 6,200 permanent residents live in eight communities. Because surface water is so plentiful, seven of the eight native villages on the North Slope rely on surface water from lakes or lagoons for their water supply. The closest permanent resident population at the village of Nuiqsut (population 550) is approximately 60 miles west of Prudhoe Bay and 50 miles from Northstar. In the North Slope area, only the village of Anaktuvuk Pass (population 325), approximately 180 miles south of Prudhoe Bay in the Endicott Mountains, has a subsurface well for their public water supply. Nuiqsut and Anaktuvuk Pass are located on the map of Alaska in Exhibit 1-1. A table of North Slope demographics for permanent residents and their potable water sources is summarized in Exhibit 4-1.

Approximately 3,000 workers temporarily reside on the North Slope in one of six major camps. The temporary populations residing at operator and contractor run camps for the North Slope oil fields all rely on surface water for their water supply. Even the base camp at Endicott's offshore facility treats seawater for its drinking water supply rather than use a subsurface source. The potable drinking water systems for these oil field camps are listed in Exhibit 4-2. With a good year round supply, the Northstar facility will also use seawater as its potable water source.

4.2 Potable Water Costs

The oil field camps produce water at an average cost of about 2 cents/gallon using surface water sources. These systems usually require filtration, flocculation and chemical treatment prior to storage. The small amount of system backwash is disposed of by flushing back to the surface. Economically, this compares with Conoco's Milne Point Unit experience in 1985 to use saline subsurface water as a source for feeding and operating a reverse osmosis (RO) process. Their system cost $10 MM and was so expensive, labor intensive, and troublesome to keep going that it was abandoned. They chose to purchase potable water at 3 cents/gallon until a surface system was installed. Additionally, ARCO reported to the EPA via letter in July 1984 that subsurface waters in their Kuparuk River Unit were not economically viable drinking water sources because a single source well and accessories would cost $2 MM more than using surface waters. Also, the sodium content was four times greater than acceptable limits and cleanup of the gassy-hydrocarbon saline waters would have been more expensive than using surface waters.

Exhibit 4-3 details comparative costs for installing and operating surface and subsurface systems. A 20,000 gallon per day plant using surface water could be installed for about $700,000, and might operate for 1.5-2.0 cents/gallon. A system using subsurface waters would cost about $3.4 million and lifting-disposal costs for operating the wells alone would run 1.5-2.0 cents/gallon of potable water. The additional RO vessel(s) and process equipment would thus make this type system more expensive.

4.3 Aquifer Status of North Slope Oil Fields

The major North Slope fields have all received determinations from the Alaska Oil and Gas Conservation Commission (AOGCC) with EPA concurrence, that the underlying aquifers are not USDWs or that the aquifers are exempted for Class II operations. In the case of the eastern half of the Prudhoe Bay Unit, the EPA has determined no USDWs are present for Class I operations as well. The aquifer status for each of the major North Slope fields is summarized in Exhibit 4-4.

4.4 Aquifer Exemption

The Northstar area aquifers could potentially meet the requirements to receive a no USDW ruling from the EPA. However, due to the preceived uncertainty in log calculated salinities and that no water sample exists, an interpretation could be made that a USDW is present. BPX is therefore requesting an aquifer exemption for the Northstar aquifers.

The aquifers below the permafrost meet all three criteria by which an aquifer can be exempted by the EPA.

- Per 40 CFR 146.4 (a): No USDW currently serves as a source for potable purposes because of the abundance of surface water within the area. The source of fresh water for the Northstar facilities will be the Beaufort Sea.

- Per 40 CFR 146.4 (b)(2): The USDWs in the Northstar area cannot now and will not in the future serve as a source of drinking water because they are situated at a depth or location which makes recovery of water for drinking purposes economically or technologically impractical. Surface water and seawater can be treated for approximately 2.0 cents/gallon. The cost to install and operate a subsurface system would be several times greater than the cost to filter and purify surface or sea waters.

- Per 40 CFR 146.4 (c): The total dissolved solids content of the ground water is more than 3,000 milligrams per liter and is not reasonably expected to supply a public water system.

Accordingly, per 40 CFR 146.4 and 144.7, BPX requests a Class I aquifer exemption for all intervals below the base of the permafrost, estimated at a depth of 1500 feet subsea in this area, and the Seabee shale marker, estimated at a depth of 6880 feet. By letter dated May 12, 1997, EPA Region 10 stated that they were prepared to process an aquifer exemption as part of the Class I well permitting process. (That letter is included in Appendix J.) The ruling is requested for all the surface area currently lying within the Unit boundary, as shown on Exhibit 4-5.

The Unit encompasses five State of Alaska leases and three Federal leases. Legally the boundary is described by UTM coordinates (NAD 1927) at 23 points. These coordinates are included on Exhibit 4-5.

Exhibit 4-1

Potable Water Sources and Demographics
Native Villages of the North Slope
(October 1994)

Village	Population	Distance from Prudhoe Bay (Miles)	PWS * I.D. Number	Potable Water Source
Barrow	3404	200	620078	Isatkook Lagoon
Wainwright	570	270	620086	Freshwater Lake
Kaktovik	280	130	620248	Freshwater Lake
Pt. Hope	711	160	620426	Freshwater Lake
Nuiqsut	550	60	620264	Freshwater Lake
Atqasuk	220	210	620094	Surface Lake
Pt. Lay	150	340	N/A	Surface Lake
Anaktuvuk Pass	325	180	650057	70 Foot Well

* Public Water Supply Identification Number

Exhibit 4-2

Potable Water Systems
North Slope Oil Field Area
(October 1994)

Oil Field Camps	Approximate Population	Potable Water Source	System Size (gal/day)	Operating & Maintenance Cost (¢/gal)
BPX Prudhoe Bay Base Operation Center	800 *	Lake	102,000	3
ARCO Prudhoe Bay Base Operation Center	1100 *	River	176,000	1.0
ARCO Kuparuk River Base Operation Center	350 *	Lake	76,000	2.1
Milne Point Central Facility	150 *	Lake	30,000	1-3
Endicott Base Operation Center	120	Seawater	20,000	1.5
Kuparuk Industrial Center	130	River	24,000	1.5
Pump Station 1	50	Purchased	N/A	N/A
Deadhorse Service Area	320	River	50,000	1.5-2.0

* Potable water also hauled to temporary drilling rig camps.

Exhibit 4-3

Investment Costs for Potable Water Systems
North Slope Oil Field Area
(December 1994)

Surface Water Source

Cost for a 20,000 gal/day filtration-purification system fed by surface water of average chemical composition.

• Process Equipment	$350,000
• 20 x 20 Building	$210,000
• Source Pumps & Pipeline Depend on Surface Situation. Assume 800 feet of Line.	$130,000
Installed Cost	$690,000

Subsurface Water Source

• Source Well 2600 feet deep with Freeze Protection, Controls, etc.	$1.18 MM
• Disposal Well for Injecting Desalination Vessel Waste Water	$1.30 MM
• Gravel Pads for wells (Permitting & Installation)	$.06 MM
• Rig Mob/Demobilization (Cost Not Included)	------
• Source-Water Gas Separation, Waste Water Tankage, Injection Pumps, Piping	$.16 MM
• 20 x 30 Building	$.31 MM
• Process Equipment Including Reverse Osmosis Unit. Probably a low side cost because additional pre-reatment for cations and ozonation most likely required.	$.38 MM
Installed Cost	$3.39 MM

Well Operating and Maintenance Cost

Assume rig workover on source well every 5 years and on disposal well every 8 -10 years: Cost ranges from 1.5 - 2.0 ¢/gallon of potable water.

Exhibit 4-4

North Slope Oil Fields
Aquifer Status

Prudhoe Bay Unit (ARCO Eastern Operating Area - Approx. 121,000 Acres)

No USDW for Class II injection per Alaska Oil and Gas Conservation Commission. Conservation Order AIO #4, finding number 5.

No USDW for Class I injection per EPA Region 10.
Waste Disposal Permits Number AK-1 I003-I, I004-I, I005-I.

Prudhoe Bay Unit (BPX Western Operating Area - Approx. 121,000 Acres)

All aquifers exempted for Class II injection per Alaska Oil and Gas Conservation Commission. Aquifer Exemption Order AEO #1.

Kuparuk River Unit (214,000 Acres)

All aquifers exempted for Class II injection per 40 CFR 147.102 (b)(3) and Alaska Conservation Order AIO #2, finding number 4.

Milne Point Unit (71,000 Acres)

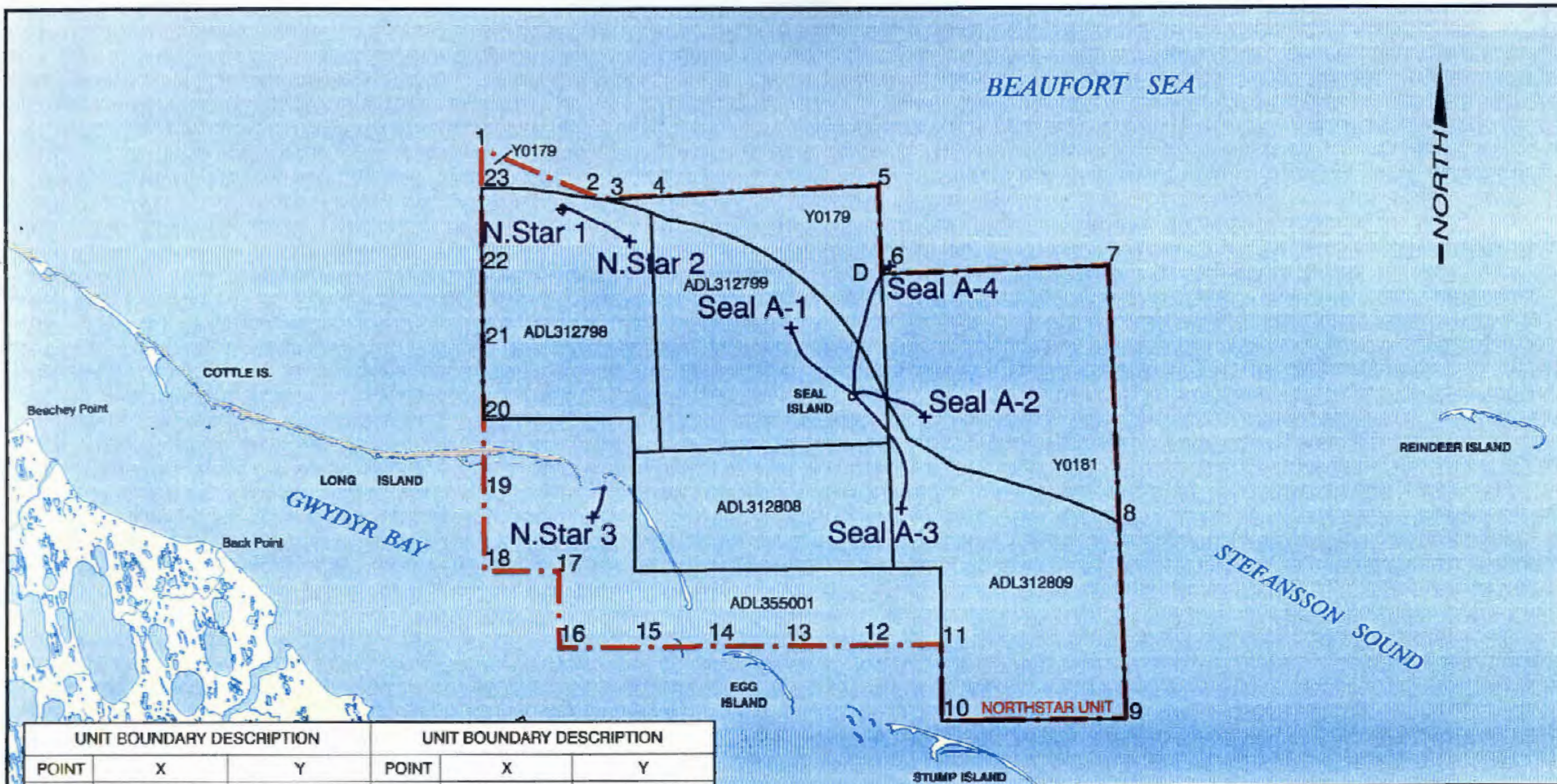
All aquifers exempted for Class II injection per Alaska Oil and Gas Conservation Commission. Aquifer Exemption Order AEO #2

Duck Island Unit (18,000 Acres)

No USDW's for Class II injection per Alaska Oil and Gas Conservation Commission. Conservation Order AIO #1, finding number 4.

Badami Unit (37,402 Acres)

No USDW for Class I injection per EPA Region 10
Waste Disposal Permit pending



UNIT BOUNDARY DESCRIPTION		
POINT	X	Y
1	429,245.54	7,826,956.85
2	431,755.41	7,825,804.90
3	431,771.75	7,825,801.52
4	432,800.00	7,825,812.71
5	437,600.00	7,825,871.00
6	437,599.80	7,824,000.25
7	442,400.00	7,824,000.00
8	442,400.00	7,818,535.48
9	442,400.00	7,814,403.64
10	438,513.04	7,814,505.49
11	438,556.60	7,816,113.60
12	436,948.42	7,816,157.66
13	435,340.28	7,816,202.89

UNIT BOUNDARY DESCRIPTION		
POINT	X	Y
14	433,732.16	7,816,249.26
15	432,124.06	7,816,296.76
16	430,516.00	7,816,345.42
17	430,559.53	7,817,953.62
18	428,965.15	7,818,002.99
19	429,015.50	7,819,610.98
20	429,065.86	7,821,219.01
21	429,116.22	7,822,827.03
22	429,166.59	7,824,435.05
23	429,219.53	7,826,126.60

Coordinates are UTM (METERS) NAD 1927

BP EXPLORATION (ALASKA) INC.

NORTHSTAR UNIT
AQUIFER EXEMPTION AREA

DATE:	SCALE:	EXHIBIT:
June 1996	1" = 2 MILES	4-5

bs13105.dgn

5.0 Area of Review

5.1 Introduction

All underground injection wells must be able to meet a performance specification that prohibits "movement of fluid containing any contamination into underground sources of drinking water (USDW)," etc. (40 CFR 144.12). However, despite the lack of any USDW, as detailed in Section 4.0, the EPA has required no movement of contaminants into the lower-most saline aquifer (i.e. non-USDW) that lies above the confining zone.

To meet this performance requirement the regulations require; a description of the geological and hydrological structure of the subsurface area, 40 CFR 146.14 (a)(4)(5)(6); and that transmissive faults or open conduits through the confining zone within the area of review be accounted for, 40 CFR 146.14 (a)(3)(4).

The area of review (AOR) is either regulatory (1/4 mile radius for Class I Industrial injection wells) or it is based upon calculations of the radius of injection pressure build-up sufficient to move fluids into the overlying aquifer. This pressurized area is termed the zone of endangering influence (ZEI). If the ZEI is larger than the statutory AOR, it becomes the appropriate area to make no contamination demonstrations.

The ZEI is defined in 40 CFR 146.6 as that area within which the elevation of the initial piezometric surface (fluid level) for the formation fluid in the injection zone is predicted to rise, during the life of the project, to equal the piezometric surface of any potential overlying USDW; or in this case, the lowermost overlying saline aquifer.

5.2 Northstar Area of Review

The effective injection zone will consist of 650 feet of net sand located between a subsurface depth of 4730 and 6500 feet, and the 340-foot-thick sand at 4000 feet. As much as 120 million barrels of waste could be injected over a 20 year period. This maximum volume was used to calculate the increase in reservoir storage pressure and the theoretical ZEI. Exhibit 5-1 shows the pressure buildup from waste injection for several different disposal scenarios. It can be seen that the increase is generally 25 psi or less. Based on the above pressure profile, past North Slope experience, and expected placement and confinement as discussed in Section 6.6, the calculated ZEI can be viewed as occurring close to the injection well or its active fracture system.

Based on the conditions that BPX has proposed for waste disposal and injection zone usage in Section 3.2.1 and the calculated pressure buildups, BPX recommends that the lower injection zone AOR be 1/2 mile and the upper zone AOR be 1/4 mile. These AORs are shown on the attached Exhibit 5-2 spider map. Justification for this proposal can be summarized as follows.

- Results from other disposal projects says that lower zone fracturing will not reach 1/4 mile from the injection point. At Northstar the average injection rate during the initial drilling phase will be approximately 850 BPD (0.6 barrels per minute if the operation was continuous). This low rate will provide enough time for fluid leak off to play an important role in mimimizing fracture size. The solids storage domain will be very different in size than what is occurring at other North Slope locations.

- Upper zone fracturing, if the interval has to be used for low solids injection, will be minor and on a whole different scale from what occurs in the lower zone during the routine disposal of drill cuttings. Fluids entering the upper zone with an average solids content below 0.5 percent and at low rates cannot generate long fractures. If an occasional new well was drilled, cuttings disposal would create a more significant fracture, however it would likely close after the slurry injection ceased.

This application consists of two wells directionally drilled as shown on Exhibit 5-2. It is anticipated that the bottom hole locations will hit within 100 feet of the intended targets. The wellbores will intersect the upper disposal interval at lateral displacements of approximately 2200 and 2700 feet, and the lower interval at departures much greater.

Abandoned exploratory wells Seal A-3 and Seal A-4 fall within the ½ mile AOR. Casing, cementing, and abandonment data on these wells is included in Appendix E. It also appears that one future development well will lie within the AOR.

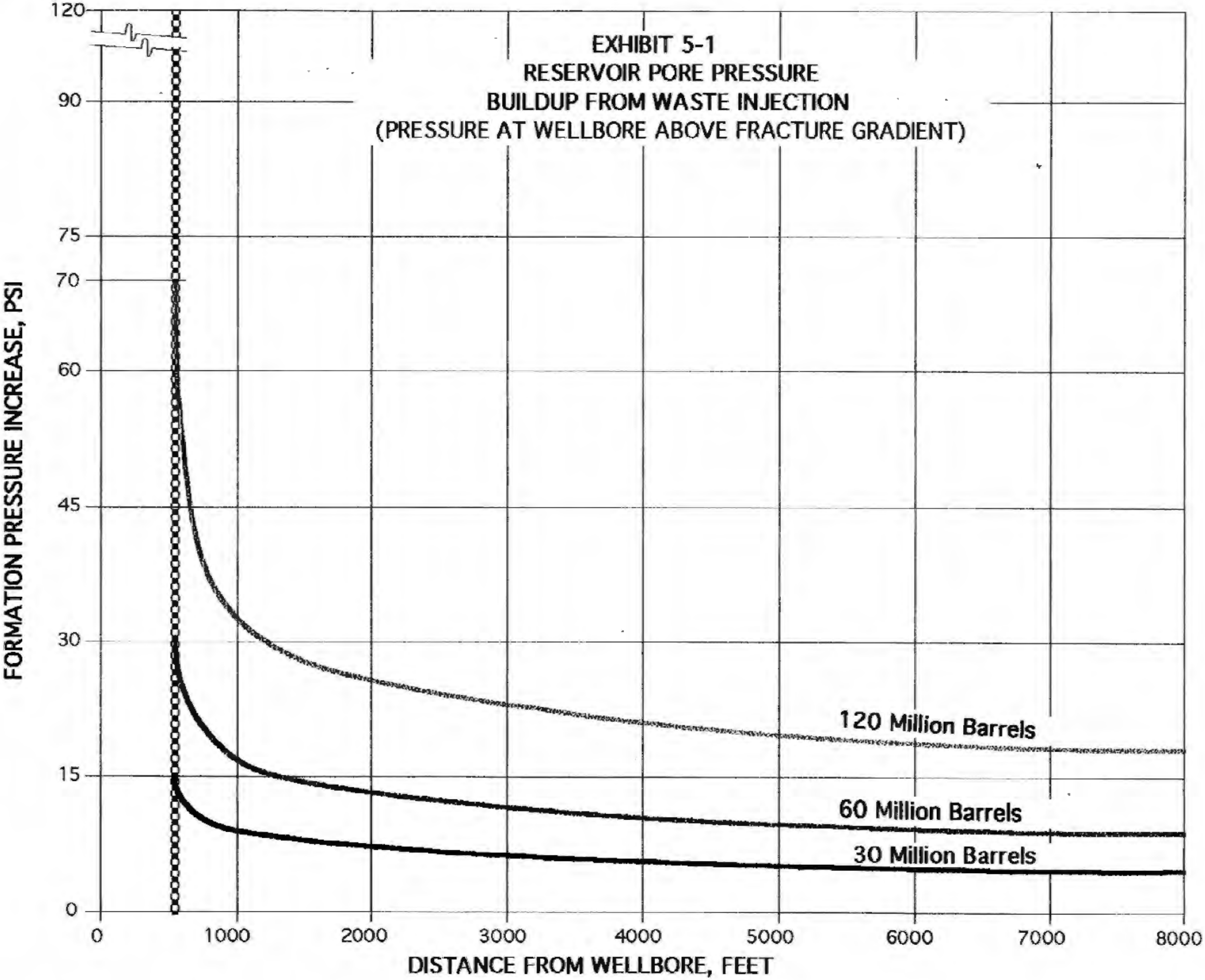


EXHIBIT 5-1
RESERVOIR PORE PRESSURE
BUILDUP FROM WASTE INJECTION
(PRESSURE AT WELLBORE ABOVE FRACTURE GRADIENT)
FORMATION PRESSURE INCREASE, PSI
DISTANCE FROM WELLBORE, FEET
120 Million Barrels
60 Million Barrels
30 Million Barrels
0
15
30
45
60
70
75
90
120
0
1000
2000
3000
4000
5000
6000
7000
8000

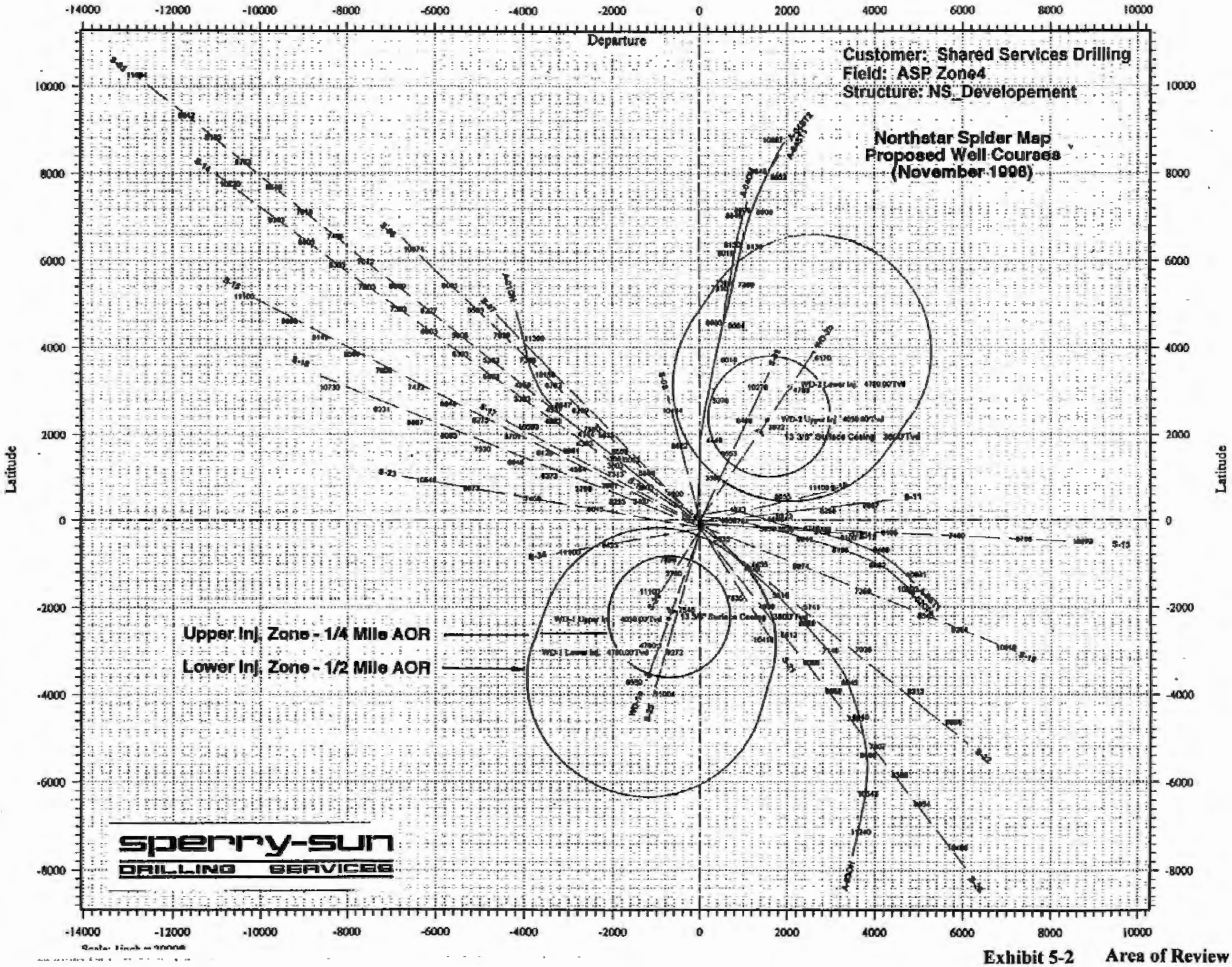


Exhibit 5-2 Area of Review

6.0 Performance Standards and Compliance

6.1 Formation Testing

Formation testing will primarily involve pressure fall-off tests (PFO). An initial PFO will be obtained after injecting water for a few days. Subsequent PFOs will be performed as needed after solids injection begins. Alternately a static reservoir pressure will be obtained upon initial completion. Open hole and cased hole logs will be run from surface to total depth, as detailed in Appendix F. No physical formation testing is planned.

The regulations require defining physical, chemical, and radiological characteristics of the receiving formation. Toward this end, core analyses from wells in the Prudhoe area have provided the rock descriptions included in Section 3.0 and Appendix C. It is therefore proposed not to obtain any additional core samples.

The regulations also ask for physical and chemical characteristics of the formation fluids. This data is readily available from the nearby Prudhoe oil field where the Ugnu formation was sampled repeatedly during a 40 day test. Water chemistry was studied extensively. Other data is also available from the more distant Milne Point Unit and Kuparuk River Unit. In addition, over a billion barrels of exempt wastes have been successfully injected and blended into these Cretaceous-Tertiary sands a few miles from Northstar. No other sampling of reservoir fluids is planned since good sampling is very costly and no additional data is justified.

No pump-in or formation breakdown tests are proposed since many Prudhoe area Class II disposal wells at this depth provide injectivity data for relatively clean fluids. Pressure monitoring of those sands enables us to map the fluid movement and confinement of large volumes of produced brine. The other Prudhoe Class II solids disposal wells, CC-2A and DS4-19, and the Class I Pad-3 wells are monitored and periodically tested to provide baseline injectivity data for solids-laden slurry. Millions of barrels have been injected in these five high-solids content disposal wells over many years. In addition, laboratory core studies, and the DS4-19 and CC-2A performance, are currently being used to predict rock behavior during solids disposal. This analytical work provides a basis for understanding and predicting injection zone performance, and provides more assurance of long term behavior than would be obtained from short term tests on a new borehole. Accordingly, it is requested that the historical data and the on-going testing, monitoring, and analytical studies be used to satisfy the formation testing requirements specified in 40 CFR 146.12 (e), and 40 CFR 146.14 (a).

A waiver request from additional sampling and testing is included in Section 3.2.6.

6.2 Reservoir Pressures

Each well will be shut in every year for a sufficient length of time to obtain a reliable reservoir pressure. This will most probably involve a pressure fall-off as previously discussed. Alternately some static surveys may be obtained.

6.3 Well Construction

Well design exceeds all Class I well requirements listed in federal and state regulations. (The details of well construction are included in Section 7.0 and Appendix F.) Should any deficiencies occur during the construction process, the EPA will be so advised and agreement reached on how to proceed. 40 CFR 146.12 (c) requires that a packer be used to isolate tubing and casing. It is BPX experience that a polished bore receptacle seal assembly interlocking the tubing and casing packer is superior to other tubing-packer systems. BPX requests that this type seal be allowed in the completion. Further, as discussed below, the tubing-casing annulus will be continuously monitored for pressure communication with the injection stream.

The well is designed so that damage from slurry injection will be minimal. Any serious internal erosion damage (like corrosion damage) will most probably be detected prior to a leak occurring. Should a leak occur, the damaged equipment will be replaced. Ninety degree bends in the injection line and well head piping have been removed and internal dimensional restrictions minimized. These are the same erosion precautions that have been taken at the Prudhoe CC-2A and DS4-19 slurry injection wells.

The slurry will erode well perforations significantly. This is not a concern because if all the casing was eroded within a perforated interval, the result would be an open hole completion, the same as currently exists at CC-2A and is planned for the original completion on WD-1.

Cementing integrity should not be compromised. The compressive strength of the specified cement exceeds formation strength, and with the proper cementing procedure, bonding between the borehole and casing should be good. With the current well design, casing collapse is not possible. Again, experience at CC-2A, DS4-19, and Pad-3 verifies the mechanical integrity of the wells during slurry injection. In addition, the many Prudhoe Class II produced water injection wells have operated at bottom hole pressures greater than 4000 psi for years, and many producing wells are stimulated with bottom hole pressures exceeding the operating maximums listed in Exhibit 3-6.

The application includes two wells and the injection zone includes two distinct disposal intervals. As shown in Exhibit 5-1, any one well can safely store the maximum volume from a fluid flow, pressure buildup standpoint. It is therefore requested that no restrictions be placed on when each well is drilled or which interval it is completed in. Should it be advantageous to change construction and/or completion methods, BPX will apply for a minor permit modification in accordance with CFR 144.41 (f).

6.4 Mechanical Integrity

An injection well has mechanical integrity if there is no significant leak in the tubular goods and if there is no fluid movement through vertical channels adjacent to the wellbore that transmit fluids outside the injection zone.

The first component of mechanical integrity may be demonstrated by a pressure test. The casing-tubing annulus will be pressure tested to 3500 psi when constructed and to 2000 psi when injection commences. Assuming the well has been drilled, the results will be reported to the EPA within 45 days after the Class I permit is received. Additional pressure tests are performed after well workovers which affect the casing-tubing annulus and when necessary for diagnostic purposes. In addition, pressure monitoring of the annulus fluid permits an ongoing analysis of changing conditions. A small tubing-seal assembly or casing leak to the formation would be detected relatively soon via this route. In the situation of a significant loss of tubing-seal assembly integrity, the wellhead pressure would immediately be noted on the annulus by means of alarms installed on the wellhead. These alarms will enunciate in the control room area, and can be installed to shut down the injection process in the event of undue annulus overpressuring. Pressure testing will initially be conducted yearly to verify internal integrity of the system. The EPA will be notified in advance of running these routine mechanical integrity tests (MIT) so that a representative can be present. The Alaska Oil and Gas Conservation Commission has also volunteered to assist the EPA in witnessing any MIT.

The second component of testing involves running either a temperature, oxygen activation, or tracer log to demonstrate the lack of fluid movement through the vertical column adjacent to the wellbore that extends through the injection zone. The log will be run according to good operating practices and interpreted by a knowledgeable log analyst. One of the acceptable diagnostic logs will be run on each well every year initially, and the results reported to EPA within 45 days. The initial log will be run within 45 days after receiving the permit.

6.5 Annulus Pressure Monitoring

The tubing-casing annulus volume will vary, and the annulus fluid itself will expand and contract due to temperature changes. Therefore, pressure monitoring for leaks, either internally from the tubing-wellhead seal system or externally in the long casing string annulus, must take these fluctuations into account.

With an 8.6 lb/gal. fluid in the annulus, the internal hydrostatic pressure balances the original formation gradient. If a lighter fluid was present, an external casing leak would be reflected by a uniform rise in annulus pressure caused by the natural subsurface hydrostatic gradient. A heavier annulus fluid would bleed off to the formation and this would be reflected in a uniform loss of annulus pressure and in the glycol volume circulated for thermal protection. An internal leak from the tubing/packer side would be seen as the annulus pressure tracking the rise and fall of the injection pressure. Any of the above events would initiate an annulus pressure test and other diagnostics to pinpoint the location of the problem.

At the present time it is hard to specify exactly what high-low annulus pressure limits should be established to trigger a shutdown. Very probably, workable limits can be set in the range of 300-500 psi. The exact points will need to be established once a repeatable pattern of fluctuation has been established. This can be determined after several months of performance that would include both the summer and winter ambient temperature swings which affect this operation.

6.6 Confining Zone Integrity and Subsurface Waste Confinement

The following discussion addresses the environmental and safety risk associated with deep well injection of Northstar drilling, production, and domestic wastes. It focuses on the possibility of failure to keep injected waste confined to the subsurface strata located below the upper confining zone, approximately 3300 feet of depth. The purpose of the assessment is to provide discussion on potential problems, how these problems will be avoided, and how they will be handled in the unlikely event that they occur.

Wells will be drilled from a single offshore island as illustrated in Exhibits 6-1 and 6-2. The production and EOR injection wells will use surface casings set and cemented in the major SV1 shale barrier at approximately 4600 feet. These wellbores will be mostly vertical to this depth. From there they will be directionally drilled into the oil reservoir at 10,500 feet.

This type of well profile will provide approximately 2000 feet or more of separation between the oil well casings and the disposal well at the upper disposal interval. At the lower interval the separations will be greater. The waste disposal wells will be deviated at a depth of 500 feet and directed as shown on the spider map of Exhibit 6-2.

6.6.1 Risks of Interest

The Safe Drinking Water Act (SWDA) established the UIC program to protect underground sources of drinking water (USDW). The aquifers in the Northstar development area meet all the criteria for exemption; therefore, no risk exists of contaminating a USDW.

No natural faulting exists that is significant enough to provide migration paths for breaching the confining shales. This means that subsurface confinement can only be jeopardized by hydraulic fracturing of the confining zone, recirculation of wastes to the surface through a source water well, fluid migration through an uncemented annulus, or an uncontrolled flow while drilling a new well.

Since the saline aquifers above the confining zone will not be used as a water source, recirculation in this manner is not a possibility. The remaining three confinement issues are defined and discussed below.

6.6.2 Risk Discussion and Assessment

- Vertical Fracturing of the Upper Confining Zone :

By necessity, solids disposal will require placement of solids between fracture planes created and held apart hydraulically. Vertical and lateral growth of the fracture system occurs whenever a stress equilibrium does not exist between the rock of the receiving formation and the fluid leakoff rate. In the deeper sands a conventional fracture is expected to develop with an unknown amount of vertical growth. Fracture height, lateral growth, fracture width, and solids transport will be governed by the fluid leakoff rate and the interacting rock mechanics and fluid rheological properties. It is possible that these lower sands will eventually lock up and become useless. Further disposal would then have to move up-hole or to a new wellbore. The intermediate sands lying below the SV1 major shale barrier will likely develop a dendritic fracture system that would have secondary systems associated with a major fracture plane. A storage domain at this depth would provide 1400 feet of separation and numerous shale bodies between the injection point and the base of the confining zone.

As discussed in Section 3.2.3, fracture height is estimated to range between 250-500 feet, which generates a large safety factor.

Should the upper interval be required for disposal, it would be perforated in the basal few feet to provide maximum separation with the confining zone (1100 feet). As discussed in Section 3.2.1, if this interval is ever used it will most likely be later in project life when the waste stream has a solids content of less than 0.5 percent. Fracturing would be on a significantly smaller scale than during slurry solids injection. Comparing operating conditions at Northstar with performance at other long term disposal facilities indicates there is virtually no chance that the confining zone would be penetrated. Additional discussion on this point was included in materials distributed at the BPX-EPA Seattle technical meeting on February 5, 1997, and in correspondence to the EPA on May 12, 1997.

- Fluid Migration Through a Poorly Cemented Wellbore :

There are two concerns associated with upward fluid migration in a poorly cemented annulus. Firstly, should migration extend past the confining zone but then leak off to the overlying aquifers, there is a regulatory problem but no environmental or safety issue since fluids would be confined to the subsurface, and in this area the aquifers will be exempted and therefore no USDW will be compromised. More seriously, should migration somehow reach the surface, while no safety issue can be envisioned, contamination of the gravel island or Beaufort Sea might occur. For this to happen, fluids would have to move through the overlying normally pressured water sands and not be diverted laterally. It is hard to envision this occurring .

A casing that was not bonded to the formation would have that portion of the wellbore filled with gelled mud. Typically this mud weight overbalances the natural pressure gradient by +/- 0.07 psi/foot of depth. The upper injection and confining zones are 700 feet apart which generates an 49 psi density overbalance, even if no cement was present. Drilling mud also has a gel strength that has been reported to vary widely; but on average, this sealing effect alone is two to three times greater than the effect of mud density. This combined overbalance is significantly greater than the general increase in formation pressure due to disposal. Exhibit 5-1 shows that for a maximum disposal situation the expected increase is about 25-30 psi at a distance of 2000 feet; therefore, migration will not occur to the overlying aquifers due to an increase in reservoir storage pressure. With surface casings set below the arresting zone, good cement bonding should exist across that area and the confining zone. Only if a major fracture plane with high pressure intersected an uncemented wellbore would migration become a possibility. The probability of this occurring with the nearest wells 2000 feet away is extremely slight.

- Uncontrolled Flow While Drilling a New Well :

This risk exists because the fracture system will be at a hydraulic pressure somewhat higher than the fracture gradient, and thus greater than the pore pressure of the surrounding reservoir rock matrix. Should the drill bit encounter a major fracture plane and a high enough pressure exist at the time, flow into the uncased wellbore would result. An extreme case could allow flow to the surface until the fracture pressure was bled down.

The risk of intersecting a pressurized fracture system with the drill bit can be effectively managed by drilling the wells closest to the disposal well early in the sequence, when the fracture system is smallest. Flowable liquid volumes would also be smaller and less pressured. Should progressive events cause increasing concern or injection pressures indicate a change in the disposal program was needed, one alternative would be to minimize injection volumes by the use of annular pumping of mud and other rig liquids. Since most of the mud and clay solids generated while drilling below 5000 feet can be pumped with little or no grinding, half of the rig waste could go down open surface casing annuli if that became a desirable course of action. This would redirect a large volume from the disposal well fracture system.

Should flow enter a new wellbore either because of bit penetration or a result of extending fracture growth, the following actions would be taken.

1. The injection well would be shut in and the EPA notified of corrective plans.
2. The mud system would be weighted up to 13 #/gallon (0.68 psi/ft of depth) or the estimated fracture gradient.
3. If the new well continued to flow, a decision would be made whether to route fluids to tankage or shut in at the wellhead and risk breaking down the cement-formation bonding at the shoe of the surface casing.
4. If the well was shut in and the casing-formation bonding broke down, flow would enter the formations above the confining zone until the pressure bled off.
5. If the well was allowed to flow up the drill string to the surface it would be routed to tankage. Surplus fluid might be weighted-up and reused as additional kill fluid, and/or injection might be started into one of the oil reservoir EOR wells.
6. As a last resort, flow might be routed to an onshore pipeline or diverted to a surface impoundment area for later disposal and cleanup.

<u>Lower Disposal Interval</u> : The lower sands will produce vertical fractures with an unknown height and length. With over 3000 feet of standoff to the closest well, this

would provide a narrow and distant target for the drill bit to intersect. With the drilling crews alerted to a potential problem during the few hours this interval is being penetrated, the risk of an uncontrolled flow of significance is minimal. However, should concerns arise that a fracture system was extending further than expected, or subsequent oil reservoir definition require that later wells be drilled closer than desirable to a disposal area, selective setting and cementing of additional casing strings or redirection of well paths can compensate for any increased risk.

Upper Disposal Zone : It is not planned to inject solids-slurry into the upper zone. This interval would only be used as a last resort and then for low solids content fluids. The primary function of the upper zone is to dispose of produced water and other liquids later in field life should that be necessary.

6.6.3 Comparison With Similar Disposal Projects

There are five waste disposal, injection projects that can be used as analogies to Northstar. Four of them are on the North Slope and one in Canada. Their relevance is as follows.

- Prudhoe Bay CC-2 Facility :

This disposal plant has been in operation six years, grinding up drill cuttings for injection into a single Class II well. Disposal volume is over 8 million barrels as shown in Exhibit 6-3. With a solids content estimated at 7-8 percent, 640,000 barrels of solids have been injected through an open hole completion at 3500 feet. The facility and well have operated without significant problems and no negative environmental impact. Oversight is provided by the Alaska Oil and Gas Conservation Commission.

- Prudhoe Bay Pad-3 Facility :

Since 1979 this facility has injected 9 million barrels of wastes which often included a significant volume of solids (Exhibit 6-4). At an estimate of 2 percent, this means 180,000 barrels of solids have been injected. These three Class I wells are completed at 2000 feet, just under the permafrost with 30 feet of separation. They are located about 600 feet from the edge of a development drilling pad with over 40 wellbores. Extensive logging and field testing have not detected any up-hole channeling or other problem. Oversight is by the Region 10 EPA Office and the Alaska Oil and Gas Conservation Commission.

- Prudhoe Bay DS4-19 Demonstration :

Operations were initiated at this facility during the Spring of 1995 to test the feasibility of using grind-inject technology for reserve pit closure on a large scale. Injection rates were high with solids slurry placed in the same zones as those proposed for Northstar. The single injection well performed as planned and no uphole communication was detected by the many surrounding pad development wells until March 1997. At that time approximately 2 million barrels of reserve pit muds and cuttings had been disposed of at injection rates of 22-27 barrels per minute (31,680 - 38,880 barrels per day).

- Endicott Island Disposal Well :

At the Endicott oil field (Duck Island Unit) just offshore of Prudhoe Bay, Class II disposal well 2-02/P18 has injected 6 million barrels since 1987, as shown on Exhibit 6-5. The solids content is less than one percent. The well is located on a drilling island with 55 other wells, all on 10-foot centers at the surface. Waste disposal at a depth of 7000 feet has been confined even though numerous wellbores pass within several hundred feet of the disposal well perforations.

- Lloydminster, Alberta Canada, Celtic Formation Fines Disposal Project :

Approved by the Canadian Government, this plant has operated for several years disposing of large volumes of formation fines and sand generated by a steam flooded oil reservoir. Injection rate is reportedly high, at a depth of 2000 feet. No other operating details are known.

The relationship of these North Slope facilities, and others, to the proposed Northstar project is tabulated in Exhibit 6-6.

6.6.4 Summary/Conclusions

- The USDWs in the Northstar development area qualify for exemption status and therefore no risk of drinking water contamination exists.

- Risk is influenced by the lateral separation between disposal point and offset wellbores. Therefore the risk of having to deal with a fluid confinement issue can be significantly reduced by selecting the proper disposal well location relative to other wells at the injection depth, and by establishing the correct drilling order.

• Confinement problems should not occur due to fracturing of the confining zone or migration through an uncemented annuli. BPX feels this is substantiated by data included within the application, correspondence transmitted to the EPA on May 12, 1997, and material distributed at the February 5, 1997 Seattle technical meeting.

• Should an uncontrolled flow into an uncased wellbore occur, it can be successfully dealt with so that no serious impact results. No unusual safety risk to personnel or equipment has been identified and the potential environmental risk is manageable.

• Proper monitoring of injection operations should provide an indication of the level of risk developing as the disposal process unfolds. If necessary, fracture growth can be minimized by initating the use of annular injection for drilling wastes generated from the lower section of each new well. However this type of corrective action should not be required.

• This assessment by necessity involves subjective judgments and some uncertainty. However the factual data, available scientific correlations and methods, and relevant comparisons with similar projects underpin those judgments. It has been determined that with proper planning and monitoring, the environmental and safety risks are extremely low and can be effectively managed. This assessment substantiates the BPX position that deep well injection is the most environmentally sound method of permanent waste disposal.

• BPX is confident that mitigation of the problems discussed can be managed at an acceptable cost and the impact of an event can be successfully handled should one occur. It is felt the risk of environmental damage should be viewed as minimal to non-existent.

6.7 Protection of Offshore Waters

Based on the above analysis, fractures can not be expected to penetrate the 290 foot thick confining zone. Subsurface confinement of injected fluids is further guaranteed by the overlying intermittent siltstone layers and the 1500-foot-thick permafrost interval.

6.8 Ambient Monitoring of Overlying Strata

It has been demonstrated in Section 4.0 that the Northstar aquifers qualify for exemption status. Section 5.0 and Appendix E demonstrate that there are no improperly sealed, completed, or abandoned wellbores within the AOR, and Section 3.0 data shows that the geological formations are continuous and not significantly faulted in the area. It has been shown above that while fracturing will occur at the injection well, it will be confined to the injection zone, and the risk of penetration of the confining zones is virtually non-existent. BPX therefore proposes not to conduct ambient monitoring in the saline aquifers overlying the upper confining zone.

Waiver Request: Accordingly, a waiver is requested from 40 CFR 146.13(b) requiring ambient monitoring of overlying strata. This request is consistent with 40 CFR 144.16 which allows the Director to waive monitoring requirements when there are no recognized USDWs to protect.

6.9 Reporting

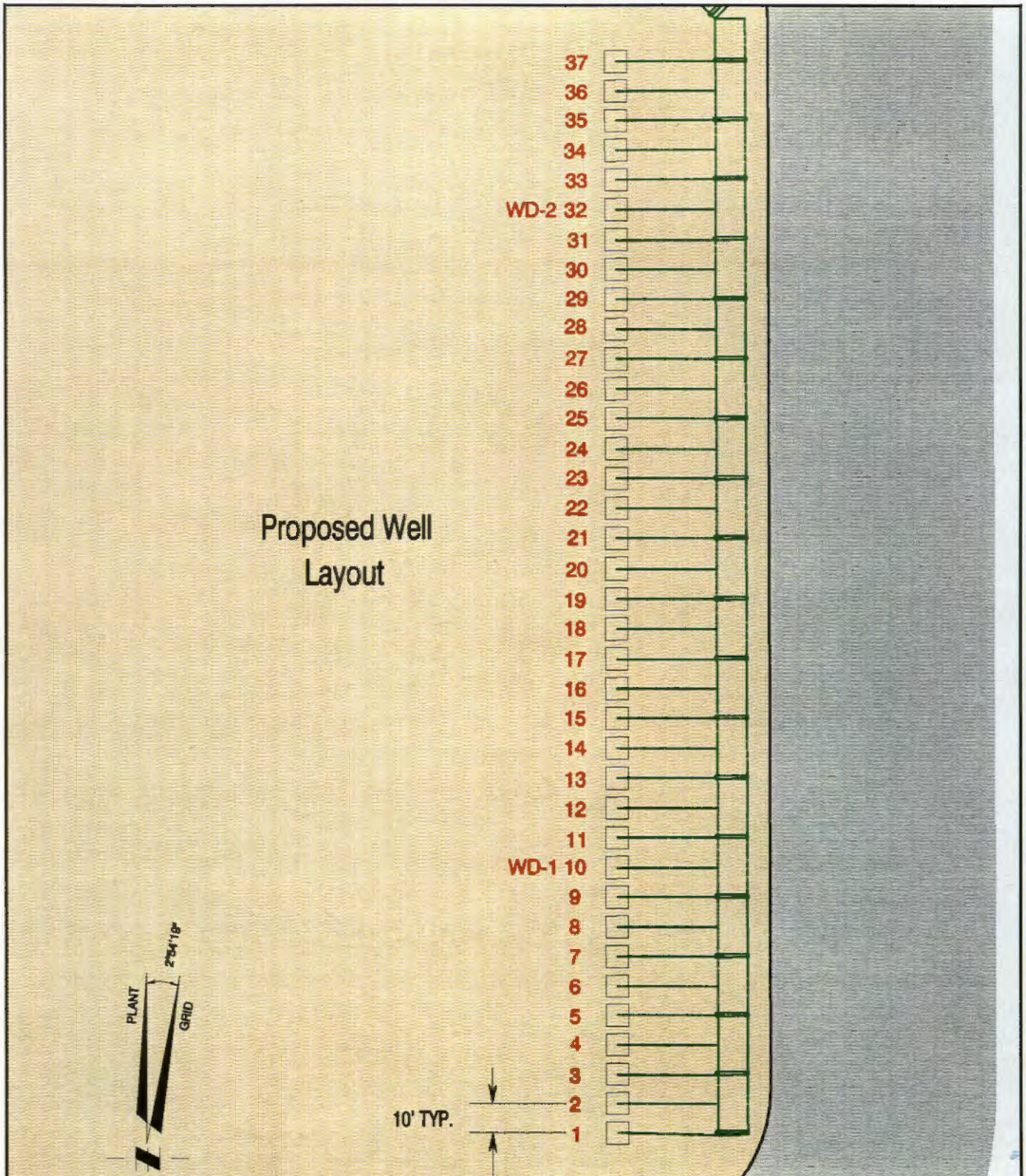
Quarterly reports will be submitted to the EPA. These will be based on the calendar year and will be submitted by the last working day of the month following the end of the quarter. A report will be prepared on each drilled and completed Class I disposal well and will include:

(1) EPA Form 7520-8 (2-84).

(2) A cover letter signed by the Manager of Northstar Field Operations, certifying, as in CFR 144.32, to the truth and completeness of the information.

A yearly report summarizing twelve months activity will be submitted per EPA Form 7520-11 (2-84).

Exhibit 6-7 certifies the Northstar Field Manager, as a duly authorized representative of BPX for the purposes of reporting to the EPA.



WD-1
EAST 659,962.78
NORTH 6,031,014.63

WD-2
EAST 659,951.26
NORTH 6,031,234.32

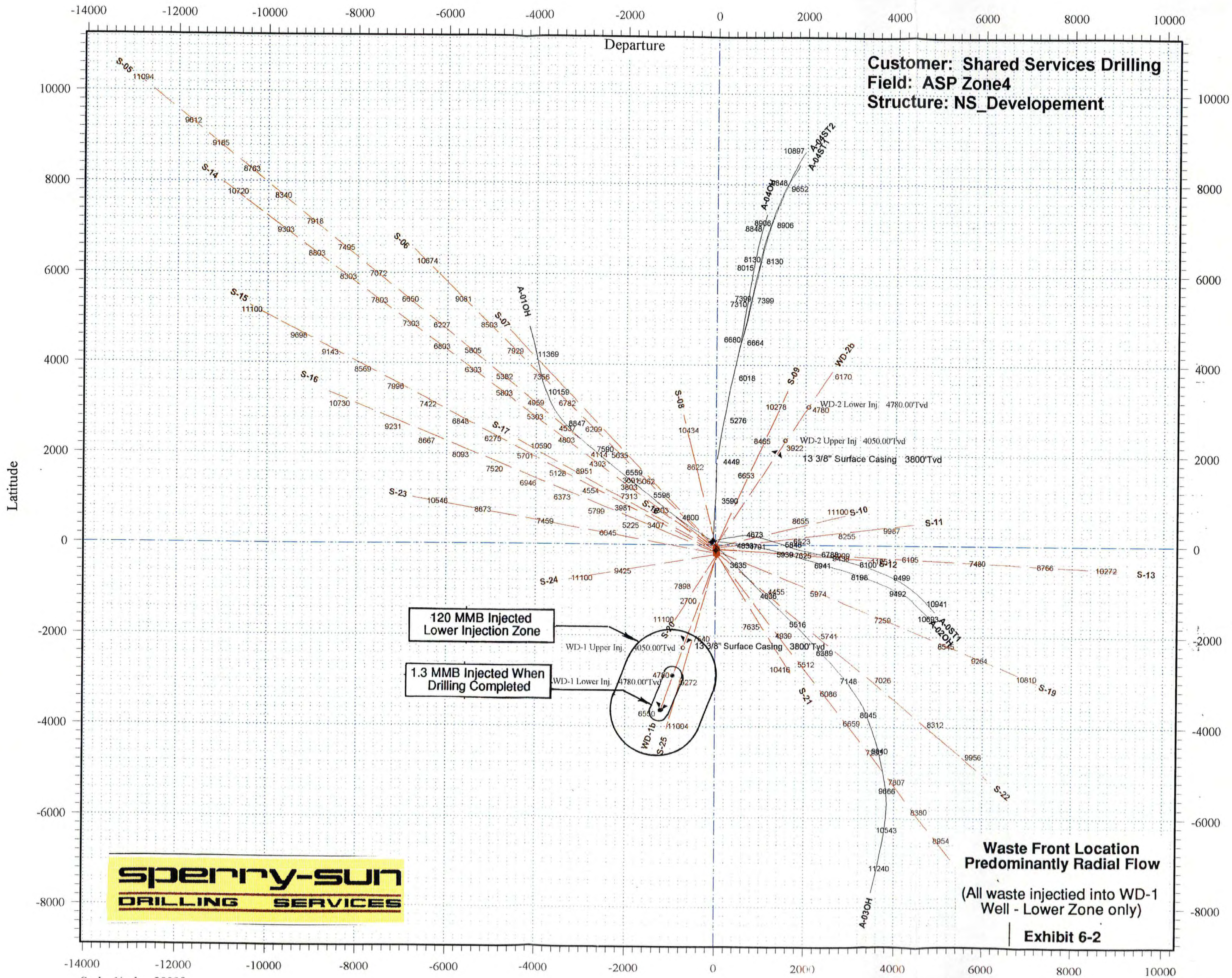
Coordinates are ASP4
NAD 1927

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
WELL SURFACE LOCATIONS

DATE:	SCALE:	EXHIBIT:
8/28/97	1" = 60'	6 - 1

bs13106.dgn



Departure
Latitude
Customer: Shared Services Drilling
Field: ASP Zone4
Structure: NS_Developement
120 MMB Injected
Lower Injection Zone
1.3 MMB Injected When
Drilling Completed
WD-1 Upper Inj. 4050.00'Tvd
WD-1 Lower Inj. 4780.00'Tvd
13 3/8" Surface Casing 3800'Tvd
WD-2 Lower Inj 4780.00'Tvd
WD-2 Upper Inj 4050.00'Tvd
13 3/8" Surface Casing 3800'Tvd
sperry-sun
DRILLING SERVICES
Waste Front Location
Predominantly Radial Flow
(All waste injectied into WD-1
Well - Lower Zone only)
Exhibit 6-2

Exhibit 6-3

Well CC-2A Injection

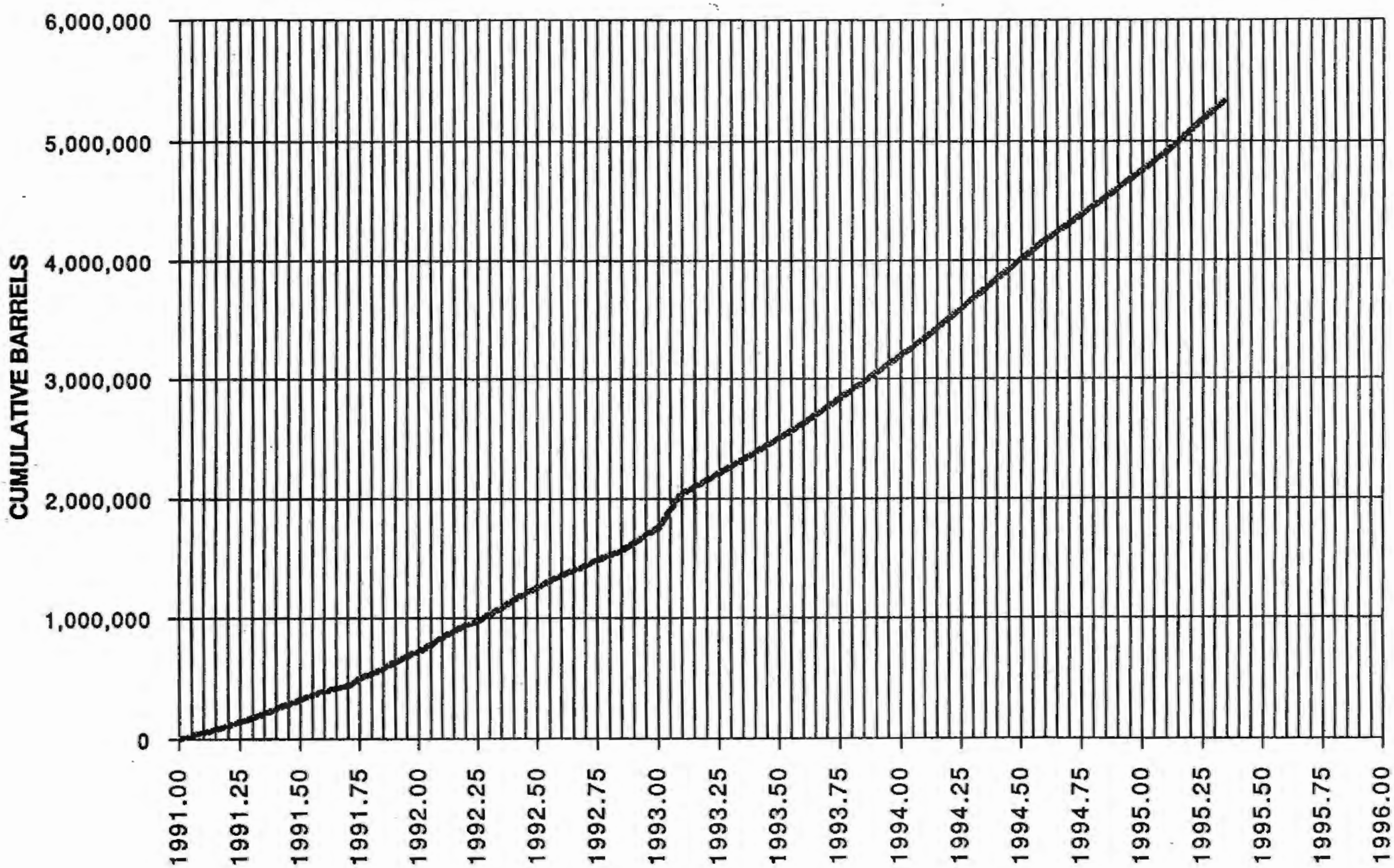


Exhibit 6-4

Pad-3 Injection

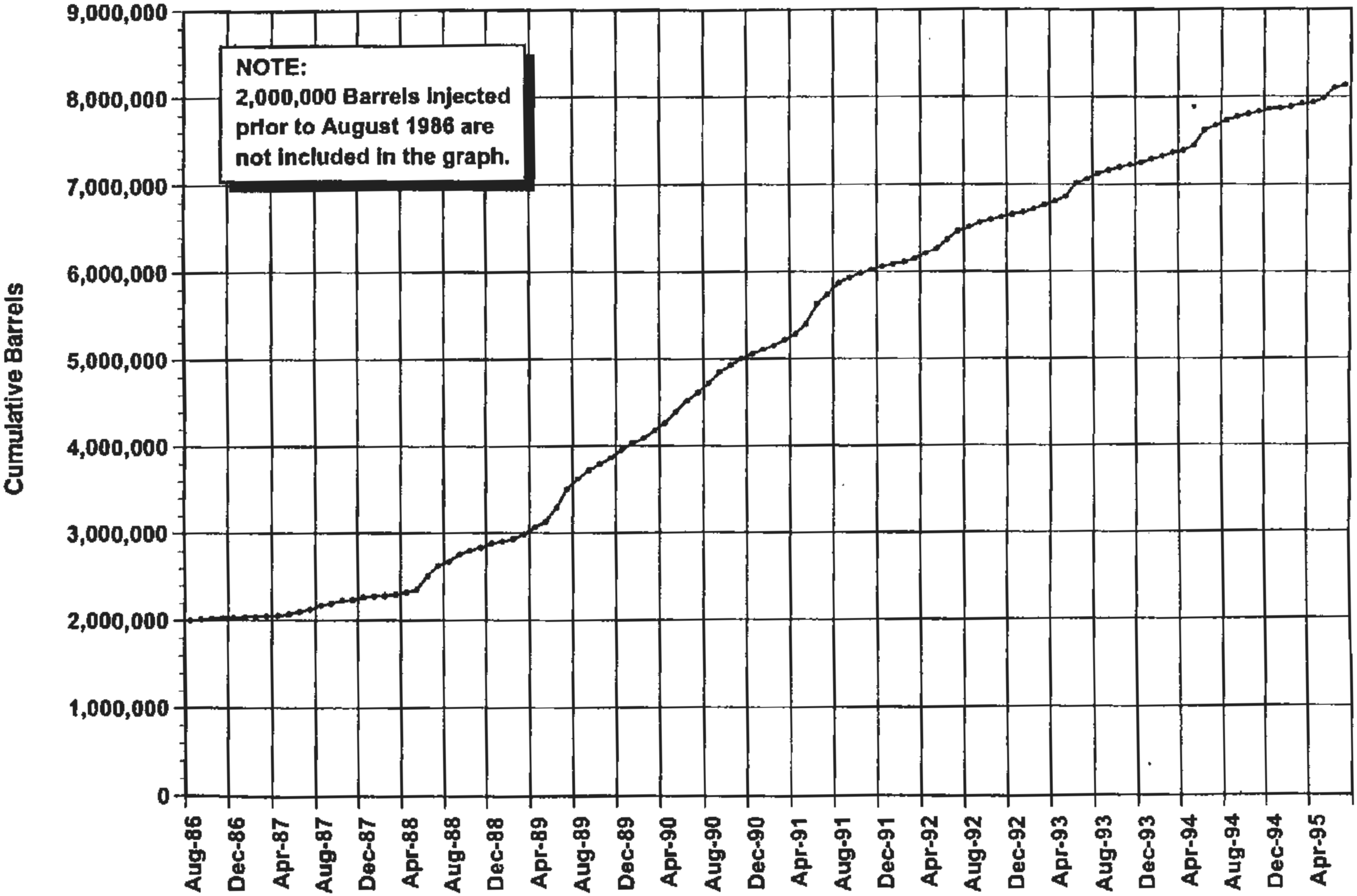


Exhibit 6-5

Endicott Well 2-02 Injection

Cumulative Disposal

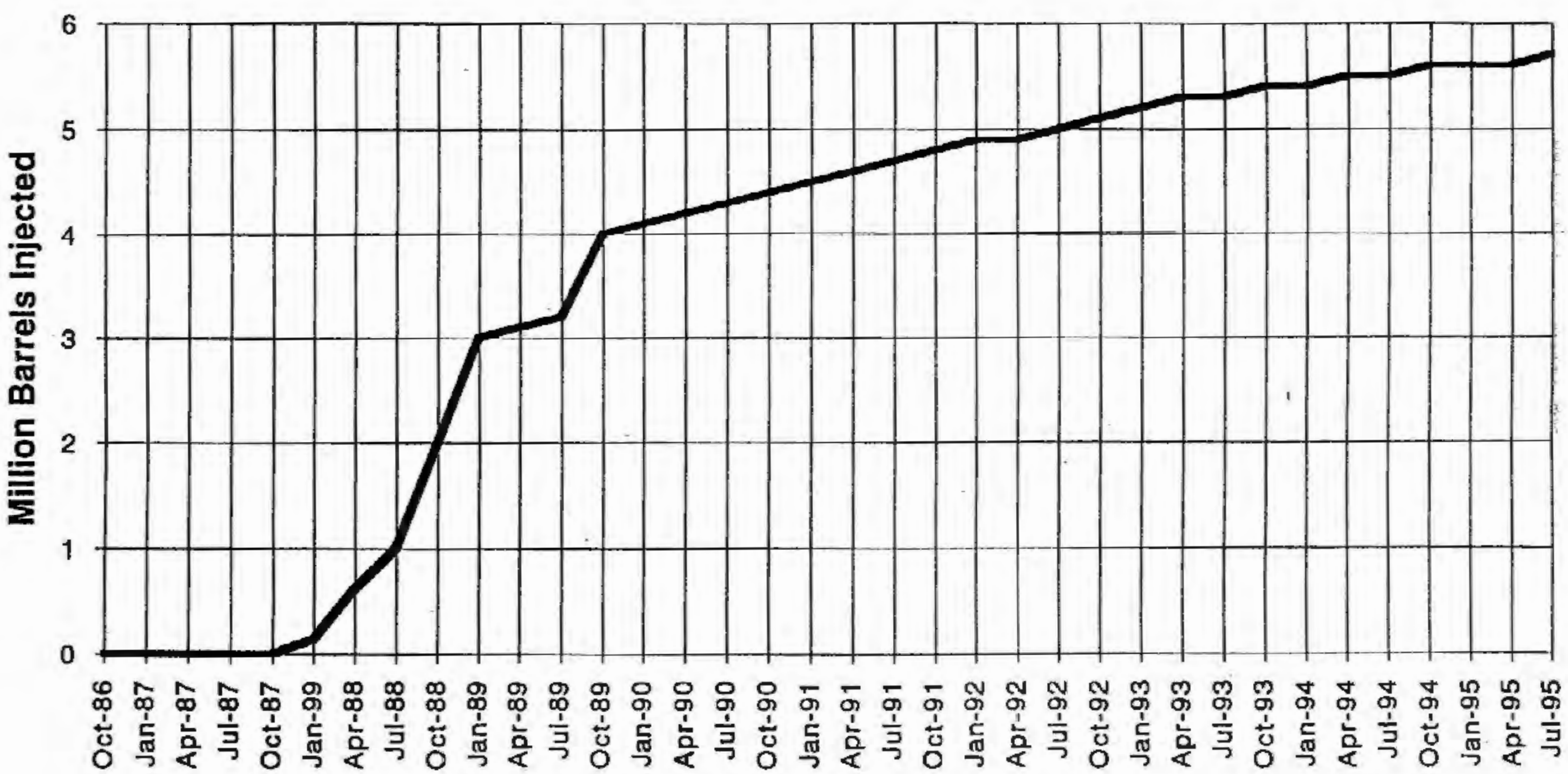


Exhibit 6 - 6 (Revised 11/96)
North Slope Solids Disposal and Fluid Confinement (1/96)
Comparison to Northstar and Badami Projects

Facility	Injection Volume (Bbls)	Solids Volume (Bbls)	Instant Rate *(BPM)	Injection Depth (Feet)	Distance to Other Wells (Feet)	Fluid Confinement Data
CC-2	8 MM	624 M	3-10	3500	+/-2000	J-pad located 2500 ft. away but may be off fracture direction. N-pad at 7000 ft. and Q-pad at 5200 ft. Three year average rate 4.4 BPM. (Volumes are thru Sept. 1996).
Pad-3	9 MM	+/-200 M	1-5	2000	600-1000	DS-6 located on strike with numerous wells within 1200 ft. All surface casings set below injection depth. Suspect horizontal fracture of limited radius and small reservoir pressure buildup. Shales at base of permafrost are sealing. (Volumes are thru July 1996).
DS4-19	38 MM	<0.1%	8-30	5930-6900	400-1500	Produced water disposal prior to slurry injection.
DS4-19	5 MM 4 MM	1137 M <0.1%	22-27 22-27	5622-5627 5622-5627		Solids disposal test at high rates. Numerous pad wells within 400-1500 ft. Seismic events seem to indicate communication up to +/-4200 ft. No communication with offset wells. Extensive annular and seismic monitoring programs are ongoing. (Volumes are thru May 1996).
Endicott P-18	6 MM	<0.1%	1-6	7200	+/-300	Several wells within 300 ft. at injection depth. No reports of uphole fluid migration. Reservoir pressure build up at 300 psi level.
GC-1 GC-2 GC-3	158 MM 138 MM 83 MM	<0.1% <0.1% <0.1%	7-40 7-27 7-10	5000 5000 5000	300-3000 300-3000 300-3000	No annular communication problems at adjacent wells or on surrounding pads at 3000 ft. Pressure at outlying pads up +/-200 psi.
Northstar Project	116 MM 4 MM	<0.1% 80 M	3-20 3-5	4000-6500 4000-6500	+/-2200 +/-2200	Produced water disposal volume (Maximum case). Project operational wastes. Average slurry injection rate is 1 BPM. Distance to other wells is 2200 ft., more at depth. Surface casings set below upper confining zone.
Badami Project	4.3 MM	60 M	3-5	5000-7200	+/-2300	Distance to other wells is 2300+ ft. Surface casings set in upper confining zone. Average rate during slurry injection is 1 BPM.

*(BPM = Bbls per minute)

BP EXPLORATION

Exhibit 6-7

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

June 25, 1996

EPA Region 10
1200 Sixth Avenue
Seattle, Washington 98101

RE: Duly Authorized Representative
BP Exploration (Alaska) Inc.

In compliance with 40 CFR 144.32 (b), the Northstar Field Manager is appointed the duly authorized representative of BP Exploration (Alaska) Inc. for purposes of reporting to the U.S. Environmental Protection Agency. The field manager has responsibility for the overall operation of the Northstar Unit, North Slope, Alaska.

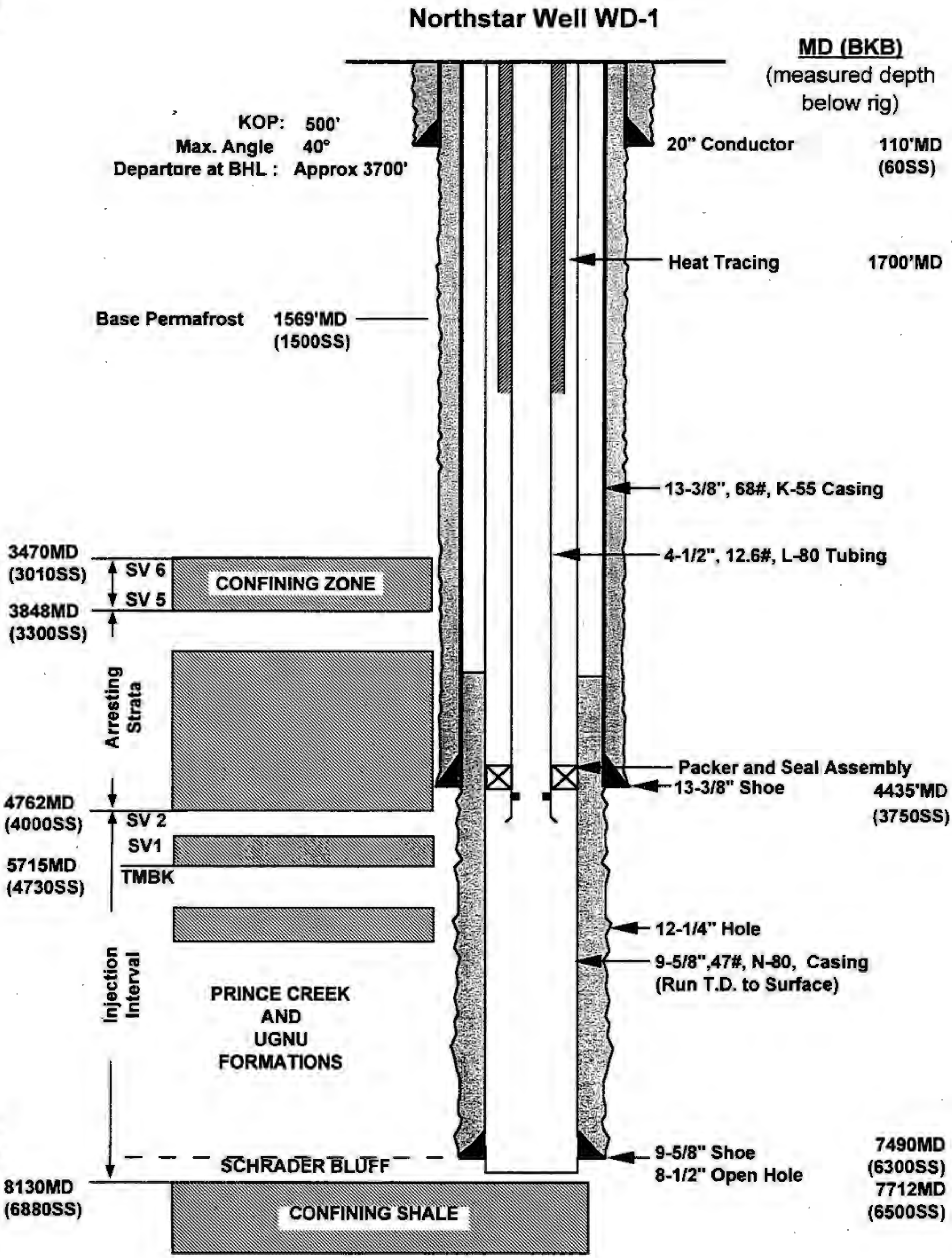
The scheduled quarterly reports filed by the field manager will include a cover letter bearing the recital of certification of truth and accuracy as specified in 40 CFR 144.32 (d).

Sincerely,

Steven D. Taylor
Manager, Environmental and Regulatory Affairs
BP Exploration (Alaska) Inc.

Exhibit 7-1 (revised)

Proposed Completion Diagram



8.0 Waste Minimization, Segregation, and Analysis

8.1 Pollution Prevention and Waste Minimization Plan

8.1.1 Major Organizational Efforts

As sole operators of the various North Slope oil fields, BPX and ARCO Alaska Inc. (ARCO) pursue pollution prevention and waste minimization opportunities for a wide range of waste streams. A global objective of pollution prevention, waste minimization, segregation, and recycling is to achieve environmentally sound operating practices while minimizing long term cost and liability associated with waste generation. Given the high cost of waste handling, transportation, disposal, and the limited availability of disposal options, there is considerable economic incentive to pursue this objective. Each operator is responsible for implementing programs designed to achieve specific company objectives for pollution prevention and waste minimization. Successful waste minimization programs of both BPX and ARCO will be the basis for future North Slope implementation.

Many successful minimization programs and initiatives have been implemented over the past few years.

In 1992, a significant major effort was undertaken to bring ten major industry and governmental organizations together to form the North Slope Pollution Prevention Committee. Participants are The North Slope Alliance, BPX, ARCO, Alyeska, North Slope Borough, Environmental Protection Agency - Alaska, Alaska Department of Environmental Conservation (ADEC), CH2M Hill, and Fluor-Daniels. The committee's charter involves identification of pollution prevention opportunities, promoting the concept of pollution prevention, breaking down barriers to prevention options, creating incentives for pollution prevention, determining technical assistance needs, and providing training. The Alliance, ADEC, and North Slope operators have been working together cooperatively since 1990 on pollution goals. Major accomplishments to date include:

(1) Recycling over 25,000 tons of scrap steel and 200,000 pounds of lead-acid batteries.
(2) Reclaiming many abandoned camps.
(3) Reducing North Slope spill volumes by 89 percent.
(4) Formalizing an Industry/Agency Pollution Prevention Task Force and its charter in 1992.

The committee's 1993 study initiatives involved on-site recycling of used oil/petroleum hydrocarbons, mobile glycol recycling, publishing a product substitution guide, implementing the Alaska Materials Exchange Program and conducting environmental training.

BPX sponsored a Pacific Northwest Pollution Prevention Research Center (PPRC) roundtable discussion of pollution prevention in the exploration, production, and drilling segments of the Alaskan oil and gas industry (December 1992). The purpose was to explore areas relating to pollution prevention including current practices, prevention opportunities, areas of research, and sources of information transfer. Participants included 27 representatives from industry, regulatory agencies, academia, and the PPRC. The group recommended thirteen specific research and educational projects be pursued.

BPX is also working with the Halon Alternatives Research Corporation (HARC) to find replacements for halon (an ozone-depleting chlorofluorocarbon). Large volumes are currently being used as a fire and explosion suppressant. HARC is also investigating the possibility of creating a recycling program for halons.

A major component of pollution prevention and waste minimization programs involves increasing the environmental awareness of all BPX employees and contractors. All individnals working at BPX North Slope facilities must attend an introductory environmental awareness class entitled Achieving Environmental Excellence prior to starting their jobs. In addition, an annual refresher is required to update employees on issues of concern or changes in our environmental programs. In addition, each BPX operated field has a local health-safety-environmental (HSE) committee that ties into an inter-company HSE Forum that meets monthly.

8.1.2 Specific Waste Minimization and Prevention Activities

Following are examples of specific field-wide programs designed to minimize, segregate, recycle, or permanently dispose of oil field related wastes.

- Drilling Muds and Cuttings

The past practice of surface disposal of muds and cuttings in reserve pits has been eliminated. The drilling of side-track and slim-hole wells in lieu of a traditional conventional well has reduced the volume of surface cuttings generated from drilling operations by approximately 50 percent. This has also reduced the volume of mud used. Also, using state-of-the-art shale shakers, desanders, desilters, and centrifuges to clean the circulating mud permits engineers to look at different ways to further clean up muds for reuse. Approximately 6,000 barrels per month are currently recycled for use in subsequent wells.

In the summer of 1992, a BPX-ARCO joint drilling organization completed a 10 well pilot program to reclaim, wash, and test drill cuttings generated in the upper 3,500 feet of surface hole for reuse as road and pad construction material. The results of this pilot program are continuing to be expanded and could lead to reuse of 25 to 30 percent of the solid wastes generated from each new well. In 1995, approximately 1530 yards of surface hole cuttings were reused in this way.

Grind and inject technology has been developed by the two joint North Slope operators to provide another means to eliminate the surface discharge of muds and cuttings. The process involves crushing the larger particles of drill cuttings and mixing them with mud. These wastes not suitable for reuse are processed through portable ball mill units located at the drill rigs and are permanently disposed of by annular injection several thousand feet back into the earth where the cuttings originated. For drill rigs not capable of handling all on-site solids disposal needs, the solids are trucked to the Prudhoe CC-2 grind and inject facility for similar processing and disposal in the Class II CC-2A injection well.

Drilling and production wastes represent the large majority of solid material which is handled and disposed of at the CC-2 facility. This includes drilling muds and cuttings, frac sand, pipeline and production vessel sludge/sand. (In early 1996, an oily solids processing system was commissioned which grinds and permanently disposes of tank sediments and other heavily oiled solids.) These wastes are now injected whereas before oily wastes were directed to the Pad-3 temporary storage cells.

- Hazardous Wastes

BPX strives to minimize the amount of hazardous waste shipped to off-site disposal facilities by source reduction and on-site recycling and reuse. In 1995, approximately 16,213 pounds of hazardous waste was generated from BPX operated facilities at the main Prudhoe Bay field. This was an increase from the 1993 volume of 10,600 pounds due to correspondence from the EPA Region 10 office stating that they did not yet concur with BPX's recycling of stoddard solvent. The BPX five year average is 13,496 lbs/year. At the offshore Endicott field, reductions were down 59 percent from 1991 to 1995. It's four year average for shipment was 940 lbs/year. The recently acquired Milne Point Field generated 2,344 pounds in 1995. The Northstar project is expected to generate much less than the Milne Point of Endicott facilities.

Most of these wastes are generated by episodic events like accidentally filling a diesel truck with gasoline, accidentally mixing a hazardous waste with a large volume of non-hazardous material, or from excess products resulting from over ordering material. BPX is committed to minimizing hazardous wastes at Northstar.

- Non-hazardous Fluids for Recycle to Enhanced Oil Recovery (EOR)

Small volumes of aqueous waste streams are also now being directed to EOR. In 1995, BPX received formal approval from the Alaska Oil and Gas Conservation Commission to utilize a number of non-hazardous waste streams as EOR fluids including:

(1) Treated effluent from the sewage treatment plants.
(2) Water left over from well drilling and workover operations.
(3) Miscellaneous rinse waters from drilling operations.
(4) Vehicle wash water.
(5) Precipitation which accumulates in containment areas.

At the Milne Point operation, this approval has allowed surface discharge of treated sewage to cease and approximately 14,000 gallons per day of effluent are being used for EOR. In addition, approximately 27,080 barrels of miscellaneous fluids, fitting other categories on the approved list, were directed to EOR in 1995. For the same year, the Endicott facility recycled approximately 28,600 barrels of these miscellaneous fluids to EOR.

- Proppant Recovery and Reuse

Certain well stimulations utilize proppant or "frac sand" to fill the producing formation fracture space created during a well stimulation. The stimulation objective is to pack the frac sand in the formation fracture and keep it there, resulting in increased well productivity. Prior to bringing a well on line following a frac job, the well can be surged to flow-back "loose" frac sand which is then held in a flow-back tank at the surface. Over time however frac sand can build up in the well bore and screen out the perforations. In this situation a wellbore clean-out may be conducted which will generate frac sand as a waste. The primary disposal option for this sand has been to place it in lined storage pits. During 1992, frac sand grinding and injection at CC-2 was successfully demonstrated and has since been incorporated into BPX operations. Frac sand is an inert ceramic material which if cleaned may be suitable for reuse as road or pad construction material when mixed with native gravel. Cleaning and reuse will continue to be evaluated for cost effective reuse alternatives.

- Contaminated Gravel

In nearly all situations, contaminated gravel is the result of spills associated with various oil field activities. The large majority of spills are of small volume and are caused by transportation, handling and transfer of fuel, crude oil and chemicals. Through training, education and increased use of permanent and portable liners and sorbent material, there has been a reduction in the number of small spills, and the resulting contaminated gravel. In 1991, BPX instituted a mandatory spill prevention program which requires all contractors performing activities with spill potential to use portable liners and sorbent material at critical locations. In the BPX operated area of the main Prudhoe field, the result has been a steady decline in the number of reportable spills from 157 in 1993 to 80 in 1995.

During the winter months, further minimization of contaminated gravel has been achieved by leaving a compacted layer of snow on roads and pads subject to spill potential. For most small spills not captured by liners or sorbent material, the natural sorbent action of the snow layer reduces the spreading of a spill and in most cases prevents contamination of gravel. In many cases the contaminated snow can be melted to recover the spilled product for reuse. Hydrocarbon based contaminants can be recycled in the production facilities.

When gravel becomes contaminated, an alternative to disposal in lined pits is treatment by incineration or water washing to allow reuse as road or pad construction material. This material can meet background standards, therefore substitution for "new" gravel is possible. One benefit of this remediation is reduced demand for developing or expanding surface mine sites. In 1992, 30,000 yards of contaminated gravel from BPX's Niakuk exploratory island was thermally remediated to be used for road and pad maintenance. Since 1992, contaminated gravel suitable for thermal treatment has been segregated and stockpiled at the Prudhoe Bay Pad-3 facility for reuse. Historically 1,000 - 1,500 yards per year have been reclaimed. Another treatment option which is being tested for contaminated gravel and soil, is in-situ bioremediation. Increased use of these and other treatment/reuse options will continue to be pursued.

- Produced Water

Produced water and gas are reinjected to maintain reservoir pressure and sweep residual oil from pore spaces in the reservoir rock. This process is known as enhanced oil recovery. Approximately 85 percent of the produced water (oil reservoir brines) on the North Slope is recycled in this manner. At the BPX operated Milne Point and Endicott fields, 100 percent is used for EOR.

- Miscellaneous Surface Waters

These waters include snow melt and precipitation, some runoff from rig wash, etc. The bulk of this volume involves the dewatering of reserve pits each summer to minimize leaching to the tundra. Several million barrels of pit water are trucked and injected each year into the Cretaceous formation Class II disposal wells.

- Closure of Reserve Pits

BPX and ARCO are researching the most environmentally sound and cost effective means of closing existing reserve pits. Grinding and deep well injection of reserve pit contents is being tested with a large pilot plant as one potential technique. Research is being conducted on alternative excavation techniques for the muds and cuttings in reserve pits and the drill site #4 disposal demonstration is again in operation during the winter and spring of 1995-96.

- Domestic Waste Recycling

BPX and ARCO have undertaken a recycling effort to minimize the volumes of domestic solid waste that is disposed of at the North Slope Borough landfill. Aluminum, high grade ledger paper, newspaper, and poly-styrene beverage and food containers are being collected and consolidated for shipment to recycling facilities in Anchorage and the Lower 48. These efforts have resulted in a substantial decrease in the waste entering the North Slope Borough facilities. Last year 188 tons of paper, 650 pounds of aluminum, and 209 laser printer cartridges were recycled.

- Scrap Metal

BPX and ARCO, in cooperation with the Prudhoe Bay Environmental Alliance, have arranged for sea lift back-hauls of recyclable scrap metal located throughout the North Slope area. Three of these back-hauls have occurred since 1989. The 1993 scrap lift resulted in 7,000 tons of metal being shipped to scrap metal dealers on the West Coast. Approximately 2,760 tons were shipped from BPX facilities in 1995. Progress is also under way to arrange for scrap metal back-hauls to dealers in Fairbanks, Alaska.

- Used Oil

In accordance with EPA guidelines established in the fall of 1992, used oil is being recycled by pumping it into the crude oil stream for down-stream refining. This practice has resulted in approximately a 75 percent drop in the volume of waste fluids transported from the North Slope for processing elsewhere. Last year over 20,000 gallons were recycled in this manner.

- Used Solvents

Ways to beneficially reuse spent solvents are currently being investigated. Using solvents as replacements for new products used to freeze protect production wells is a process that was undertaken and resulted in a 50 percent reduction in these waste streams. This substitution results in an onsite recycling mechanism for a waste stream that previously was transported to the West Coast for blending into cement kiln fuels. This practice has been largely suspended pending more review by the EPA.

- Used Glycol

Used anti-freeze is being recycled through a simple regeneration system for reuse. Research is currently underway to determine if there are means to expand the glycol recycling capabilities.

- Alternative Products

There is a continual search for environmentally safer products to minimize waste generation. An example is the conversion of the entire motor fleet at Prudhoe to propylene glycol which is far less toxic to the environment than ethylene glycol. Citrus based solvents are being tested as alternatives to petroleum based solvents used in parts cleaning and degreasing. Drilling operations have expanded use of lead-free pipe dope for the protection of pipe threads.

BPX has continued its practice of buying chemicals on an as-needed basis instead of in yearly anticipated volumes. This eliminates chemicals being disposed of as off-specification due to exceeding shelf life. Chemicals are also purchased in bulk containers whenever possible. This has eliminated the necessity to dispose of chemicals left over in drum stock as well as reduced the disposal of drums.

- Naturally Occurring Radioactive Material (NORM)

NORM is produced in solution with oil field brines and deposited as scale on the inside of vessels and piping. The Operators have consulted with state and federal agencies to develop a safe and effective handling/disposal program. The Alaska Oil and Gas

Conservation Commission authorized disposal of NORM by underground injection in Class II wells or by mixing with cement slurry for use in well abandonment activities.

In early 1993, the Operators contracted with an experienced firm to clean and process NORM scale from about 3,000 tubulars (pieces of well pipe) stored on the North Slope. This process uses a new, state-of-the-art, closed-loop hydroblasting system which provides complete containment of all NORM solids and vapors. The NORM material was disposed of by Class II injection at the CC-2 facility. Approximately 1700 more tubulars are stored awaiting the next cleaning cycle.

- Materials Exchange

BPX and ARCO, in cooperation with the Prudhoe Bay Environmental Alliance, have developed a materials exchange program for the North Slope operators and contractors. This Exchange creates a mechanism to advertise goods that are no longer needed by one company and provide them to others that may have a use. This centralizes the recycling effort and reduces the amount of materials entering the waste disposal process.

8.2 Segregation of Class I and II Wastes at Northstar

Class I and II wastes will not be segregated for the following reasons:

- It would be expensive to install facilities to handle the Class I industrial liquids separately. This would also be accompanied by increased operating costs as discussed in Section 2.0. In addition, either a Class I municipal waste disposal well would have to be permitted or camp sewage would be discharged to the Beaufort Sea under an NPDES permit.

- There would be no way of handling any Class I solids except at a large expense, even when lightly contaminated. Disposal would have to involve incineration, transportation, or pit storage as discussed in Section 2.0.

- There is no regulatory need for segregation since well construction and operation adheres to Class I standards, and both classes of waste can go down the Class I well, provided the EPA grants the regulatory permit.

- No long term storage or blending will occur that requires segregation and special handling, and no wastes leave after arrival except as noted below (unless some extreme condition develops where gravel or oily material might be incinerated elsewhere).

• No radioactive or hazardous materials are produced at the facility. Class I hazardous wastes that are generated will be segregated for storage and shipped to an authorized disposal site.

8.3 Analysis of Injected Fluids

BPX will control for disposal only wastes generated by unit operation of the Northstar facilities, or by contractors under BPX control working at the complex. Wastes from non-unit or third party generators will not be accepted. Since the complex is not connected to a road system, uncontrolled third party access is not possible. Only RCRA exempt and non-exempt, non-hazardous wastes will be injected.

Non-hazardous fluid determinations may be made based on laboratory data, material safety data sheets, and generator knowledge. "Personal knowledge" of a waste product may be substituted for analytical data according to 40 CFR 262.11 (c)(2), and therefore sampling and analysis may not be necessary for:

(1) RCRA exempt oil-gas wastes.
(Chemical analysis is not required unless the operator desires it.)
(2) Known non-hazardous industrial wastes as described in the Waste Analysis Plan.
(3) Domestic waste water streams.

Exhibit 8-1 summarizes how the individual wastes described in Section 2.2 are combined to form the composite disposal stream. The main waste generators are the drilling rig and grinding plant complex, the process facilities, and the field camp. The result is the following projected disposal volumes, assuming a maximum produced water disposal situation develops.

Rig muds and other liquids	360,000 Bbls
Rig drill cuttings and other solids	80,000 Bbls
Flush waters for cuttings disposal	60,000 Bbls
Camp sewage and gray water (Class I)	600,000 Bbls
Wells, process facilities, etc. waste	400,000 Bbls
Industrial non-hazardous wastes (Class I)	40,000 Bbls
Produced water (oil reservoir brine)	~118,500,000 Bbls
Total disposal volume	~120,000,000 Bbls

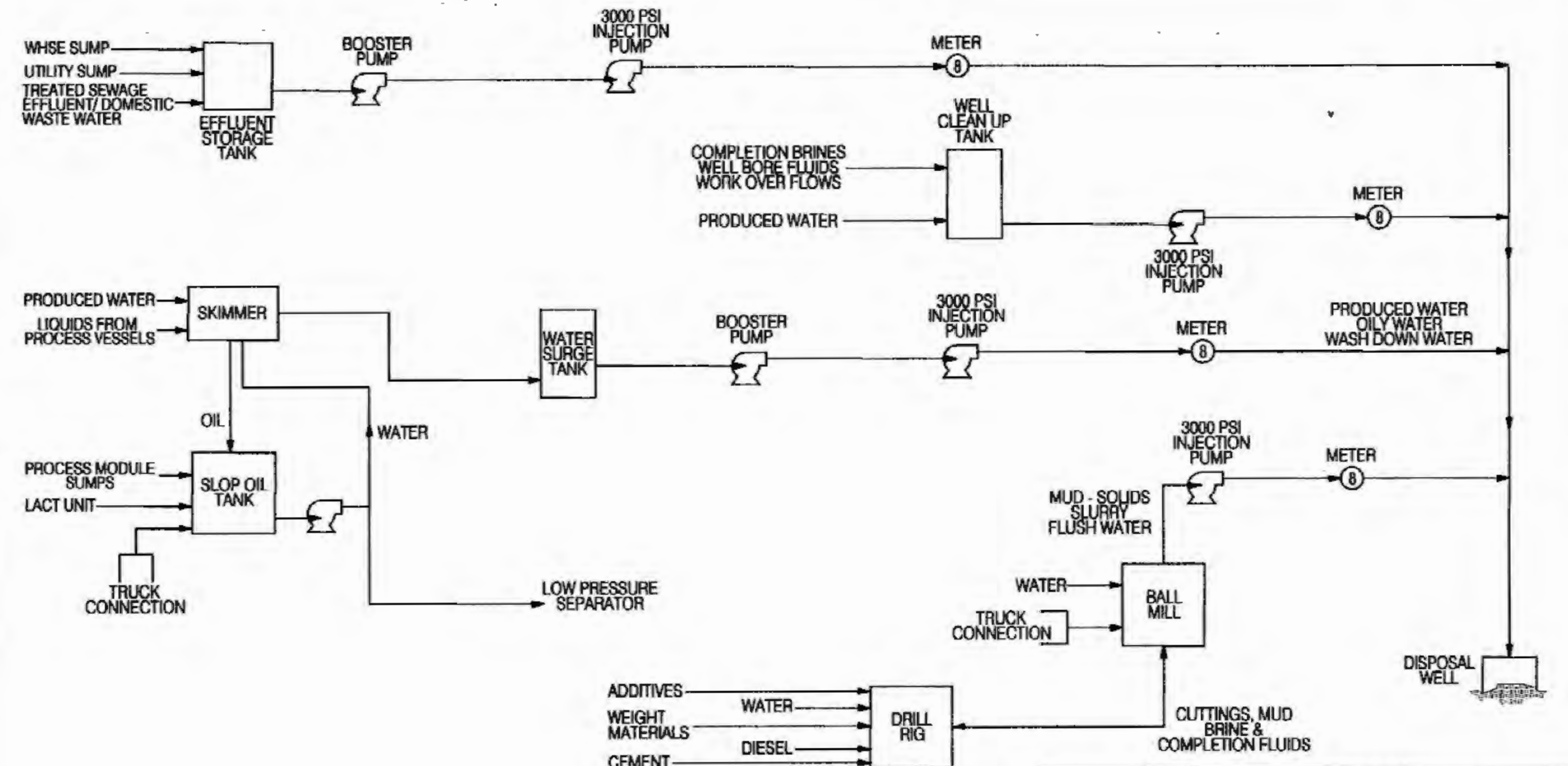
Waste hard-piped from these sources to the injection facility will not require a manifesting record but will be tracked by a daily injection log, as discussed in the Waste Analysis Plan (Appendix G).

It is the intent of BPX to do minimal sampling of the hard-piped streams since they are consistently predictable and are all exempt wastes, except for the domestic waste water. Operationally driven sampling will be done as needed and will be recorded in the Daily Events Log. Sampling reports will be filed, but no other records or forms will be maintained on these streams.

The intermittent processes that are not hard-piped will require a manifest for each batch operation, and the activity will be entered on other logs. (Exhibit 8-2 is the proposed manifest form). Sampling will occur on the batches as dictated by manifest facts and other concerns. Analysis will be carried out at the BPX North Slope laboratory or other approved commercial laboratories.

BPX intends to do some initial stream characterization work and follow up with periodic "fingerprinting" to confirm that wastes are within the guidelines outlined in Appendix G. Other North Slope disposal activities rely on manifest data, individual waste stream characterization, field screening tests, knowledge of a waste's origin, MSDS information, and/or analytical data to ensure that a given waste load can be accepted for disposal. Trained operators at those facilities are critical to proper handling of exempt and non-exempt waste. In December 1995, BPX instituted a waste training pilot program which was expanded and implemented Slope-wide in early 1996. Similar or appropriate training will be implemented at the Northstar facility.

BPX believes the proposed manifest system, operational procedures, and the Waste Analysis Plan are sufficient for ensuring proper waste handling. Wastes will be managed by trained Environmental Safety Technicians, "Certified Generators", and "Certified Operators" as outlined in Appendix G. Additional guidance and support come from the Slope-based Health-Safety-Environmental Supervisor and BPX's Environmental and Regulatory Staff in Anchorage.



BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
WASTE DISPOSAL FLOW SCHEMATIC
CLASS 1 INJECTION WELL

DATE:	SCALE:	EXHIBIT:
8/14/97	N/A	8-1

nsv897.dgn

EXHIBIT 8-2

NORTHSTAR WASTE DISPOSAL MANIFEST (Batch Load)

Nº NS-0001

GENERATOR OF WASTE

Company ☐ BPX ☐ Contractor ☐ Other	**Specify**	**Date**
Supervisor (Print name)	**Phone / PP number**	**Time** ☐ AM ☐ PM
Number / **Charge code**	**AFE**	**Source code**

SOURCE OF WASTE

Well number	**Process**	**Facility**
Other	**Volume** ☐ BBLS ☐ Gal. ☐ Cu. Yds.	

Waste container
☐ Sump ☐ Drums ☐ Vessel ☐ Tank ☐ Pit ☐ Trailer ☐ Other (specify) ____________

COMPOSITION OF WASTE

Waste Description — List Composition by Percent (%)

☐ Fresh water	☐ Frac sand	☐ Stimulation Fluid
☐ Source water	☐ Brine	☐ Production vessel sludge/sand
☐ Produced water	☐ Diesel gel	☐ Line pigging material
☐ Crude oil	☐ Production chemicals	☐ Loss circulation material
☐ Diesel	☐ Spent caustic	☐ Cuttings
☐ Methanol	☐ Workover fluid	☐ Contaminated gravel
☐ Water / Diesel gel	☐ Hydrocarbons	☐ Contaminated snow
☐ Spent acid	☐ Glycol	☐ Domestic wastewater
☐ Cement contaminate	☐ Drilling Mud	☐ Other ____________

Waste Stream Classification — (Check one) ☐ **RCRA Exempt** ☐ **Non-exempt / Industrial**

☐ Contained Snow / Produced Water	☐ Non-Exempt Spill Clean Up	☐ Tank Cleaning / Drum Rinsate
☐ Sump Fluids	☐ Off Spec Product	☐ Hydro Test Fluid
☐ Photo Processor Waste	☐ Operation Maintenance	☐ Equipment Facility Washwater
☐ Heat Exchanger Media	☐ Fluid from Remediation	☐ Other ____________

CERTIFICATION

Generator's Certification:
I hereby declare that the contents of this consignment are fully and accurately described above, and that this material is not a Hazardous Waste as defined by applicable Federal and State regulations.

Waste generator signature	**Waste Classification** ☐ Exempt ☐ Non-exempt, Non-hazardous

DELIVERY

Transporter - Operator	**Trailer - Truck number**
Driver name (print)	**Signature**

RECEIVED AT INJECTION FACILITY

Injection facility operator			**Date**		**Time** ☐ AM ☐ PM
Comments			**Volume received** ☐ BBLS ☐ Gal. ☐ Cu. Yds.		
			Percent solids	**Chlorides (PPM)**	**pH** / **Flash point**
Injection Facility	**Solids Plant**	**Other**	**Compatibility class**		

DISTRIBUTION: **WHITE - To HSE** **PINK & GREEN - Use as required** **BLUE - Retain in log book**

9.0 Permits and Financial Responsibility

9.1 Existing EPA Permits

The following EPA permits have been issued to BP Exploration (Alaska) Inc. (BPX) and are currently active. They are all at sites located on the North Slope:

NPDES	-	AK0038661 11/22/91 through 12/23/96 Endicott sewage/gray water/sea water treatment plant
NPDES	-	AK0028606 7/1/83 through Indefinite Central sewage treatment facility - Prudhoe BOC Companion Alaska DEC permit 9036DB001
NPDES	-	AK0051667 1/19/93 through 1/18/98 Mine site dewatering - Kuparuk Deadarm
NPDES	-	AK0050938 1/19/93 through 1/18/98 Mine site dewatering - Duck Island pit
NPDES	-	AKR00A022 9/9/92 through 9/9/97 Storm water discharge - Endicott
NPDES	-	AKR00A023 9/9/92 through 9/9/97 Storm water discharge - Prudhoe WOA
NPDES	-	AKR00A905 Storm water discharge - Milne Point
RCRA -	-	Interim status storage facility at Prudhoe C-pad Waiting on Part B approval Generator reference No. AKD000643239
RCRA -	-	Endicott Field - small quantity generator Generator reference No. AKD980834675
RCRA	-	Milne Point Field - small quantity generator Generator reference No. AKD980977680
RCRA	-	Badami Field - Class I Industrial Well Reference number and permit pending

9.2 BPX Business Description

BP Exploration (Alaska) Inc. is a wholly-owned subsidiary of BP America, Inc. with corporate offices in Cleveland, Ohio. The nature of its business is to engage in activities relative to the exploration and production of oil and gas. It is one of the largest owners of domestic crude oil reserves, principally the Prudhoe Bay Field. BPX has been involved in the Alaskan oil business since the initial exploration of the Prudhoe Bay leases in the 1960's. BPX also operates the Endicott Field located 15 miles northeast of Prudhoe Bay, offshore of the Sagavanirktok River delta, and the Milne Point Field, just west of Prudhoe Bay. In addition to its interest in the Prudhoe Bay, Milne Point and Endicott Fields, BPX has interests in the Lisburne oil pool in the northeastern part of the Prudhoe Bay Field, the Kuparuk River Field forty miles west of Prudhoe Bay, and other areas. These leases now provide about 20 percent of the daily United States oil supply. Further information concerning BPX business can be found in the annual corporate reports, available upon request.

9.3 Necessary Financial Resources 40 CFR 144.52 (a)(7) and 144.70 (f)(g)

BPX is the operator of the Northstar Unit. The operation is governed by a Unit Agreement between the lessees and the State of Alaska. Financial resources necessary for operation of the unit, including plugging and abandonment of injection wells, are shared by the co-owners: BPX and Murphy Exploration and Production Company, New Orleans, Lousiana.

Per 40 CFR 144.52 (a)(7) the permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. Evidence of such financial responsibility shall be shown by the submission of a surety bond, or other adequate assurance, such as financial statements or other materials acceptable to the EPA.

Although this application is for a Class I Industrial well permit, BPX chooses to use the more rigorous financial tests, detailed in 40 CFR 144.63(f) and 144.70 for hazardous waste wells, to demonstrate financial assurance for closure. Appendix H details the documentation used to demonstrate assurance for closure of BPX facilities located in Alaska and other parts of the United States. The documentation includes a letter signed by Steven W. Percy, Chief Financial Officer, with wording as specified in 40 CFR 144.70 (f), and a Corporate Guarantee for Plugging and Abandonment, executed on behalf of BPX. Wording of the guarantee is as specified in 40 CFR 144.70 (g). Also included is a financial statement by independent auditors, Ernst & Young.

Upon receipt of the permit, subsequent annual statements and bond ratings will be forwarded to the EPA no later than three months after the end of BP America Inc.'s fiscal year, which ends on December 31.

10.0 Summary and Conclusions

Construction of the proposed injection facility at the Northstar development site is the most cost effective and environmentally sound method for disposal of Class I non-hazardous, Class II exempt, and camp sewage waste streams. In addition, this consolidated long-term disposal facility is consistent with the directive by EPA Administrator, Carol M. Browner, as reported in the Washington Post, July 20, 1994. That directive proposes to shift from a historical focus on specific problems covered by individual pollutants to solving overall impacts of entire industries.

Summarized below are the major conclusions reached within the permit application regarding the management of Northstar wastes in a manner that protects human health and the environment.

- This disposal system will meet the BPX objective of minimum storage and zero discharge of drilling, production, and domestic sewage wastes. The Class I well will reduce safety and environmental risks to the Northstar area, in part because it will reduce handling and transportation activities and will provide for permanent disposal in a controlled manner.

- Geologically, the subsurface environment is very compatible with the proposed disposal process. It is lithologically and structurally predictable, free of any influential faulting, and has adequate confining intervals; and, the injectant has been successfully disposed of into these same storage reservoirs for many years at the adjacent Prudhoe Bay and Kuparuk fields.

- No wells penetrate the area of review. Corrective action plans are thus not necessary.

- Years of large-volume slurry injection of drilling mud and cuttings, coupled with other field and laboratory data, permits a realistic prediction of how rock behavior will occur during solids disposal. At the same time, the information also supports the requirement that the confining zone not be penetrated. It is felt that existing experience, the ongoing monitoring of existing operations, and other planned tests will support current fracturing concepts and the long-term understanding of solids disposal.

- The environmental and safety assessment of Section 6.6 looked at the issues involved with deep well disposal for the life of the project. It was determined that with proper planning and monitoring, the probability of injectant escaping the injection zone was extremely small. BPX is confident that mitigation of any confinement problem can be managed at an acceptable cost and the impact successfully handled. It is therefore felt that the risk of environmental damage should be viewed as minimal to non-existent.

- The facility has been located in an area where the aquifers meet exemption criteria below the 1500-foot-thick permafrost. Accordingly, three waivers of UIC program requirements are requested.

  (1) The performance standard which prohibits fracturing the injection zone. 40 CFR 146.13(a).
  (2) The requirement to sample and characterize formation fluids and rock matrix. 40 CFR 146.12(e).
  (3) The stipulation to perform ambient monitoring of the saline aquifers above the confining zone. 40 CFR 146.13(b).

- Adequate BPX experience exists to assure that proper well construction and operation will occur. Systems are in place for proper operator training to monitor and control all surface equipment, guarantee well mechanical integrity, and to use the waste manifesting system as intended. This is further backed up by a competent technical staff, a Spill Prevention and Control Plan, and relief well contingency plans should they be required.

- With proper well construction, contamination of offshore waters will not occur from deep well injection. The combination of confining beds, confining zone, overlying siltstone intervals and 1500 feet of permafrost will ensure that offshore waters are not contaminated.

- The application requests two wells be permitted because of the desire for redundancy. An approved backup location must be available in case a down-hole well problem requires an unexpected abandonment.

- A concerted effort to minimize, segregate and reuse North Slope wastes has resulted in a successful pollution prevention program endorsed by regulators and practiced industry-wide. These pollution prevention practices will be extended to the Northstar project.

- The manifesting system and Waste Analysis Plan will adequately ensure proper handling of non-exempt and batch processed wastes.

- Financial resources necessary for proper operation of the facility, including plugging and abandonment of the wells, are shared with co-owner companies; however, BPX is by far the largest owner and is prepared to carry this responsibility alone. The operation is governed by an agreement between the lessees, the State of Alaska, and the Minerals Management Service, with direct oversight by the State Oil and Gas Conservation Commission.

BPX respectfully requests the EPA expeditiously authorize the drilling and operation of two Class I industrial waste wells at the Northstar oil development project.

Appendix A

North Slope Waste Management Brochure

This brochure is available by contacting the BPX environmental department in Anchorage, Mr. Tom Barnes at (907) 564-5154.

Appendix B

Surface Facility Description and Injection Procedures

Introduction

The Northstar Project is a stand-alone, self-contained, offshore drilling and production facility located on a gravel island, including the necessary support infrastructure. Exhibit B-1 outlines the project schedule and shows that drilling could begin in May 1999. This production facility will be built over the existing Seal exploration island. A plan view of the production island is shown in Exhibit B-2. Dimensions of the island work surface will need to be 421 by 465 feet to accommodate drilling, processing, and life-support needs. The slope armor design around the island incorporates a steel sheet pile perimeter that completely surrounds the work surface. The wall will rise about 23 feet above the island slopes, with the top of the wall +27 feet above mean sea level (MSL). This is 11 feet above the work surface elevation of +16 feet MSL.

Northstar oil is a light gravity crude with a relatively high gas-oil ratio of approximately 1,900 to 2,400 standard cubic feet per barrel of oil. Processing facilities, as illustrated in Exhibit B-3, would result in a nominal 65,000 barrels per day of sales-quality crude oil pipelined to shore. Produced gas and a make-up gas stream will be re-injected from initial startup in order to maintain reservoir pressure and improve oil recovery. NGLs are recovered before produced gas is re-injected. Produced water will be disposed of by injection into the Class 1 disposal well. There will be approximately 14 producing wells, 7 gas injection wells, and one waste disposal well (22 total). Space for up to 38 wells will be provided at a wellhead spacing of approximately 10 feet. The operational design life is 15 years.

General Facility Description

Process Module: This consists of the primary crude processing equipment. It will perform oil-water-gas separation. This module consists of a steel structure, 240 by 80 feet in width and three stories tall. It will weigh 3500 tons. A significant percentage of the equipment will be installed outside of the module enclosure to minimize the areas requiring fire and gas control systems.

Compressor Module: This Module provides 5 stages of compression for gas injection into the reservoir to maintain pressure during oil production. The steel structure is 125 by 80 feet in width and two stories tall. Enclosures for the compressors will be local to each unit. As in the process module, the enclosed area will be kept to a minimum.

Permanent Quarters: The camp is configured to accommodate 75 drilling and operations personnel. The complex is wood/steel construction three stories high.

Utilities Module: This building consists of the following functional skids constructed into a single module with a footprint of approximately 60 by 60 feet and is two stories high.

Potable Water: This facility will consist of a vapor compression desalination unit that is totally self contained.

Power: This facility will consist of two 1.2 megawatt continuous power generator sets and a motor control center.

Domestic Waste Water: This facility will consist of a square tank digester and all associated equipment. The aeration tank, clarification tank, chlorine tank, and sludge holding tank are incorporated into one footprint. Effluent will be hard-piped to tankage for injection as shown in Exhibit B-4.

Firewater System: The firewater system for the island will be incorporated within the design of the sea water intake-lift system. Two 100 percent firewater units are planned with at least one being driven by a stand-alone diesel engine.

Warehouse and Shop: This pre-engineered, pre-fabricated, field-erected building will incorporate shop space, warehousing space (including hazardous materials storage), and a mezzanine area with office space. The 60 by 150 foot warehouse will be one of the last facilities to be installed.

Waste Collection System

The waste collection system is shown in Exhibit B-4. It consists of wastes hard-piped from their sources to the injection facility and connections for intermittent or batch generated wastes. Volumes expected, and handling and controlling activities are discussed in Section 8.3 and Appendix G.

Drilling Operations

The drilling rig and associated equipment will occupy the east side of the island. Drilling activity is planned to start to coincide with the availability of fuel gas on the island to power the rig generators. Drilling will continue uninterrupted. The first well to be drilled will be the Class I disposal well, followed by 21 development wells. Additional slots will be available to allow for reservoir uncertainties, potential reservoir growth, or in-fill drilling.

Island Surface Drainage

Storm water runoff will be permitted as deck drainage under the NPDES permit for the facility. In conformance with this permit, a Best Management Practices (BMP) plan will be developed for the Northstar facility. Only discharges associated with this NPDES permitted activity are allowed. The majority of facility operations will be located in modules or within containment areas where there is little risk of a spill.

Runoff from the Northstar facility is limited to the period from June to September, with the greatest volume being composed of snow melt. Uncontaminated snow may be pushed off the edge of the island, where it will gradually melt into the Beaufort Sea at breakup. Contaminated snow, or snow mixed with gravel, may not be pushed offshore.

Surface drainage of snow melt and other runoff will be managed by a simple gravity drainage and catchment system. There will be two surface pumps to collect surface run off. One will be located north of the process facilities and the other south of the warehouse. The island surface will be graded to direct snow melt or run off to the two sumps. If there is no reason to suspect contamination, the collected storm water will be visually examined for surface sheen. If the water is found to be uncontaminated, it will be allowed to drain from the basin to the ocean. Should there be evidence of contamination, runoff collected in the catchment basin will be sampled and analyzed. If contamination is indicated, the collected water will be injected into the disposal well.

Injection Facility Description

The disposal system network encompasses various facets of rig, well, production, pipeline, and camp equipment. Source generation, the collection system, and injection operations must all be coordinated to function properly since everything is close coupled and tankage is minimal. From an operational and regulatory view point, the injection facility needs to be defined as all of the equipment downstream of dedicated disposal tankage, injection pumps and associated manifolding. This would include the dedicated external batch process connections and manifolding tied directly to the system, tank(s), the injection pumps, screens, piping and instrumentation, and the injection well.

Detailed Facility Design

Detailed engineering design is in process and should be completed by late 1998. Piping, valving, metering, controls, and shutdown actions will be developed during this phase of the project. Instrumentation will exceed the monitoring and reporting requirements specified in 40 CFR 146.13 (b)(2).

Injection Procedures

Operation of the injection facility may be on an intermittent basis. Staffing will involve "Certified Operators". To handle and inject any batch load will also require involvement of a "Certified Generator" to initiate action. When detailed engineering is complete and facility-wide operating plans developed, specific responsibilities and injection procedures will be developed and included in the Waste Analysis Plan for these people. Appendix G, Exhibit 4 illustrates the manifest form that will be used for batch loads.

Monitoring and Shutdown Action

Records will be maintained for all wastes disposed of at the facility. Pressure and flow measurement points will be designed into the monitoring system. The well injection and annulus pressures will be monitored and recorded along with injection rate. If the annulus pressure exceeds predetermined high-low limits, an alarm will be given to the operator so that he can take appropriate action. More discussion on this point is included in the text, Sections 6.5 and 7.2.

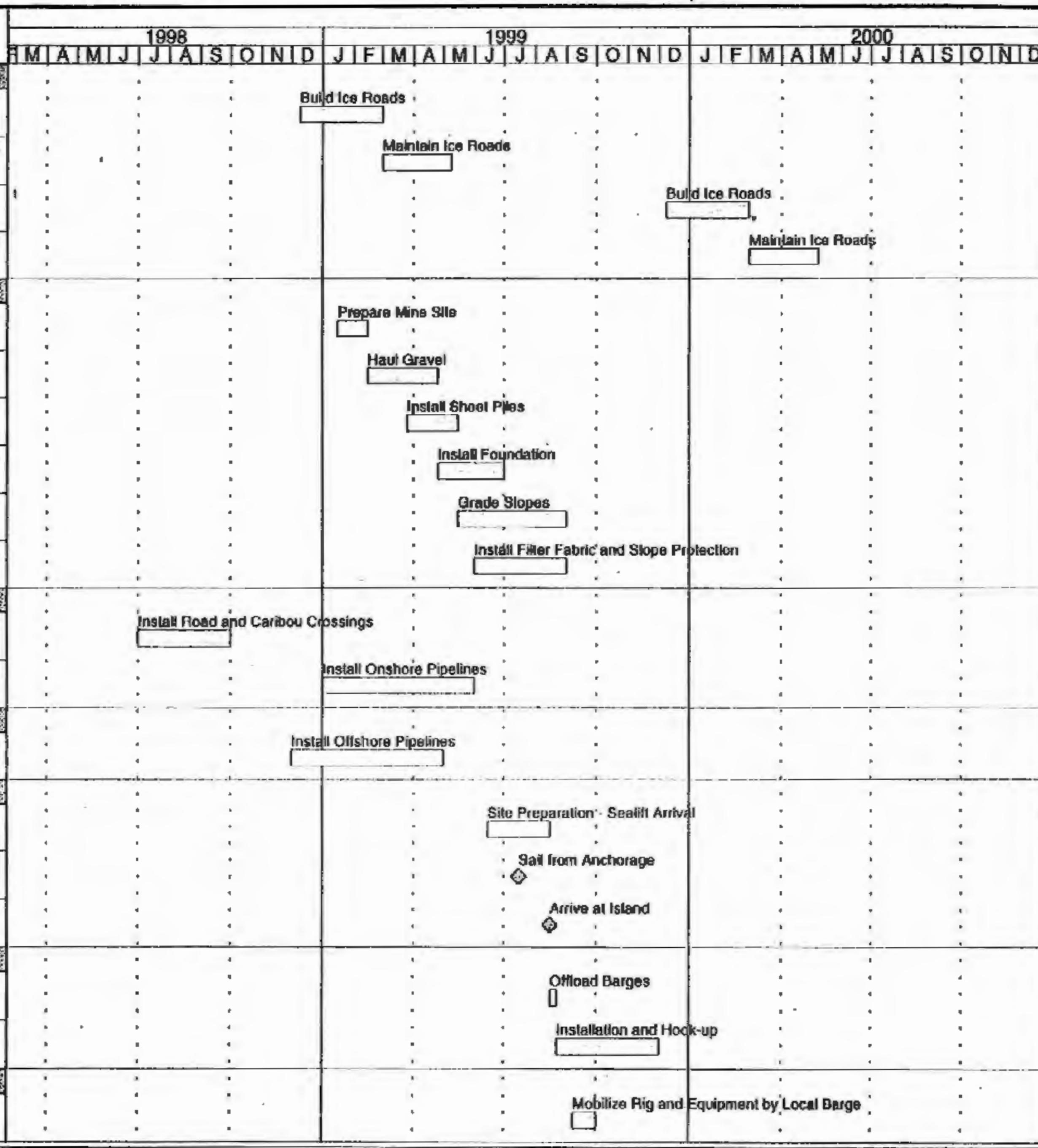
Spill Control and Mitigation

The facility will be designed to contain any spill which might occur during processing or handling of batch loads . For truck unloading, spill aprons and/or catchment basins will be installed under hose connections prior to the unloading operation. All spills (including those which might occur outside the apron area) will be immediately reported to the BPX north slope environmental staff and the appropriate governmental agencies. Spill prevention will be a part of the active management plan in place for injection lines, connections, discharge pumps, and well head. A significant part of mitigating spills involves training. Initial and on-going operator training will be an integral part of the operation.

Facility Safety

The Northstar facility is located 6 miles offshore, therefore public access is not available. Security will be provided by a professionally trained controller. It is likely that a critical part of the injection facility itself can be locked-up when operations cease and personnel are not present. Equipment will have to be started up and controls activated before the well can be used. Fire extinguishers and safety alarms are present to protect both people and equipment. Further safety backup will be provided by an emergency response team staffed by operations personnel and a comprehensive offsite safety/training department.

ACT. ID	ACTIVITY DESCRIPTION	EARLY START	EARLY FINISH
Ice Road			
01-010	Build Ice Roads	08DEC98*	28FEB99
01-020	Maintain Ice Roads	01MAR99	08MAY99
01-030	Build Ice Roads	08DEC99*	28FEB00
01-040	Maintain Ice Roads	29FEB00	07MAY00
Build Island			
02-010	Prepare Mine Site	15JAN99*	13FEB99
02-020	Haul Gravel	14FEB99	24APR99
02-050	Install Sheet Piles	25MAR99	14MAY99
02-060	Install Foundation	25APR99	30JUN99
02-070	Grade Slopes	15MAY99	31AUG99
02-090	Install Filter Fabric and Slope Protection	01JUN99	31AUG99
Onshore Pipelines			
03-010	Install Road and Caribou Crossings	01JUL98*	30SEP98
03-020	Install Onshore Pipelines	01JAN99*	31MAY99
Offshore Pipelines			
04-010	Install Offshore Pipelines	01DEC98*	30APR99
Sealift Modules			
05-010	Site Preparation - Sealift Arrival	15JUN99	15AUG99
05-020	Sail from Anchorage	15JUL99*	
05-030	Arrive at Island		15AUG99
Module Installation			
06-010	Offload Barges	15AUG99	21AUG99
06-020	Installation and Hook-up	22AUG99	30NOV99
Drilling			
07-010	Mobilize Rig and Equipment by Local Barge	07SEP99*	30SEP99



Project Start	01JAN98
Project Finish	31DEC01
Data Date	01JAN98
Plot Date	21JUL97

Early Bar
Progress Bar

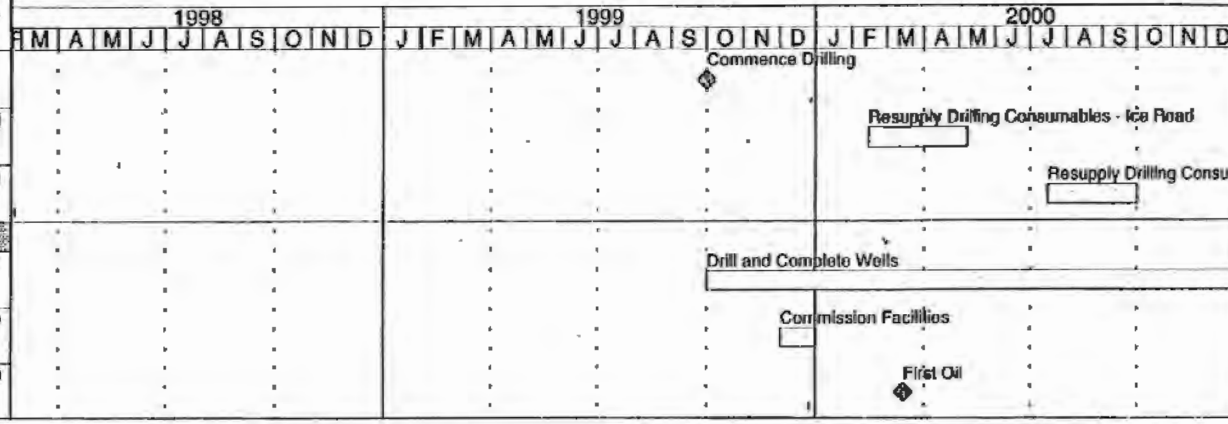
6531

Sheet 1 of 2

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-1 Single Season Program

BP

ACT. ID	ACTIVITY DESCRIPTION	EARLY START	EARLY FINISH
07-020	Commence Drilling	01OCT99	
07-030	Resupply Drilling Consumables - Ice Road	14FEB00	07MAY00
07-040	Resupply Drilling Consumables - Barge	15JUL00*	30SEP00
Operations			
08-020	Drill and Complete Wells	01OCT99	31DEC01
08-010	Commission Facilities	01DEC99	31DEC99
08-030	First Oil		14MAR00



Project Start 01JAN98
Project Finish 31DEC01
Data Date 01JAN98
Plot Date 21JUL07

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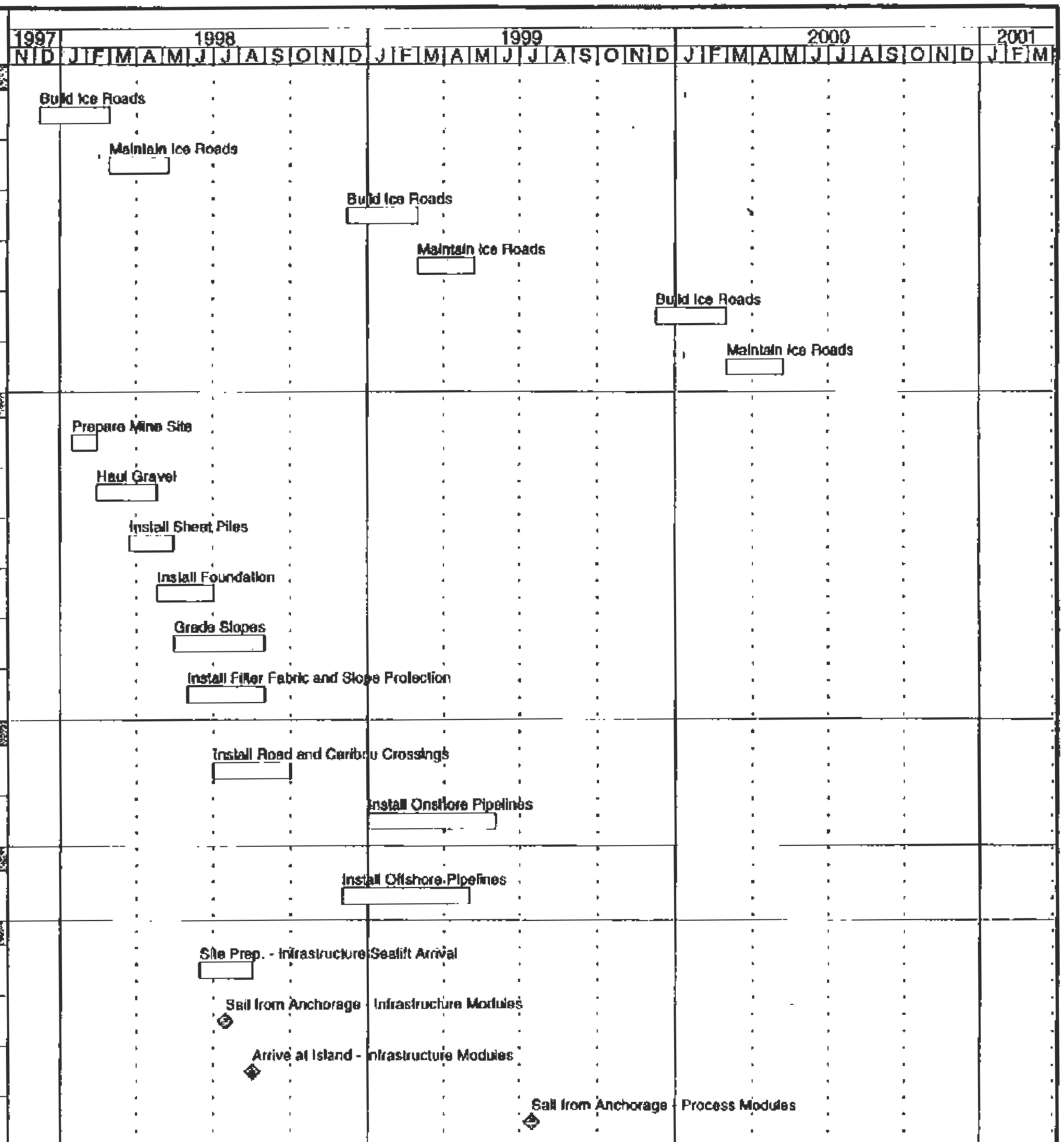
Early Bar
Progress Bar

0531

Sheet 2 of 2

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-1 Single Season Program

ACT. ID	ACTIVITY DESCRIPTION	EARLY START	EARLY FINISH
Ice Road			
01-010	Build Ice Roads	08DEC97*	28FEB98
01-020	Maintain Ice Roads	01MAR98	08MAY98
01-030	Build Ice Roads	08DEC98*	28FEB99
01-035	Maintain Ice Roads	01MAR99	08MAY99
01-040	Build Ice Roads	08DEC99*	29FEB00
01-050	Maintain Ice Roads	01MAR00	08MAY00
Build Island			
02-010	Prepare Mine Site	15JAN98*	13FEB98
02-020	Haul Gravel	14FEB98	24APR98
02-050	Install Sheet Piles	25MAR98	14MAY98
02-060	Install Foundation	25APR98	30JUN98
02-070	Grade Slopes	15MAY98	31AUG98
02-090	Install Filter Fabric and Slope Protection	01JUN98	31AUG98
Onshore Pipelines			
03-010	Install Road and Caribou Crossings	01JUL98*	30SEP98
03-020	Install Onshore Pipelines	01JAN99*	31MAY99
Offshore Pipelines			
04-010	Install Offshore Pipelines	01DEC98*	30APR99
Sealift Modules			
05-010	Site Prep. - Infrastructure Sealift Arrival	15JUN98	15AUG98
05-020	Sail from Anchorage - Infrastructure Modules	15JUL98*	
05-030	Arrive at Island - Infrastructure Modules		15AUG98
05-050	Sail from Anchorage - Process Modules	15JUL99*	



Project Start 01JAN97
Project Finish 31DEC01
Data Date 01JAN97
Plot Date 21JUL97

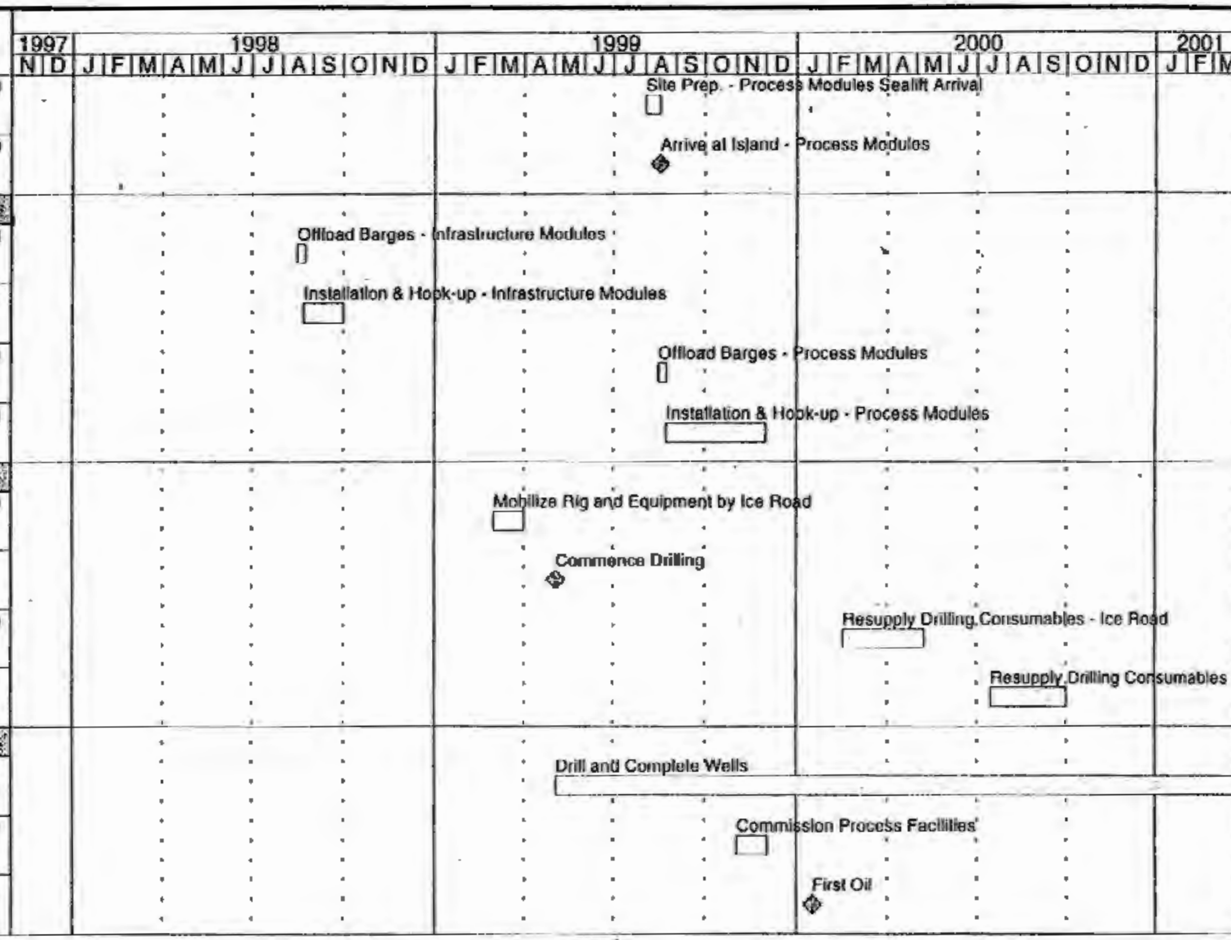
Early Bar
Progress Bar

0533

Sheet 1 of 3

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-2 Two Season Program

ACT. ID	ACTIVITY DESCRIPTION	EARLY START	EARLY FINISH
05-040	Site Prep. - Process Modules Sealift Arrival	01AUG99	15AUG99
05-060	Arrive at Island - Process Modules		15AUG99
Module Installation			
06-010	Offload Barges - Infrastructure Modules	15AUG98	22AUG98
06-020	Installation & Hook-up - Infrastructure Modules	22AUG98	30SEP98
06-040	Offload Barges - Process Modules	15AUG99	22AUG99
06-050	Installation & Hook-up - Process Modules	22AUG99	30NOV99
Drilling			
07-010	Mobilize Rig and Equipment by Ice Road	01MAR99*	31MAR99
07-020	Commence Drilling	03MAY99	
07-030	Resupply Drilling Consumables - Ice Road	16FEB00	08MAY00
07-040	Resupply Drilling Consumables - Barge	15JUL00*	30SEP00
Operations			
08-020	Drill and Complete Wells	03MAY99	31DEC01
08-010	Commission Process Facilities	01NOV99	01DEC99
08-030	First Oil		15JAN00

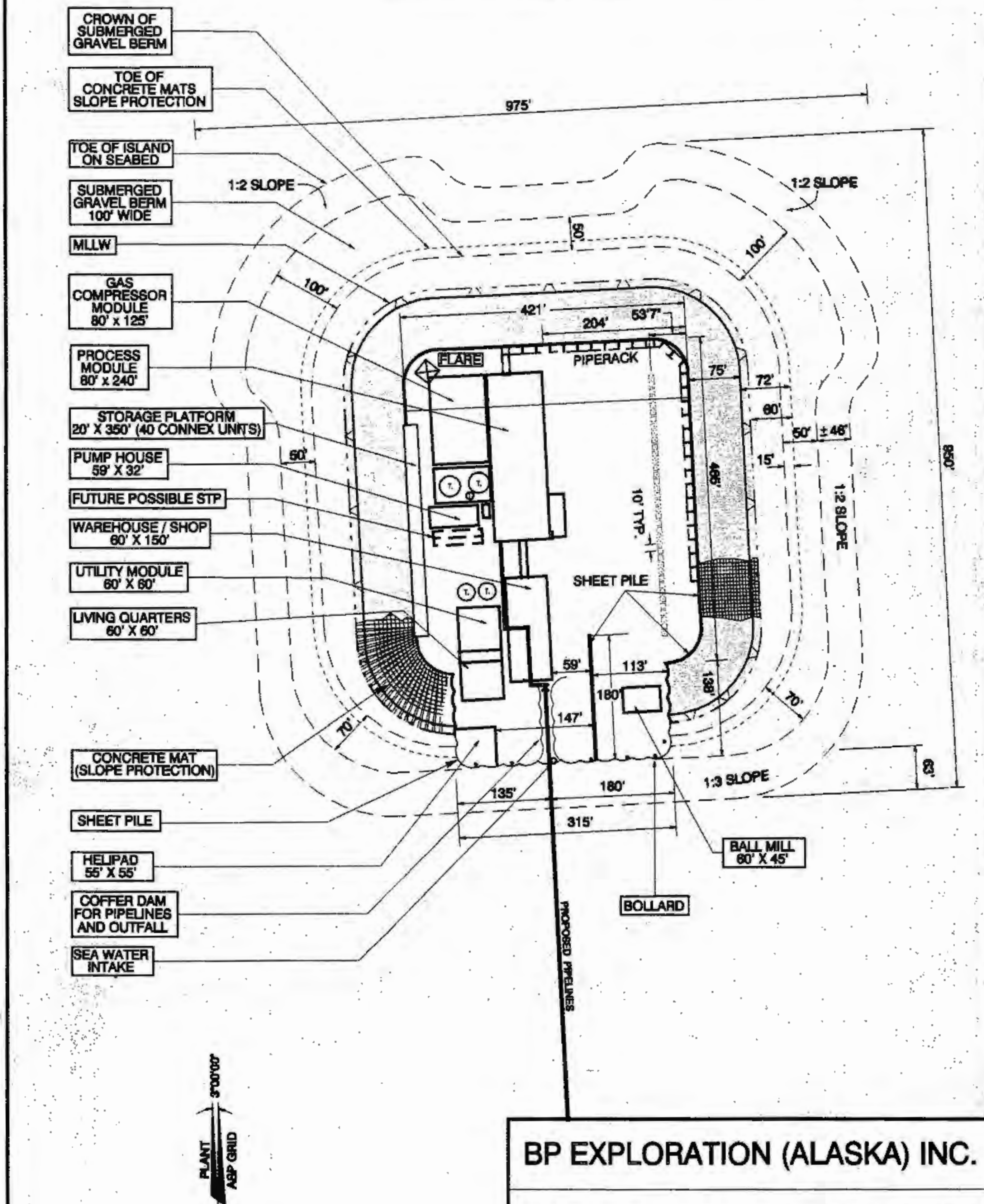


Project Start	01JAN97	Early Bar
Project Finish	31DEC01	Progress Bar
Data Date	01JAN97	
Plot Date	21JUL97	

0832

Sheet 2 of 2

BP Exploration (Alaska) Inc.
Northstar Development Project
Figure 5.3-2 Two Season Program



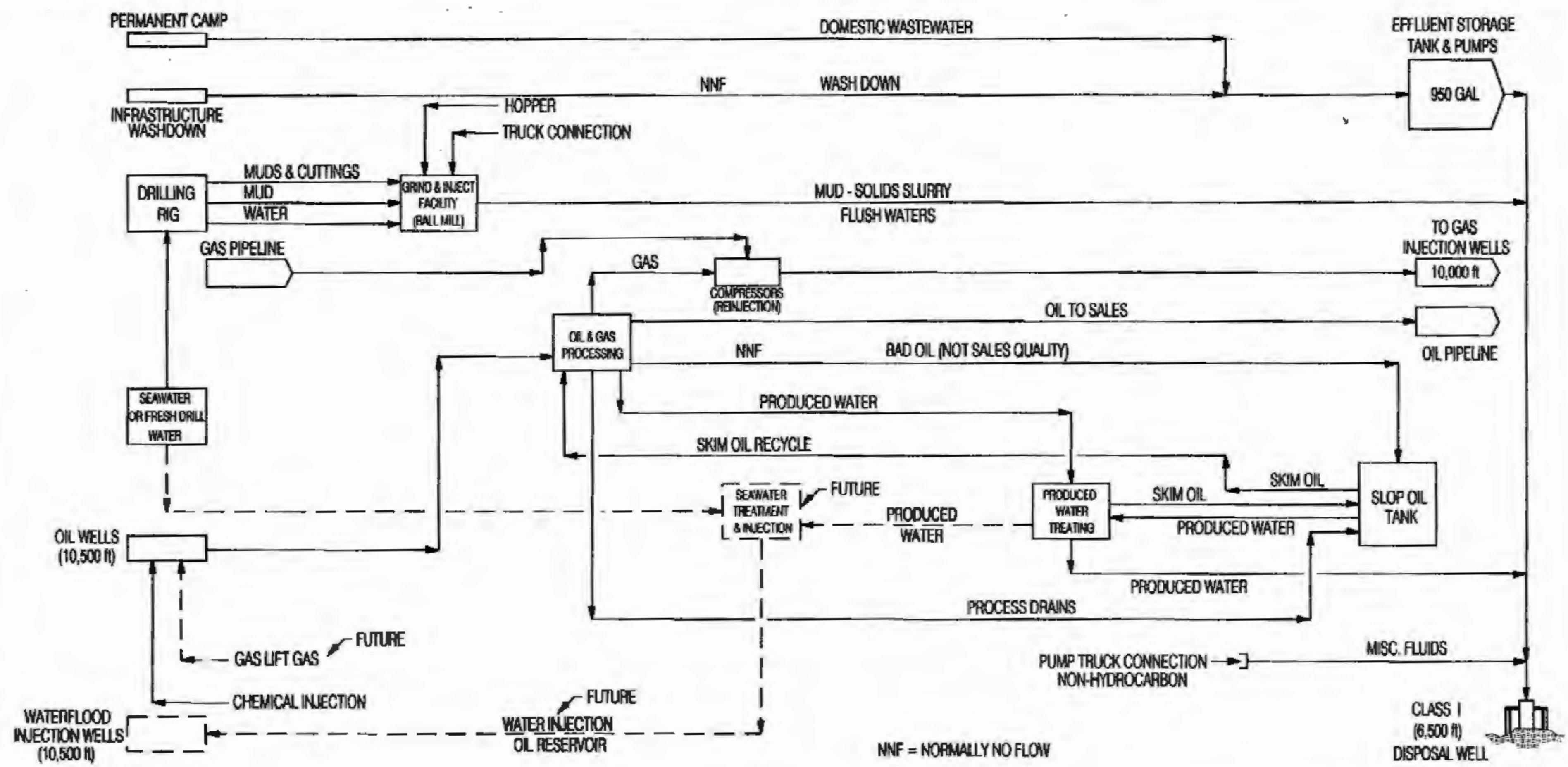
ISLAND SEABOTTOM FOOTPRINT = 18.1 ACRES
ISLAND WORKING SURFACE = 5.4 ACRES
ISLAND SURFACE ABOVE MLLW = 8.7 ACRES
ISLAND SURFACE BELOW MLLW = 9.4 ACRES

BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
SEAL ISLAND AND PIPELINE APPROACH
PLAN VIEW

DATE:	SCALE:	EXHIBIT:
7/22/97	NOT TO SCALE	B-2

nsv897.dgn

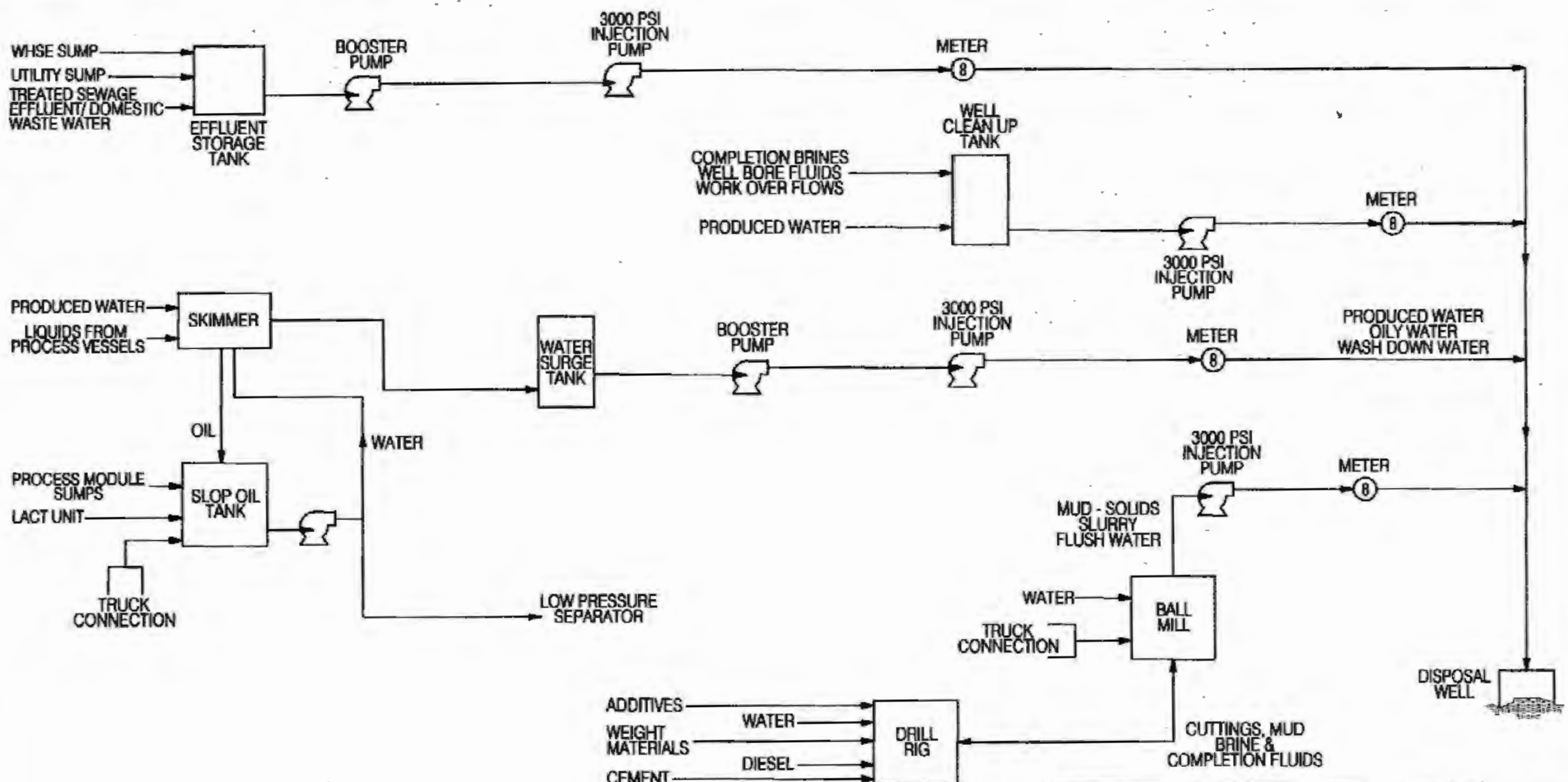


BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
BLOCK FLOW DIAGRAM
ALL PROCESSES

DATE:	SCALE:	EXHIBIT:
8/14/97	N/A	B-3

nsv897.dgn



BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
WASTE DISPOSAL FLOW SCHEMATIC
CLASS 1 INJECTION WELL

DATE:	SCALE:	EXHIBIT:
8/14/97	N/A	B-4

nsv897.dgn

Appendix C

Geologic Details

Maps and Cross Sections of Structure and Stratigraphy

Introduction

A description of the geology of Upper Cretaceous and Tertiary age stratigraphy across the Northstar Unit area, with specific reference to proposed injection and confining intervals, is included in this appendix. A series of markers have been correlated westward though the Milne Point and Kuparuk Fields, and south through the Prudhoe Bay Field. Nomenclature from the Prudhoe and Milne Fields have been used for these markers. These markers are shown in the type log (Exhibit C-1) and regional cross section (Exhibit C-2). These markers are strictly litho-stratigraphic, but can be correlated regionally. The intervals comprise siliciclastic rocks in the Colville group and Sagavanirktok Formation. The Colville group is comprised of the Colville Mudstones (Seabee Formation), the Schrader Bluff (West Sak) Formation, and the Prince Creek (Ugnu) Formation. Structure maps on key horizons are presented in Exhibits C3-C9 (The approximate location of the disposal wells WD-1 and WD-2 is noted).

The overall sequence including the Seabee Formation/Colville Muds, Schrader Bluff/West Sak Formation, and Prince Creek/Ugnu Formations comprises a major regressive sequence in the Middle Brookian of Upper Cretaceous and Tertiary (Palaeocene) age. The overlying Sagavanirktok comprises several cycles of relatively minor transgression and regression in the Upper Brookian section of Tertiary age (Upper Eocene to Miocene). The overall Upper Brookian section also represents a large regression.

The Middle Brookian sequence shows a pronounced upward shallowing cycle, starting with deep water shales and slope muds and silts of the Seabee Formation/Colville Muds (Exhibit C-1). These slope sediments grade up into the shallow marine fine to medium grained sands and silts of the Schrader Bluff/West Sak Formation. The Schrader Bluff is overlain by a thick section of Prince Creek/Ugnu Formation deltaic and fluvial fine to medium grained sands, silts and muds. This Prince Creek Formation gets increasingly sand rich and coarser grained as it gets younger.

The sands throughout are probably moderately to poorly consolidated, and they contain a large component of ductile lithic sand grains. The sandstone porosity is more susceptible to degradation by compaction, rather than cementation. There are no cores from the Brookian section in the area.

The Upper Brookian sequence begins with a major shaley and silty interval which is the result of a transgression creating a subsiding muddy shelf. This shaley interval is overlain by six coarsening up, prograding shale, silt and sand cycles of the Sagavanirktok Formation. These cycles of deltaic and shoreline deposits are extremely correlative on a regional scale, and show a series of relatively minor transgressive and regressive cycles overlain on a larger scale regression. The upper section of the Sagavanirktok Formation consists of coastal plain deposits that are very sandy, with some shales and silts.

The shallower Sagavanirktok sands are less consolidated. They retain good porosity and permeability, and have much of their original porosity framework owing to their shallow burial. These sands grade upward into the gravel deposits of the Gubik Formation near the surface. The base of the wedging permafrost intersects the section within the coastal plain deposits of the upper Sagavanirktok Formation. The permafrost on land, to the south of the Northstar Unit, is quite consistent and is approximately 2000 feet thick. The permafrost thins offshore, and appears to be in regionally extensive lenses. The nature of the permafrost can be seen in Exhibit C-2. The structure on the base of the permafrost is shown in Exhibit C-10.

Formation Names

Age	Marker	Formation	Depositional environment and lithology
Pleistocene		Gubik Fm.	Fluvial gravels, sands, silts, and shales.
Eocene-Mio.	G1	Sagavanirktok Fm.	Coastal plain sands, silts, and shales
Eocene-Mio.	SV6	Sagavanirktok Fm.	Marine shelf muds and silts
Eocene-Mio.	SV5	Sagavanirktok Fm.	Deltaic and shoreline sand, silt and shale packages.
Eocene-Mio.	SV2	Sagavanirktok Fm.	Deltaic and shoreline sand, silt and shale packages.
Eocene-Mio.	inter-SV1	Sagavanirktok Fm.	Marine shelf muds and silts, transgression.
Palaeocene	TMBK	Prince Creek/Ugnu Fm.	Fluvial sands, silts and rare shales. Very sandy.
Palaeocene	inter-Ugnu	Prince Creek/Ugnu Fm.	Fluvial/deltaic sands, silts, and shales. Lower N:G.
Maastrich.	M87F	Schrader Bluff (W.Sak)	Shallow marine sands, silts, and shales.
Tur.-Maast.	Top Colville	Seabee/Colville muds	Slope muds and silts.
Apt.-Albian	Top HRZ	HRZ	Distal marine muds.
	Base HRZ		Base of the Brookian Megasequence

Geology of the Upper and Middle Brookian Strata

The geologic subdivisions encompassing the confining, arresting, and proposed injection zones are shown on the Type Log (Seal-A-01, Exhibit C-1) and on the regional correlation cross section (Exhibit C-2). Seal-A-01 was picked as the type log because of its relatively complete logging coverage, and its proximity to the proposed development area and disposal well site. The wells closest to the development area are Seal-A-01, Seal-A-02, Seal-A-03, Northstar-01, Seal-A-04, and the nearby Long Island-01. These wells best depict the expected properties of the confining, arresting, and injection zones. The Seal wells lack adequate log coverage for up-hole petrophysical evaluation. The two wells, Northstar-01 and Long Island, were selected for the numerical petrophysical calculations because they are representative of the shallow sands for the Northstar injection area, and have complete up-hole wireline logs. Other wells (Sandpiper-01 and Reindeer-01) are included on the regional cross section for the sake of showing continuity of marker horizons and stratigraphy. The lithologic column on the well plots includes the well cuttings description data acquired by Amstrat Well Services. These data are quite good.

The table below relates the injection, arresting, and confining zones to the formations and markers displayed in the exhibits. The stratigraphic nomenclature follows field terminology from the Prudhoe Bay and Milne Point Fields, and also that of the US Geological Survey (Molenaar, Bird and Kirk, 1986 and Molenaar, Bird and Collett, 1986). Many of the lithologic units described by the following markers are easily correlatable to the onshore fields to the south and southwest.

Marker tops	Formation	Injection, Arresting, and Confining Zones
	Gubik Fm.	
Base PRF	Base Permafrost Zone	There is still significant permafrost at Northstar
G1	Sagavanirktok Fm.	
SV6	Sagavanirktok Fm.	Upper Confining Zone
SV5	Sagavanirktok Fm.	Upper Arresting Zone
SV2	Sagavanirktok Fm.	Upper Injection Zone
inter-SV1	Sagavanirktok Fm.	Major Barrier
TMBK	Prince Creek/Ugnu Fm.	Lower Injection Zone
M87F	Schrader Bluff (W.Sak)	Lower Injection Zone
Top Colville	Seabee/Colville muds	Lower Confining Zone
Top HRZ	HRZ	Lower Confining Zone
Base HRZ		

Lower Confining Zone

Seabee Formation/Colville Muds: In the Northstar Unit area the 1600 feet of slope shales and silts in the lower part of the Middle Brookian are called either the Seabee Formation or the Colville Muds. This thick unit contains shale and shaley siltstone originally deposited as muddy sediments on a deep marine slope and basin floor. Maximum water depths could have exceeded several thousand feet. The marine slope prograded to the northeast. The slope sediments are shaliest at the bottom, and get increasingly silty upwards as they grade up towards the shallow marine shelf sands in the Schrader Bluff Fm. The transition from Colville Muds to Schrader Bluff Formation is clear on Exhibits C-1 and C-2.

The thick section of Colville Muds is extremely extensive. It extends south over Prudhoe Bay, west over the Kuparuk Field, and thickens to the east and north of the Unit. There are no significant sands within the Colville Muds in the Northstar area.

Below the Colville Muds are additional shales of the HRZ and Kalubik Formations. Their distribution is not critical because the Colville Muds alone are an excellent barrier for waste confinment.

Lower Proposed Injection Zone

Schrader Bluff/West Sak Formation: Within the Northstar Unit area, the Schrader Bluff Formation constitutes an injection zone composed of sands interbedded with siltstones and shales (Exhibit C-1). This interval is called the Schrader Bluff Formation in the Milne Point Area, but is usually referred to as the West Sak in the Prudhoe Bay and Kuparuk Fields. The sandstones are mostly fine to very fine grained, and have moderate reservoir quality. These rocks have reached a hurial depth of 6000-7000' feet and are more lithified than the rocks in the shallower section. The Schrader Bluff averages 600 feet thick in the Northstar area. It gets sandier up-dip to the southwest over Milne and Kuparuk Fields. The top of the Schrader Bluff interval is picked by correlation with the Milne Point Field. The top of the Schrader Bluff, as shown on Exhibit C-1, may be considered part of the overlying Ugnu Formation by some interpreters. The bottom on the interval is picked at the transition to the Colville Muds. There is a significant shift in gamma ray log value at this marker.

Ugnu Formation: The lowermost 1100 feet of rock in the Ugnu Formation form the middle of the lower injection zone. These deltaic to fluvial shales, silts, and sands are expected to have variable lateral continuity. The sand beds in the Ugnu have a variety of wireline log signatures indicating shifting environments of deposition ranging from fluvial, to marine deltaic channels, to shoreline, and shallow marine near shore sands bars. The mudstones and occasional coals are consistent with deposits in bays, lakes and swamps characteristic of delta environments.

The transition from shales of the Colville Muds to Seabee marine sands to deltaic and fluvial sands in the Ugnu is part of a large regression in the Middle Brookian. The cleanest, sandiest part of this sequence is in the uppermost part of the Ugnu (Exhibit C-1). There are approximately 500 feet of good sands and interspersed silts and shales which form the top of lower injection zone. These sands are primarily fluvial in origin. The top of the injection zone is picked at the sharp top of the Ugnu sands, at the top of the Middle Brookian Megasequence, and at the base of the thick shale marking a significant transgression at the beginning of the Upper Brookian Megasequence.

The Ugnu sands are likely to be poorly consolidated, particularly near the top. They retain significant original porosity and permeability in the upper part of the lower injection zone (average of 26-28% porosity, and a predicted permeability of 600 millidarcy, with a range of 200-2000 millidarcy, based on the petrophysical log interpretation of Northstar-01 and Long Island wells). The interbedded mudstones and siltstones greatly reduce the vertical permeability and should provide at least local barriers to vertical flow. Because of the high ratio of net reservoir sands to gross thickness in the upper part of the zone (65%, based on the gamma ray log of Seal-A-01), connectivity between the Ugnu sands should be expected. The overlying silt and shale barrier provides confinement immediately above. The lower injection zone as a whole has slightly lower rock properties than the upper Ugnu alone (26-28% porosity, 600 millidarcy, and 45% net:gross). These sands are used very successfully for waste disposal in the Prudhoe Bay area.

Major Barrier Between Injection Zones

Between the two proposed injection zones there are 250 feet of shale and silt deposited during the major marine transgression at the beginning of the Upper Brookian. The sediments are aggradational deposits of mainly muddy sediment accumulating on a broad shelf. The base of this barrier is defined by the top Middle Brookian marker (TMBK on Enclosure C-1), and the top is at the base of the first regressive Sagavanirktok sand. This shaley and silty interval is extremely correlative regionally, and is very consistent in character and thickness. There are shales with occasional thin sands near the base, and it grades into a silty section upwards.

Upper Proposed Injection Zone

The lower portion of the Sagavanirktok Formation is made up of deltaic/shoreline deposits which form six upward coarsening cycles of shale, silt and sand (Enclosures C-1 and C-2). These cycles are very recognizable, and are much more correlatable than the fluvial/deltaic sands of the Ugnu. These six Sagavanirktok sands correlate lithostratigraphically all the way south across the Prudhoe Bay Field. The Prudhoe nomenclature was used in naming these sands. The proposed upper injection zone is greater than 450 feet thick, and is made up of the first three cyclic sands of the Sagavanirktok Formation. The sands have excellent rock properties (average of 30% porosity and a range of 27-32%, and a predicted permeability of 1000 millidarcy, with a range of 400-2000 millidarcy, based on the petrophysical log evaluation of Northstar-01 and Long Island-01). They are shallow enough to be loosely consolidated. These sands are important waste disposal sands at Prudhoe Bay.

The top of the proposed injection zone is picked at the SV2 marker, and the base is picked at the base of the SV1 sand. The silty shales between the two SV2 sands and between the SV2 and SV1 sands are very regionally extensive, and they will act as serious barriers to vertical fluid movement within the upper injection zone. Flow is likely to stay almost entirely within the sand unit receiving the injection since the horizontal permeability is much higher than the vertical permeability in this system.

Upper Arresting Zone

The overlying arresting zone is made up of the top three coarsening upwards cycles of the lower Sagavanirktok Formation. While the sands certainly have good rock properties, the three thick shale and silt barriers between the sands, and the overall thickness of 700 feet, constitutes a significant barrier to vertical flow. Any fluids leaking into this system would be expected to stay in the first sand reached.

The arresting zone is defined by the marker SV5 at the top (the top of the sixth upward coarsening cycle) and by the SV2 marker at the bottom.

Upper Confining Zone

The upper arresting zone is capped by about 300 feet of regionally correlatable silt and shale between the SV6 and SV5 markers. This shaley zone marks deposition on a mud dominated shelf during the maximum transgression within the Upper Brookian, and immediately precedes the regressive sequence of the upper Sagavanirktok which makes up most of the overburden in this area. The shale is extremely consistent and represents a competent barrier to vertical fluid movement.

Structure

Structure maps for all of the important horizons are included as Exhibit C-3 through C-9. These maps were constructed from contouring well data, and were not directly constrained by the mapping of seismic data. There are 6 wells within the Unit, and up to 17 additional wells from the area used for mapping (Exhibit C-3).

The dip of the beds is quite consistent, and is to the east-northeast. There is a slight shift in the dip towards the north with increasing depth. The dips are extremely gentle (100 feet per mile, or approximately 1 degree). Examination of the shallow horizons on the 2D seismic data did not indicate any significant offsets due to faulting (Exhibit 3-3 is a sample seismic line).

The structural contour of the permafrost is shown in Exhibit C-10. Base-permafrost picks are based on resistivity and sonic log measurements. As mentioned above, the permafrost in the offshore Northstar area is less consistent than onshore (Exhibit C-2, Exhibit 3-2), and the base is shallower. The permafrost has not disappeared in the Northstar area, but has thinned. There is still significant, regionally extensive permafrost across the unit (the deeper wedge in Seal-A-01 is at least 400 feet thick). This permafrost forms an additional barrier to any upward fluid migration.

Occurrence of Hydrocarbons

There are no indications of trapped hydrocarbons in the Brookian section within the Northstar Unit. Not only are there no hydrocarbons on logs, but there are none seen in the detailed Amstrat cuttings description which can catch subtler shows.

The Ugnu and Schrader Bluff/West Sak Formations are well known to contain oil accumulations far up dip to the southwest in the Milne Point area. These accumulations do not extend anywhere near the Northstar Unit.

Outcrops and Recharge

None of the formations proposed as confining, arresting, or injection zones outcrop in the general area. Within the Northstar Unit, the top of the upper confining zone is at least 3000 feet deep (Exhibit C-3), and the top of the proposed upper injection zone is 4000 feet deep subsea (Exhibit C-5). Regional correlation on wells and seismic show that these zones approach the surface towards the southwest (Kuparuk Field area), but on the way there they intersect approximately 2000 feet of permafrost. These zones themselves do not reach the surface, as they were eroded by an unconformity, and the shallowest rocks are all the more recent deposits of the Gubik Formation.

References

Badami Development Project, North Slope, Alaska. UIC Permit Application, Class I (Industrial). March, 1996.

Molenaar, C.M., Bird, K.J., Kirk, A.R., 1986, Cretaceous and Tertiary stratigraphy of northeastern Alaska, in Talleur, I.K., and Weimer, Paul, eds., Alaskan North Slope geology: Pacific section, Society of Economic Paleontologists and Mineralogists.

Molenaar, C.M., Bird, K.J., and Collett, T.S., 1986, Regional Correlation Sections across the North Slope of Alaska, U.S. Geological Survey Miscellaneous Field Studies Map, MF-1907.

Exhibit C-1

Type Well Log

The Seal A-01 type log is on a scale of 1 inch equal to 200 feet TVD. Please remove it from the original June 1996 permit application sent to you and insert it here.

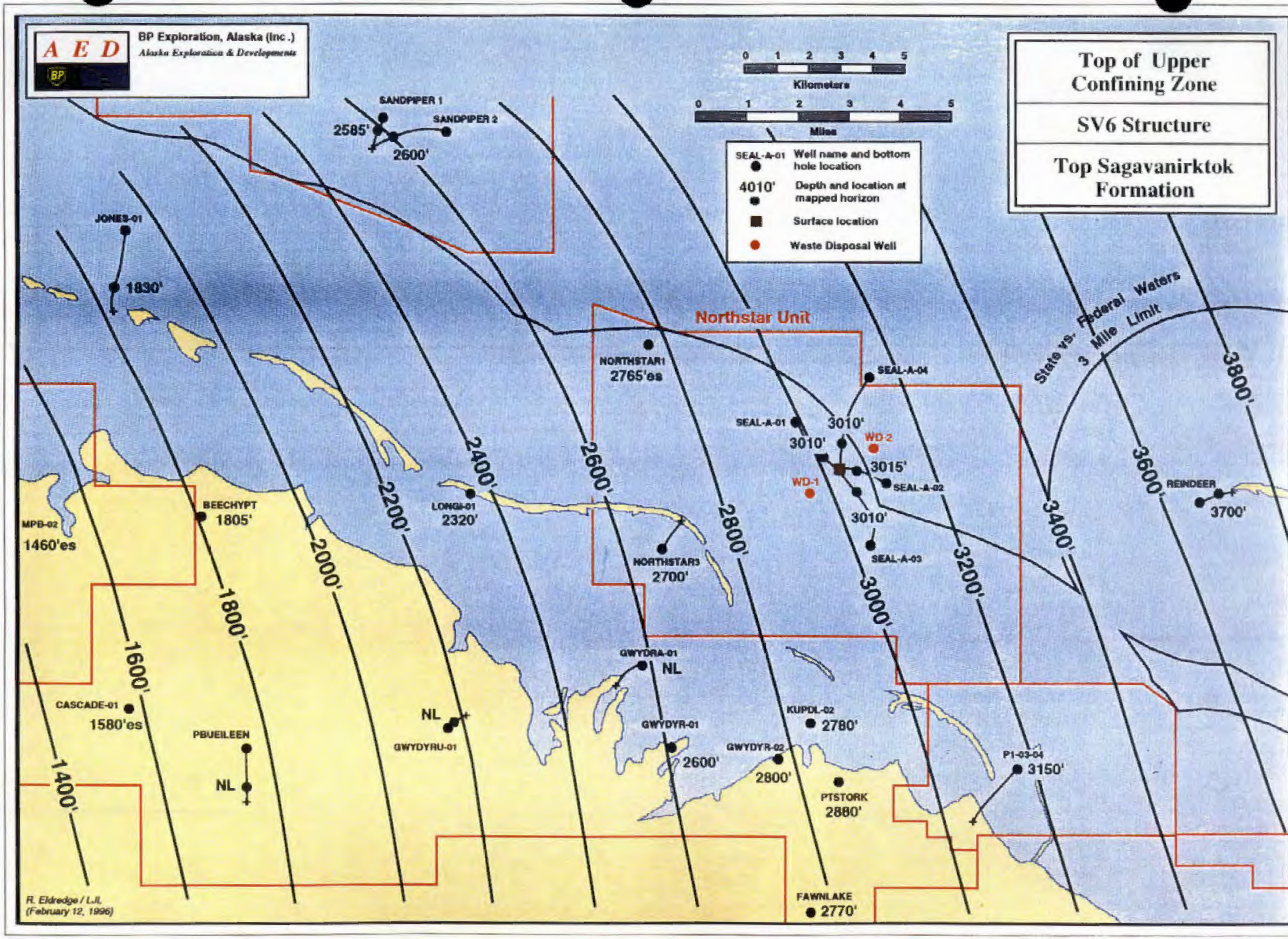
Exhibit C1
SEAL-A-01

Exhibit C-2

Regional Cross-Section

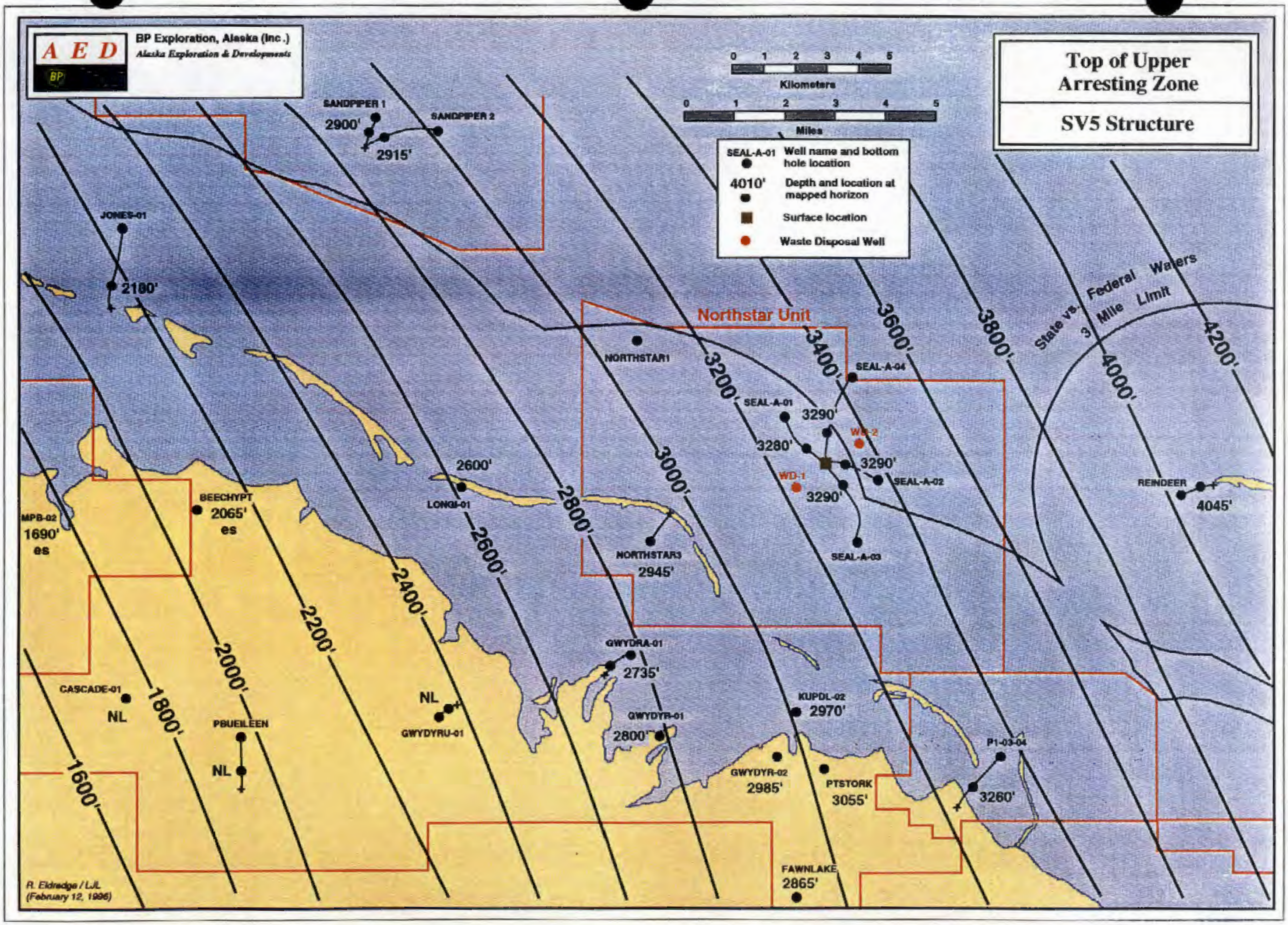
Please remove the regional cross section included in the june 1996 permit application sent to you and include it here

PLACEHOLDER FOR EXHIBIT C2
NORTHSTAR AREA CROSS SECTION



A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Development
Top of Upper Confining Zone
SV6 Structure
Top Sagavanirktok Formation
Kilometers
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters
3 Mile Limit
SANDPIPER 1
SANDPIPER 2
2585'
2600'
JONES-01
1830'
NORTHSTAR1
2765'es
SEAL-A-04
SEAL-A-01
3010'
3010'
WD-2
3015'
WD-1
SEAL-A-02
3010'
SEAL-A-03
REINDEER
3700'
BEECHYPT
1805'
MPB-02
1460'es
LONGI-01
2320'
NORTHSTAR3
2700'
GWYDRA-01
NL
CASCADE-01
1580'es
PBUEILEEN
NL
NL
GWYDYRU-01
GWYDYR-01
2600'
GWYDYR-02
2800'
KUPDL-02
2780'
PTSTORK
2880'
P1-03-04
3150'
FAWNLAKE
2770'
1400'
1600'
1800'
2000'
2200'
2400'
2600'
2800'
3000'
3200'
3400'
3600'
3800'
R. Eldredge / LJL
(February 12, 1996)

Exhibit C-3



A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Developments
Top of Upper Arresting Zone
SV5 Structure
Kilometers
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters 3 Mile Limit
SANDPIPER 1
2900'
SANDPIPER 2
2915'
JONES-01
2180'
NORTHSTAR1
SEAL-A-04
SEAL-A-01
3290'
3280'
WD-2
3290'
WD-1
3290'
SEAL-A-02
SEAL-A-03
REINDEER
4045'
2600'
LONGI-01
BEECHYPT
2065'
es
MPB-02
1690'
es
NORTHSTAR3
2945'
GWYDRA-01
2735'
CASCADE-01
NL
PBUEILEEN
NL
NL
GWYDYRU-01
GWYDYR-01
2800'
KUPDL-02
2970'
GWYDYR-02
2985'
PTSTORK
3055'
P1-03-04
3260'
FAWNLAKE
2865'
1600'
1800'
2000'
2200'
2400'
2600'
2800'
3000'
3200'
3400'
3600'
3800'
4000'
4200'
R. Eldredge / LJL
(February 12, 1996)

Exhibit C-4

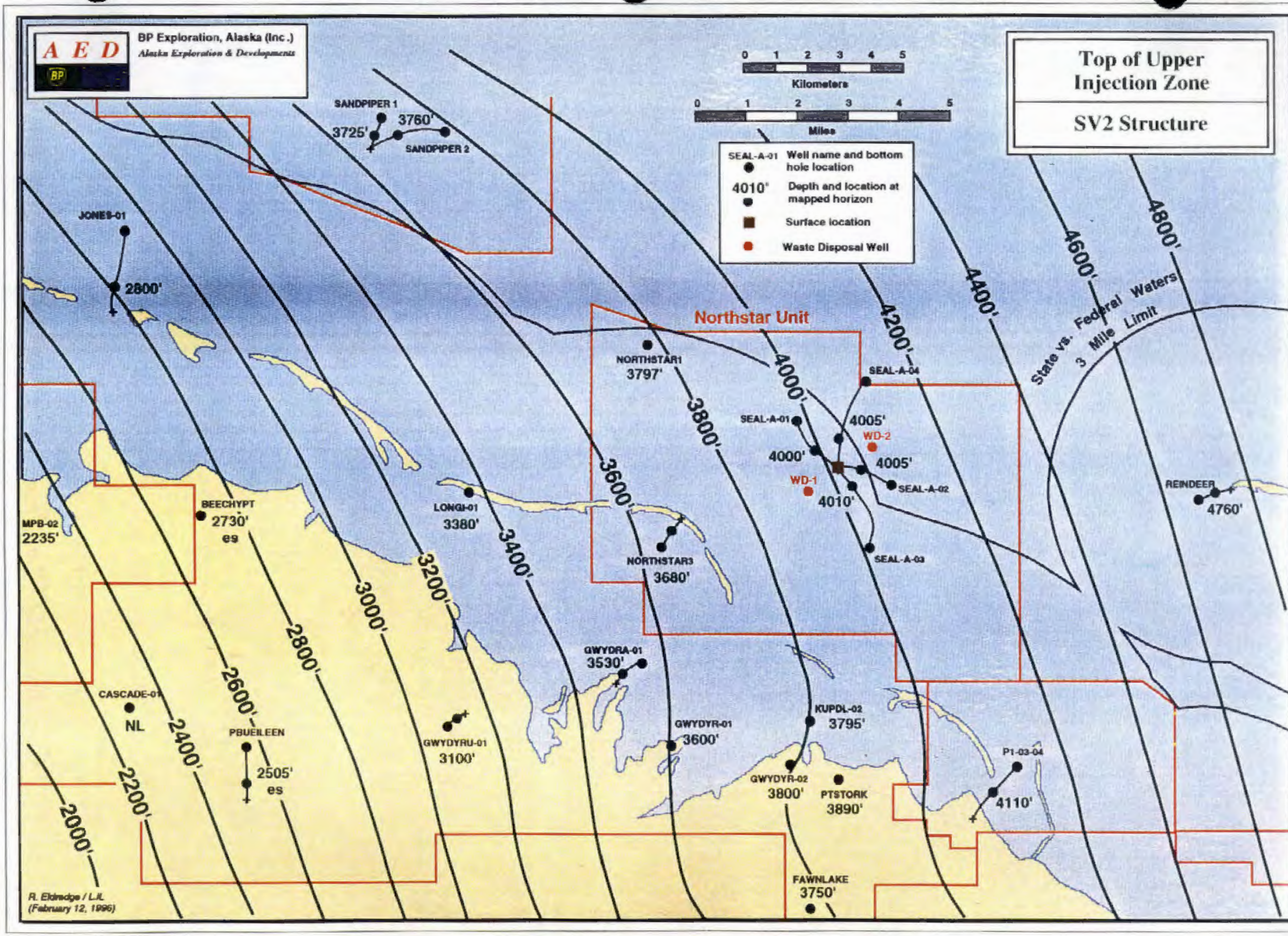
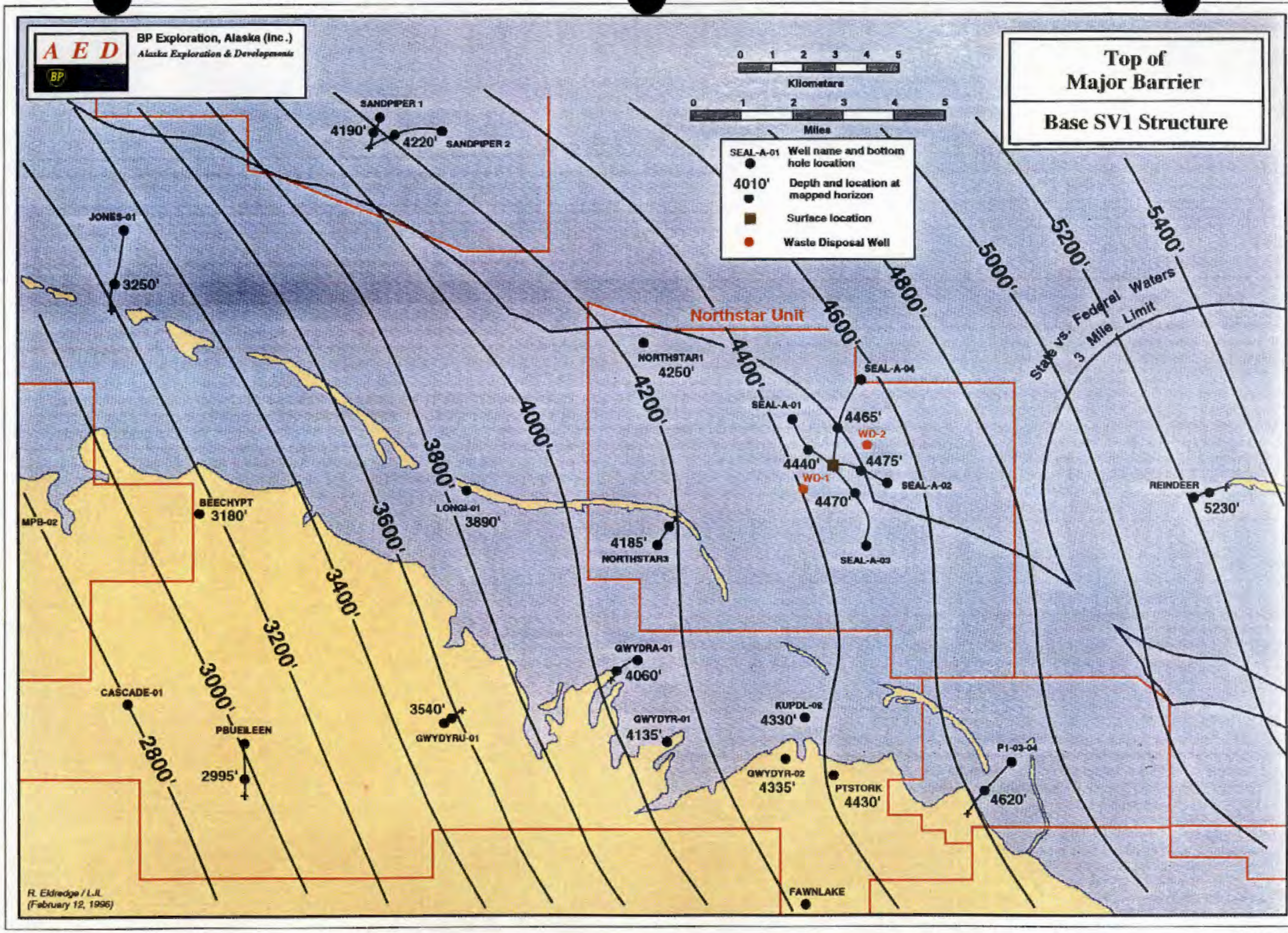

A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Developments
Top of Upper Injection Zone
SV2 Structure
Kilometers
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters
3 Mile Limit
SANDPIPER 1
SANDPIPER 2
3760'
3725'
JONES-01
2800'
NORTHSTAR1
3797'
SEAL-A-04
SEAL-A-01
4005'
WD-2
4000'
4005'
WD-1
4010'
SEAL-A-02
SEAL-A-03
REINDEER
4760'
MPB-02
2235'
BEECHYPT
2730'
es
LONGI-01
3380'
NORTHSTAR3
3680'
GWYDRA-01
3530'
CASCADE-01
NL
PBUEILEEN
2505'
es
GWYDYRU-01
3100'
GWYDYR-01
3600'
KUPDL-02
3795'
GWYDYR-02
3800'
PTSTORK
3890'
P1-03-04
4110'
FAWNLAKE
3750'
2000'
2200'
2400'
2600'
2800'
3000'
3200'
3400'
3600'
3800'
4000'
4200'
4400'
4600'
4800'
R. Eldredge / LJL
(February 12, 1996)

Exhibit C-5



A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Developments
Top of
Major Barrier
Base SV1 Structure
Kilometers
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters
3 Mile Limit
SANDPIPER 1
4190'
4220' SANDPIPER 2
JONES-01
3250'
NORTHSTAR1
4250'
SEAL-A-04
SEAL-A-01
4465'
WD-2
4440'
4475'
WD-1
SEAL-A-02
4470'
SEAL-A-03
REINDEER
5230'
BEECHYPT
3180'
MPB-02
LONGI-01
3890'
4185'
NORTHSTAR3
GWYDRA-01
4060'
CASCADE-01
3540'
GWYDYRU-01
GWYDYR-01
4135'
KUPDL-02
4330'
PBUEILEEN
2995'
GWYDYR-02
4335'
PTSTORK
4430'
P1-03-04
4620'
FAWNLAKE
2800'
3000'
3200'
3400'
3600'
3800'
4000'
4200'
4400'
4600'
4800'
5000'
5200'
5400'
R. Eldredge / LJL
(February 12, 1996)

Exhibit C-6

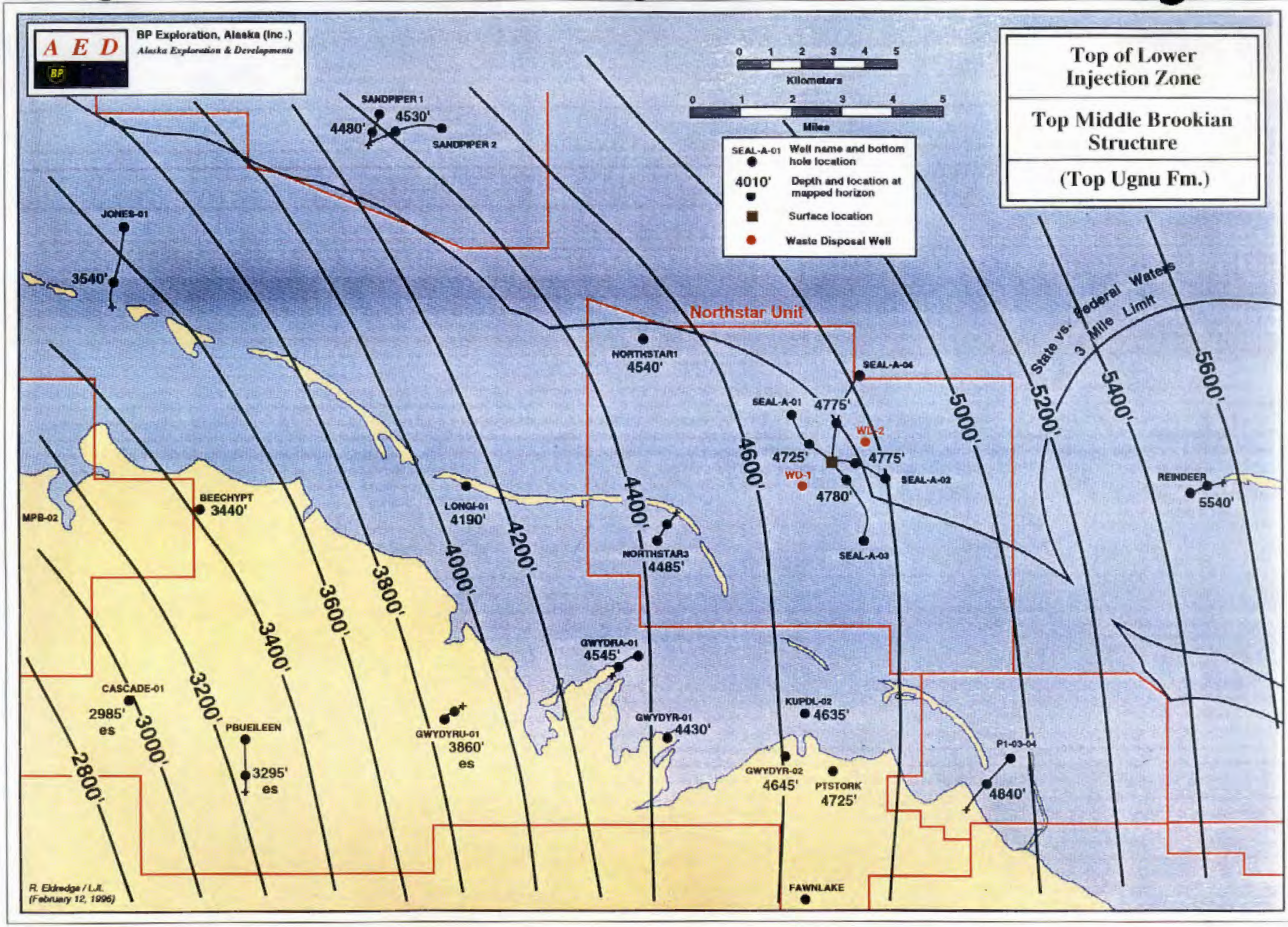

A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Developments
Top of Lower Injection Zone
Top Middle Brookian Structure
(Top Ugnu Fm.)
0 1 2 3 4 5
Kilometers
0 1 2 3 4 5
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters
3 Mile Limit
SANDPIPER 1
4530'
4480'
SANDPIPER 2
JONES-01
3540'
NORTHSTAR1
4540'
SEAL-A-04
SEAL-A-01
4775'
WD-2
4725'
4775'
WD-1
SEAL-A-02
4780'
SEAL-A-03
REINDEER
5540'
BEECHYPT
3440'
MPB-02
LONGI-01
4190'
NORTHSTAR3
4485'
GWYDRA-01
4545'
CASCADE-01
2985'
es
PBUEILEEN
3295'
es
GWYDYRU-01
3860'
es
GWYDYR-01
4430'
KUPDL-02
4635'
GWYDYR-02
4645'
PTSTORK
4725'
P1-03-04
4840'
FAWNLAKE
2800'
3000'
3200'
3400'
3600'
3800'
4000'
4200'
4400'
4600'
5000'
5200'
5400'
5600'
R. Eldredge / L.Jt.
(February 12, 1996)

Exhibit C-7

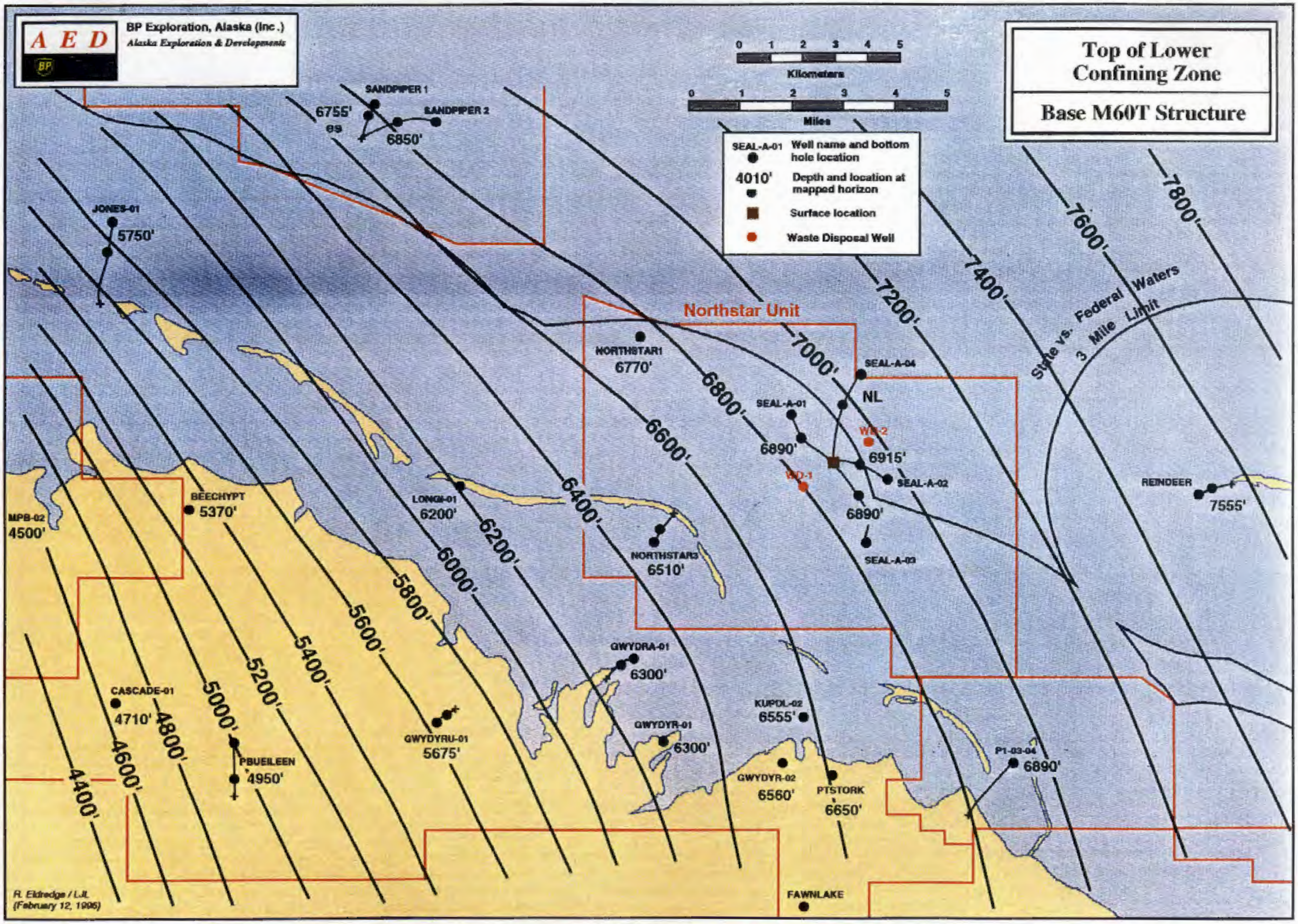
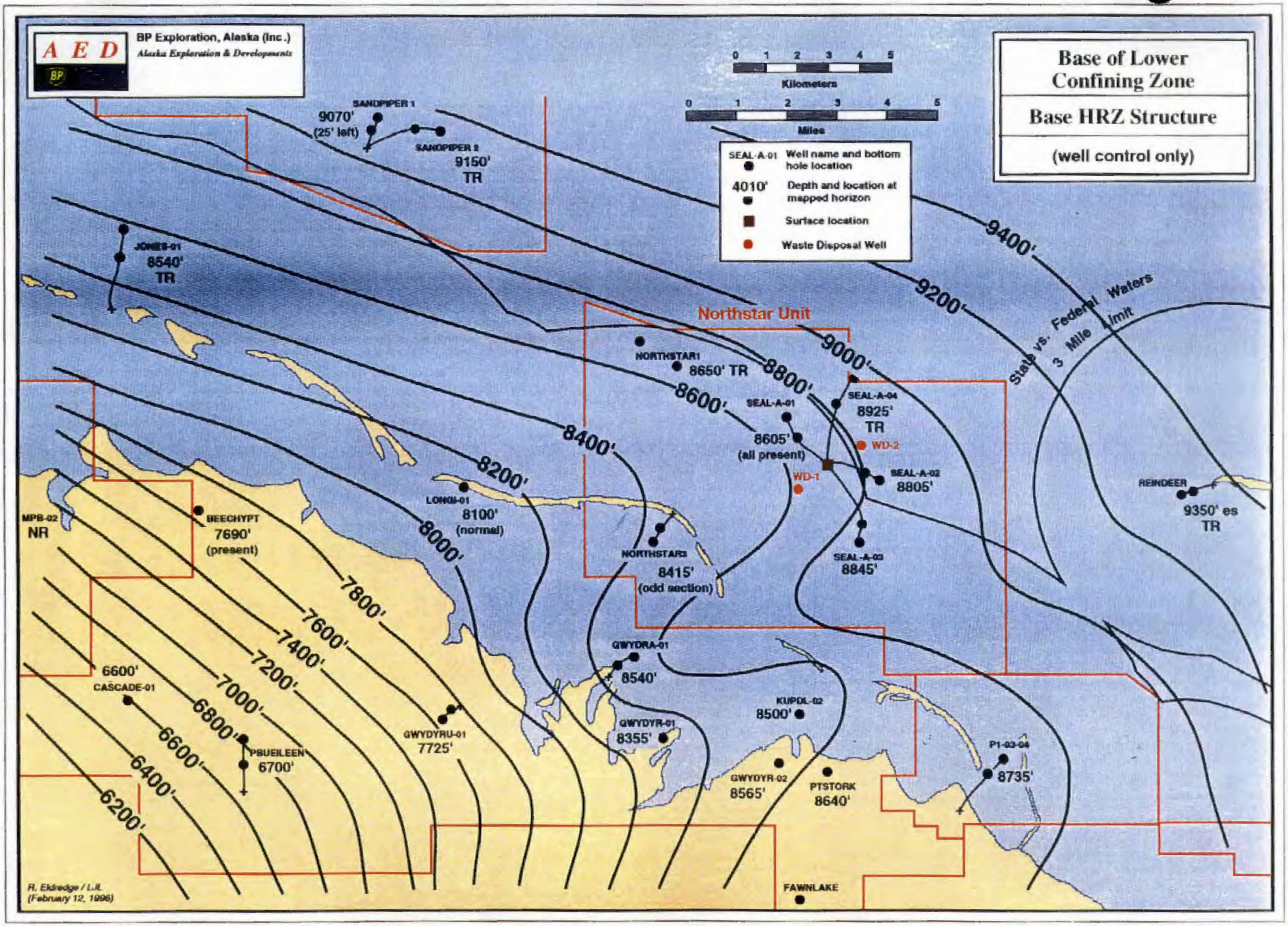
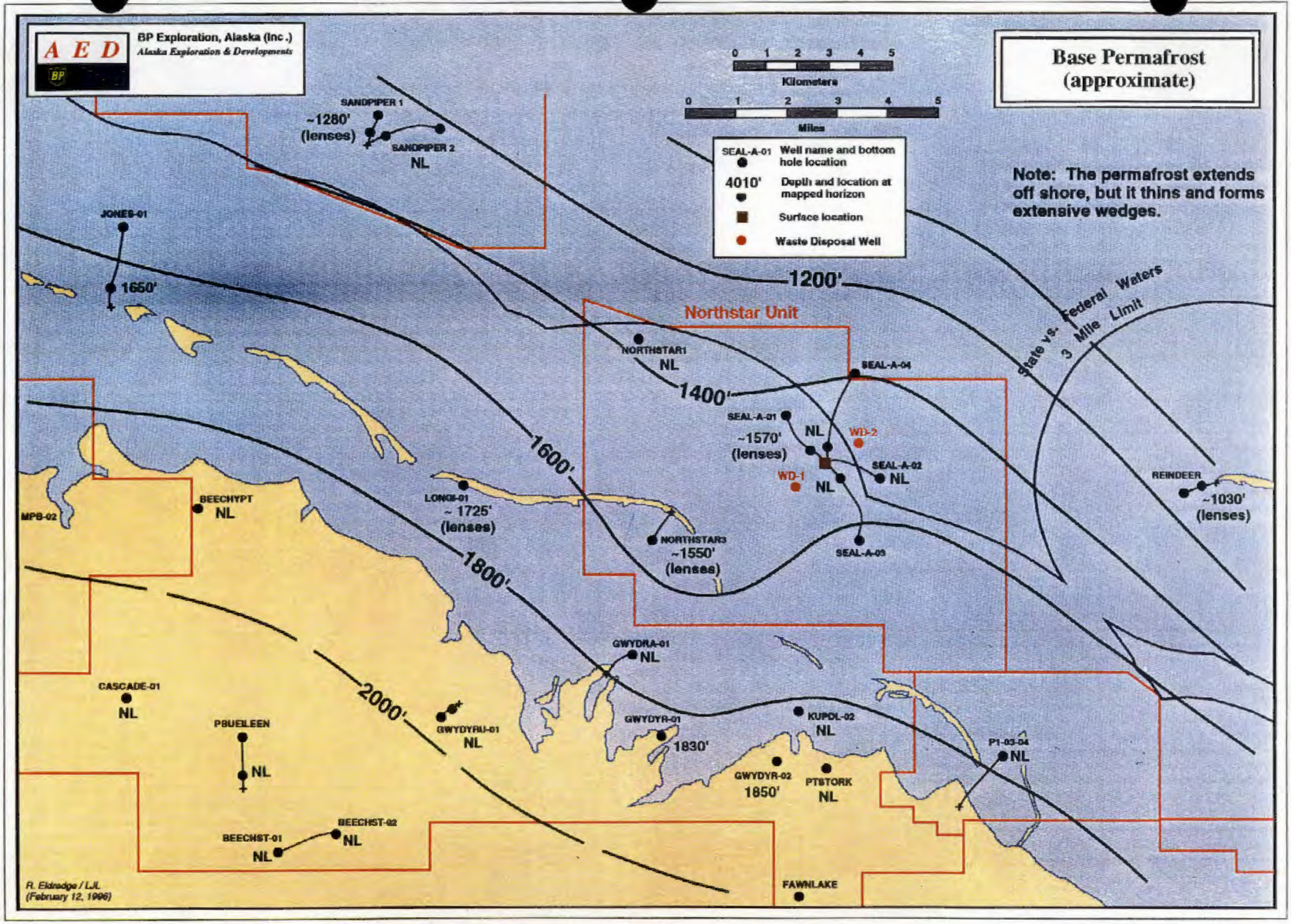

BP Exploration, Alaska (Inc.)
Alaska Exploration & Developments
A E D
Top of Lower Confining Zone
Base M60T Structure
Kilometers
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters
3 Mile Limit
SANDPIPER 1
SANDPIPER 2
6755'
6850'
JONES-01
5750'
NORTHSTAR1
6770'
SEAL-A-04
NL
SEAL-A-01
6890'
WD-2
6915'
WD-1
SEAL-A-02
6890'
SEAL-A-03
REINDEER
7555'
BEECHYPT
5370'
MPB-02
4500'
LONGI-01
6200'
NORTHSTAR3
6510'
GWYDRA-01
6300'
CASCADE-01
4710'
PBUEILEEN
4950'
GWYDYRU-01
5675'
KUPDL-02
6555'
GWYDYR-01
6300'
GWYDYR-02
6560'
PTSTORK
6650'
P1-03-04
6890'
FAWNLAKE
4400'
4600'
4800'
5000'
5200'
5400'
5600'
5800'
6000'
6200'
6400'
6600'
6800'
7000'
7200'
7400'
7600'
7800'
R. Eldredge / LJL
(February 12, 1996)

Exhibit C-8



A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Developments
Base of Lower Confining Zone
Base HRZ Structure
(well control only)
Kilometers
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Northstar Unit
State vs. Federal Waters 3 Mile Limit
SANDPIPER 1
9070' (25' left)
SANDPIPER 2
9150' TR
JONES-01
8540' TR
NORTHSTAR1
8650' TR
SEAL-A-01
8605' (all present)
SEAL-A-04
8925' TR
WD-2
WD-1
SEAL-A-02
8805'
SEAL-A-03
8845'
REINDEER
9350' es TR
LONGI-01
8100' (normal)
NORTHSTAR3
8415' (odd section)
MPB-02
NR
BEECHYPT
7690' (present)
6600'
CASCADE-01
PBUEILEEN
6700'
GWYDYRU-01
7725'
GWYDRA-01
8540'
GWYDYR-01
8355'
KUPDL-02
8500'
GWYDYR-02
8565'
PTSTORK
8640'
P1-03-04
8735'
FAWNLAKE
9400'
9200'
9000'
8800'
8600'
8400'
8200'
8000'
7800'
7600'
7400'
7200'
7000'
6800'
6600'
6400'
6200'
R. Eldredge / LJL (February 12, 1996)

Exhibit C-9



A E D
BP Exploration, Alaska (Inc.)
Alaska Exploration & Developments
Base Permafrost (approximate)
0 1 2 3 4 5
Kilometers
0 1 2 3 4 5
Miles
SEAL-A-01 Well name and bottom hole location
4010' Depth and location at mapped horizon
Surface location
Waste Disposal Well
Note: The permafrost extends off shore, but it thins and forms extensive wedges.
SANDPIPER 1
~1280' (lenses)
SANDPIPER 2
NL
JONES-01
1650'
1200'
Northstar Unit
NORTHSTAR1
NL
1400'
SEAL-A-04
SEAL-A-01
~1570' (lenses)
NL
WD-2
SEAL-A-02
NL
WD-1
NL
SEAL-A-03
State vs. Federal Waters
3 Mile Limit
REINDEER
~1030' (lenses)
1600'
LONGI-01
~ 1725' (lenses)
NORTHSTAR3
~1550' (lenses)
BEECHYPT
NL
MPB-02
1800'
2000'
GWYDRA-01
NL
CASCADE-01
NL
PBUEILEEN
NL
GWYDYRU-01
NL
GWYDYR-01
1830'
KUPOL-02
NL
P1-03-04
NL
GWYDYR-02
1850'
PTSTORK
NL
BEECHST-02
NL
BEECHST-01
NL
FAWNLAKE
R. Eldredge / LJL
(February 12, 1996)

Exhibit C-10

Appendix D

Aquifer Exemption Supplemental Information

This appendix consists of the following exhibits :

Exhibit D-1 : U.S. Fish and Wildlife Service Brochure. This brochure is available by contacting Mr. John Hall at the Alaska Region office, U. S. Fish and Wildlife Service, Tudor road, Anchorage, Alaska; or alternately, Mr. Tom Barnes at the BPX office, (907) 564-5154

Exhibit D-2 : BPX brochure on Wetlands and the Alaskan Oil Industry. This brochure is available by contacting Mr. Tom Barnes at the BPX office, (907) 564-5154.

Exhibit D-3 : Water salinity calculations for aquifers in the Northstar area.

Exhibit D-3

Water Salinity Determination

In the Northstar area, two wells have been logged below the permafrost through the tertiary-cretaceous interval between 2000-7000 feet (Northstar-01 and Long Island). Salinity calculations of the clean sand intervals using the industry accepted Archie equation are attached. The common data used and the various steps involved in the Archie calculation are explained and the total dissolved solids values (TDS) are shown in the tabulation in column eight. This data is also plotted on page 7.

Other area wells Seal-01, Seal-02, Seal-03 and Seal-04 do not have adequate log coverage in the up-hole section for discrete calculations. In particular density logs were missing which is required for porosity estimations. Consequently, porosity values and the subsequent salinity determinations for these wells are based on a regression of data from the Northstar and Long Island wells.

Water Salinity Calculation Procedure

The two wells, Northstar-01 and Long Island, were selected for direct calculations because they are representative of the shallow sands in the Northstar area and have available wireline logs in the up-hole section. There were no actual water samples taken from the shallow sections in the Northstar area.

The steps in the calculation were:

1) Approximate Temperature Below Permafrost:

   Temperature = 0.022*(Depth-Permafrost)+32
   Permafrost Depth= ~1,520 feet subsea

2) Porosity from the Density Log:

   Phi=(Rhoma-Rhob)/(Rhoma-Rhof)

   Rhoma = 2.65 g/cc
   Rhof = 1.00 g/cc

3) Apparent Formation Water Resistivity (m from the Archie equation):

   Rwa = Phi^m * Rt
   m = 1.80

4) Water Resistivity @ 75 deg. (Schlumberger):

   Rw@75 = (Rwa * Temperature + 6.77)/81.77

5) Total Dissolved Solids in NaCl Equivalents (Dresser Atlas):

   TDS = 10^(3.562-LOG10)(Rw@75 - 0.0123))/0.955

WELL	DEPTH FROM	DEPTH TO	TVDSS FROM	TVDSS TO	AVG TVDSS	H	AVG TDS	AVG PHIE	AVG KA	AVG TEMP	AVG RWA	AVG GR
NORTHSTAR1	3210	3223	3152	3165	3158	13	52085	0.35	4000	68	0.10	50
NORTHSTAR1	3447	3466	3388	3408	3398	19	35711	0.25	246	74	0.13	40
NORTHSTAR1	3678	3707	3620	3648	3634	28	28177	0.30	1214	79	0.15	42
NORTHSTAR1	3712	3746	3653	3688	3670	34	18611	0.27	621	80	0.28	45
NORTHSTAR1	3750	3790	3692	3732	3712	40	57074	0.22	261	81	0.23	46
NORTHSTAR1	3805	3816	3747	3757	3752	10	22503	0.28	381	82	0.17	51
NORTHSTAR1	3855	3869	3797	3811	3804	14	25045	0.32	1543	83	0.15	46
NORTHSTAR1	3870	4003	3811	3944	3878	133	27041	0.32	1908	85	0.14	42
NORTHSTAR1	4003	4016	3945	3957	3951	12	25735	0.30	943	86	0.14	50
NORTHSTAR1	4028	4115	3970	4056	4013	87	26834	0.31	1338	88	0.14	43
NORTHSTAR1	4249	4303	4190	4244	4217	54	23211	0.31	1659	92	0.15	44
NORTHSTAR1	4610	4627	4551	4568	4559	17	23159	0.33	2627	100	0.14	44
NORTHSTAR1	4684	4702	4625	4643	4634	18	24646	0.33	2675	102	0.13	48
NORTHSTAR1	4741	4753	4682	4694	4688	12	25993	0.33	2307	103	0.13	46
NORTHSTAR1	4755	4780	4696	4721	4709	25	27063	0.33	2823	104	0.12	44
NORTHSTAR1	4787	4833	4728	4774	4751	46	26448	0.31	1228	105	0.12	44
NORTHSTAR1	4835	4906	4776	4847	4812	71	28659	0.32	2036	106	0.11	42
NORTHSTAR1	4910	4920	4851	4861	4856	10	23699	0.29	651	107	0.13	48
NORTHSTAR1	4929	4953	4870	4894	4882	24	24689	0.32	1824	108	0.12	45
NORTHSTAR1	4954	4965	4895	4906	4901	11	28772	0.31	1643	108	0.11	46
NORTHSTAR1	5564	5584	5505	5525	5515	20	23581	0.30	1191	122	0.12	45
NORTHSTAR1	5585	5596	5526	5536	5531	11	18735	0.29	586	122	0.14	49
NORTHSTAR1	5632	5660	5573	5600	5587	27	23198	0.31	1097	124	0.11	47
NORTHSTAR1	5691	5701	5632	5642	5637	10	19373	0.31	1212	125	0.13	48
NORTHSTAR1	5712	5736	5653	5677	5665	24	98811	0.28	985	125	0.11	44
NORTHSTAR1	5764	5775	5705	5715	5710	11	23626	0.30	893	127	0.11	45
NORTHSTAR1	5855	5891	5796	5831	5813	36	29213	0.27	371	129	0.09	44
NORTHSTAR1	6080	6116	6021	6056	6038	36	48757	0.26	459	134	0.09	46
NORTHSTAR1	6240	6251	6181	6191	6186	10	30484	0.27	467	137	0.10	47
NORTHSTAR1	6271	6300	6212	6240	6226	28	28978	0.28	500	138	0.09	45
NORTHSTAR1	6324	6336	6264	6277	6271	12	27009	0.28	602	139	0.09	45
NORTHSTAR1	6355	6377	6296	6317	6307	21	25434	0.27	443	140	0.09	46
NORTHSTAR1	6378	6396	6318	6337	6328	18	26488	0.28	389	141	0.09	45
NORTHSTAR1	6764	6796	6705	6737	6721	32	16706	0.24	217	150	0.15	44
NORTHSTAR1	6806	6816	6747	6757	6752	10	17628	0.25	259	150	0.13	44
SEAL-A-01	1570	1623	1514	1567	1540	53	15640	0.35	3870	32	0.55	46
SEAL-A-01	1625	1681	1569	1625	1597	56	20090	0.35	4000	33	0.43	44
SEAL-A-01	1712	1732	1656	1676	1666	20	21665	0.35	4000	34	0.40	43
SEAL-A-01	1733	1860	1677	1804	1740	126	34672	0.35	4000	36	0.24	35
SEAL-A-01	1872	1897	1816	1841	1828	25	33964	0.35	4000	38	0.24	44
SEAL-A-01	1904	1972	1848	1916	1882	68	35844	0.35	4000	39	0.23	42
SEAL-A-01	1973	1995	1917	1939	1928	22	30121	0.35	4000	40	0.26	45
SEAL-A-01	1996	2014	1940	1958	1949	18	26233	0.35	4000	41	0.27	48
SEAL-A-01	2017	2052	1961	1996	1978	35	37240	0.35	4000	41	0.22	39
SEAL-A-01	2062	2155	2006	2099	2052	93	42624	0.35	4000	43	0.18	38

SEAL-A-01	2157	2186	2101	2130	2115	29	39140	0.35	4000	44	0.19	41
SEAL-A-01	2188	2204	2132	2148	2140	15	28255	0.35	4000	45	0.25	46
SEAL-A-01	2205	2302	2149	2246	2197	97	40738	0.35	4000	46	0.17	37
SEAL-A-01	2336	2357	2280	2301	2291	21	26094	0.35	4000	48	0.24	47
SEAL-A-01	2370	2384	2314	2328	2321	14	33687	0.35	4000	49	0.19	39
SEAL-A-01	2387	2447	2331	2391	2361	60	34368	0.35	4000	50	0.20	45
SEAL-A-01	2464	2512	2408	2456	2432	48	35526	0.35	4000	52	0.18	45
SEAL-A-01	2786	2817	2730	2761	2745	31	39088	0.35	3724	59	0.14	45
SEAL-A-01	2822	2947	2766	2890	2828	124	47694	0.35	3994	61	0.11	46
SEAL-A-01	2980	2990	2923	2933	2928	10	37830	0.35	3744	63	0.14	47
SEAL-A-01	2995	3019	2939	2963	2951	24	41680	0.35	3960	64	0.12	47
SEAL-A-01	3056	3071	3000	3014	3007	14	43543	0.35	3808	65	0.12	48
SEAL-A-01	3358	3378	3296	3315	3305	19	41937	0.35	4000	72	0.11	49
SEAL-A-01	3680	3704	3598	3620	3609	21	24533	0.32	1914	79	0.17	44
SEAL-A-01	3937	3954	3828	3842	3835	14	28618	0.33	2507	84	0.13	49
SEAL-A-01	4139	4296	3995	4121	4058	126	26445	0.33	2365	89	0.14	41
SEAL-A-01	4362	4432	4174	4230	4202	56	25620	0.33	2087	92	0.14	43
SEAL-A-01	4634	4655	4392	4408	4400	16	23512	0.31	1303	97	0.14	48
SEAL-A-01	5049	5064	4727	4739	4733	12	22760	0.31	1153	104	0.13	48
SEAL-A-01	5089	5126	4759	4789	4774	30	24995	0.33	1904	105	0.12	42
SEAL-A-01	5175	5240	4828	4879	4854	51	26600	0.33	2424	107	0.11	41
SEAL-A-01	5414	5431	5016	5029	5022	13	23861	0.32	1341	111	0.12	48
SEAL-A-01	5485	5515	5070	5093	5082	23	25034	0.32	1717	112	0.11	45
SEAL-A-01	6946	6959	6186	6196	6191	10	21341	0.30	751	137	0.11	47
SEAL-A-01	7200	7214	6383	6394	6388	11	22816	0.30	932	142	0.10	46
SEAL-A-02	2795	2969	2745	2918	2831	173	38088	0.35	3584	61	0.14	44
SEAL-A-02	2976	3003	2926	2952	2939	27	31533	0.34	2844	63	0.16	47
SEAL-A-02	3004	3057	2953	3006	2979	53	36766	0.35	3736	64	0.14	46
SEAL-A-02	3064	3076	3013	3025	3019	12	40018	0.35	3838	65	0.13	41
SEAL-A-02	3342	3374	3288	3319	3304	31	35304	0.35	3904	72	0.13	47
SEAL-A-02	3375	3389	3321	3334	3327	14	48683	0.35	3992	72	0.10	49
SEAL-A-02	3395	3414	3341	3359	3350	18	41191	0.35	4000	73	0.11	49
SEAL-A-02	3665	3689	3603	3626	3614	23	21551	0.31	1255	79	0.19	40
SEAL-A-02	3703	3713	3639	3648	3643	10	24396	0.31	1254	79	0.16	52
SEAL-A-02	3913	3955	3835	3873	3854	38	24582	0.32	1575	84	0.15	46
SEAL-A-02	3959	3983	3877	3899	3888	21	23352	0.31	1180	85	0.16	50
SEAL-A-02	3989	4003	3904	3917	3910	13	22403	0.31	1031	85	0.16	49
SEAL-A-02	4012	4023	3924	3934	3929	10	20467	0.30	697	86	0.18	51
SEAL-A-02	4102	4255	4005	4136	4070	132	24113	0.32	1670	89	0.15	42
SEAL-A-02	4257	4286	4139	4163	4151	25	23675	0.32	1322	91	0.15	48
SEAL-A-02	4312	4395	4185	4255	4220	70	23782	0.32	1693	92	0.14	41
SEAL-A-02	4396	4415	4256	4271	4263	16	19930	0.30	722	93	0.17	47
SEAL-A-02	4589	4659	4412	4468	4440	56	20369	0.30	793	98	0.16	47
SEAL-A-02	4979	4992	4723	4733	4728	10	19376	0.30	735	104	0.16	44
SEAL-A-02	5077	5110	4800	4826	4813	26	21124	0.31	1128	106	0.14	40
SEAL-A-02	5143	5171	4851	4873	4862	22	22343	0.31	1308	107	0.13	42
SEAL-A-02	5172	5187	4874	4885	4880	12	22594	0.31	1252	108	0.13	44

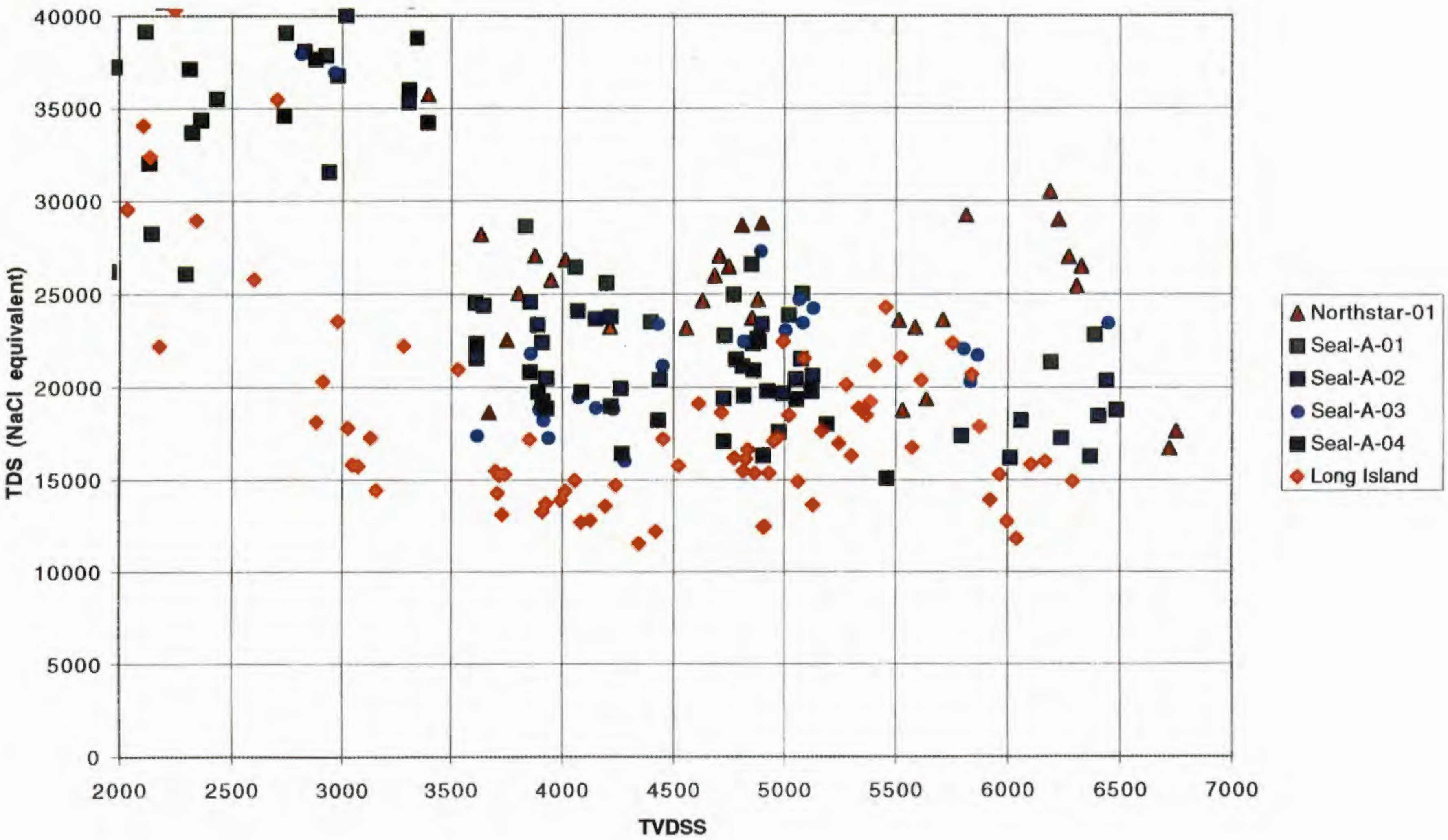
SEAL-A-02	5188	5217	4886	4909	4898	23	23403	0.32	1659	108	0.13	40
SEAL-A-02	5294	5311	4969	4983	4976	14	17562	0.28	405	110	0.16	50
SEAL-A-02	5319	5336	4989	5002	4995	13	19636	0.29	654	110	0.15	47
SEAL-A-02	5378	5421	5035	5069	5052	34	20438	0.30	822	111	0.14	46
SEAL-A-02	5423	5437	5070	5081	5076	11	21516	0.31	1056	112	0.13	44
SEAL-A-02	5482	5513	5116	5140	5128	24	20607	0.30	875	113	0.14	44
SEAL-A-02	6360	6385	5785	5803	5794	18	17368	0.28	357	128	0.14	47
SEAL-A-02	6656	6681	6002	6020	6011	18	16177	0.26	255	133	0.15	48
SEAL-A-02	6714	6750	6045	6071	6058	27	18192	0.28	410	134	0.13	47
SEAL-A-02	6967	6980	6234	6243	6238	10	17267	0.27	317	139	0.13	47
SEAL-A-02	7134	7155	6360	6376	6368	16	16279	0.26	269	142	0.14	48
SEAL-A-02	7180	7204	6395	6412	6403	18	18465	0.28	376	142	0.12	48
SEAL-A-02	7232	7247	6434	6445	6440	11	20347	0.29	680	143	0.11	43
SEAL-A-02	7278	7321	6469	6502	6485	33	18771	0.28	435	144	0.12	46
SEAL-A-03	1605	1618	1549	1563	1556	13	21477	0.35	3913	32	0.41	44
SEAL-A-03	1620	1653	1564	1598	1581	33	26800	0.35	3764	32	0.34	44
SEAL-A-03	1654	1669	1599	1613	1606	14	26185	0.35	3933	33	0.33	47
SEAL-A-03	1709	1723	1654	1667	1660	13	29310	0.35	3966	34	0.29	43
SEAL-A-03	1728	1855	1673	1799	1736	126	43450	0.35	4000	36	0.20	34
SEAL-A-03	1874	1893	1818	1837	1827	19	45632	0.35	4000	38	0.18	44
SEAL-A-03	1912	1924	1856	1868	1862	12	34789	0.35	4000	39	0.22	48
SEAL-A-03	1924	1961	1868	1905	1886	36	52536	0.35	4000	39	0.15	36
SEAL-A-03	1979	1989	1923	1933	1928	10	40727	0.35	4000	40	0.19	40
SEAL-A-03	2020	2047	1964	1990	1977	26	50628	0.35	4000	41	0.15	36
SEAL-A-03	2066	2148	2010	2090	2050	80	52010	0.35	4000	43	0.14	34
SEAL-A-03	2154	2180	2096	2122	2109	25	52608	0.35	4000	44	0.14	36
SEAL-A-03	2218	2239	2160	2180	2170	20	44474	0.35	4000	46	0.15	40
SEAL-A-03	2240	2280	2181	2220	2200	39	44170	0.35	4000	46	0.15	38
SEAL-A-03	2280	2300	2221	2239	2230	19	47372	0.35	4000	47	0.14	38
SEAL-A-03	2407	2440	2344	2375	2360	31	47034	0.35	4000	50	0.14	36
SEAL-A-03	2474	2511	2409	2444	2426	35	44221	0.35	4000	52	0.14	38
SEAL-A-03	2591	2632	2520	2559	2540	39	42869	0.35	4000	54	0.14	36
SEAL-A-03	2811	3009	2726	2904	2815	178	37968	0.35	3971	60	0.14	38
SEAL-A-03	3027	3130	2920	3009	2964	89	36920	0.35	3913	64	0.14	39
SEAL-A-03	3470	3534	3288	3338	3313	50	40735	0.35	3979	72	0.11	43
SEAL-A-03	3895	3928	3604	3627	3615	23	17360	0.33	2656	79	0.23	32
SEAL-A-03	4225	4272	3840	3873	3856	34	21795	0.34	3534	84	0.18	40
SEAL-A-03	4295	4309	3890	3900	3895	10	18801	0.33	2297	85	0.19	46
SEAL-A-03	4321	4337	3909	3920	3915	11	18205	0.33	2157	86	0.20	47
SEAL-A-03	4350	4364	3930	3940	3935	10	17255	0.31	1260	86	0.21	47
SEAL-A-03	4458	4639	4008	4140	4074	132	19452	0.35	3691	89	0.18	33
SEAL-A-03	4642	4666	4142	4160	4151	18	18871	0.33	2299	91	0.18	42
SEAL-A-03	4705	4817	4188	4270	4229	82	18816	0.33	2855	93	0.18	36
SEAL-A-03	4826	4840	4277	4287	4282	10	16011	0.29	534	94	0.20	50
SEAL-A-03	5027	5051	4424	4441	4432	18	23402	0.32	1365	97	0.14	46
SEAL-A-03	5052	5077	4442	4460	4451	18	21137	0.30	859	98	0.15	49
SEAL-A-03	5572	5598	4808	4826	4817	18	22462	0.31	1402	106	0.13	42

SEAL-A-03	5650	5744	4862	4927	4894	64	27299	0.33	2708	108	0.11	41
SEAL-A-03	5846	5864	4999	5011	5005	13	23046	0.31	1283	110	0.12	45
SEAL-A-03	5935	5949	5062	5072	5067	10	24714	0.32	1743	112	0.12	43
SEAL-A-03	5958	5974	5078	5089	5083	11	23440	0.31	1395	112	0.12	45
SEAL-A-03	6016	6050	5118	5142	5130	23	24234	0.32	1546	113	0.12	45
SEAL-A-03	6970	6984	5797	5807	5802	10	22055	0.30	816	129	0.11	51
SEAL-A-03	6990	7046	5812	5851	5831	39	20306	0.29	794	129	0.13	47
SEAL-A-03	7047	7082	5852	5877	5864	25	21723	0.30	894	130	0.11	46
SEAL-A-03	7890	7910	6439	6452	6446	13	23453	0.31	1079	143	0.10	45
SEAL-A-04	1617	1649	1561	1594	1577	32	24855	0.34	3495	32	0.36	44
SEAL-A-04	1650	1666	1594	1611	1602	16	25158	0.35	3872	33	0.34	45
SEAL-A-04	1708	1723	1653	1667	1660	14	28311	0.35	3869	34	0.30	44
SEAL-A-04	1726	1797	1671	1742	1706	71	35632	0.35	4000	35	0.24	35
SEAL-A-04	1802	1850	1747	1794	1771	48	46311	0.35	4000	37	0.18	34
SEAL-A-04	1872	1889	1817	1833	1825	16	42430	0.35	3941	38	0.19	41
SEAL-A-04	1909	1959	1853	1903	1878	50	45963	0.35	4000	39	0.18	38
SEAL-A-04	1973	1984	1917	1928	1922	11	41484	0.35	4000	40	0.19	38
SEAL-A-04	2014	2043	1958	1986	1972	28	50678	0.35	4000	41	0.16	36
SEAL-A-04	2065	2148	2009	2091	2050	82	51954	0.35	3984	43	0.14	34
SEAL-A-04	2149	2176	2092	2119	2105	26	43737	0.35	4000	44	0.17	40
SEAL-A-04	2181	2193	2124	2135	2129	12	32023	0.35	3754	45	0.23	44
SEAL-A-04	2195	2235	2137	2176	2157	39	47299	0.35	4000	45	0.15	38
SEAL-A-04	2236	2287	2178	2227	2203	49	45578	0.35	4000	46	0.15	37
SEAL-A-04	2367	2382	2306	2320	2313	14	37124	0.35	4000	49	0.17	40
SEAL-A-04	2405	2428	2343	2365	2354	22	45835	0.35	4000	50	0.14	34
SEAL-A-04	2433	2444	2370	2381	2375	10	41871	0.35	4000	50	0.15	43
SEAL-A-04	2466	2509	2402	2443	2422	41	43898	0.34	3648	51	0.15	39
SEAL-A-04	2575	2628	2506	2555	2531	49	43914	0.35	3994	54	0.14	34
SEAL-A-04	2810	2838	2724	2748	2736	25	34616	0.35	3729	59	0.16	39
SEAL-A-04	2839	3140	2750	3012	2881	263	37657	0.35	3927	62	0.14	37
SEAL-A-04	3491	3544	3285	3325	3305	39	35994	0.35	3901	72	0.13	43
SEAL-A-04	3563	3580	3339	3351	3345	12	38804	0.35	4000	73	0.11	50
SEAL-A-04	3633	3648	3390	3401	3396	11	34241	0.35	4000	74	0.13	51
SEAL-A-04	3922	3951	3603	3624	3613	21	22342	0.32	2243	79	0.18	35
SEAL-A-04	4246	4299	3835	3873	3854	38	20800	0.35	3560	84	0.18	40
SEAL-A-04	4307	4339	3879	3901	3890	22	19728	0.33	2274	85	0.18	47
SEAL-A-04	4347	4364	3907	3919	3913	12	19250	0.32	1566	85	0.19	46
SEAL-A-04	4368	4389	3922	3936	3929	14	18846	0.32	1429	86	0.19	47
SEAL-A-04	4486	4726	4004	4170	4087	166	19722	0.34	3417	89	0.18	36
SEAL-A-04	4737	4861	4178	4263	4220	85	18952	0.34	3028	93	0.18	36
SEAL-A-04	4862	4883	4263	4277	4270	14	16404	0.30	791	94	0.20	48
SEAL-A-04	5073	5151	4407	4461	4434	54	18201	0.32	1981	97	0.18	43
SEAL-A-04	5532	5547	4723	4733	4728	10	17072	0.33	2784	104	0.18	35
SEAL-A-04	5611	5637	4777	4794	4785	17	21477	0.34	3386	105	0.14	35
SEAL-A-04	5660	5689	4809	4829	4819	20	19532	0.34	3353	106	0.16	36
SEAL-A-04	5715	5763	4847	4879	4863	32	20907	0.33	2717	107	0.15	37
SEAL-A-04	5765	5788	4880	4895	4888	15	22468	0.35	3693	108	0.14	35

SEAL-A-04	5798	5813	4902	4911	4907	10	16293	0.32	1875	108	0.18	43
SEAL-A-04	5818	5850	4915	4936	4925	21	19783	0.33	2897	109	0.15	38
SEAL-A-04	6001	6063	5034	5075	5054	40	19330	0.34	3006	112	0.15	39
SEAL-A-04	6109	6170	5104	5144	5124	40	19772	0.33	2658	113	0.15	42
SEAL-A-04	6227	6257	5181	5201	5191	19	18001	0.33	2271	115	0.15	47
SEAL-A-04	6634	6690	5442	5477	5459	36	15068	0.31	1294	121	0.17	49
LONGIS	1782	1793	1741	1752	1746	6	26269	0.35	3692	31	0.34	51
LONGIS	1795	1801	1754	1760	1757	3	18463	0.32	1303	32	0.47	61
LONGIS	1826	1833	1785	1792	1788	4	20345	0.32	1557	32	0.42	59
LONGIS	1835	1842	1794	1801	1797	3	18434	0.33	2189	32	0.46	59
LONGIS	1853	1869	1812	1828	1820	8	19142	0.34	2851	32	0.44	52
LONGIS	1888	1895	1847	1854	1850	3	19543	0.32	1725	33	0.43	57
LONGIS	1895	1902	1854	1861	1858	3	19907	0.33	2417	33	0.42	56
LONGIS	1906	1920	1865	1879	1872	7	21139	0.35	3576	34	0.39	54
LONGIS	1927	1970	1886	1929	1907	21	28656	0.35	3774	34	0.30	43
LONGIS	2009	2140	1968	2099	2033	66	29513	0.34	3268	37	0.28	50
LONGIS	2145	2152	2104	2111	2107	3	34060	0.35	3747	39	0.23	49
LONGIS	2158	2195	2117	2154	2135	19	32353	0.34	3488	40	0.23	41
LONGIS	2211	2222	2170	2181	2176	5	22162	0.31	943	40	0.32	59
LONGIS	2223	2356	2182	2315	2248	66	40324	0.35	3681	42	0.18	39
LONGIS	2371	2386	2330	2345	2338	7	28941	0.33	2300	44	0.23	53
LONGIS	2630	2650	2589	2609	2599	10	25789	0.30	760	50	0.23	52
LONGIS	2678	2815	2637	2774	2706	68	35456	0.35	3654	52	0.17	44
LONGIS	2922	2931	2881	2890	2885	4	18087	0.28	449	56	0.30	56
LONGIS	2931	2977	2890	2936	2913	23	20270	0.31	2328	57	0.27	37
LONGIS	2987	3055	2946	3014	2980	34	23518	0.33	2788	58	0.23	47
LONGIS	3055	3081	3014	3040	3027	13	17776	0.30	789	59	0.28	57
LONGIS	3084	3094	3043	3053	3048	5	15788	0.30	744	60	0.31	59
LONGIS	3104	3126	3063	3085	3074	11	15710	0.30	936	60	0.32	60
LONGIS	3158	3186	3117	3145	3131	14	17234	0.31	1337	62	0.31	56
LONGIS	3193	3202	3152	3161	3156	4	14392	0.30	708	62	0.33	59
LONGIS	3236	3407	3195	3366	3281	85	22188	0.31	1703	65	0.24	45
LONGIS	3412	3730	3371	3689	3530	159	20926	0.33	2673	71	0.21	38
LONGIS	3734	3745	3693	3703	3698	5	15435	0.26	253	74	0.26	56
LONGIS	3745	3753	3704	3711	3708	4	14250	0.26	211	75	0.28	61
LONGIS	3754	3760	3713	3719	3716	3	15230	0.27	284	75	0.26	53
LONGIS	3769	3774	3728	3733	3730	3	13082	0.26	209	75	0.30	60
LONGIS	3778	3787	3737	3745	3741	4	15287	0.25	133	75	0.26	55
LONGIS	3846	3942	3805	3901	3853	48	17150	0.30	1459	78	0.23	46
LONGIS	3947	3953	3906	3911	3909	3	13243	0.24	118	79	0.29	62
LONGIS	3963	3972	3922	3930	3926	4	13678	0.24	114	80	0.28	61
LONGIS	4028	4040	3987	3999	3993	6	13861	0.25	185	81	0.27	58
LONGIS	4044	4067	4003	4025	4014	11	14370	0.26	234	82	0.26	53
LONGIS	4073	4121	4032	4079	4056	24	14922	0.29	824	82	0.25	47
LONGIS	4122	4132	4081	4090	4086	5	12675	0.24	103	83	0.29	61
LONGIS	4165	4173	4124	4132	4128	4	12761	0.26	210	84	0.28	58
LONGIS	4227	4249	4186	4208	4197	11	13528	0.33	2733	86	0.27	43

LONGIS	4254	4313	4213	4271	4242	29	14681	0.32	2288	87	0.25	42
LONGIS	4325	4449	4284	4408	4346	62	11487	0.30	1886	89	0.57	37
LONGIS	4456	4467	4415	4425	4420	5	12182	0.26	259	91	0.27	54
LONGIS	4474	4515	4433	4474	4454	20	17176	0.30	1354	91	0.20	39
LONGIS	4518	4615	4477	4573	4525	48	15732	0.30	1072	93	0.21	46
LONGIS	4624	4694	4583	4652	4618	35	19091	0.33	2860	95	0.17	43
LONGIS	4742	4780	4701	4739	4720	19	18607	0.31	1766	97	0.17	49
LONGIS	4785	4848	4744	4806	4775	31	16140	0.29	1162	99	0.20	50
LONGIS	4850	4863	4809	4821	4815	6	15455	0.28	421	99	0.20	56
LONGIS	4864	4874	4823	4833	4828	5	16098	0.29	657	100	0.19	57
LONGIS	4875	4884	4834	4843	4838	5	16595	0.31	1647	100	0.19	50
LONGIS	4891	4926	4850	4885	4868	17	15321	0.30	1195	101	0.26	50
LONGIS	4944	4950	4903	4909	4906	3	12396	0.26	184	101	0.24	61
LONGIS	4952	4958	4911	4916	4914	3	12421	0.25	172	102	0.24	59
LONGIS	4968	4979	4927	4938	4932	6	15331	0.28	595	102	0.20	54
LONGIS	4980	5006	4939	4965	4952	13	17075	0.31	1464	102	0.18	50
LONGIS	5007	5019	4966	4977	4972	6	17272	0.30	1041	103	0.18	51
LONGIS	5033	5040	4992	4998	4995	3	22433	0.31	2526	103	0.25	45
LONGIS	5056	5072	5015	5031	5023	8	18460	0.27	467	104	0.17	55
LONGIS	5099	5109	5058	5068	5063	5	14866	0.26	213	105	0.20	58
LONGIS	5112	5153	5071	5112	5091	21	21508	0.32	2650	106	0.15	39
LONGIS	5168	5177	5127	5135	5131	4	13606	0.24	99	107	0.21	61
LONGIS	5188	5230	5147	5188	5168	21	17588	0.28	695	107	0.17	46
LONGIS	5281	5296	5240	5255	5247	8	16955	0.25	225	109	0.17	55
LONGIS	5317	5323	5276	5282	5279	3	20108	0.29	607	110	0.14	48
LONGIS	5337	5346	5296	5304	5300	4	16278	0.28	493	110	0.17	51
LONGIS	5347	5402	5306	5360	5333	27	18852	0.29	742	111	0.15	46
LONGIS	5407	5415	5366	5373	5370	4	18465	0.26	240	112	0.15	55
LONGIS	5421	5435	5380	5393	5387	7	19200	0.26	500	112	0.15	54
LONGIS	5440	5454	5399	5413	5406	7	21149	0.29	1094	113	0.14	51
LONGIS	5487	5505	5446	5464	5455	9	24275	0.27	1448	114	0.13	39
LONGIS	5517	5610	5476	5569	5522	46	21571	0.29	982	115	0.13	43
LONGIS	5611	5618	5570	5577	5573	4	16721	0.21	45	116	0.16	55
LONGIS	5620	5689	5579	5648	5613	35	20355	0.27	552	117	0.14	47
LONGIS	5721	5867	5680	5825	5752	73	22330	0.28	725	120	0.12	40
LONGIS	5875	5885	5834	5843	5838	5	20661	0.25	206	122	0.13	53
LONGIS	5911	5919	5869	5877	5873	4	17853	0.24	104	123	0.14	60
LONGIS	5956	5969	5915	5928	5921	6	13873	0.23	100	124	0.18	54
LONGIS	5996	6012	5955	5970	5963	8	15262	0.24	126	125	0.17	51
LONGIS	6022	6054	5981	6012	5997	16	12713	0.23	94	126	0.20	55
LONGIS	6072	6089	6031	6047	6039	8	11769	0.25	131	127	0.21	57
LONGIS	6127	6162	6086	6120	6103	17	15810	0.24	153	128	0.16	53
LONGIS	6187	6230	6145	6188	6167	22	15969	0.26	621	130	0.15	45
LONGIS	6329	6334	6287	6292	6290	3	14892	0.17	11	132	0.16	59

Northstar Project-Log Derived TDS



Appendix E

Area of Review - Well Data

As shown in Exhibit E-1, exploratory wells Seal A-3 and Seal A-4 fall within the ½ mile area of review (AOR). Corrective action plans are not needed on these two wells. Data on the wells is attached.

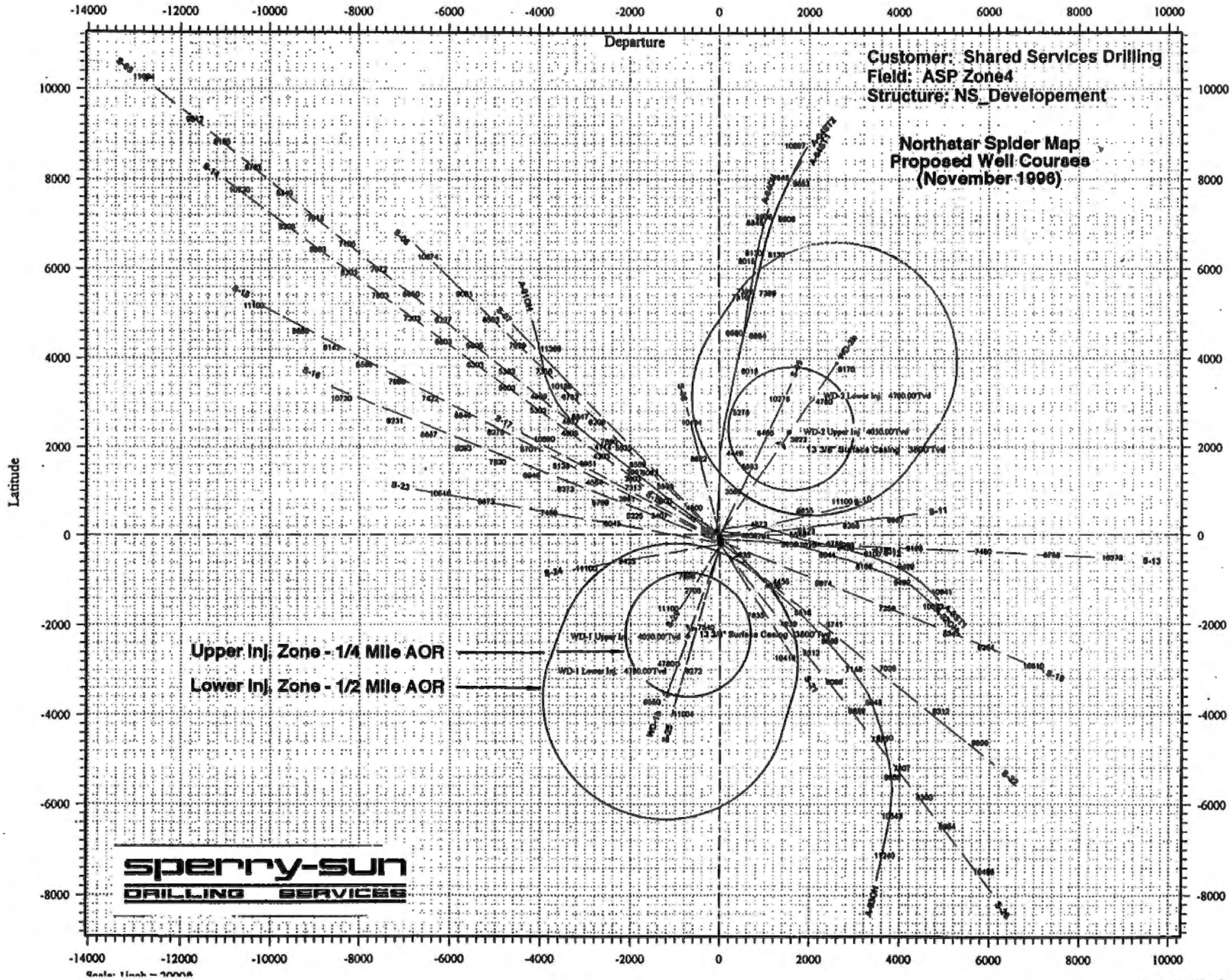
After development drilling occurs, it appears that one additional well will fall within the AOR. Well plans call for drilling mostly vertical holes to a depth of approximately 4600 feet TVD and cementing surface casing at that point. This will put good cement across the arresting and confining zones and promote good formation-casing bonding. Casing and cementing programs will ensure that fluid confinement is not jeopardized by the development wells. Any deficiencies or failed casing-cementing pressure tests will be corrected immediately. It is standard BPX policy and State of Alaska requirements that any well failing to test properly be repaired before drilling continues.

Seal A-3 Status:

The attached State reports show that 5000 feet of surface casing was set at 4459 feet TVD and cemented to the surface. This depth puts the casing shoe below the arresting zone. The lower part of the well was abandoned with five bridge plugs and three cement plugs. Two cement plugs were placed inside the 9 5/8 casing above the 13 3/8 shoe, and the 9 5/8 X 13 3/8 annulus was squeezed as shown on the near-surface schematic. All casings were cut off 19 feet below the original mud line.

Seal A-4 Status:

The attached State report shows that 6673 feet of surface casing was set at 5512 feet TVD and cemented to the surface. This depth places the casing shoe in the middle of the lower injection zone. The original hole was subsequently lost at 6450 feet TVD. A cement plug was set and and sidetrack #1 initiated. The intermediate casing was set and this hole was also lost. Sidetrack #2 was started at 12207 feet (9001 TVD). The lower hole was abandoned using two cement plugs. Two plugs were placed in the 9 5/8 casing above the 13 3/8 surface casing shoe and the 9 5/8 X 13 3/8 annulus was squeezed as shown on the near-wellbore schematic. All casings were cut off 19 feet below the original mud line.



Departure
Latitude
Customer: Shared Services Drilling
Field: ASP Zone4
Structure: NS_Developement
Northstar Spider Map
Proposed Well Courses
(November 1996)
Upper Inj. Zone - 1/4 Mile AOR
Lower Inj. Zone - 1/2 Mile AOR
WD-2 Lower Inj. 4700.00'Tvd
WD-2 Upper Inj. 4030.00'Tvd
13 3/8" Surface Casing 3800'Tvd
WD-1 Upper Inj. 4030.00'Tvd
WD-1 Lower Inj. 4700.00'Tvd
sperry-sun
DRILLING SERVICES

Exhibit E-1

FAIRWEATHER
E & P SERVICES, INC.

June 23, 1994

Mr. David Johnston, Chairman
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501

ATT: Blair Wondzell, Senior Petroleum Engineer

RE: Final Abandonment of Wells on Seal Island, Beaufort Sea, Alaska

Gentlemen:

Please find enclosed three (3) originals of AOGCC Form 10-403 and supporting documentation covering the final abandonment of the following wells:

Shell Western E&P Inc.	BF-47 No. 1 (Seal A-1)	83-074
Shell Western E&P Inc.	OCS Y-181 No. 1 RD (Seal A-2)	84-017
Shell Western E&P Inc.	BF-57 No. 1 (Seal A-3)	84-093
Shell Western E&P Inc.	OCS Y-180 No. 1	84-220

These wells are located on Seal Island in the Beaufort Sea. The lease upon which Seal Island is located is committed to the Northstar Unit, and Amerada Hess Corporation (AHC) is the Unit Operator. Accordingly, the final abandonment work on the above wells will be performed by AHC. A separate submittal is being made to the MMS for the OCS wells.

If you have any questions concerning this work, please contact the undersigned. We would appreciate receiving a copy of the approved 10-403 forms in this office. The originals should go to AHC in Houston, as the address appears on the form.

Sincerely,

R. C. Gardner
for Amerada Hess Corporation

Enclosure

cc: John Simon, Amerada Hess Corporation
Cliff Richard, Amerada Hess Corporation

Jo
Note the last ¶
The orig to Houston
The copy to Fairweather

O.K.!
Thanks.
JOS

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

1. Status of Well: OIL ☒ GAS ☐ SUSPENDED ☐ ABANDONED ☐ SERVICE ☐

Classification of Service Well:

2. Name of Operator: Shell Western E&P Inc.

3. Address: 601 West 5th Ave., #810, Anchorage, AK 99501

4. Location of well at surface: 1541.5' FSL, 629' FEL, Sec. 11, T13N, R13E

At Top Producing Interval: 4912' FSL, 2788' FWL, Sec.24, T13N, R13E

At Total Depth: 4124' FSL, 2613' FWL, Sec. 24, T13N, R13E

5. Elevation in feet (indicate KB, DF, etc.): 55' KB

6. Lease Designation and Serial No.: ADL 312809

7. Permit Number: 84-93

8. API Number: 50- 029-21130

9. Unit or Lease Name: BF-57

10. Well Number: No. ~~1~~ 3

11. Field and Pool: WILDCAT

12. Date Spudded	13. Date T.D. Reached	14. Date Comp., Susp. or Aband.	15. Water Depth, if offshore feet MSL	16. No. of Completions
7/9/84	11/12/84	2/10/85		0

17. Total Depth (MD+TVD)	18. Plug Back Depth (MD+TVD)	19. Directional Survey	20. Depth where SSSV set	21. Thickness of Permafrost
15455/11605	110/110	YES ☒ NO ☐	- feet MD	1700'

22. Type Electric or Other Logs Run: SP/GR/DISFL/BHCS/NGT/LDT/CNL/ML/DIL/BHC/SGT/DCL/CET/CCL/CNT

23. CASING, LINER AND CEMENTING RECORD

CASING SIZE	WT. PER FT.	GRADE	SETTING DEPTH MD TOP	SETTING DEPTH MD BOTTOM	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	133#	K-55	0	1602	26"	3700 Sx Permafrost2	-0-
13-3/8"	72#	N-80	0	5000	17½"	1950 Sx Permafrost E	
						900 Sx Class G	-0-
9-5/8"	53.5#	N-80&L-80	0	14280	12¼"	1450 Sx Class G	-0-
7"	32#	L-80 LTC	8427	15455	8½"	475 Sx Class G	-0-

24. Perforations open to Production (MD+TVD of Top and Bottom and interval, size and number)

11714-11763' MD
9100-9133' TVD
9045-9078' SS

196 Holes
4 JSP 22.0 gram RDX Charges

25. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)

26. ACID, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT & KIND OF MATERIAL USED

27. PRODUCTION TEST

Date First Production: 1/22/85

Method of Operation (Flowing, gas lift, etc.): Flowing

Date of Test	Hours Tested	PRODUCTION FOR TEST PERIOD	OIL-BBL	GAS-MCF	WATER-BBL	CHOKE SIZE	GAS-OIL RATIO
2/6/85	12		0	0	1039	32/64	-

Flow Tubing Press.	Casing Pressure	CALCULATED 24-HOUR RATE	OIL-BBL	GAS-MCF	WATER-BBL	OIL GRAVITY-API (corr)
261	0		0	0	2500	-

28. CORE DATA

Brief description of lithology, porosity, fractures, apparent dips and presence of oil, gas or water. Submit core chips.

See Attached Core Depths

CONFIDENTIAL

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MAR 27 1985
Alaska Oil & Gas Cons. Commission
Anchorage

Form 10-407
Rev. 7-1-80

CONTINUED ON REVERSE SIDE

Submit in duplicate

STATE OF ALASKA
A[illegible]KA OIL AND GAS CONSERVATION COMMIS[illegible]N

APPLICATION FOR SUNDRY APPROVALS

1. Type of Request: Abandon X Suspend __ Operation shutdown __ Re-enter suspended well __ Alter casing __ Repair well __ Plugging __ Time extension __ Stimulate __ Change approved program __ Pull tubing __ Variance __ Perforate __ Other __

2. Name of Operator: Amerada Hess Corporation

3. Address: 1201 Louisiana, Suite 700, Houston, TX 77002

4. Location of well at surface: 1541.5 ft FSL, 629 ft FEL, Sec. 11, T13N, R13E, UM

At top of productive interval: 4912 ft FSL, 2788 ft FWL, Sec. 24, T13N, R13E, UM

At effective depth: Same as surface location

ORIGINAL

At total depth: 4124 ft FSL, 2613 ft FWL, Sec. 24, T13N, R13E, UM

5. Type of Well: Development __ Exploratory X Stratigraphic __ Service __

6. Datum elevation (DF or KB): 55 ft KB feet

7. Unit or Property name: Northstar Unit/Seal Island

8. Well number: BF-57 #1 (Seal A-3)

9. Permit number: 84-93

10. API number: 50—029-21130

11. Field/Pool: Exploratory

12. Present well condition summary

Total depth: measured 15,455 feet; true vertical 11,605 feet

Plugs (measured): BP @ 14,812', BP @ 14,678, BP @ 14,533', BP @ 14,402', 14,402-14,118, BP @ 11,590, 11,590-11,200, 8517-8190, 2900-2610, 380-110

Effective depth: measured 110 feet; true vertical 110 feet

Junk (measured): BP Fish @ 14,816, mill and packer fish @ 12,000'

Casing	Length	Size	Cemented	Measured depth	True vertical depth
Structural	149'	30"	Driven	149'	149'
Conductor	1602'	20"	3700 SX(to surf)	1602'	1602'
Surface	5000'	13-3/8"	2850 SX(to surf)	5000'	4459'
Intermediate	14,280'	9-5/8"	1450 SX	14,280'	10,911'
Production	-	-	-	-	-
Liner	7028'	7"	475 SX	15,455'	11,588'

Perforation depth: measured 15,250-15,350 14,704-14,714 14,570-14,620 14,497-14,522 11,714-11,763

true vertical 11,473-11,529 11,163-11,169 11,084-11,114 11,041-11,056 9153-9186

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JUN 24 1994

Alaska Oil & Gas Cons. Commission
Anchorage

Tubing (size, grade, and measured depth): None

Packers and SSSV (type and measured depth): Junked packer @ 12,000 ft MD

13. Attachments: Description summary of proposal __ Detailed operations program X BOP sketch __

14. Estimated date for commencing operation: July 15, 1994

15. Status of well classification as: Oil __ Gas __ Suspended X Service ____

16. If proposal was verbally approved: Name of approver ____ Date approved ____

17. I hereby certify that the foregoing is true and correct to the best of my knowledge.
R. C. Gardner
Signed [signature] Title Agent, Amerada Hess Corporation Date June 16, 1994

FOR COMMISSION USE ONLY

Conditions of approval: Notify Commission so representative may witness
Plug integrity __ BOP Test __ Location clearance ✓
Mechanical Integrity Test __ Subsequent form required 10-407

Approval No. 94-169

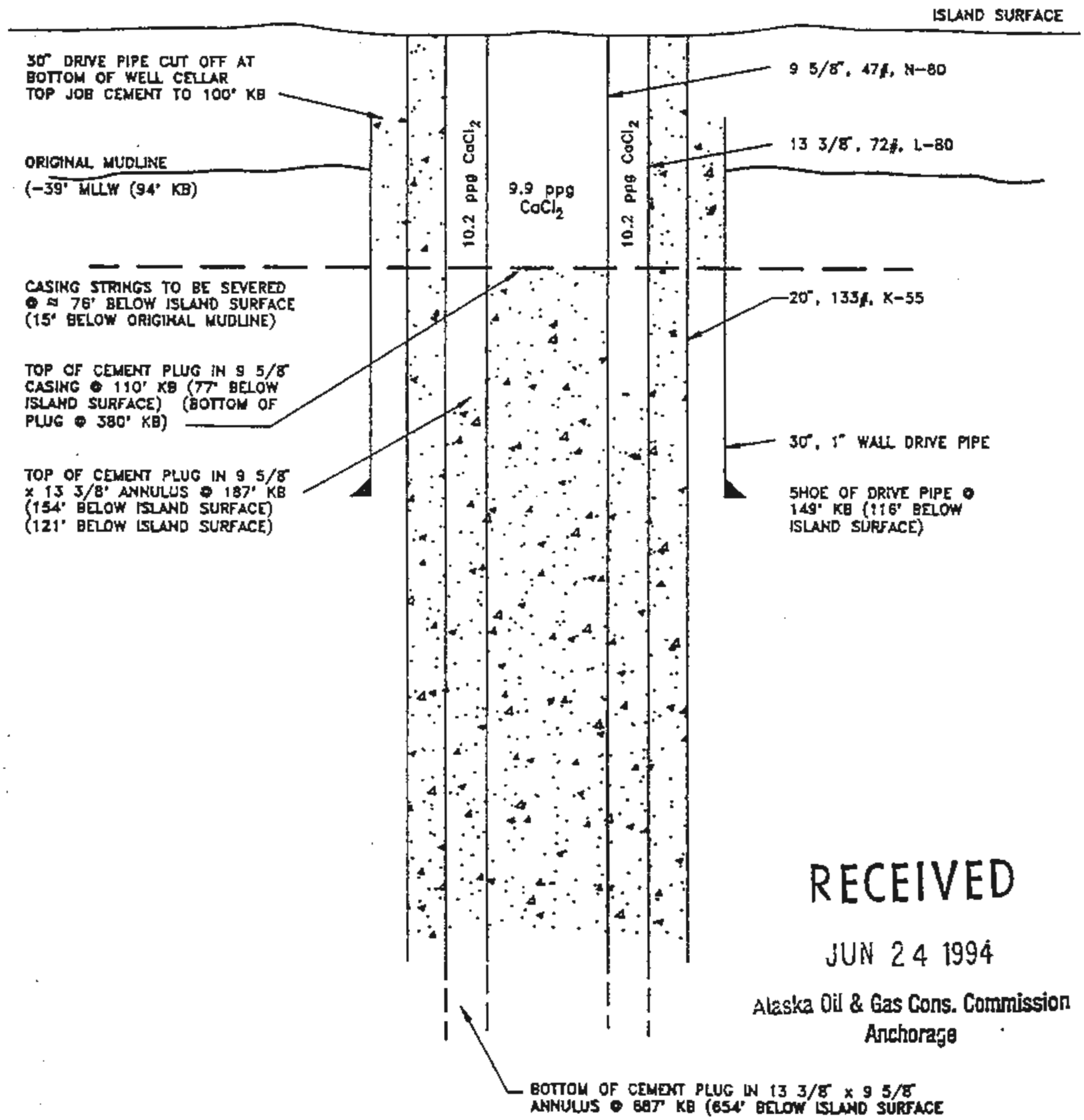
Approved by order of the Commission ORIGINAL SIGNED BY RUSSELL A. DOUGLASS Commissioner Date 6/29/94

Form 10-403 Rev 06/15/88 SUBMIT IN TRIPLICATE

Approved Copy
Returned
6-29-94

Attachment No. 2
BF 57 No. 1 (Seal A–3) Near Surface Detail
(Attached to and made a part of program for final abandonment of BF 57 No. 1 well)

Original KB Elevation = +55' (33' above island surface)



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JUN 24 1994
Alaska Oil & Gas Cons. Commission
Anchorage

002-05-3/0C53/8/21/94 CS:1:1 DISK: 2/94

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
Surface Abandonment / Location Clearance Report
(Title 20 AAC 25, Article 2)

FILE INFORMATION:

Operator: *Amerada Hess Corp.*
Address: *1201 Louisiana, Suite 700*
Houston, Texas 77002-5681
Surface Location:
F L, F L
Section *11* ,T *13N* ,R *13E* ,M *Um*

Well Name: *Seal Island BF-57-1*
PTD No.: *84-093*
API No. 50-
Unit or Lease Name: *North Star Unit*
Field and Pool:
Downhole P&A Date:

Inspection Date: *N/A* | **20 AAC 25.125 - ABANDONMENT MARKER:** | Approval Date:

Steel Post OD: (4" min) *N/A* " Length (10' min.) *N/A* ft. Height Above Final Grade Level (4' min.) *N/A* ft.
Top of Marker Post Closed With: *N/A* (Welded, Cmt., Cap), Set: *N/A* (On Wellhead, Csg, In Cmt)
Distance Below Final Grade Level: *19* ft.
Side Outlets: All valves and nipples removed ? *N/A* All openings closed? *N/A* With *N/A*

Marker Plate Diameter: *N/A* " Thickness: *N/A* " Distance Below Final Grade Level: *N/A* ft.
Marker Plate Attached To: Wellhead *N/A* Cutoff Csg *N/A* Other *N/A*

Information Beadwelded Directly to Marker Post or Blind Marker Plate: (Note when different from file information)
Operator: *N/A*
Well Name: *N/A*
Surface Location:
F L, F L
Section ,T ,R ,M

Unit / Lease Name: *N/A*
Remarks: *Seal Island is being abandoned. Casing was cut and removed 19 feet below original mud line. No marker plate was installed due to offshore location.*

Inspection Date: *8/10/94* | **20 AAC 25.170 - LOCATION CLEANUP:** | Approval Date:

PITS:
Filled In: *N/A* Liners Removed or Buried: *N/A* Debris Removed: *Yes*

SURFACE CONDITION OF PAD AND / OR LOCATION :
Contoured (Rough, Smooth, Contoured, Flat, Compacted)
Clean: *Yes* Type & Quan. of Debris if any remaining on pad and / or location: *None*

TYPE AND CONDITION OF SURROUNDING AREA :
Arctic Ocean (Wooded, Tundra, Grass, Brush, Dirt, Gravel, Sand)
Clean: *Yes* Type & Quan. of Debris if any remaining on surrounding area : *None*

TYPE AND CONDITION OF ACCESS ROAD AND SURROUNDING AREA:
N/A (Dirt, Gravel, Ice, Other)
Clean: *N/A* Type & Quan. of Debris if any remaining on access road or surrounding area : *N/A*

CLEANUP WORK REMAINING TO BE DONE : *None*

RECOMMENDED FOR APPROVAL OF ABANDONMENT: Yes *XX* No (If "No" See Reason)

Reason:

FINAL INSPECTION: Yes *XX* No

INSPECTED BY: *Jerry Herring* DATE: *8/10/94*

Distribution:
orig - Well file
c - Operator
c - Database
c - Inspector

FI-000 (Rev. 3/93)
I99KHKBD.XLS

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

1. Status of Well: OIL ☐ GAS ☐ SUSPENDED ☐ ABANDONED ☒ SERVICE ☐

Classification of Service Well:

LOCATION VERIFIED

2. Name of Operator: Amerada Hess Corporation

3. Address: 1201 Louisiana, Suite 700, Houston, Texas 77002

4. Location of well at surface: 1565 ft. FSL, 604 ft. FEL, Sec. 11, T13N, R13E, UM

At Top Producing Interval: N/A

At Total Depth: 861 ft.FSL, 638 ft. FWL, Sec. 1, T13N, R13E, U.M.

5. Elevation in feet (indicate KB, DF, etc.): 50 ft. KB (G.L. = 22 ft.)

6. Lease Designation and Serial No.: OCS Y-180 (BHL)

7. Permit Number: 84-220

8. API Number: 50-029-21236

9. Unit or Lease Name: Northstar Unit/Seal Island

10. Well Number: OCS Y-180, #1, (Seal A-4)

11. Field and Pool: Exploratory

12. Date Spudded	13. Date T.D. Reached	14. Date Comp., Susp. or Aband.	15. Water Depth, if offshore	16. No. of Completions
2/19/85	7/15/85	7/30/94 Final Abandonment	39 feet MSL	0

17. Total Depth (MD+TVD)	18. Plug Back Depth (MD+TVD)	19. Directional Survey	20. Depth where SSSV set	21. Thickness of Permafrost
16,090 MD/12,103 TVD	212' KB (MD + TVD)	YES ☒ NO ☐	None feet MD	1600

22. Type Electric or Other Logs Run: DIL/SP/GR/BHC,SFL, LDT/CNL-G/NGT/AMS,DIL/CCL All logs previously submitted

23. CASING, LINER AND CEMENTING RECORD

CASING SIZE	WT. PER FT.	GRADE	SETTING DEPTH MD TOP	SETTING DEPTH MD BOTTOM	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
30"	310#	1" wall	surface	273'KB	30"	Driven	80 ft.
20"	133#	K-55	surface	1603'KB	26"	3100 SX Permafrost II	80 ft.
13-3/8"	72#	L-80	surface	6673'KB	17-1/2"	2700 SX Permafrost	80 ft.
9-5/8"	53.5#	N-80/L-80	surface	12,131'KB	12-1/4"	800 SX Class G	80 ft.
7"	32 #	L-80	11,815'KB	15,015'KB	8-1/2"	1100 SX Class G	0

24. Perforations open to Production (MD+TVD of Top and Bottom and interval, size and number)

None

NOTE: 30", 20", 13-3/8" and 9-5/8" casing strings severed at 19 ft. below original mudline (≈80 ft. below island surface [G.L.])

25. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
None		

26. ACID, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT & KIND OF MATERIAL USED
None	

27. PRODUCTION TEST

Date First Production: None

Method of Operation (Flowing, gas lift, etc.):

Date of Test	Hours Tested	PRODUCTION FOR TEST PERIOD →	OIL-BBL	GAS-MCF	WATER-BBL	CHOKE SIZE	GAS-OIL RATIO

Flow Tubing Press.	Casing Pressure	CALCULATED 24-HOUR RATE →	OIL-BBL	GAS-MCF	WATER-BBL	OIL GRAVITY-API (corr)

28. CORE DATA

Brief description of lithology, porosity, fractures, apparent dips and presence of oil, gas or water. Submit core chips.

None

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AUG 25 1994
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Anchorage

Form 10-407
Rev. 7-1-80

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Submit in duplicate

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
APPLICATION FOR SUNDRY APPROVALS

1. Type of Request: Abandon X Suspend ___ Operation shutdown ___ Re-enter suspended well ___ Alter casing ___ Repair well ___ Plugging ___ Time extension ___ Stimulate ___ Change approved program ___ Pull tubing ___ Variance ___ Perforate ___ Other ___

2. Name of Operator: AMERADA HESS CORPORATION

3. Address: 1201 Louisiana St., Ste 700, Houston, Texas 77002

5. Type of Well: Development ___ Exploratory X Stratigraphic ___ Service ___

6. Datum elevation (DF or KB): 55 ft. KB feet

7. Unit or Property name: Northstar Unit/Seal Island

4. Location of well at surface: 1565 ft. FSL, 604 ft. FEL, Sec. 11, T13N, R13E, UM

At top of productive interval: No productive interval

ORIGINAL

At effective depth: 212 ft

At total depth: 861 ft. FSL, 638 ft.FWL, Sec. 1, T13N, R13E, UM.

8. Well number: OCS Y-180, #1(Seal A-4)

9. Permit number: 84-220

10. API number: 50— 029-21236

11. Field/Pool: Exploratory

12. Present well condition summary

Total depth: measured 16,090 feet; true vertical 12,103 feet

Plugs (measured): 15,015'-14,735', 11,918'-11,585', 2,800'-2,581', 400'-212'

Effective depth: measured 212 feet; true vertical 212 feet

Junk (measured): 12,548'-8,620', BHA and HWDP; 14,363'-12,692' - BHA, HWDP & DP

Casing	Length	Size	Cemented	Measured depth	True vertical depth
Structural	237'	30"	Driven	237'	237'
Conductor	1,603'	20"	3100 sx + top job	1,603'	1,603'
Surface	6,673'	13-3/8"	2700 sx (to surf)	6,673'	5,522'
Intermediate	12,131'	9-5/8"	800 sx	12,131'	8,960'
Production	-	-	-	-	-
Liner	3,200'	7"	1100 sx	15,015'	11,139'

Perforation depth: measured — No perforations; true vertical

Tubing (size, grade, and measured depth): None

Packers and SSSV (type and measured depth): None

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Anchorage

13. Attachments: Description summary of proposal ___ Detailed operations program X BOP sketch ___

14. Estimated date for commencing operation: July 15, 1994

15. Status of well classification as: Oil ___ Gas ___ Suspended X Service ___

16. If proposal was verbally approved — Name of approver ___ Date approved ___

17. I hereby certify that the foregoing is true and correct to the best of my knowledge.
R. C. Gardner
Signed [signature] Title Agent, Amerada Hess Corporation Date June 10, 1994

FOR COMMISSION USE ONLY

Conditions of approval: Notify Commission so representative may witness
Plug integrity ___ BOP Test ___ Location clearance ✓
Mechanical integrity Test ___ Subsequent form required 10-407

Approval No. 94-170

ORIGINAL SIGNED BY
RUSSELL A. DOUGLASS

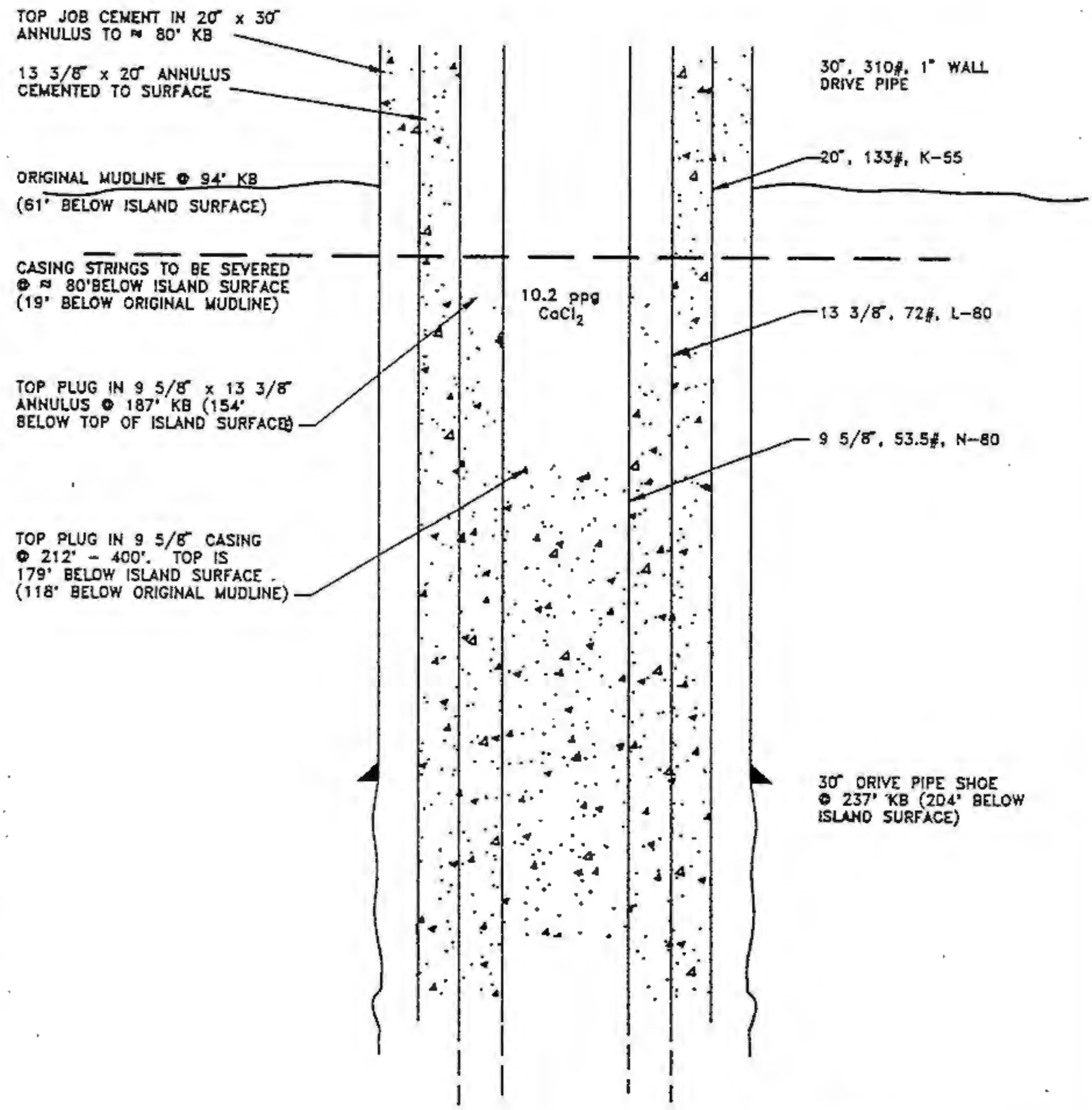
Approved by order of the Commission — Commissioner — Date 6/29/94

Form 10-403 Rev 06/15/88 — SUBMIT IN TRIPLICATE

Approved Copy
Returned
6-29-94

Attachment No. 2
OCS Y-0181 No. 1 (Seal A-4) Near Surface Casing Detail
(Attached to and made a part of program for
final abandonment of OCS Y-0181 No. 1 well)

All depths are from original KB, unless otherwise noted.



002-03-3/OCS2/6/21/94 CS:1:1 DISK: 2/94

RECEIVED

JUN 24 1994

Alaska Oil & Gas Cons. Commission
Anchorage

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
Surface Abandonment / Location Clearance Report
(Title 20 AAC 25, Article 2)

FILE INFORMATION:

Operator: Amerada Hess Corp. — Well Name: Seal Island OCS-Y-180-1
Address: 1201 Louisiana, Suite 700 — PTD No.: 84-220
Houston, Texas 77002-5681 — API No. 50-
Surface Location: — Unit or Lease Name: North Star Unit
F L, F L — Field and Pool:
Section 11 ,T 13N ,R 13E ,M Um — Downhole P&A Date:

Inspection Date: N/A	20 AAC 25.125 - ABANDONMENT MARKER:	Approval Date:

Steel Post OD: (4" min) N/A " Length (10' min.) N/A ft. Height Above Final Grade Level (4' min.) N/A ft.
Top of Marker Post Closed With: N/A (Welded, Cmt., Cap), Set: N/A (On Wellhead, Csg , In Cmt)
Distance Below Final Grade Level: 19 ft.
Side Outlets: All valves and nipples removed ? N/A All openings closed? N/A With N/A

Marker Plate Diameter: N/A " Thickness: N/A " Distance Below Final Grade Level: N/A ft.
Marker Plate Attached To: Wellhead N/A Cutoff Csg N/A Other N/A

Information Beadwelded Directly to Marker Post or Blind Marker Plate: (Note when different from file information)
Operator: N/A — Unit / Lease Name: N/A
Well Name: N/A — Remarks: Seal Island is being abandoned. Casing was cut and removed 19 feet below original mud line. No marker plate was installed due to offshore location.
Surface Location:
F L, F L
Section ,T ,R ,M

Inspection Date: 8/10/94	20 AAC 25.170 - LOCATION CLEANUP:	Approval Date:

PITS:
Filled In: N/A Liners Removed or Buried: N/A Debris Removed: Yes

SURFACE CONDITION OF PAD AND / OR LOCATION :
Contoured (Rough, Smooth, Contoured, Flat, Compacted)
Clean: Yes Type & Quan. of Debris if any remaining on pad and / or location: None

TYPE AND CONDITION OF SURROUNDING AREA :
Arctic Ocean (Wooded,Tundra,Grass,Brush,Dirt,Gravel,Sand)
Clean: Yes Type & Quan. of Debris if any remaining on surrounding area : None

TYPE AND CONDITION OF ACCESS ROAD AND SURROUNDING AREA:
N/A (Dirt, Gravel, Ice, Other)
Clean: N/A Type & Quan. of Debris if any remaining on access road or surrounding area : N/A

CLEANUP WORK REMAINING TO BE DONE : None

RECOMMENDED FOR APPROVAL OF ABANDONMENT: Yes XX No (If "No" See Reason)

Reason:

Distribution:
orig - Well file
c - Operator
c - Database
c - Inspector

FINAL INSPECTION: Yes XX No

INSPECTED BY: Jerry Herring DATE: 8/10/94

FI-000 (Rev. 3/93) I99KHLBD.XLS

Appendix F

Well Construction and Abandonment

Construction Procedures and Details

These wells will be directionally drilled to bottom hole locations with departure of approximately 3653 and 4667 feet, and to a final vertical depth of approximately 6500 feet TVD. This appendix includes the construction details for well WD-1 and the directional surveys for both wells. The drilling program for WD-1 calls for kicking out from the vertical at 500 feet, building angle to 40 degrees, and maintaining an accuracy that will allow for hitting within 100 feet of the target at the upper injection zone (4000 feet subsea). The angle will then be allowed to drop to approximately 25 degrees for the rest of the well course. All construction requirements exceed the specifications required by the Code of Federal Regulations and State of Alaska regulations.

The casing-cementing program is depicted in the schematic of Exhibit F-1. The surface hole will be logged as specified to ensure that the surface casing shoe is set near the base of the arresting zone. This placement, plus the use of Class-G cement as the tail slurry around the casing shoe will ensure good zonal isolation up to the permafrost. A full logging program will be run in the lower 12 ¼ hole. The 9 5/8 casing string will be cemented with an excess volume to ensure good bonding between it and the 13 3/8 surface casing. Zonal isolation will be verified by cement bond logs. Both surface and long-string integrity will be verified by pressure testing.

The tubing- casing annulus will be isolated above the injection intervals by stabbing a tubing seal assembly into a packer. A landing nipple to accept a wire line deployed downhole check valve will be installed in the tubing string. The annulus will be filled with corrosion inhibited sea water with a diesel cap for freeze protection. The tubing and tubing-casing annulus will be pressure tested to 3500 psi. Should the well not pressure test satisfactorily the tubing will be removed and the problem corrected before the drilling rig leaves location.

The well head assembly is shown in Exhibit F-2. The wellhead, controls, and monitoring instrumentation will all be enclosed in an insulated and heated well house. The lines to the well will be heat traced and insulated.

Proposed Drilling and Completion Program : Well WD-1

Surface location :	ASP "X" 659963 & ASP "Y" 6031015 ASP 4, NAD 1927
Target location :	4000 feet subsea: 2000 south, 728 west 6500 feet subsea: 3433 south, 1250 west
Target Accuracy	100 ft Radius at 4000 subsea
Estimated start date :	May or October 1999
Maximum angle:	40 degrees
Kick off depth :	500 feet MD/TVD
Wellbore azmith :	S 20 degrees W (200 degrees grid)
Kelly bushing (KB) elevation:	Assumed 50 feet above ground level

Item and Depths	Subsea	TVD (BKB)	MD (BKB) (measured depth) (below rig floor)
20" Conductor	±60	±110	±110
Base Permafrost	1500	1550	1569
Top Confining Zone	3010	3060	3470
Base Confining Zone	3300	3350	3848
13 3/8" Casing Shoe	3750	3800	4435
Top Injection Zone	4000	4050	4762
Lower Injection Interval	4730	4780	5715
9 5/8 casing	+/- 6300	+/- 6350	+/- 7490
Total Depth	+/- 6500	+/- 6550	+/- 7712

Logging Program

Open Hole:

17 1/2 Surface Hole : DIL/GR/SP/Caliper (From TD to 500')
12 1/4 Hole: DIL/GR/SP/BHC/CNL

Cased Hole:

Cement bond log from 13 3/8 shoe up to 500 feet.
Cement bond log from total depth to 13 3/8 shoe.
Directional survey from total depth.

Freeze Protection Plan

The tubing will be heat traced to +/- 1600 feet. The 4-1/2 X 9-5/8 annulus will be freeze protected with corrosion inhibited sea water with a diesel cap through the permafrost interval.

Casing / Tubing Specifications

Type	Size	Weight	Grade	Tension	Burst	Collapse
Surface	13 3/8"	68 lb /ft	K-55	1,140,000 lbs	3450 psi	1950 psi
Inj.Csg.	9 5/8"	47 lb /ft	L-80	1,161,000 lbs	6870 psi	6620 psi
Inj. Tbg	4-1/2"	12.6 lb /ft	L-80	304,000 lbs	7780 psi	6350 psi

Cement Volumes

13 3/8 Inch Surface Casing :

Measured Depth:	4435 feet
Basis:	Pump excess annular volume (17 ½ X 13 3/8")
Total Cement Vol.:	7000 (cu ft) Subject to revision
Lead Slurry Vol.:	2370 (cu ft) 1234 sacks (sx) Cold Set III at 1.92 cu ft/sx (from surface to 500 feet MD below Permafrost)
Tail Slurry Vol.:	4630 (cu ft) 4026 sx Class G cement at 1.15 cu ft/sx (from 500 feet MD below Permafrost to casing shoe)

Top Job : If no cement returns to surface the EPA and Alaska Oil and Gas Commission (AOGCC) will be notified. Appropriate logs and other tests will be conducted and procedures followed as specified by AOGCC regulations dealing with surface casings (AAC 25.030).

9 5/8 Inch Injection String :

Measured Depth:	7490 feet
Basis:	12 ¼ X 9 5/8 annulus volume with 30 % excess , plus lap of 13 3/8 shoe.
Total Cement Vol.:	1343 cu ft, 1140 sx at 1.18 cu ft/sx. Subject to revision based on hole conditions.

Construction Procedures

- Drive 20 inch conductor casing at ±110' TVD. Move in the drilling rig. Install the diverter and function test .

- Directionally drill a 17 1/2 inch hole to the surface casing point. Rig up and run E-line logs: DIL/GR/SP/ Caliper. Run and cement the 13 3/8 surface casing. Install the blow out preventer (BOP) and pressure test per AOGCC regulations.

- Pick up a 12 1/4 inch bottom hole assembly (BHA) and run in the hole. Test the casing to 2,500 psi for 15 minutes.

- Drill a 12 1/4 hole through the proposed injection interval to a depth of 6350 TVD. Rig up and run E-line logs: DIL/GR/SP/BHC/CNL.

- Run the 9 5/8 casing to TD. Cement the string from TD to above the surface casing shoe. Circulate out excess cement.

- Clean out the 9 5/8 casing with 8 ½ bottom hole assembly, pressure test, and drill to +/- 6550 TVD. Circulate the hole clean.

- Run a cement bond log from TD to the surface casing shoe.

- Run 4 1/2, 12.6#, L-80 tubing with heat tracing. Freeze protect annulus with corrosion inhibited water with diesel cap. Test the tubing and tubing-annulus separately to 3500 psi.

- Install the wellhead and test to 5000 psi. Release drilling rig.
- The drilling fluid program and surface system will conform to the regulations set forth in the AOGCC Regulations - 20 AAC 25.033.

Final Well Abandonment Plans

Abandonment plans for waste disposal wells will be implemented in accordance with the following procedures. At the time of final abandonment, these plans will be revised to reflect the current State of Alaska Oil and Gas Conservation Commission regulatory requirements and/or current EPA regulations, as well as utilizing current technology applicable to the condition of the well at the time. These agencies will be notified in sufficient time to witness the abandonment operation. Approvals will be obtained via AOGCC Form 10-403 and EPA Form 7520-14.

Placement of Plugs Above Lower Completion intervals

Two or more separate intervals will most probably be opened in any given well, with the sequence starting at the bottom. Should a lower interval become useless, it will be abandoned to ensure that it does not interfere with future injection activity. Integrity will be verified. Possible isolation methods include the leaving of hard fill-solid, and placement of cement caps, or mechanical plugs above the completion. The areas or intervals below and between plugs will be filled with fluid of sufficient density to control formation pressures, as illustrated on the abandonment schematic (Exhibit F-5). An upper interval will then be perforated. This process may continue up-hole as dictated by operating circumstances. After a well is no longer useful, steps will be taken for final well abandonment.

Final Well Abandonment (Closure)

Exhibit F-5 is used to represent a possible abandonment scenario for the WD-1 well. It is used to provide abandonment data for illustrative purposes on the attached EPA Form 7520-14 (Exhibit F-6). Understandably, specific action plans can not be included in some places on the form because perforation intervals will vary depending upon how the disposal process proceeds. Also the type, grade, and quantity of cement used will depend on the well bore geometry and physical conditions existing at the time of each abandonment operation. At closure, a rig will remove the tubing and place the appropriate plugs. The abandonment schematic shows plugs across perforated intervals and where the final up-hole abandonment plugs will be placed, and how the well will be left.

The following detailed procedure outlines how the final abandonment plugs may be placed and the well left. Should well conditions dictate a major revision, both regulatory agencies will be consulted and agreement reached on a satisfactory plan.

Abandonment procedures

1. Move in rig and prepare to abandon the well.

2. Circulate fluid and kill the well so it will not flow.

3. Rig down the tree, install the blow out preventers and pressure test per AOGCC regulations.

4. Circulate fluid until well is stable.

5. Pull tubing out of the hole and lay it down.

6. Run in the hole with a work string.

7. Spot cement plugs as required by AOGCC & EPA using the displacement, down squeeze, or mechanical bridge plug method as follows: (Sufficient notification must be given to the AOGCC so a representative may be present to witness the work)

   a. Set appropriate plugs across all open perforated intervals. Wait on cement, tag each plug to confirm its location, and record its actual location.

   b. Set cement plugs across the upper confining zone and at the base of permafrost.

   c. Set the surface plug per AOGCC requirements.

   (**Note:** Record the actual location and integrity of cement plugs after setting sufficient weight on the plug to confirm its location, that the cement has set, and that a competent plug is in place.)

8. Remove blowout preventers, cut off casings below ground level and weld on cover per AOGCC requirements.

9. Breakdown rig and move off location.

10. Install permanent well marker above ground level per AOGCC requirements.

Exhibit F-1 (revised)

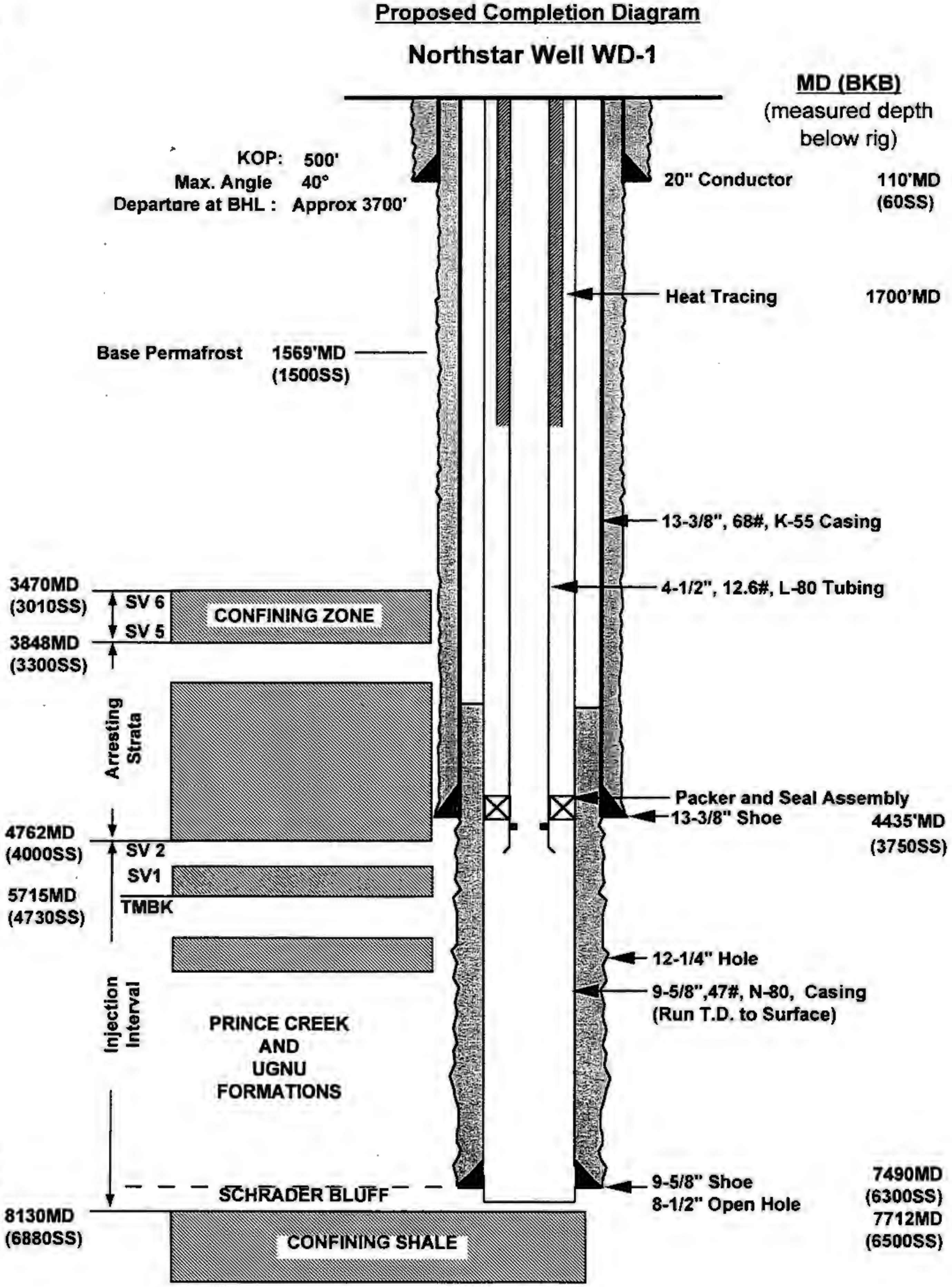
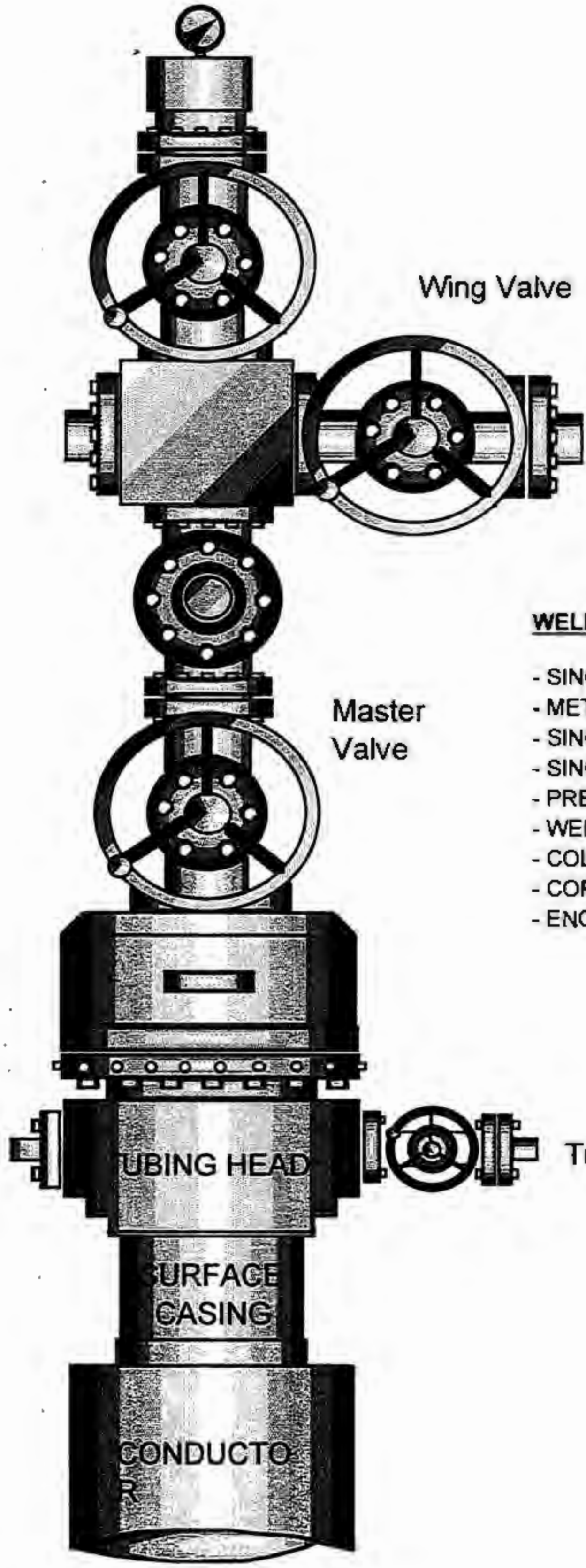


Exhibit F-2
Well Head Schematic WD-1



WELL HEAD - TREE DESCRIPTION

- SINGLE TUBING HANGER/ WELLHEAD - 4 1/2"
- METAL TO METAL RING SEAL ASSEMBLY
- SINGLE MASTER VALVE - MANUAL
- SINGLE WING VALVE - AUTOMATED FOR SHUT IN
- PRESSURE RATING - 5000 PSI
- WELL HEAD TEST PORTS - AS REQUIRED
- COLD WEATHER METALLURGY - TYPICAL N. S.
- CORROSSION METALLURGY - WASTE DISPOSAL WELL
- ENCLOSURE (INSIDE INSULATED WELLHOUSE)

Exhibit F-3

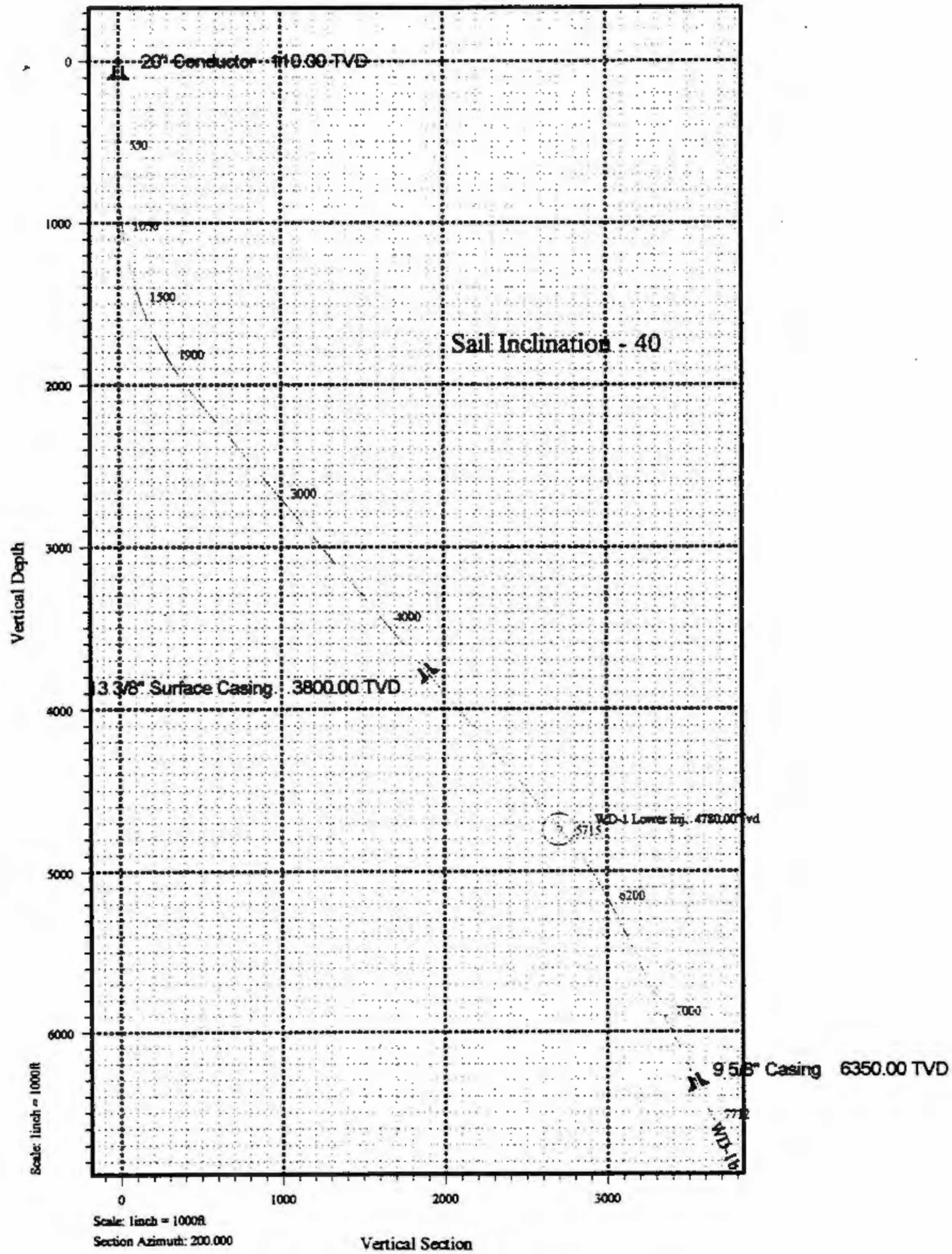
WELL PLANNING REPORT

BPX - Shared Services Drilling

Northstar development

WD-1
Thursday, October 31, 1996

sperry-sun DRILLING SERVICES	Customer: Shared Services Drilling Project: ASP Zone4	Structure: NS_Development Wellhead: WD-1		

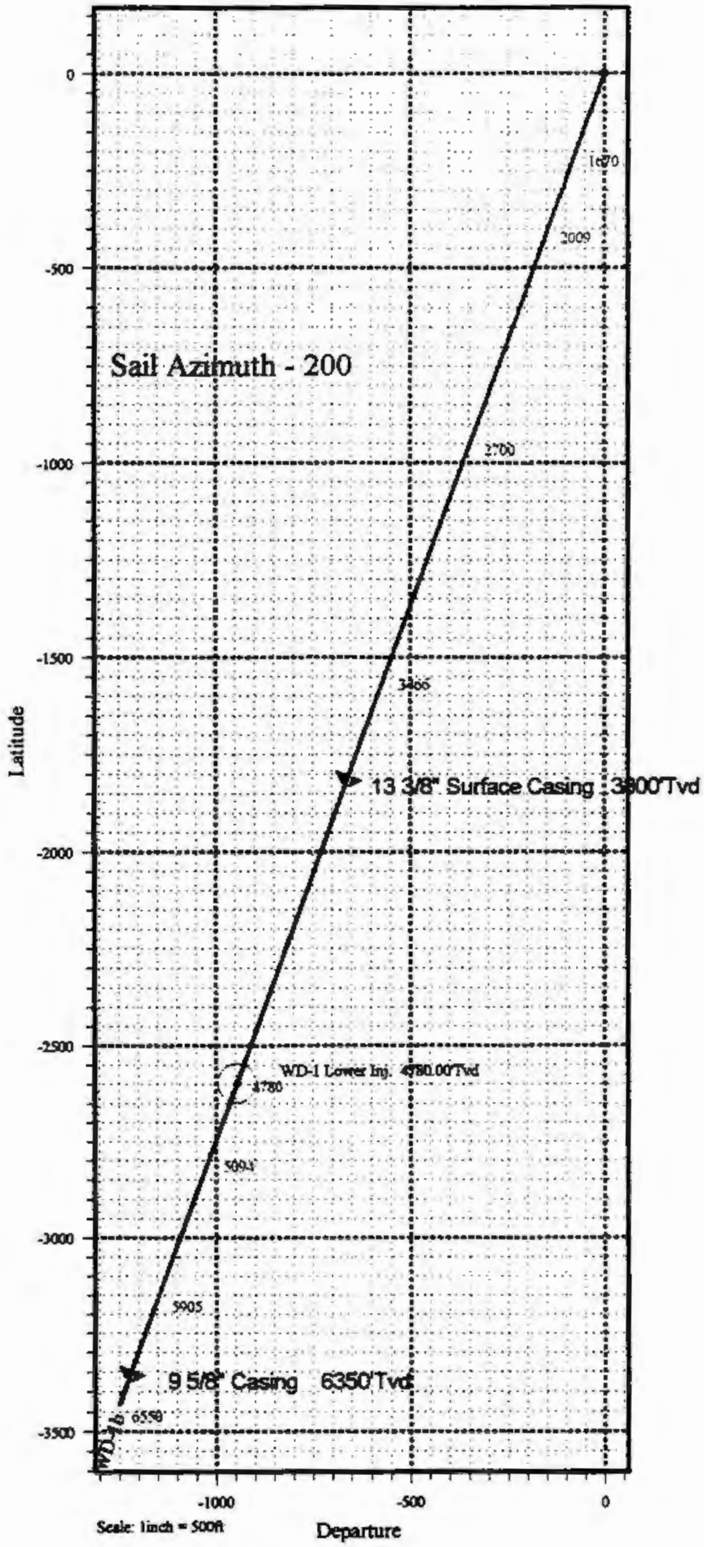


Prepared:	Checked:	Approved:

sperry-sun DRILLING SERVICES

Customer: Shared Services Drilling
Project: ASP Zone4

Structure: NS_Development
Wellhead: WD-1



Prepared:	Checked:	Approved:

SPERRY-SUN DRILLING SERVICES
WELL PROFILE DATA

CONFIDENTIAL

BPX - Shared Services Drilling
Northstar development

WD-1
Thursday, October 31, 1996

MEASURED DEPTH	ANGLE DEG	DIRECTION DEG	VERTICAL DEPTH	LATITUDE (Ft.)	DEPARTURE (Ft.)	VERTICAL SECTION	DOG LEG
0.00	0.000	0.000	0.00	0.00	0.00	0.00	
500.00	0.000	0.000	500.00	0.00	0.00	0.00	0.000
550.00	0.000	0.000	550.00	0.00	0.00	0.00	0.000
800.00	2.500	200.000	799.92	5.12 S	1.87 W	5.45	1.000
1000.00	6.500	200.000	999.26	19.87 S	7.23 W	21.14	2.000
1050.00	7.500	200.000	1048.89	25.59 S	9.32 W	27.24	2.000
1290.00	13.500	200.000	1284.76	66.67 S	24.27 W	70.95	2.500
1500.00	19.800	200.000	1485.86	123.19 S	44.84 W	131.09	3.000
2000.00	34.800	200.000	1928.90	338.07 S	123.05 W	359.76	3.000
2173.33	40.000	200.000	2066.55	436.96 S	159.04 W	465.00	3.000
2500.00	40.000	200.000	2316.79	634.28 S	230.86 W	674.98	0.000
3000.00	40.000	200.000	2699.81	936.29 S	340.78 W	996.38	0.000
3500.00	40.000	200.000	3082.84	1238.30 S	450.70 W	1317.77	0.000
4000.00	40.000	200.000	3465.86	1540.31 S	560.63 W	1639.16	0.000
4500.00	40.000	200.000	3848.88	1842.32 S	670.55 W	1960.56	0.000
5000.00	40.000	200.000	4231.90	2144.33 S	780.47 W	2281.95	0.000
5500.00	40.000	200.000	4614.93	2446.34 S	890.40 W	2603.35	0.000
5715.49	40.000	200.000	4780.00	2576.51 S	937.77 W	2741.86	0.000
6000.00	32.887	200.000	5008.73	2735.22 S	995.54 W	2910.76	2.500
6315.49	25.000	200.000	5284.59	2878.58 S	1047.72 W	3063.32	2.500
6500.00	25.000	200.000	5451.82	2951.85 S	1074.39 W	3141.30	0.000
7000.00	25.000	200.000	5904.97	3150.42 S	1146.66 W	3352.61	0.000
7500.00	25.000	200.000	6358.12	3348.98 S	1218.93 W	3563.91	0.000
7711.72	25.000	200.000	6550.00	3433.06 S	1249.53 W	3653.39	0.000

The Dogleg Severity is in Degrees per 100.00 Feet
Vertical Section was calculated along an Azimuth of 200.000° (Grid)

Based upon Minimum Curvature type calculations. At a Measured Depth of 7711.72 Feet, the Bottom Hole Displacement is 3653.39 Feet, in the Direction of 200.000° (Grid)

SPERRY-SUN DRILLING SERVICES
WELL PROFILE DATA

CONFIDENTIAL

BPX - Shared Services Drilling
Northstar development

WD-1
Thursday, October 31, 1996

INTERPOLATIONS

MEASURED DEPTH	ANGLE DEG	DIRECTION DEG	VERTICAL DEPTH	LATITUDE (Ft.)	DEPARTURE (Ft.)	VERTICAL SECTION	
5715.49	40.000	200.000	4780.00	2576.51 S	937.77 W	2741.86	TARGET

Vertical Section Direction = 200.000° (Grid)

FORMATION TOPS

MEASURED DEPTH	ANGLE DEG	DIRECTION DEG	VERTICAL DEPTH	LATITUDE (Ft.)	DEPARTURE (Ft.)	SUB SEA DEPTH	
3470.19	40.000	200.000	3060.00	1220.29 S	444.15 W	-3010.00	Top Upper Confining Zone
3848.76	40.000	200.000	3350.00	1448.96 S	527.38 W	-3300.00	Base Upper Confining Zone
4762.54	40.000	200.000	4050.00	2000.90 S	728.27 W	-4000.00	Upper Injection Zone
5715.49	40.000	200.000	4780.00	2576.50 S	937.77 W	-4730.00	Lower Injection Zone

RKB Elevation = 50.00 Feet

Exhibit F-4

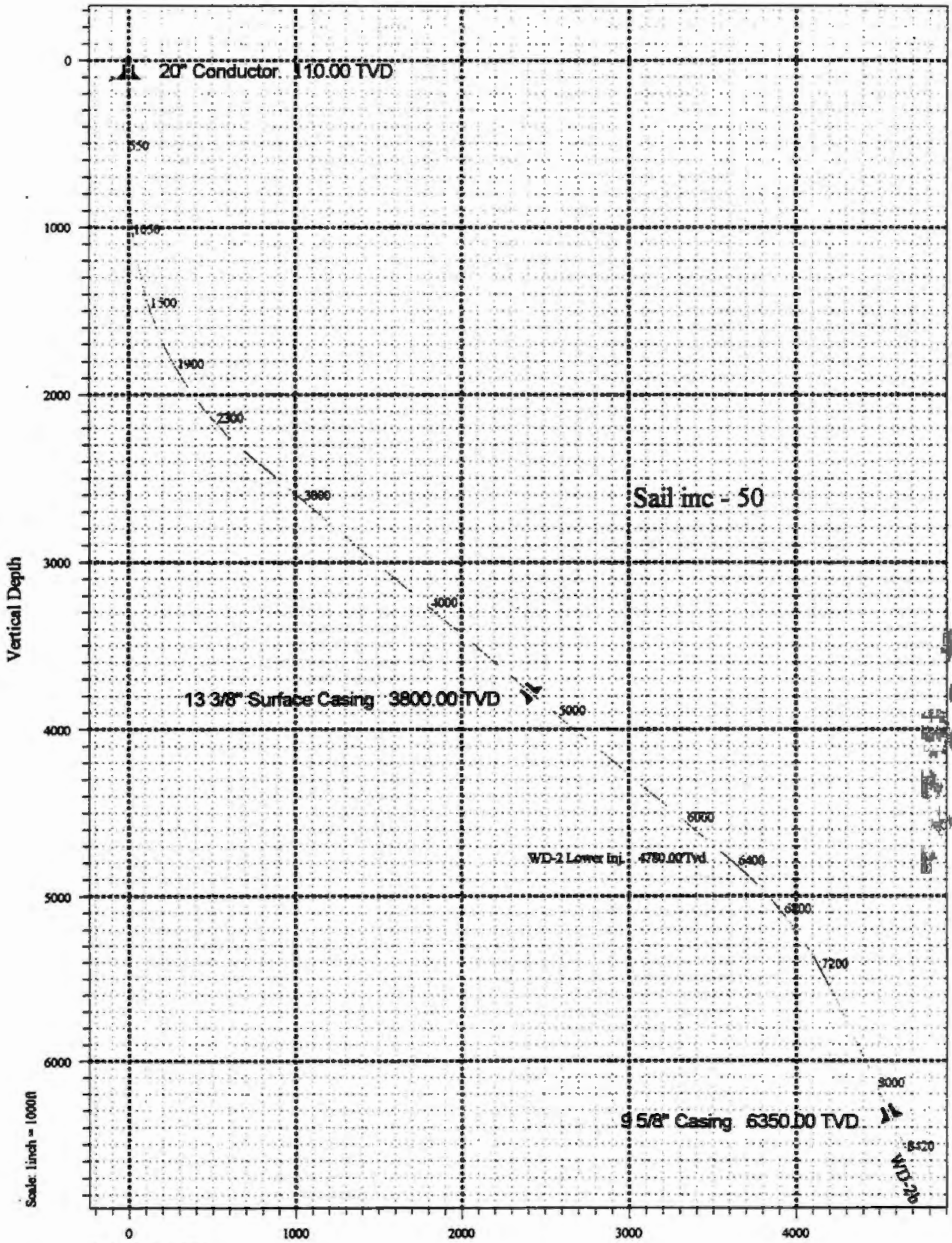
WELL PLANNING REPORT

BPX - Shared Services Drilling

Northstar development

WD-2
Thursday, October 31, 1996

sperry-sun DRILLING SERVICES | Customer: Shared Services Drilling | Structure: NS_Development
Project: ASP Zone4 | Wellhead: WD-2



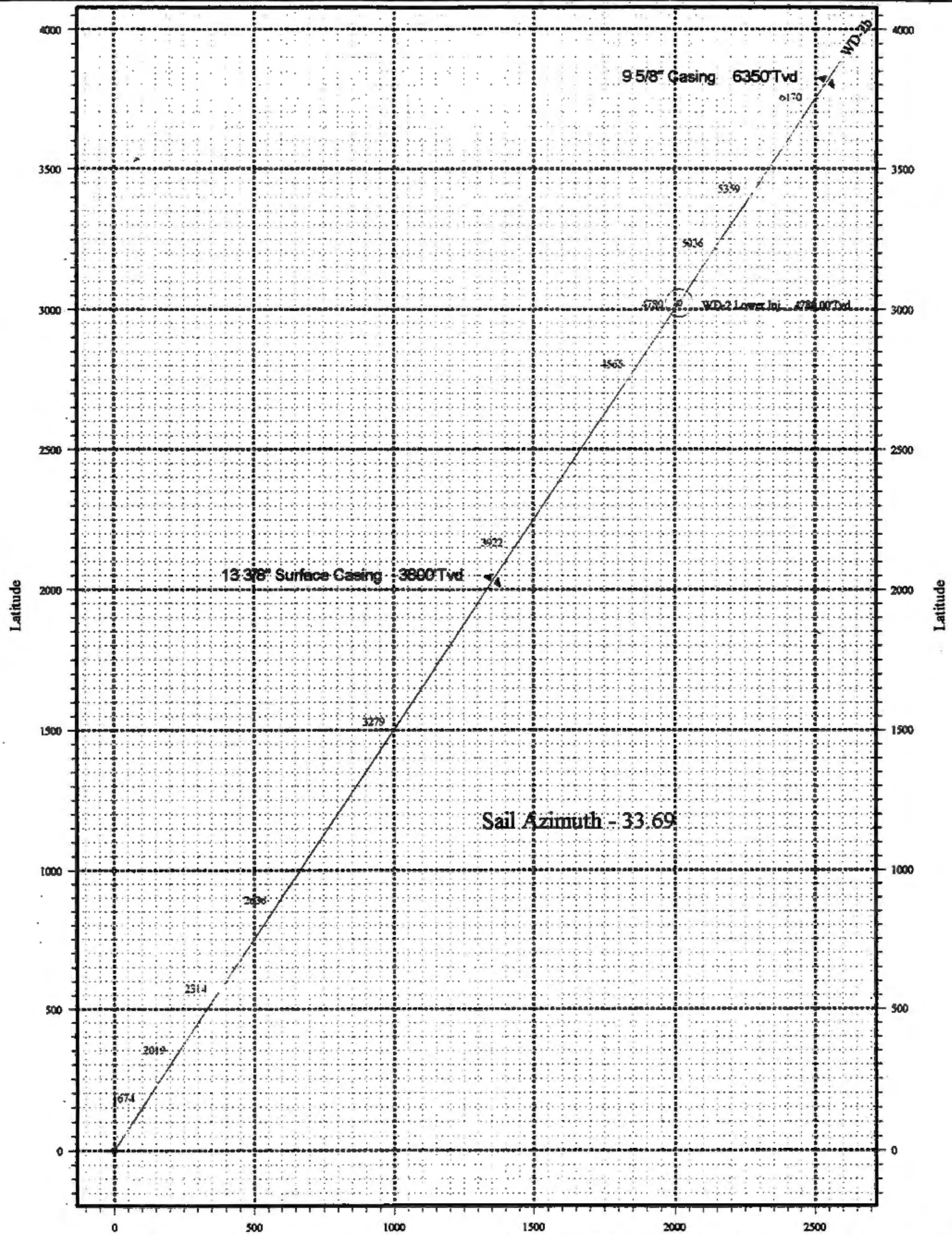
Scale: 1inch = 1000ft
Section Azimuth: 33.690

Prepared: | Checked: | Approved:

sperry-sun DRILLING SERVICES

Customer: Shared Services Drilling
Project: ASP Zone4

Structure: NS_Development
Wellhead: WD-2



Scale: 1inch = 500ft

Prepared:	Checked:	Approved:

SPERRY-SUN DRILLING SERVICES
WELL PROFILE DATA

CONFIDENTIAL

BPX - Shared Services Drilling
Northstar development

WD-2
Thursday, October 31, 1996

MEASURED DEPTH	ANGLE DEG	DIRECTION DEG	VERTICAL DEPTH	LATITUDE (Ft.)	DEPARTURE (Ft.)	VERTICAL SECTION	DOG LEG
0.00	0.000	0.000	0.00	0.00	0.00	0.00	
500.00	0.000	0.000	500.00	0.00	0.00	0.00	0.000
550.00	0.000	0.000	550.00	0.00	0.00	0.00	0.000
800.00	2.500	33.690	799.92	4.54 N	3.02 E	5.45	1.000
1000.00	6.500	33.690	999.26	17.59 N	11.73 E	21.14	2.000
1050.00	7.500	33.690	1048.89	22.66 N	15.11 E	27.24	2.000
1300.00	13.750	33.690	1294.48	61.00 N	40.66 E	73.31	2.500
1350.59	13.750	33.690	1343.62	71.00 N	47.33 E	85.33	0.000
1500.00	18.232	33.690	1487.22	105.24 N	70.16 E	126.48	3.000
2000.00	33.232	33.690	1936.35	285.35 N	190.23 E	342.94	3.000
2500.00	48.232	33.690	2314.15	556.04 N	370.69 E	668.27	3.000
2558.93	50.000	33.690	2352.72	593.10 N	395.40 E	712.82	3.000
3000.00	50.000	33.690	2636.24	874.24 N	582.83 E	1050.71	0.000
3500.00	50.000	33.690	2957.63	1192.93 N	795.29 E	1433.73	0.000
4000.00	50.000	33.690	3279.02	1511.63 N	1007.75 E	1816.75	0.000
4500.00	50.000	33.690	3600.42	1830.32 N	1220.21 E	2199.77	0.000
5000.00	50.000	33.690	3921.81	2149.02 N	1432.67 E	2582.79	0.000
5500.00	50.000	33.690	4243.21	2467.71 N	1645.14 E	2965.82	0.000
6000.00	50.000	33.690	4564.60	2786.40 N	1857.60 E	3348.84	0.000
6335.11	50.000	33.690	4780.00	3000.00 N	1999.99 E	3605.55	0.000
6500.00	45.878	33.690	4890.44	3101.84 N	2067.89 E	3727.94	2.500
7000.00	33.378	33.690	5274.78	3366.65 N	2244.43 E	4046.21	2.500
7335.11	25.000	33.690	5567.08	3502.51 N	2335.00 E	4209.49	2.500
7500.00	25.000	33.690	5716.52	3560.50 N	2373.66 E	4279.18	0.000
8000.00	25.000	33.690	6169.67	3736.32 N	2490.87 E	4490.49	0.000
8419.65	25.000	33.690	6550.00	3883.88 N	2589.25 E	4667.84	0.000

The Dogleg Severity is in Degrees per 100.00 Feet
Vertical Section was calculated along an Azimuth of 33.690° (Grid)

Based upon Minimum Curvature type calculations. At a Measured Depth of 8419.65 Feet, the Bottom Hole Displacement is 4667.84 Feet, in the Direction of 33.690° (Grid)

SPERRY-SUN DRILLING SERVICES
WELL PROFILE DATA

CONFIDENTIAL

BPX - Shared Services Drilling
Northstar development

WD-2
Thursday, October 31, 1996

INTERPOLATIONS

MEASURED DEPTH	ANGLE DEG	DIRECTION DEG	VERTICAL DEPTH	LATITUDE (Ft.)	DEPARTURE (Ft.)	VERTICAL SECTION	
6335.10	50.000	33.690	4780.00	2999.99 N	1999.99 E	3605.54	TARGET

Vertical Section Direction = 33.690° (Grid)

FORMATION TOPS

MEASURED DEPTH	ANGLE DEG	DIRECTION DEG	VERTICAL DEPTH	LATITUDE (Ft.)	DEPARTURE (Ft.)	SUB SEA DEPTH	
3659.26	50.000	33.690	3060.00	1294.44 N	862.96 E	-3010.00	Top Upper Confining Zone
4110.42	50.000	33.690	3350.00	1582.01 N	1054.67 E	-3300.00	Base Upper Confining Zone
5199.43	50.000	33.690	4050.00	2276.13 N	1517.41 E	-4000.00	Upper Injection Zone
6335.10	50.000	33.690	4780.00	3000.00 N	1999.99 E	-4730.00	Lower Injection Zone

RKB Elevation = 50.00 Feet

Exhibit F-5

Proposed Abaondonment Schematic

Northstar Well WD-1

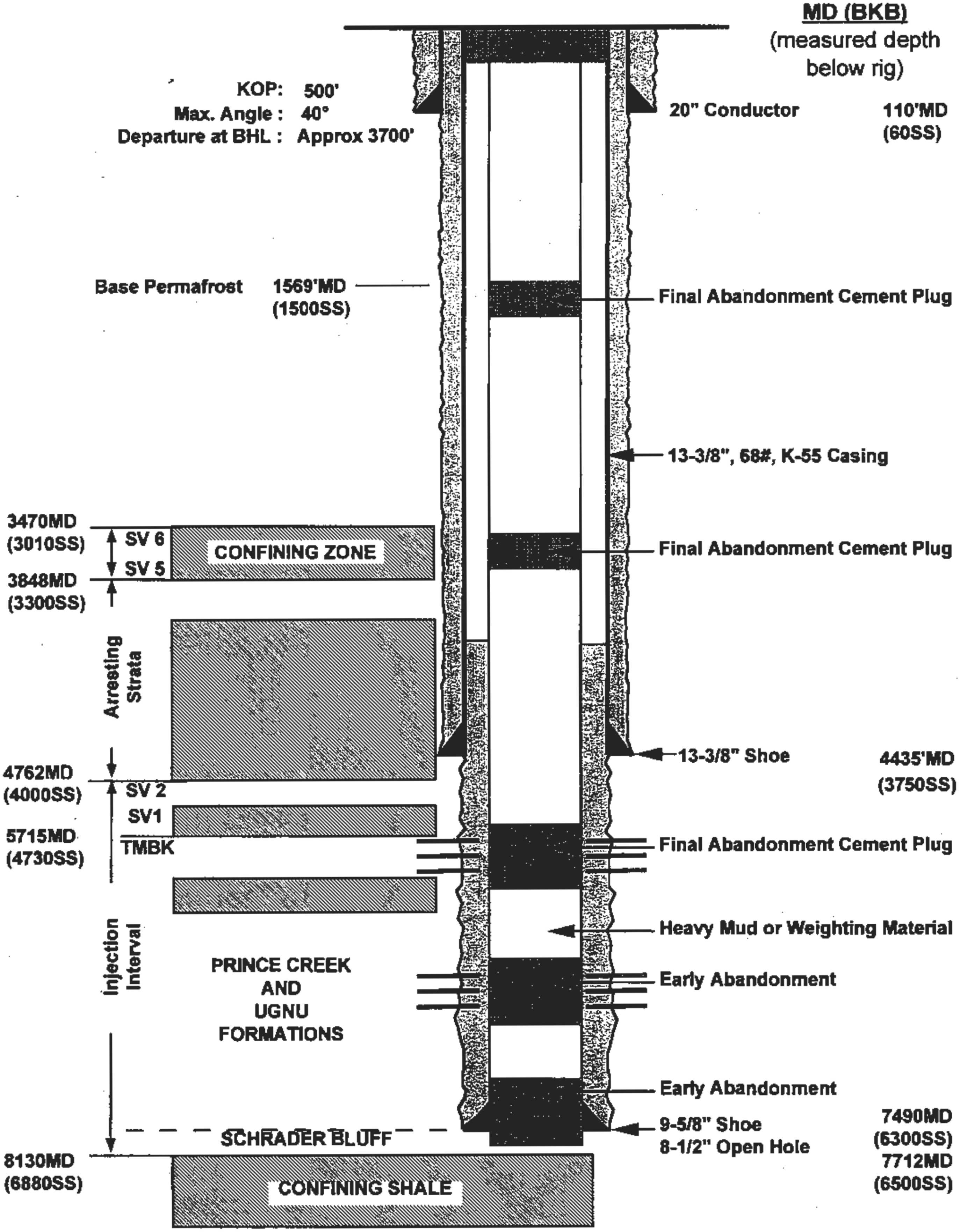


Exhibit F-6

Form Approved. OMB No. 2040-0042. Approval expires 9-30-91

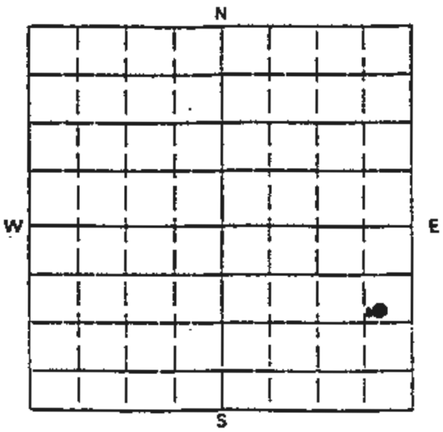
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

PLUGGING AND ABANDONMENT PLAN

NAME AND ADDRESS OF FACILITY	NAME AND ADDRESS OF OWNER/OPERATOR
Northstar Development Project Seal Island - Stefasson Sound (North Slope) Deadhorse, Alaska	BP Exploration (Alaska) Inc. 900 E. Benson Blvd. Anchorage, Alaska 99508

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES



STATE	COUNTY	PERMIT NUMBER
AK	North Slope	

SURFACE LOCATION DESCRIPTION

SE ¼ OF NE ¼ OF SE ¼ SECTION 11 TOWNSHIP 13N RANGE 13E

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location 1360 ft. from (N/S) S Line of quarter section

and 615 ft. from (E/W) E Line of quarter section

TYPE OF AUTHORIZATION	WELL ACTIVITY
XX Individual Permit ☐ Area Permit ☐ Rule Number of Wells 1 Lease Name Northstar Unit	XX CLASS I ☐ CLASS II ☐ Brine Disposal ☐ Enhanced Recovery ☐ Hydrocarbon Storage ☐ CLASS III Well Number WD-1

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT(LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE

METHOD OF EMPLACEMENT OF CEMENT PLUGS

☐ The Balance Method
☐ The Dump Bailer Method
☐ The Two-Plug Method
☐ Other

To be determined at abandonment.

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inches)	9 5/8	9 5/8	9 5/8	9 5/8			
Depth to Bottom of Tubing or Drill Pipe (ft.)	upper	conf	perma	top			
Sacks of Cement To Be Used (each plug)	zone	zone	frost				
Slurry Volume To Be Pumped (cu. ft.)							
Calculated Top of Plug (ft.)							
Measured Top of Plug (if tagged ft.) Planned Length	200	150	150	150			
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED *(if any)*

From	To	From	To
	Not available at this	time	

Estimated Cost to Plug Wells

$400,000 each

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED
Northstar Unit Field Manager		

Appendix G

Waste Analysis Plan

Northstar Unit

North Slope - Alaska

Waste Analysis Plan

August 1997

This plan will be revised within 90 days of startup and will outline training and operating procedures once all specific facility details are firmed up.

Prepared By:

BP Exploration (Alaska) Inc.
900 E. Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612

RECORD OF REVISIONS

REVISION NUMBER	REVISION DATE	SECTIONS AFFECTED	ENTERED BY

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Attachment A

EPA Regulatory Determination of Exempt Waste (53 FR 129, July 6, 1988)

The actual text is not included here because it is so bulky and is publicly available. It will be included in full in the Waste Analysis Plan on file at the BPX Prudhoe Bay environmental office.

Attachment B

Crude Oil and Natural Gas Exploration and Production Wastes: Exemption from RCRA Subtitle C Regulation. EPA Publication 530-K-95-003 (May, 1995).

1.0 INTRODUCTION

BP Exploration (Alaska) Inc. (BPX) plans to construct an oil production and waste handling facility at the Northstar site on the Alaskan North Slope. BPX has applied to the Environmental Protection Agency (EPA) for an Underground Injection Control (UIC) Permit to operate a Class I Non-hazardous Industrial Well at the site. This Waste Analysis Plan (WAP) outlines procedures for controlling, sampling and analyzing wastes prior to deep injection well disposal. The WAP is based on information available at the time of application for the UIC permit. It is subject to review and revision as engineering design finalizes the flow process and specific operating plans are developed.

Wastes streams and sources will continue to be evaluated to ensure that they can be injected safely, with minimal environmental or health risks. In addition, wastes must be physically and chemically compatible with the well structure, rock formations, and other materials in the disposal stream.

1.1 General Description of Facility

The Northstar facility will inject permitted oil field wastes between 4000 and 6500 feet below the ground surface. Wastes will be confined in the injection zone by impermeable rock layers and the permafrost. (The aquifers below the permafrost all qualify for EPA aquifer exemption status) A complete description of the disposal process and the injection facility is contained in BPX's UIC Permit Application. A block diagram of the facility processes is included here as Exhibit 1.

1.2 Description of Wastes and Sources

Waste sources and their characteristics are also discussed in Section 2.0 of the text and waste minimization, segregation and analysis is discussed in Section 8.0. A waste flow schematic that summarizes the disposal picture for the Northstar complex is included here as Exhibit 2.

The main waste generators are the drilling rig-grinding plant system, the process facilities, and the field camp. The following volumes are projected for disposal over the 20 year project life, assuming a maximum produced water disposal situation developes.

Rig muds and other liquids	360,000 Bbls
Rig drill cuttings and other solids	80,000 Bbls
Flush waters for cuttings disposal	60,000 Bbls
Camp sewage and gray water (Class I)	600,000 Bbls

Wells, process facilities, etc. waste	400,000 Bbls
Industrial non-hazardous wastes (Class I)	40,000 Bbls
Produced water (oil reservoir brine)	~118,500,000 Bbls
Total disposal volume	~120,000,000 Bbls

It is estimated that all but about 10,000 barrels will arrive at the injection tankage via pipeline from the camp, drilling rig, wells, or production complex. Most of this material will have been previously hauled to the Northstar site and inventoried, or alternately, it could have been generated on site but is not piped to the disposal system because of its small volume or intermittent generation.

The following wastes are the major components of the injection stream. A short paragraph discusses the source and characteristics of each. They are divided into two major categories: Wastes requiring little or no grinding prior to injection and injectable wastes requiring grinding prior to injection.

1.2.1 Description of Wastes Requiring Little or no Grinding

1. Drilling Muds, Water-Based: Spent drilling muds have been used for cooling and flushing of cuttings during the drilling of wells. The muds consist of water, clay (usually bentonite), cuttings which include soil and rock fragments and small amounts of dissolved chemicals which enhance certain properties of the mud. The mud is typically dark gray in color, viscous and lacks a distinctive odor. The mud may carry a significant amount of solids. Muds are denser than water and may contain barium compounds. Spent drilling mud is used to suspend solids during the grinding and injection disposal process.

2. Drilling Muds, Oil-Based: Oil based drilling muds are used for cooling and for the flushing of cuttings during the well drilling process. Oil based mud is typically a mixture of a hydrocarbon fluid (usually mineral oil or diesel), clay or asphalt, some water, cuttings which will include soil and rock fragments and dissolved chemicals which enhance certain properties of the mud. The mud is dark gray in color, viscous and may carry a significant amount of solids. The odor is characterized by the hydrocarbon fluid. Drilling muds are denser than water and may contain significant amounts of barium compounds.

3. Workover Fluids: Workover fluids are wastes from the maintenance of a hydrocarbon production well. The fluid may contain small amounts of chemicals, crude oil and solids; however, the fluid is predominantly water. The workover fluids are about neutral in pH.

4. Stimulation Fluid: Stimulation fluids are chemical compounds which have been designed to enhance the productivity or the injectivity of a well. They are injected into producing or injection zones. The fluid is normally acidic and may contain various chemicals to enhance its properties. The fluid is usually non-viscous, low in pH and has a pale color except for the soil contaminants which will sometimes be present.

5. Clean-Up Fluids: Clean-up fluids, or washwaters, are predominantly water which has been contaminated in the process of washdown of an area, engine, etc. The fluid is normally turbid, has a moderate pH, contains some amount of hydrocarbon material and has a density very close to water.

6. Crude Oil: Contaminated crude oil is generated during spills of crude oil or as a waste from a well workover. The contaminants in the crude oil are normally water and some amounts of soil. Crude oil is basically a blend of many types of hydrocarbons with some impurities. It is black in color, somewhat acidic, viscous and has an odor somewhat like refined motor oil. It may contain nitrogen and sulfur compounds, salts and trace metals.

7. Diesel: Diesel fuel wastes are generated from a variety of sources by workers who use diesel as a fuel, solvent, workover fluid or as a freeze prevention fluid. The diesel will normally be contaminated with small amounts of chemicals or water. It will be pale in color, fluid, near neutral in pH and have a characteristic hydrocarbon odor.

8. Condensate: These fluids can vary in composition since they are collected from drain sumps, blow case discharge, and knock-out pots. This is an effluent from normal process separation of oil, water, and gas. The specific gravity is less than 1.0 and pH is about neutral.

9. Natural Gas Liquids (NGL): Natural gas liquids are petroleum products (propane, butane, etc.) which are disposed of as wastes when they become contaminated with water, solids or some other hydrocarbon. NGL will normally be a contaminant in a waste of another classification; however, the NGL is ignitable and will usually be the waste constituent of most concern. Wastes containing NGL will not be accepted for disposal unless they are non-hazardous. NGL will be pale in color, near neutral in pH, less dense than water, fluid, have a distinctive chemical odor and will evaporate quickly.

10. Lubricating Oils and Hydraulic Fluids: Spent lubricating oils and hydraulic fluids are produced as wastes of engines and power transmission systems. They contain small amounts of metal and chemical additives to enhance their

properties. Whereas some hydraulic fluids may be light in color, normally these materials will be dark in color, moderate in pH, of moderate viscosity and have a characteristic oil odor. They will be less dense than water.

11. Arctic Pack: Arctic Pack is a proprietary product which consists of diesel with some gel additives. It is used to prevent freezing of well facilities which are exposed to cold weather. It will be disposed as a result of contamination by water, soil, or hydrocarbons, or as a result of a well workover. It is pale in color, moderate in pH, fluid and has a characteristic hydrocarbon odor.

12. Solvents: Solvents typically consist of a wide range of hydrocarbon products. Spent solvents are normally contaminated with grease, solids and/or water. Solvent contaminated wastes will not be accepted for disposal unless they are non-hazardous. The solvents often have a density less than water, have a low flash point and have distinctive hydrocarbon or chemical odors.

13. Spent Acid: Acids are used widely as cleaning fluids and in chemical reactions. Spent acids result from an acid being excess to needs, off specification, or contaminated with solids, water or some other chemical. Acids will be characterized by low pH and sometimes will have a biting odor. The acids will normally be fluid with moderate to low reactivity.

14. Caustic Fluid: Caustic fluids involve a wide range of materials which are characterized by high pH and corrosivity. These materials are normally generated by cleaning operations, as off-specification chemical compounds, or as the result of chemical combinations which are characterized as caustic because they are high in pH. These materials will be high in pH, fluid, and may have a biting odor. Color will often be pale and density will normally be greater than water.

15. Glycol: Glycol is an alcohol which is widely used in circulating fluid systems to prevent freezing. It will be disposed of when contaminated with water, hydrocarbons or solids. Glycol is pale in color, denser than water, moderate in pH, fluid and has a characteristic hydrocarbon odor.

16. Methanol: Methanol is a light alcohol which is widely used as a freeze prevention fluid. It is often used in combination with other materials, such as glycol, and will often be a contaminant in wastes of other characteristics. Because it is ignitable, it will often be the contaminant of concern in mixtures. Methanol is a pale fluid which is less dense than water, has a somewhat low pH and has a distinctive chemical odor.

17. Production Chemicals: This broad category includes chemicals used in the production or transportation of crude oil to achieve certain desirable effects. Examples are corrosion inhibitors, emulsion breakers and foam suppressants. Other production chemicals include proprietary compounds used in drilling fluids, muds and cleaning products.

18. Laboratory Waste: Laboratory waste will be similar to Production Chemicals in that it will contain various chemicals, products and contaminants in varying proportions. Normally laboratory waste will be spent and its potential for incompatibility with other wastes has already been exhausted. Laboratory wastes will not be accepted for disposal unless they are non-hazardous. The volume will be minuscule.

19. Transformer Oil: This oil is used as a non-conducting medium in electrical power transformers and is discarded when the equipment is abandoned. It will not be accepted for disposal unless it is non-hazardous. The volume will be very small.

20. Source Water: This is subsurface water produced from the saline aquifers below the permafrost; however, its use is not planned at this time. If so, it would be used for making drilling mud and flushing the disposal well. It has a high dissolved solids content and is useful only for industrial purposes. The specific gravity is in the 1.034 range. This water is not considered a waste.

21. Miscellaneous Waters: This includes sea water, surface runoff to well cellars, snowmelt, and fresh water which is not considered as clean-up fluid. These wastes may contain small amounts of contaminates and the sea water will contain significant amounts of salt and dissolved solids. These waters will be clear in color, of moderate pH, fluid, lacking in characteristic odor and will be near or slightly above the density of pure laboratory water.

22. Produced Water: This is brine produced from the oil reservoir during the oil recovery process. It is separated from the oil and gas and must be disposed of or reused. It is moderate in pH and has a high dissolved solids content.

23. Boiler Blowdown Water: This is fresh water used in boilers, typically to make steam for drilling rigs. It is collected when the boiler is taken out of service for some reason. It will not be contaminated but will have some amount of cations/anion concentration reflective of the initial fresh water source. The volume will be small.

24. Domestic Waste Water: This waste stream was originally potable water used for human consumption. It comes from the kitchen, showers, lavatories, laundry, toilets, and any camp floor drains. It will have a gray turbid look and some associated odor. It typically has a suspended and dissolved solids content of less than one percent. If the raw stream is treated it is possible to concentrate and collect the solids as sludge which can be disposed of separately.

1.2.2 Description of Wastes Requiring Grinding Prior to Injection

25. Drill Cuttings: Drill cuttings are generated when the drill bit penetrates the rock formation. Drill cuttings are circulated to the surface with the drilling mud and are separated from the liquid mud with the use of a "shale shaker". Cuttings can be composed of sand, gravel, clay, shale, hydrocarbon bearing rock or other naturally occurring formation solids and are denser than water. Residual mud (water or oil base) can remain on the cuttings following the shale shaker. Water base mud is typically used to suspend cuttings during transport from the point of generation to the grinding and injection facility if it is not located adjacent to the drilling rig. Mud is also required to maintain suspension of solids during processing through the grinding and injection circuit.

26. Frac Sand: Certain well stimulations utilize proppant or "frac sand" to fill the producing formation fracture space created during a well stimulation. The stimulation objective involves keeping the frac sand in the formation fracture to increase well productivity. At the well head, "loose" frac sand can be backflowed to the surface as part of the frac job or later as part of a well clean-out. Frac sand can be transported from down hole to production facility separation vessels, where it will accumulate until removed during a vessel clean-out. In addition, small quantities of frac sand can be found in flow line pigging material. Frac sand is an inert ceramic material, and as a waste it is commonly accompanied with crude oil, fresh or sea water, formation solids, small amounts of chemicals and spent acid. Carbo-Lite is a common proppant used on the North Slope and is composed primarily of aluminum oxide and silicon oxide. As with drill cuttings, transportation to and processing of frac sand at the grinding and injection facility requires the use of mud to maintain solids in suspension.

27. Vessel Sludge/Sand: Fine solids particles from the oil producing formation, biomass, pipe scale, or frac sand can accumulate in test separators, tanks, production facility vessels, and heat exchangers. These solids are periodically removed and can be associated with crude oil, fresh or sea water, and production chemicals or solvents. The solids are denser than water, have a distinctive

hydrocarbon odor, and usually assume the dark brown or black color of crude. Mud can be used to transport vessel solids to the grinding and injection facility and would be required to suspend solids during processing.

28. Contaminated Gravel: Contaminated gravel is the result of spills associated with various oil field operations. The major source of gravel contamination is caused by fuel and crude spills; however, spills of the other injectable wastes can be the source of gravel contamination. The characteristics of the contaminated gravel will be dependent on the source and concentration of spilled material in the gravel. Gravel that is not readily treatable for reuse can be disposed of by grinding and injection. Pre-crushing of the gravel may be required before it enters the ball mill grinding process, and the addition of mud would be required to suspend the solids through the grinding process.

29. Line Pigging Material: Crude oil pipelines and produced water or sea water pipelines require pigging to remove materials which have built up on the pipe walls. Normally the pigging waste is pushed through the pipelines back to the production facilities and is deposited in facility vessels where it is later removed as vessel sludge/sand. Occasionally pigging waste will be removed directly from the pipelines at certain locations. The pigging waste composition can include crude, produced or sea water, biomass, paraffin, formation solids, frac sand, calcium scale, and iron sulfide. Pigging waste has a density greater than water, can be a thick viscous sludge, and typically has a very strong hydrocarbon or rotten egg odor.

30. Naturally Occurring Radioactive Material (NORM): NORM is a weakly radioactive natural material which sometimes forms as pipe scale or sludge in production pipelines, tubing, and separation vessels. This material has been approved for injection in Class II disposal wells in Alaska by the state agencies and the EPA. The material is below activity levels of concern by the NRC. The EPA UIC office has specifically referred to this material as "pipe scale" or "vessel sediments" which are cited in UIC regulations as material which can be injected in Class II wells. The material is typically found as barium sulfate scale with some radium 226 or 228 co-precipitating with barium to provide radiation levels of 1 to 2 millirems per hour.

31. Incinerator Ash: This is the result of burning paper, wood products, rags, etc. in an incinerator. The residue is typically gray in color. It can be disposed of by slurry injection if it tests non-hazardous.

32. Waste Water Treatment Plant sludge: This is a semi-solid material that is the residue from treating camp domestic waste water. It is grey in color and has a rotten egg odor. It can be disposed of by slurry injection.

33. Diatomaceous Earth: This is a filter media used to clean up returned sea water, brines, and produced water. When back washed or physically removed it is dark in color and contains contaminates removed from the process stream. It has a specific gravity greater than 1.0 and should have a pH about neutral.

34. Cement and Cement Rinsate: This can be composed of many variations of the standard Portland cements. They are manufactured by combining limestone (calcium carbonate) and clay (silicon dioxide plus iron oxides) in a ratio of about 2:1. When heated, with time, one of four crystalline states can result. Other additives are used such as accelerators, retarders, fluid loss additives, etc. The specific gravity ranges from 1.3 to 2.2. The rinsate come from cleaning tanks, pumps, and associated equipment.

1.3 <u>Waste Classification</u>

Three general categories of waste will be injected.

1. Oil and gas exploration and production wastes that are exempt from regulation under the Resource Conservation and Recovery Act (RCRA) Subtitle C. Exempt wastes are described in Section 1.3.1.

2. Non-exempt, non-hazardous industrial wastes as described in Section 1.3.2. No hazardous wastes will be injected. Hazardous wastes require special precautions and must adhere to strict handling procedures. Such wastes are described in Section 1.3.4. Additionally, waste mixtures will be categorized according to the EPA guidelines described in Section 1.3.5.

3. Camp domestic waste water as described in Section 1.3.3.

1.3.1 Exempt Wastes

The EPA has determined that some materials are exempt from the hazardous waste handling requirements of RCRA Subtitle C, regardless of chemical characteristics.[(1)] The exemption includes certain wastes that are uniquely associated with oil and gas exploration and production. Appropriate reference materials will be available on site, and additional resources will be available at the Prudhoe Bay environmental office as well as Anchorage headquarters.

Exempt wastes constitute an estimated 99 percent of the disposal volume. Examples include drilling muds, drill cuttings, produced water, crude oil, and fluids associated with the primary production stream. A listing of exempt wastes is included as Table 1 and in the Appendix B, EPA handbook.

Drilling muds are usually water-based mixtures of clays and weighting materials with small amounts of various additives. (Occasionally, an oil-based mud is used in special drilling applications such as highly deviated wells.) Muds serve to lubricate the drill bit, remove the cuttings from the well bore, and control the pressures in the underground formations. Cuttings are rock fragments removed from the well bore by the mud system.

Produced water that comes to the surface mixed with the oil and gas must be separated before the oil can be sent to the Trans-Alaska Pipeline. Produced water is treated and then routed to the disposal well for injection. Initially the rate will be very low but will increase to an average of 16,000 BPD.

Other associated wastes specifically includes waste materials intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil and natural gas. "Intrinsically derived from primary field operations" is intended to distinguish exploration, development, and production from transportation and manufacturing. With respect to crude oil, primary field operations include activities occurring at or near the wellhead and before the point where the oil is transferred from an individual field facility or a centrally located facility to a carrier for transport to a refinery or a refiner. It also includes the primary, secondary and tertiary production operations. Crude oil processing, such as water separation, de-emulsifying, degassing, and storage at tank batteries associated with a specific well or wells, are examples of primary field operations. In general, the exempt status of an exploration and production waste depends on how the material was used or generated as waste, not necessarily whether the material

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(1) EPA Regulatory Determination of Oil and Gas and Geothermal Exploration, Development, and Production Waste: 53 FR 129, July 6, 1988

is hazardous or toxic. Some major associated wastes which are covered by the RCRA oil and gas exemption are:

- Tank bottoms and pit sludges
- Wastes from well workovers and stimulations
- Pipeline pigging wastes
- Gas dehydration wastes
- Truck/tank/cellar waste waters
- Spill residues and contaminated soils
- Produced formation sand and hydrocarbon soils

1.3.2 Non-Exempt, Non-Hazardous Industrial Wastes

Wastes are generally not exempt if they have not been circulated down a well or come into direct contact with the production stream. Non-exempt wastes include items like used solvents, cleaners, unused chemicals, lubricating oils, etc. Typically, these wastes are from ancillary operations, such as facility maintenance. A listing of non-exempt wastes is included in Table 2 and in the Appendix B, EPA handbook.

An unused product is not generally considered a waste unless (1) it is spilled and cannot be recovered for its intended use; or (2) it no longer meets specifications for use due to product expiration or process changes. Such wastes may be eligible for injection if the product itself is non-hazardous, as described in Section 2.1.2.

1.3.3 Domestic Waste Water

This waste stream was originally potable water used for human consumption. It comes from the kitchens, showers, lavatories, laundry, toilets, and any camp floor drains. It typically has a suspended and dissolved solids content considerably less than one percent.

1.3.4 Hazardous Wastes

A waste is considered hazardous if it is listed by name as a bazardous waste in 40 CFR 261, Subpart D, or if it displays any of the characteristics described in 40 CFR 261, Subpart C. If a waste contains any listed constituents, it is considered hazardous regardless of its other properties and it may not be injected. Hazardous waste characteristics, as outlined in Table 3, include ignitability, corrosivity, reactivity, and toxicity. Toxicity characteristics of various compounds are provided in Table 4. A mixture of listed hazardous and non-hazardous waste is considered hazardous, and may not be injected. BPX will maintain an EPA Hazardous Waste Generator I.D. number for the Northstar Unit. The facility will be managed under the RCRA regulations appropriate to the amount generated. North Slope hazardous waste volumes have diminished steadily for years and Northstar may qualify as a Continually Exempt small quantity generator.

Hazardous wastes may not be transported across unit boundaries unless they are under the control of a licensed transporter enroute to a licensed disposal facility. Therefore, Northstar may not receive hazardous wastes from other operating areas of the North Slope. BPX ships hazardous waste from the North Slope to licensed TSD facilities in the continental U.S., using licensed transporters. This practice will apply to Northstar.

1.3.5 Mixing Wastes

Included as Appendix B to the WAP is the May, 1995 EPA publication, *Crude Oil and Natural Gas Exploration and Production Wastes: Exemption from RCRA Subtitle C Regulation.* This recent document lists guidance rules for mixing different classes of wastes as follows:

1. A mixture of an exempt waste with another exempt waste remains exempt.

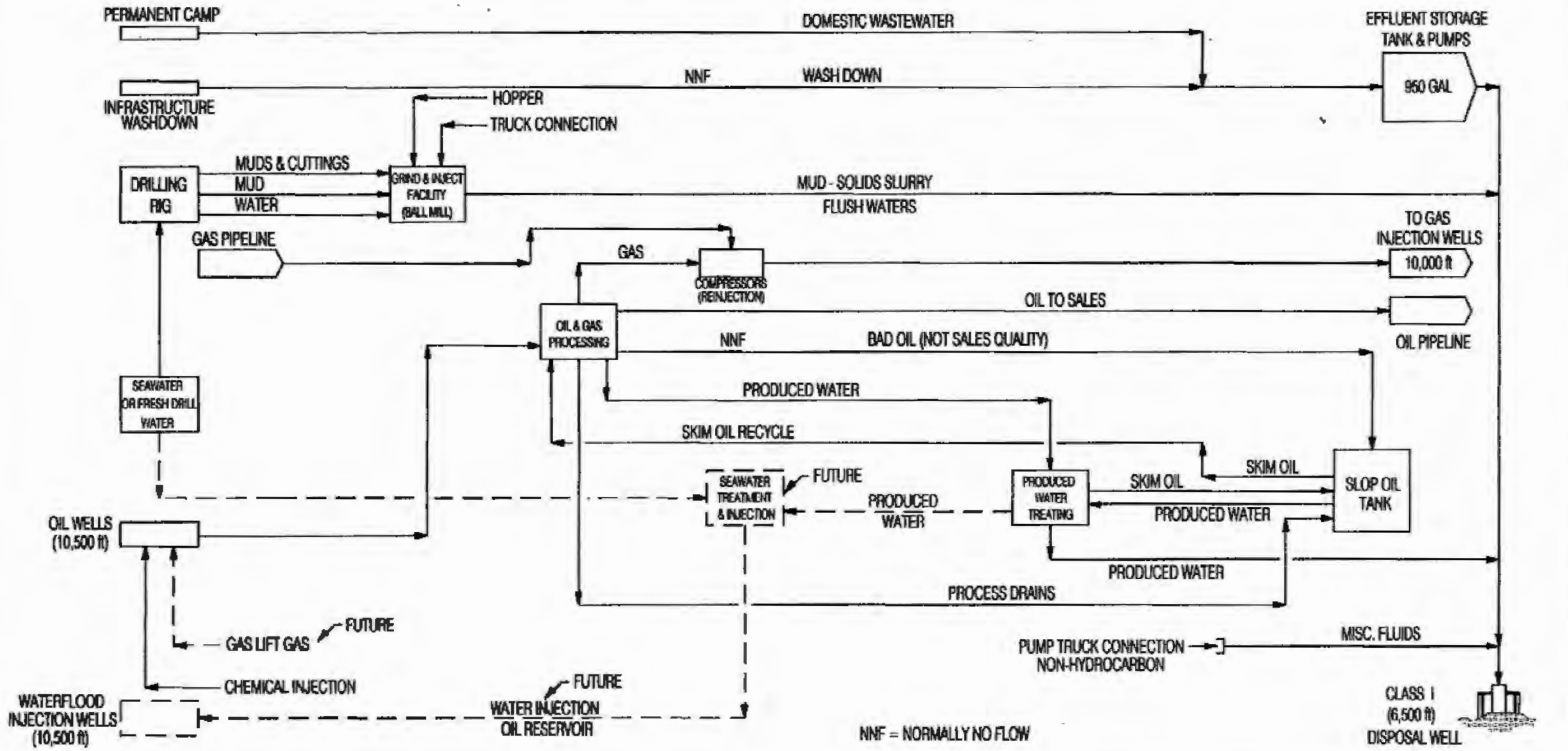
2. Mixing a non-hazardous waste (exempt or non-exempt) with an exempt waste results in a mixture that is also exempt.

3. If, after mixing a non-exempt characteristic hazardous waste with an exempt waste, the resulting mixture exhibits any of the same hazardous characteristics as the hazardous waste (ignitability, corrosivity, reactivity, or toxicity), the mixture is a non-exempt hazardous waste.

4. If, after mixing a non-exempt characteristic hazardous waste with an exempt waste, the resulting mixture does not exhibit any of the same characteristics as the hazardous waste, the mixture is exempt. Even if the mixture exhibits some other characteristic of a hazardous waste, it is still exempt.

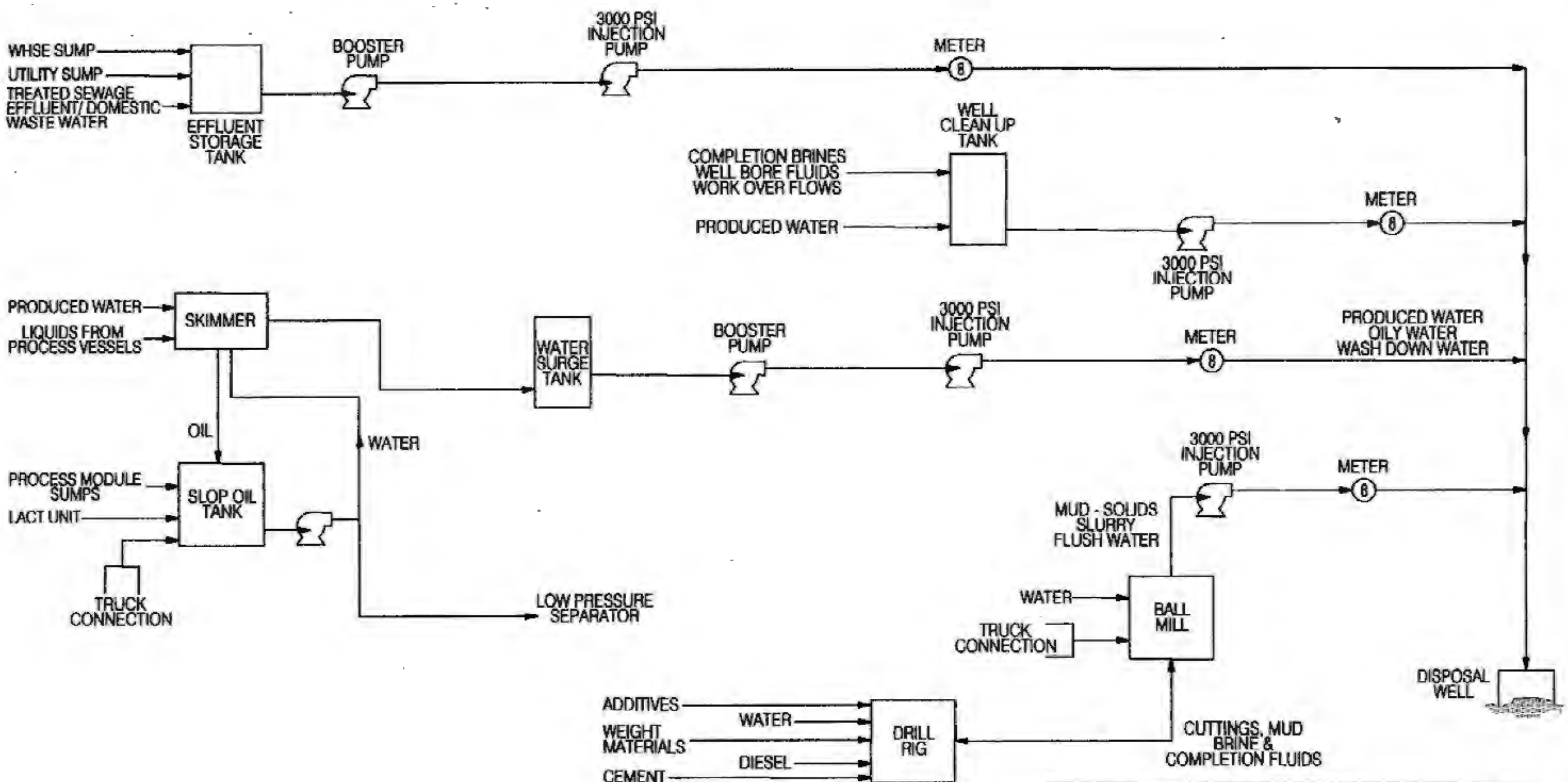
1.4 Unit vs. Non-Unit or Third Party Wastes

Non-unit and third party wastes will not be accepted for disposal unless they have been properly handled, accounted for, and manifested. This will not be a problem since Northstar is not connected to a road system and common access will be controlled. All wastes will result from Northstar Unit operations. On-site contractors will be under BPX control and consumables will have been specified, inventoried, and stored for specific purposes. All wastes will be in BPX ownership.



BP EXPLORATION (ALASKA) INC.		
NORTHSTAR DEVELOPMENT PROJECT BLOCK FLOW DIAGRAM ALL PROCESSES		
DATE: 8/14/97	SCALE: N/A	EXHIBIT: G-1

nsv897.dgn



BP EXPLORATION (ALASKA) INC.

NORTHSTAR DEVELOPMENT PROJECT
WASTE DISPOSAL FLOW SCHEMATIC
CLASS 1 INJECTION WELL

DATE:	SCALE:	EXHIBIT:
8/14/97	N/A	G-2

nsv897.dgn

Table 1

Examples of Exempt Oil and Gas Wastes

- accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments
- cooling tower blowdown
- dehydration wastes, including glycol-based compounds, glycol filters, filter media, backwash, and molecular sieves
- drilling fluids and cuttings from offshore operations disposed of onshore
- drilling fluids and cuttings, including well completion, treatment, and stimulation fluids, excess cement slurries, and cement cuttings
- gases removed from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons
- iron sulfide
- light organics volatilized from exempt wastes in reserve pits, impoundments, or production equipment.
- liquid hydrocarbons removed from the production stream but not from oil refining
- materials ejected from a producing well during the process known as blowdown
- naturally occurring radioactive materials (NORM) in pipe scale
- packing fluids
- pigging wastes from gathering lines
- pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation
- pit sludges and tank bottoms from storage or disposal of product or exempt wastes
- produced sand
- produced water and constituents removed from produced water before it is injected or otherwise disposed of
- production line hydrates/preserving fluids utilizing produced water
- rigwash
- soil containing downhole hydrocarbons, crude, or produced water
- spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)
- sweetening wastes, including catalyst, filters, filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge
- waste crude oil from primary field operations and production
- wastes from subsurface gas storage and retrieval, except for listed non-exempt wastes
- workover wastes

Table 2

Examples of Non-exempt Oil and Gas Wastes

- unused fracturing fluids, solids, or acids
- gas plant cooling tower cleaning wastes
- painting wastes
- oil and gas service company wastes, such as empty drums, drum rinsate, vacuum truck rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids
- vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste
- refinery wastes
- liquid and solid wastes generated by crude oil and tank bottom reclaimers
- used equipment lubrication oils
- waste compressor oil, filters and blowdown
- used hydraulic fluids
- waste solvents
- waste in transportation pipeline-related pits
- caustic or acid cleaners (that are not generated from well treatment or stimulation)
- boiler cleaning wastes
- boiler refractory bricks
- incinerator ash
- laboratory wastes
- sanitary wastes
- pesticide wastes
- radioactive tracer wastes
- drums, insulation, and miscellaneous solids

Table 3

Hazardous Waste Characteristics

Ignitability	Alcohol content of greater than 24 percent, or Flash point less than 140 degrees Fahrenheit (60 degrees centigrade)
Corrosivity	pH less than or equal to 2 or greater than or equal to 12.5, or Corrodes steel (SAE 1020) at a rate greater than 6.35 mm (0.250 inch) per year at a test temperature of 55°C (130°F)
Reactivity	Normally unstable and readily undergoes violent change without detonating Reacts violently with water Forms potentially explosive mixtures with water When mixed with water, generates toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment Is a cyanide or sulfide bearing waste which, when exposed to pH conditions between 2 and 12.5 can generate toxic gases; Is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement Is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure; or Is a forbidden explosive as defined in 49 CFR 163.51, a Class A explosive as defined in 49 CFR 163.53, or a Class B explosive as defined in 49 CFR 163.88.
Toxicity	Contains any of the contaminants listed on Table 4 above the indicated concentration

Table 4

Hazardous Waste Toxicity Characteristics

As determined by Toxicity Characteristics Leaching Procedure (TCLP)

Contaminant	Maximum concentration (mg/L)	Contaminant	Maximum concentration (mg/L)
Arsenic	5.0	Hexachlorobenzene	0.13
Barium	100.0	Hexachloro-1,3-butadiene	0.5
Benzene*	0.5	Hexachloroethane	3.0
Cadmium	1.0	Lead	5.0
Carbon tetrachloride*	0.5	Lindane	0.4
Chlordane	0.03	Mercury	0.2
Chlorobenzene*	100.0	Methoxychlor	10.0
Chloroform*	6.0	Methyl ethyl ketone*	200.0
Chromium	5.0	Nitrobenzene	2.0
o-Cresol	200.0**	Pentachlorophenol	100.0
m-Cresol	200.0**	Pyridine	5.0
p-Cresol	200.0**	Selenium	1.0
Cresol (total)	200.0**	Silver	5.0
2,4-D	10.0	Tetrachloroethylene*	0.7
1,4-Dichlorobenzene	7.5	Toxaphene	0.5
1,2-Dichlorobenzene*	0.5	Trichloroethylene*	0.5
1,1-Dichlorobenzene*	0.7	2,4,5-Trichlorophenol	400.0
2,4-Dinitrotoluene	0.13b	2,4,6-Trichlorophenol	2.0
Endrin	0.02	2,4,5-TP (Silvex)	1.0
Heptachlor (and its hydroxide)	0.008	Vinyl chloride*	0.2

* Listed as a volatile organic compound (VOC) in the TCLP test method.

** If o-, m-, and p-cresol concentrations cannot be differentiated, the total cresol concentration is used.

2.0 WASTE ANALYSIS

To be eligible for injection, wastes must be characterized as exempt or non-hazardous. "Certified Generators" and "Certified Operators" are responsible for making this determination before transporting or injecting any wastes at the facility. The injection staff will confirm, on a case by case basis, whether any sampling and analysis are required.

2.1 Characterization Without Analysis

Non-hazardous fluid determinations may be made based on laboratory data, material safety data sheets (MSDS), and generator knowledge. Knowledge of a waste product may be substituted for analytical data according to 40 CFR 262.11(c)(2) and therefore, sampling and analysis may not be necessary for:

- RCRA-exempt E&P wastes.

(Chemical analysis is not required for exempt wastes unless the operator desires it.)

- Known non-hazardous industrial wastes as described below.

- Domestic waste water streams.

Due to the isolated nature of the facility, and the limited number of personnel, there will be a high level of control used on materials and processes used on site. The number of potentially hazardous products will be minimized by screening before purchase or use. Process controls and training will be implemented to reduce the risk of hazardous waste entry into the process waste streams.

2.1.1 Exempt Wastes

Guidance on exempt vs. non-exempt status is provided in Tables 1 and 2 and in Attachments A and B. Exemption status is not always straight forward, and it must be realized that the rules are subject to revision or reinterpretation at any time. The BPX Environmental-Safety Tech will receive up-to-date regulatory training and will assist the "Certified Generators" and "Operators" in determining whether specific wastes are exempt. Additional support will be provided by the BPX North Slope environmental staff and the Environmental and Regulatory Affairs Department in Anchorage.

In general, exempt status applies to all fluids that come from downhole during E&P operations; or has otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants as described in Section 1.3.1.

2.1.2 Non-Exempt, Non-Hazardous Industrial Wastes

The following sources of information may be sufficient to characterize a waste without further analysis:

Materials Safety Data Sheets (MSDS): BPX maintains a computerized MSDS database for many products used on the North Slope. The MSDS should indicate whether a product has hazardous characteristics or compatibility problems. This information may be sufficient to characterize wastes resulting from spills or off-spec products. If the MSDS for a product clearly indicates that it is not hazardous, the spilled material or off-spec surplus will generally be eligible for injection without further analysis.

Waste stream profiles: Non-exempt E&P wastes are sometimes generated by ongoing, routine processes. Their chemical and physical properties are consistent over time. Many common North Slope waste streams have been analyzed to establish the range of properties shown in Table 5; however, this information is subject to revision as additional data become available.

Once an initial profiling has been completed, as described in the following section, certain diagnostic or "fingerprint" parameters can be used to confirm the identity of the waste in the field. Fingerprint properties include color, specific gravity, odor, hydrocarbon content, organic halide content, settleable solids, and general appearance. Table 6 includes fingerprint parameters for common North Slope waste streams.

Waste streams that have undergone profiling will be tested periodically for fingerprint parameters. This will confirm that the wastes have not changed significantly over time. Profiled waste streams may be tested more frequently if there is a change in the generating process, or if there is reason to believe that a product does not match the expected profile.

2.1.3 Non-Exempt Domestic Waste Water

Domestic waste water is excluded from the definition of solid waste by 40 CFR 261.4(a)(1), and is not routinely characterized by detailed laboratory analysis. Some fingerprinting may be done as an operational aide however detailed analysis is not required for this type of permanent disposal of domestic waste water.

2.2 Characterization by Analysis

If sampling and analysis are required, staff will determine the appropriate sampling procedures and analytical parameters on a case-by-case basis. Any non-exempt waste stream that has not previously been characterized on the North Slope, or can not be characterized by generator knowledge, will be analyzed for hazardous constituents that are reasonably expected to be present. The wastes will be held until analytical results are received and reviewed by BPX.

Once initial profiling is complete, testing requirements can be reduced for subsequent shipments of the same waste. As long as the waste stream remains consistent, testing will consist of periodic fingerprint analysis as described in Section 2.2.3.

2.2.1 Analytical Parameters

Analysis will include the physical and chemical parameters needed to characterize the waste stream. Hazardous waste characteristics (Table 3) are mandatory for initial profiling of non-exempt wastes. Other parameters may be used for fingerprinting or confirmation testing. Certain properties, while not hazardous by definition, may make a waste unsuitable for injection. For example, there are operational and geological constraints on the percentage of solids in the waste stream. In addition, compatibility problems may result when certain wastes are combined, even though the individual streams may meet injection criteria. These factors will be considered on a case-by-case basis.

BPX will use qualified analytical laboratories that adhere to the Quality Assurance/Quality Control program described in Section 4. Appropriate analytical methods are outlined in Table 6.

2.2.2 Sampling Methods

"Generators" will contact on site environmental staff when they have a batch of waste for disposal that they desire sampled. Trained personnel will be dispatched to collect samples in accordance with approved EPA procedures. [1, 2] Samples will be transferred to clean containers provided by the analytical laboratory. Table 6 shows the minimum sample volumes and container types required for various analyses.

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1 40 CFR 261, Appendix I

2 SW-846, Chapter 9

Composite Liquid Waste Samplers (coliwasas) or long pipettes are recommended for drums and other small containers. A coliwasa takes a continuous sample throughout the height of the container, and can provide reasonably accurate representation of the waste with relatively few samples. Other sampling devices are available for different types of containers and materials.

Grab samples from large containers should be collected, if possible, during waste transfer operations (pumping by vacuum truck, for example). At least three samples should be collected: one each at the beginning, approximate midpoint, and end of transfer. Fluids should be carefully observed during the transfer. Any change in appearance may indicate a change in physical or chemical properties. If the waste appears homogeneous, a composite sample may be prepared. If the waste appears stratified or otherwise inhomogeneous, a separate set of samples should be collected to characterize each phase of the waste. The approximate volume of each phase should be estimated. Different phases may be combined into a single composite if (1) the phases cannot or will not be separated for disposal and (2) samples from each phase are combined in proportion to their estimated volume in the container. (Note that if one phase proves hazardous and the other does not, the entire container must be handled as a hazardous waste.)

For fingerprint analysis of previously profiled wastes, composite samples from several containers are acceptable, providing all containers are derived from the same process. If a composite sample shows any RCRA hazardous waste characteristics, individual containers must be analyzed; otherwise, the entire shipment is a hazardous waste. If there are measurable levels of toxic components (Table 4) in the composite, based on the Toxicity Characteristics Leaching Procedure (TCLP), the concentration must be multiplied by the number of samples in the composite. If this level exceeds RCRA limits (Table 4), the individual containers must be evaluated to isolate the hazardous material; otherwise, the entire shipment is a hazardous waste.

2.2.3 Sampling Frequency for Waste Streams

Once initial profiling is completed on appropriate streams, testing on a quarterly to semi-annual basis will be done for diagnostic "fingerprint" parameters.

Waste streams will be re-analyzed if fingerprint analysis falls outside of the range identified in the waste stream profile (Table 5). New analysis will also be required if the generating process changes in a way that could significantly change the properties or status (exempt/non-exempt) of the waste. Transitory events such as start-up, shutdown, upsets, and maintenance may produce wastes that are not representative of the normal operation. There may be changes in raw material, process temperatures, and other factors that affect the composition of the waste over time.

Wastes may also require re-analysis if there are regulatory changes affecting testing requirements or waste classification.

Table 5

Typical Non-Exempt Waste Stream Profiles
(Subject to Revision)

Non-Exempt Waste (1)	Color & Appearance	Odor	Physical State	Specific Gravity	pH	Main Constituents	Other Typical Properties	Potentially Hazardous Properties or Constituents	Typical Non-Exempt Sources (1)
Chemical products (off-spec or spilled)	Varies	Varies	Aqueous fluid	1.0 - 1.5	3 - 11	Varies	Flash point >60°C	Check MSDS for hazardous properties	Products spilled, out-dated or no longer acceptable for original purpose
Heat exchange media	Green to red	Sweet	Viscous fluid	1.0 - 1.6	6.5 - 11.5	Methylene Glycol	Flash point ±100°C	Not a hazardous waste	Heating and cooling systems (buildings, vehicles)
Hydrotest waters (non-exempt operations)	Varies	Possible hydrocarbon odor	Aqueous, possible particulates	0.8 - 1.5	4 - 7	Water, possible traces of hydrocarbon, methanol, glycol, biocide	Flash point >60°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Non-exempt vessel and pipeline pressure testing
Laboratory waste	Varies	None to "chemical" odor	Liquid	≥ 1	Varies	Varies	Varies	Check MSDS of known constituents. May require testing for hazardous characteristics	Production laboratory
Lubricating oils & hydraulic fluid	Light to dark	Characteristic oily odor	Moderately viscous	≤ 1	5.0 - 7.5	Hydrocarbon with chemical additives	Flash point generally >60°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Waste from engines and equipment
Methanol	Pale	Pungent	Aqueous fluid	< 1	< 7	Methyl alcohol, may contain glycol or other wastes	Flash point 11°C for pure methanol	May be hazardous due to ignitability	Freeze protection (non-exempt applications)
Remediation wastes	Brownish, turbid	Possible faint hydrocarbon odor	Aqueous with particulates	± 1	4 - 10	Water with hydrocarbons (diesel, crude, etc.)	Flash point >60°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Fluid generated by treatment of non-exempt contaminated soils
Sanitary wastes	Clear to brownish & turbid	Sewage odor	Aqueous with particulates	± 1	6 - 9	Water with domestic wastes	Flash point >90°C	May be treated or untreated	Sewage and graywater from residences and work sites
Spill cleanup (non-exempt)	Clear to turbid	Hydrocarbon	Aqueous fluid	1.0 - 2.0	4 - 8	Water with possible hydrocarbon or chemical products	Flash point >60°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Fluids recovered from cleanup of non-exempt spills on or off pads and roads
Sump fluids	Cloudy, possible oily sheen	None to faint hydrocarbon odor	Aqueous fluid, some particulates	± 1	5.0 - 7.5	Water with possible hydrocarbon or chemical products	Flash point >90°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Non-exempt facility drainage; runoff; floor washing (e.g. from third party facilities)

(1) Note that similar wastes may be exempt from RCRA Subtitle C according to criteria outlined in section 1.3 of text.
(2) Benzene estimated as percentage of total petroleum hydrocarbon content.

Table 5

Typical Non-Exempt Waste Stream Profiles
(Subject to Revision)

Continued

Waste	Color & Appearance	Odor	Physical State	Specific Gravity	pH	Main Constituents	Other Typical Properties	Potentially Hazardous Properties or Constituents	Typical Non-Exempt Sources (1)
Tank and drum rinsate (non-exempt)	Varies	Possible hydrocarbon odor	Multi-phase fluid	0.8 - 1.5	4 - 7	Water, possible traces of hydrocarbon and chemicals	Flash point >60°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Rinsate from empty tanks and drums used for fuel or chemical storage
Water, from equipment and facility washdown	Clear to cloudy	Possible hydrocarbon odor	Aqueous, possibly multi-phased	0.8 - 1.5	6.0 - 8.5	Water, possible traces of hydrocarbon, chemicals, detergent	Flash point >90°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Various maintenance and cleaning activities
Water, from snowmelt and impoundments	Clear to cloudy	None	Aqueous, some particulates	± 1	5.0 - 7.5	Water, possible traces of hydrocarbon or chemicals	Flash point >90°C	Check: MSDS of known chemical constituents; benzene (2) in hydrocarbons; flash point	Secondary containment areas, depressions on or between pads & roads

(1) Note that similar wastes may be exempt from RCRA Subtitle C according to criteria outlined in section 1.3 of text.
(2) Benzene estimated as percentage of total petroleum hydrocarbon content.

Table 6

Analytical Parameters and Methods [1]

Analysis and Method	Container	Preservative	Holding Time	Acceptable Range for Non-Hazardous Material
Ignitability (flash point) SW-846, 1010 (Pensky-Martens) SW-846, 1020 (Setaflash)	500 ml glass, Teflon-lined cap	Chill to 4°C		Flash point ≥140°F (60°C)
Corrosivity (pH) SW-846, EPA 9040	250 ml polyethylene/glass	Chill to 4°C	1 hour	$2<\mathrm{pH}<12.5$
Reactivity SW-846, 7.3.3.2 (Reactive cyanide)	4-oz polyethylene or glass	Chill to 4°C 10N NaOH to pH>12	7 days	nonreactive
SW-846, 7.3.4.2 (Reactive sulfide)		Chill to 4°C		
Toxicity Characteristics Leaching Procedure (TCLP) Metals and Organics SW-846, 1311	2 ea 2.5 L amber glass, Teflon-lined cap	Chill to 4°C	14 days	See Table 4
Total Organic Halides (TOX) EPA 9020	500 ml glass, Teflon-lined cap	H_2SO_4 to pH<2; Chill to 4°C	7 days	≤1000 ppm
Chlor-in-oil test or equivalent	100 ml glass, Teflon cap			
Solids SW 160.5 (settleable solids)	1 L poly or glass	Chill to 4°C	7 days	
SW 160.3 (percent solids)	250 ml poly or glass			
Hydrocarbon Content EPA 418.1	1 L glass, Teflon- lined cap	Chill to 4°C	28 days	
SW 846 5050/8020	1 L glass		14 days	
Specific Gravity ASTM D1298		Chill to 4°C	N/A	
SM 213E			28 days	

1 Alternate EPA-approved test methods may be substituted

3.0 RECORD KEEPING AND DOCUMENTATION

BPX will maintain copies of the following documents at the Northstar facility.

- Manifests
- Daily Injection Log
- Daily Events Log
  (Used to record events, observations, and data collected at the site)
- Records on wastes rejected by the facility
- Sampling logs
- Analytical data provided by laboratories

Exhibit 3 illustrates the Daily Injection Log for recording factual events. Training and written procedures will be provided for the generators, transporters, and receivers once the facility design is finalized and field operating plans developed. An Injection Fluid Key will also be generated at that time. Exhibit 4 illustrates the manifest form that will be used for batch loads.

Records pertaining to underground injection must, in general, be kept for a period of three years, according to federal regulations (40 CFR 144.28, 144.51, 146.13).

EXHIBIT 3

Daily Injection Log (Northstar Disposal Well 01)

Date	Name of "Certified" Operator	*Type of Fluid	Source (use key)	Volume (BBLS)	Name of "Certified" Generator

NOTE: Only Certified Generators may request injectable fluid pickup. Only Certified Operators may complete this log and inject fluids.
Only sources identified on the source key code may be injected. If a source for injection is not listed on the key code the Env-Safety Tech must be contacted to identify source name and for approval prior to injection.

* Breakout the percentages of fluid types if product is co-mingled. Be specific.

NORTHSTAR WASTE DISPOSAL MANIFEST (Batch Load)

Nº NS-0001

GENERATOR OF WASTE

Company ☐ BPX ☐ Contractor ☐ Other	**Specify**	**Date**
Supervisor (Print name)	**Phone / PP number**	**Time** ☐ AM ☐ PM
Number / **Charge code**	**AFE**	**Source code**

SOURCE OF WASTE

Well number	**Process**	**Facility**
Other	**Volume** ☐ BBLS ☐ Gal. ☐ Cu. Yds.	

Waste container
☐ Sump ☐ Drums ☐ Vessel ☐ Tank ☐ Pit ☐ Trailer ☐ Other (specify) ____________

COMPOSITION OF WASTE

Waste Description — List Composition by Percent (%)

☐ Fresh water	☐ Frac sand	☐ Stimulation Fluid
☐ Source water	☐ Brine	☐ Production vessel sludge/sand
☐ Produced water	☐ Diesel gel	☐ Line pigging material
☐ Crude oil	☐ Production chemicals	☐ Loss circulation material
☐ Diesel	☐ Spent caustic	☐ Cuttings
☐ Methanol	☐ Workover fluid	☐ Contaminated gravel
☐ Water / Diesel gel	☐ Hydrocarbons	☐ Contaminated snow
☐ Spent acid	☐ Glycol	☐ Domestic wastewater
☐ Cement contaminate	☐ Drilling Mud	☐ Other ____________

Waste Stream Classification — (Check one) ☐ **RCRA Exempt** ☐ **Non-exempt / Industrial**

☐ Contained Snow / Produced Water	☐ Non-Exempt Spill Clean Up	☐ Tank Cleaning / Drum Rinsate
☐ Sump Fluids	☐ Off Spec Product	☐ Hydro Test Fluid
☐ Photo Processor Waste	☐ Operation Maintenance	☐ Equipment Facility Washwater
☐ Heat Exchanger Media	☐ Fluid from Remediation	☐ Other ____________

CERTIFICATION

Generator's Certification:
I hereby declare that the contents of this consignment are fully and accurately described above, and that this material is not a Hazardous Waste as defined by applicable Federal and State regulations.

Waste generator signature	**Waste Classification** ☐ Exempt ☐ Non-exempt, Non-hazardous

DELIVERY

Transporter - Operator	**Trailer - Truck number**
Driver name (print)	**Signature**

RECEIVED AT INJECTION FACILITY

Injection facility operator			**Date**		**Time** ☐ AM ☐ PM	
Comments			**Volume received** ☐ BBLS ☐ Gal. ☐ Cu. Yds.			
			Percent solids	**Chlorides (PPM)**	**pH**	**Flash point**
Injection Facility	**Solids Plant**	**Other**	**Compatibility class**			

DISTRIBUTION: WHITE - To HSE PINK & GREEN - Use as required BLUE - Retain in log book

4.0 QUALITY ASSURANCE AND QUALITY CONTROL

BPX will follow a strict QA/QC program to ensure consistency and integrity in the handling and injection of all waste streams, and in the sampling and analytical program. It is the intent of BPX to do minimal sampling of the hard-piped waste streams since they are compositionally consistent, and are all exempt or recycled wastes, except for the domestic waste water. Operationally driven sampling will be done as needed and will be recorded on the daily log of events. No other records or forms will be maintained. Sampling will occur on the batch processes as dictated by manifest facts or other concerns.

4.1 <u>Field Operations</u>

All sampling will be conducted by trained personnel under BPX supervision. Training will include:

- Pertinent regulatory aspects of the program
- Hazardous materials handling
- Environmental awareness
- Representative sampling methods
- Sample handling, preservation, and documentation

4.1.1 Sample Handling and Custody Procedures

Sampling procedures, preservation methods, and holding times should be confirmed with the analytical laboratory. Each sample container will be labeled with the sample description and source, date, required analyses (if known), and sampler's initials. A Chain-of-Custody form will accompany each sample, and will be verified and signed by each person handling the sample until its final disposition.

4.1.2 Quality Control Samples

Specific requirements for field duplicates and trip blanks will be established by the on site environmental staff in consultation with laboratory personnel.

4.1.3 Decontamination

Re-usable sampling equipment will be thoroughly cleaned before and after each use to avoid cross-contamination or mixing of incompatible materials. Spent decon solutions, and all disposable sampling equipment, will be appropriately handled according to BPX

North Slope environmental procedures. The following procedure is recommended for equipment decontamination:

- Disassemble equipment, if appropriate
- Wash with detergent and tap water
- Rinse with tap water
- Rinse with distilled water
- Store in a clean location

4.1.4 Records

Sampling logs, custody forms, and other field reports will be subject to review by supervisors. Any problems with sampling methods or documentation should be resolved immediately.

4.2 Laboratories

BPX will utilize a combination of contract and company laboratories for waste characterization. Contract laboratories will be carefully evaluated before they are selected.

4.2.1 Quality Assurance and Quality Control Plans

All analytical laboratories involved in waste analysis shall maintain and comply with QA/QC programs. Laboratory QA/QC plans should address, at a minimum, the following items:

- Objectives of the QA/QC program
- Organization and responsibility
- Sample integrity requirements
- Equipment calibration requirements
- Quality control samples and acceptance criteria
- Preventative maintenance for instrumentation
- Data reduction and review
- Corrective action

4.2.2 Audits

BPX may, at any time, conduct audits of contract laboratories to verify that the quality assurance-control objectives are being met.

4.2.3 Data Reports

BPX will review all data provided by the analytical laboratory. BPX will establish the level of QA/QC documentation required with each analysis report.

Attachment A

EPA Regulatory Determination of Oil and Gas and Geothermal Exploration, Development, and Production Waste

53 CFR 129 (July 6, 1988)

The actual text is not included here because it is so bulky and is publicly available. It will be included in full with the Waste Analysis Plan on file at the Prudhoe Bay environmental office.

Attachment B

EPA publication 530-K-95-003 (May 1995). Crude Oil and Natural Gas Exploration and Production Wastes: Exemption from RCRA Subtitle C Regulations. This publication is available from the EPA publications office in Washington D. C.

Appendix H

BPX Fiscal Responsibility Documents

40 CFR 144.52 (a)(7) and 144.70 (f)(g)

BPX is the operator of the Northstar Unit. The operation is governed by a Unit Agreement between the lessees and the State of Alaska. Financial resources necessary for operation of the unit, including plugging and abandonment of injection wells, are shared by the co-owners: BPX and Murphy Exploration and Production Company, New Orleans, Lousiana.

Per 40 CFR 144.52 (a)(7) the permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. Evidence of such financial responsibility shall be shown by the submission of a surety bond, or other adequate assurance, such as financial statements or other materials acceptable to the EPA.

Although this application is for a Class I Industrial well permit, BPX chooses to use the more rigorous financial tests, detailed in 40 CFR 144.63(f) and 144.70 for hazardous waste wells, to demonstrate financial assurance for closure. The enclosed documentation is used to demonstrate assurance for closure of BPX facilities located in Alaska and other parts of the United States. The documentation includes a letter, signed by Steven W. Percy, Chief Financial Officer, with wording as specified in 40 CFR 144.70 (f), and a Corporate Guarantee for Plugging and Abandonment, executed on behalf of BPX. Wording of the guarantee is as specified in 40 CFR 144.70 (g). Also included is a financial statement by independent auditors, Ernst & Young.

Upon receipt of the permit, subsequent annual statements and bond ratings will be forwarded to the EPA no later than three months after the end of BP America Inc.'s fiscal year, which ends on December 31.

BP AMERICA

BP America Inc.
200 Public Square
Cleveland, Ohio 44114-2375
(216) 586-4141

Mr. Jonathan Williams
Regional Administrator
U. S. Environmental Protection Agency
Region 10
1200 Sixth Avenue
Mail Stop SO 1211
Seattle, Washington 98101

June 30, 1997

Dear Mr. Williams:

I am the Chairman, CEO & CFO of BP America Inc., a Delaware Corporation, 200 Public Square, Cleveland, Ohio 44114-2375. This letter is in support of this firm's use of the financial test to demonstrate financial assurance, as specified in subpart F of 40 CFR part 144.

1. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is demonstrated through the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by the test is shown for each injection well: None.

2. This firm guarantees, through the corporate guarantee specified in subpart F of 40 CFR part 144, the plugging and abandonment of the following injection wells owned or operated by subsidiaries of this firm. The current cost estimate for plugging and abandonment so guaranteed is shown for each well:

BP Exploration (Alaska) Inc.
Badami Oil Field (North Slope Alaska)
P. O. Box 196612
Anchorage, AK 99519-6612
EPA# TBD
Closure Estimate - $ 400,000
Post-Closure Estimate -0-

BP Exploration (Alaska) Inc.
Northstar Unit Oil Field
P. O. Box 196612
Anchorage, AK 99519-6612
EPA# TBD
Closure Estimate - $ 400,000
Post-Closure Estimate -0-

3. In States where EPA is not administering the financial requirements of subpart F of 40 CFR part 144, this firm, as owner or operator or guarantor, is demonstrating financial assurance for the plugging and abandonment of the following injection wells through the use of a test equivalent or substantially equivalent to the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by such a test is shown for each injection well:

BP Chemicals Inc.
Green Lake Chemical Plant
Texas Highway #185N
Port Lavaca, TX 77979-0659
EPA #TXD000751172
Closure Estimate $ 476,972
Post-Closure Estimate -0-

BP Chemicals Inc.
Lima Chemical Plant
P. O. Box 628
Lima, OH 45802-0628
EPA #OHD042157644
Closure Estimate - $ 646,170
Post-Closure Estimate - $ 160,750

4. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is not demonstrated either to EPA or a State through the financial test or any other financial assurance mechanism specified in subpart F of 40 CFR part 144 or equivalent or substantially equivalent State mechanisms. The current plugging and abandonment cost estimate not covered by such financial assurance is shown for each injection well: None.

This firm is not required to file a Form 10-K with the Securities and Exchange Commission (SEC) for the latest fiscal year.

The fiscal year of this firm ends on December 31. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended December 31, 1996.

Alternative II

1.	(a) Current plugging and abandonment cost	$ 2,083,892
	(b) Sum of company's financial responsibilities under 40 CFR Parts 264 and 265, Subpart H, currently met using the financial test or corporate guarantee	$ 52,009,884
	(c) Total of lines a and b	$ 54,093,776
2.	Current bond rating of most recent issuance of this firm and name of rating service	Moody's Aa2
3.	Date of issuance of bond	April 23, 1996
4.	Date of maturity of bond	April 1, 2031
5.*	Tangible net worth	$ 1.8 Billion
6.*	Total assets in U.S. (required only if less than 90% of firm's assets are located in U.S.)	$ 16.1 Billion

		YES	NO
7.	Is line 5 at least $10 million?	X	
8.	Is line 5 at least 6 times line 1(c)?	X	
9.*	Are at least 90% of the firm's assets located in the U.S.? If not, complete line 10		X
10.	Is line 6 at least 6 times line 1(c)?	X	

Steven W. Percy
Chairman, CEO & CFO
June 30, 1997

akp&a97.doc

GUARANTEE FOR PLUGGING AND ABANDONMENT

Guarantee made this 30th day of June, 1997, by BP America Inc., a Delaware corporation, a business corporation organized under the laws of the State of Delaware, herein referred to as guarantor, to the United States Environmental Protection Agency (EPA), obligee, on behalf of our subsidiary BP Exploration (Alaska) Inc., of 200 Public Square, Cleveland, Ohio 44114-2375.

Recitals

1. Guarantor meets or exceeds the financial test criteria and agrees to comply with the reporting requirements for guarantors as specified in 40 CFR 144.63(f).

2. BP Exploration (Alaska) Inc. owns or operates the following Class I non-hazardous waste injection well covered by this guarantee:

BP Exploration (Alaska) Inc. Badami Oil Field (North Slope Alaska) P. O. Box 196612 Anchorage, AK 99519-6612 EPA #TBD	BP Exploration (Alaska) Inc. Northstar Unit Oil Field P. O. Box 196612 Anchorage, AK 99519-6612 EPA #TBD

Guarantee is for both closure and post-closure care

3. "Plugging and abandonment plan" as used below refers to the plans maintained as required by 40 CFR Part 144 for the plugging and abandonment of injection wells as identified above.

4. For value received from BP Exploration (Alaska) Inc., guarantor guarantees to the EPA that in the event that BP Exploration (Alaska) Inc. fails to perform ["plugging and abandonment"] of the above facility(ies) in accordance with the plugging and abandonment plan and other requirements when required to do so, the guarantor will do so or fund a trust fund as specified in 40 CFR 144.63 in the name of BP Exploration (Alaska) Inc. in the amount of the adjusted plugging and abandonment cost estimates prepared as specified in 40 CFR 144.62.

5. Guarantor agrees that, if at the end of any fiscal year before termination of this guarantee, the guarantor fails to meet the financial test criteria, guarantor will send within 90 days, by certified mail, notice to the EPA and to BP Exploration (Alaska) Inc. that he intends to provide alternate financial assurance as specified in 40 CFR 144.63 in the name of BP Exploration (Alaska) Inc. Within 30 days after sending such notice, the guarantor will establish such financial assurance if BP Exploration (Alaska) Inc. has not done so.

6. The guarantor agrees to notify the Regional Administrator by certified mail, of a voluntary or involuntary case under Title 11, U. S. Code, naming guarantor as debtor, within 10 days after its commencement.

7. Guarantor agrees that within 30 days after being notified by the EPA Regional Administrator of a determination that guarantor no longer meets the financial test criteria or that he is disallowed from continuing as a guarantor of plugging and abandonment, he will establish alternate financial assurance, as specified in 40 CFR 144.63, in the name of BP Exploration (Alaska) Inc. if BP Exploration (Alaska) Inc. has not done so.

8. Guarantor agrees to remain bound under this guarantee notwithstanding any or all of the following: amendment or modification of the plugging and abandonment plan, the extension or reduction of the time of performance of plugging and abandonment or any other modification or alteration of an obligation of BP Exploration (Alaska) Inc. pursuant to 40 CFR Part 144.

9. Guarantor agrees to remain bound under this guarantee for so long as BP Exploration (Alaska) Inc. must comply with the applicable financial assurance requirements of 40 CFR Part 144 for the above-listed facilities, except that guarantor may cancel this guarantee by sending notice by certified mail, to the EPA Regional Administrator for the Region in which the facility is located and to BP Exploration (Alaska) Inc., such cancellation to become effective no earlier that 120 days after actual receipt of such notice by both the EPA and BP Exploration (Alaska) Inc. as evidenced by the return receipts.

10. Guarantor agrees that if BP Exploration (Alaska) Inc. fails to provide alternate financial assurance and obtain written approval of such assurance from the EPA Regional Administrator within 90 days after a notice of cancellation by the guarantor is received by both the EPA Regional Administrator and BP Exploration (Alaska) Inc., guarantor will provide alternate financial assurance as specified in 40 CFR 144.63 in the name of BP Exploration (Alaska) Inc..

11. Guarantor expressly waives notice of acceptance of this guarantee by the EPA or by BP Exploration (Alaska) Inc.. Guarantor also expressly waives notice of amendments or modifications of the plugging and abandonment plan.

Effective date: June 30, 1997
BP America Inc.

Steven W. Percy
Chairman, CEO & CFO

Signature of witness or notary: Nancy A. Fedorov

NANCY A. FEDOROV, Notary Public
State of Ohio & Cuyahoga County
My commission expires Oct. 12, 1999

ERNST & YOUNG LLP

1300 Huntington Building
925 Euclid Avenue
Cleveland, Ohio 44115-1405

Phone: 216 861 5000

Report of Independent Accountants

Board of Directors
BP America Inc.

We have audited, in accordance with generally accepted auditing standards, the consolidated financial statements of BP America Inc. (the "Company" - an indirect wholly owned subsidiary of The British Petroleum Company p.l.c.) and subsidiaries for the year ended December 31, 1996 and have issued our report thereon dated February 4, 1997.

Steven W. Percy's (Chairman, CEO & CFO of BP America Inc.) June 30. 1997 letter pertaining to financial assurance is addressed to the United States Environmental Protection Agency-Region 10.

In connection with our audit and in accordance with subpart F of 40 CFR part 144, we have compared the amounts presented in that letter, listed under the caption Alternative II, Items 5 and 6, with the corresponding amounts included in or derived from the consolidated financial statements referred to above. In connection with that procedure, no matters came to our attention that caused us to believe that the amounts shown on lines 5 and 6 should be adjusted.

This report is intended solely for your information and use and for the information and use of the United States Environmental Protection Agency-Region 10 and should not be used for any other purpose.

Ernst + Young LLP

June 30, 1997

Appendix I

Acronyms and Definitions

AOGCC	Alaska Oil and Gas Conservation Commission
AOR	Area of Review
Aquifer	Subsurface Water (Fresh or Saline)
ARCO	ARCO Alaska Inc. (Atlantic Richfield Co.)
BHA	Bottom Hole Assembly
BHCS	Log - Borehole Compensated Sonic
BKB	Below Kelly Bushing (rig floor)
BOP	Blow Out Protector
BPD	Barrels Per Day
BPX	BP Exploration (Alaska) Inc.
Brine	Saline Waters
CC2-A	Prudhoe Bay Class II Disposal Well
CFR	Code Federal Regulations
CNL	Log - Compensated Neutron
csg	Casing
cu ft	Cubic feet
CWHF	Consolidated Waste Handling Facility
CZM	Coastal Zone Management
DEC	Alaska Department of Environmental Conservation
DI	Duck Island Unit (Endicott OilField)
DIL	Log - Dual Induction
DS4-19	Prudhoe Bay Class II Test Disposal Well
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
frac	Fracture
FM (Fm)	Formation
FS	Flow Station (Produced Fluid Separation)
GC	Gathering Center (Produced Fluid Separation)
G/I	Grind and Inject (Disposal Technology)
GR	Log - Gamma Ray
HRZ	Geologic Marker
KOP	Kick Off Point
KRU	Kuparuk River Unit
kppm	Thousand parts per million
M	Thousand

MBbl	Thousand Barrels
MD	Measured Depth
md	Millidarcy - rock permeability
md ft	Millidarcy feet (product of permeability and sand thickness)
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MM	Million
MMBbl	Million Barrels
MPU	Milne Point Unit
MSDS	Material Safety Data Sheet
M87F	Geologic marker - Schrader Bluff Formation
NGL	Natural Gas Liquids
NORM	Natural Occurring Radioactive Material
NPDES	National Pollutant Discharge Elimination System
NRC	National Response Center (USCG)
O & G	Oil and Gas
Pad-3	Prudhoe Bay Class I Disposal Facility (3 Wells)
PBU	Prudhoe Bay Unit
perfs	Perforations (Wellbore)
PF (P/F)	Permafrost
pH	Measure of Acidity
pkr	Packer (Wellbore)
ppm	Parts per million
psi	Pounds per square inch (pressure)
PWI	Produced Water Injection
QA/QC	Quality Assurance/Quality Control
RCRA	Resource Conservation Recovery Act
RFT	Repeat Formation Testor (logging tool)
RIH	Run In Hole
SEABEE	Geologic Marker - Top Lower Confining Zone
SG	Specific Gravity (water = 1.0)
SP	Log - Spontaneous Potential
SPCP	Spill Prevention Control Plan
SS/ss	Subsea (Depth)
SV6	Geologic Marker - Top Upper Confining Zone
SV5	Geologic Marker - Top Upper Arresting Zone
SV2	Geologic Marker - Top Upper Injection Interval (Zone)
Sx	Sacks
TD	Total Depth
TDS	Total Dissolved Solids

TMBK	Geologic Markert - Base Major Shale Barrier (Top Lower Inj. Zone)
TVD	Total Vertical Depth
Tbg	Tubing
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
WAP	Waste Analysis Plan
WMT	Waste Management Team
ZEI	Zone of Endangering Influence
#	Pounds or Number
2-02/P18	Endicott Class II Disposal Well

Appendix J

Significant EPA Correspondence

This appendix consists of the following exhibits :

Exhibit J-1 : EPA Region 10 letter of March 27, 1997 stating the application is considered complete as set forth in 40 CFR 144.31.

Exhibit J-2 : EPA Region 10 letter of May 12, 1997 stating that aquifers beneath the permafrost meet the criteria for an aquifer exemption under 40 CFR 144.6.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

ENVIRONMENTAL
APR 01 1997
& REG. AFFAIRS

MAR 27 1997

Reply To The
Attn. Of: OW-137

Steven D. Taylor, Manager
Environmental and Regulatory Affairs
BP Exploration (Alaska) Inc.
P O Box 196612
Anchorage, AK 99519-6612

Re: Completeness Review
Class I Injection Well Permit Applications
Badami and Northstar Development Projects

Dear Mr. Taylor:

We have completed our review of the BPX Underground Injection Control (UIC) Program permit applications for Class I non-hazardous industrial waste injection wells at the Badami and Northstar fields on the North Slope of Alaska. We have also reviewed your responses to our letter of January 14, 1997, and additional information provided by your staff in Seattle on February 5, 1997. We now consider that the applications are complete as set forth in 40 CFR 144.31 *et seq.* and are sufficient for us to issue permits as will be described below.

Our proposed schedule for the issuance of the Badami permit is as follows:

May 15: Internal draft permit complete
July 1: Public Notice (and public draft permit) issued
August 1: Public hearing held (if requested)
August 15: Final permit issued

The permit could be effective upon issuance if no significant adverse comments are received.

A final decision on the requested North Star permit cannot be made until the Environmental Impact Statement on that project has been completed.

Based on all the information we have seen to date, we think that the proposed slurry injection by formation fracturing should either be conducted with continuous microseismic monitoring or under very prudent stratigraphic and injection rate limitations. Therefore, given the expenses of monitoring, we intend to draft a permit which would propose to authorize slurry injection at not more that two barrels per minute into the lower injection interval only (i.e., below the shale barrier at the base of the Sagavanirktok formation.) We believe these limitations will adequately prohibit fluid movement to the surface and are willing to forgo requiring extensive subsurface monitoring.

If you have any questions, please call Grover Partee at (206) 553–6697 or Jonathan Williams at (206) 553–1369.

Sincerely,

Philip G. Millam
Director, Office of Water

cc: David Johnston, AOGCC

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

ENVIRONMENTAL
MAY 19 1997
& REG. AFFAIRS

Reply To
Attn Of: OW-137

May 12, 1997

Alison Cooke, Senior Geologist
BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612

Subject: EPA Determination Regarding Underground Sources of Drinking Water (USDWs) in the Badami and Northstar Field Areas of the North Slope of Alaska

Dear Ms. Cooke:

This letter confirms and augments our telephone conversation of May 6, 1997, regarding EPA's determination that there are no USDWs in the Badami field area. Also, this letter will serve to document EPA's determination that, based upon the information submitted to date, there are aquifers which narrowly meet the regulatory formation water quality threshold for protection as USDWs in the Northstar field area.

EPA determined that there are no USDWs at Badami shortly after receiving the supplemental Class I injection well permit information that BPX sent us on June 10, 1996. That submittal contains a detailed set of calculated formation water quality estimates based upon geophysical borehole log data and a realistic range of technical assumptions. We think that this information amply demonstrates that the aquifers beneath the permafrost at Badami are too naturally saline to meet the Underground Injection Control (UIC) program regulatory threshold of 10,000 milligrams per liter (mg/L) of total dissolved solids (TDS), and thus do not qualify for protection as USDWs under the Safe Drinking Water Act.

Our first permit application review letter of September 30, 1996, did not mention whether or not EPA agreed with BPX's assertion that there are no USDWs beneath the permafrost at Badami. Subsequent letters also made no mention of the topic. We think that's because those letters focused upon EPA questions and concerns rather than the many areas of agreement with the permit application. The information BPX submitted on June 10, 1996, had convinced us that there are no USDWs in the Badami field area, as you know from our past conversations. We trust that this letter will serve to document that understanding.

In terms of Northstar, our review of the permit application has led us to conclude that there are most likely some USDWs beneath the permafrost. And we also think that they meet the aquifer exemption criteria under 40 CFR 144.6, as described in the BPX permit application. Therefore, we are prepared to process an aquifer exemption at Northstar as part of the Class I injection well permitting process, as BPX has requested. However, a final decision to prepare a draft permit for Northstar cannot be made until the Environmental Impact Statement (EIS) on that proposed project has been completed.

Sincerely,

Jonathan Williams

Jonathan Williams, Hydrogeologist
Regional UIC Program Coordinator

cc: David Johnston, AOGCC

U.S. ARMY CORP of ENGINEERS PERMIT
(SEC.404/10/103)

NORTHSTAR DEVELOPMENT PROJECT
BP EXPLORATION (ALASKA), INC. (BPXA)

PERMIT APPLICATIONS TO BE FILED WITH :

U. S. Army Corps of Engineers (USACE)

Authorization To Discharge Into Waters of the U.S. (Sec.404 - Clean Water Act; and Section 10 - Rivers and Harbors Act of 1899)
Ocean Discharge Authorization (Sec. 103 - Marine Protection, Research, and Sanctuaries Act)

- The Northstar Final Project Description, Rev.1 will serve as the basis for the request for authorization to discharge into waters of the U. S. under the authorizations listed above. It is understood that the USACE will not consider the project description complete or the public review process initiated under USACE regulations until issuance of the Draft Environmental Impact Statement (DEIS) by the Corps of Engineers. It is also understood that the USACE will likely issue the Ocean Discharge permit on behalf of the U. S. Environmental Protection Agency (EPA).

- BPXA submitted an application to the USACE in June 1995, and the USACE recognized the application as complete in December 1996 with the submittal of the Northstar Final Project Description, dated 12/20/96.

USFWS - LOA

NORTHSTAR DEVELOPMENT PROJECT
BP EXPLORATION (ALASKA), INC. (BPXA)

PERMIT APPLICATIONS TO BE FILED WITH :

U. S. Fish and Wildlife Service

Letter of Authorization (LOA)

- An individual application for an LOA (polar bears) will be applied for at least 90 days in advance of construction. Application will include specific interaction plans for each phase of construction, if more than single season. LOA expected to cover construction and operations.
- Rule making for a Letter of Authorization (LOA) will be requested at least 180 days prior to expiration of regulations on 12/15/98.

NMFS - IHA and LOA

NORTHSTAR DEVELOPMENT PROJECT
BP EXPLORATION (ALASKA), INC. (BPXA)

PERMIT APPLICATIONS TO BE FILED WITH :

National Marine Fisheries Service (NMFS)

Incidental Harassment Authorization (IHA); and
Letter of Authorization (LOA)

- On the advice of NMFS, Silver Spring, Maryland, an individual application for an IHA (Bowhead whales and ringed seals) will be submitted at least 120 days in advance of construction. In a two-season scenario, two separate applications will be filed for two separate IHA's, one for each year of construction. In a one-season construction scenario, only one application will be submitted.

- Rule making for a Letter of Authorization (LOA) will be requested at least 180 days prior to the start of operations ("first oil"). LOA can be issued for life of rule, usually 5 years.

MMS: DEVELOPMENT and PRODUCTION PLAN

NORTHSTAR DEVELOPMENT PROJECT
BP EXPLORATION (ALASKA), INC. (BPXA)

PERMIT APPLICATIONS TO BE FILED WITH :

Minerals Management Service (MMS)

Development and Production Plan

- The Northstar Final Project Description, Rev.1 is also the Development and Production Plan (DPP) required for MMS approval. BPXA can reissue, at MMS's request, the Northstar Final Project Description, Rev.1 with a different title cover labeled Development and Production Plan. It is understood that MMS will not consider the project description complete or the public review process initiated under MMS regulations until issuance of the Draft Environmental Impact Statement (DEIS) by the Corps of Engineers.

- Because the majority of Northstar activity will take place on State lands, the MMS will work with the State to coordinate their respective approvals and regulatory responsibilities to avoid overlap and to accommodate the State process and time frames as much as possible.

NSB: REZONING REQUEST and MASTER PLAN

NORTHSTAR DEVELOPMENT PROJECT
BP EXPLORATION (ALASKA), INC. (BPXA)

PERMIT APPLICATIONS TO BE FILED WITH :

North Slope Borough (NSB)

Master Plan and Rezoning Approval

- The Northstar Final Project Description, Rev.1, is also the Master Plan and Rezone request to the Resource Development District required for approval. BPXA can reissue, at the NSB's request, the Northstar Final Project Description, Rev.1 with a different title cover labeled Northstar Master Plan and Rezoning Request. Mr. Tom Lohman, NSB representative to the Northstar EIS Team, has requested that BPXA withhold submittal of the application for Master Plan and Rezoning approval until after issuance of the DEIS. Mr. Lohman has indicated that the public review process will not be initiated under NSB regulations until after issuance of the Draft Environmental Impact Statement (DEIS) by the Corps of Engineers.

- A Statement of Conformance with North Slope Borough Land Management Regulation (LMR) Policies will be included in the application to the NSB.

APPENDIX B

Appendix B
Northstar Development Project
Final Project Description, Rev. 1

Required State Approvals

AGENCY	PERMIT/ APPROVAL	ACTIVITY
State		
Office of the Governor/Division of Governmental Coordination (DGC)	Coastal Zone Consistency	Coordinate state permitting on Northstar
Alaska Oil & Gas Conservation Commission (AOGCC)	Underground Injection Control Class II Wells	Injection of class II fluids into cretaceous wells
Department of Natural Resources, Division of Oil and Gas (DNR/DOG)	Unit Plan of Operations	Construction of island; installation of outfall line
Department of Natural Resources, Joint Pipeline Office (DNR/JPO)	Pipeline Right-of-Way Lease	Pipeline construction and operations
Department of Natural Resources, Division of Land (DNR/DL)	Miscellaneous Land Use Permit	Ice roads on state land/state fresh water bodies
Department of Natural Resources, Division of Land (DNR/DL)	Material sales contract	Gravel mining and purchase
Department of Fish and Game (ADFG)	Fish Habitat permit - Title 16	New Kuparuk delta mine site and Put River pipe crossing
Department of Natural Resources, Division of Mining and Water Management (DNR/DMWM)	Temporary Water Use and Water Rights	Water use for construction and operations
Department of Environmental Conservation (ADEC)	Prevention of Significant Deterioration (Air Quality Control) - Facilities	Air quality impacts resulting from operation of facilities
Department of Environmental Conservation (ADEC)	Mixing Zone Approval (Cooling water, desal effluent, temporary camp effluent)	Discharges from facilities to meet state water quality standards
Department of Environmental Conservation (ADEC)	Prevention of Significant Deterioration (Air Quality Control) - Pipelines, Drilling & Construction	Air quality impacts resulting from construction of island & pipeline, and drilling
Department of Environmental Conservation (ADEC)	Section 401 Water Quality Certification - Civil & Offshore Pipeline	Water quality impacts associated w/ construction discharges/contingency on-ice spoils disposal; operational

APPENDIX C

Northstar Development Project
Final Project Description
Rev. 1, March 27, 1997

GLOSSARY OF TERMS

ANTIFOAM.
Chemical substance added to prevent the generation of foam in equipment used to remove air from the water that will be injected into the reservoir.

BACKPASS.
Refers to the activity of excavating the gravel placed in the island protective berm, and moving it from a location where it is not required, to another location where it is required.

BALL MILL.
Facility used for crushing the drilling cuttings prior to reinjection into the Class I disposal well.

BBL.
Barrel. Measurement of volume equivalent to 42 US Gallons.

BLOWOUT.
Uncontrolled release of fluids e.g. water, oil, gas from a well.

BLOWOUT PREVENTER (BOP).
Mechanical device used to control the release of fluids from a well.

BOD.
Biochemical oxygen demand. A wastewater pollutant parameter.

COD.
Chemical oxygen demand. A wastewater pollutant parameter.

COMPLETION BRINE.
Fluid left in the well between the production tubing and intermediate casing string, usually with corrosion inhibitor added.

CONEX-(ES).

Short for CONtainer EXport. Metal containers used for the transport of goods. Nominal dimensions are 20' x 8' x 8.5'(L x W x H).

CY.

Cubic yard(s).. Measure of volume.

DIVERTER.

Mechanical device installed at the top of a well and used to divert the flow of fluids from the well through a 12-inch pipe away from the drilling rig in the event of shallow gas blow-out.

EXTENDED REACH.

Wells with higher than usual horizontal distance between the top of the well i.e. island, pad, etc. and target i.e. bottom hole location in the reservoir. The distance at which a well is termed "extended reach" varies depending upon drilling location and depth of reservoir. A generic distance for North Slope wells would be a horizontal displacement greater than 15,000 feet.

FAA.

Federal Aviation Administration

GAS CYCLING.

Reservoir management technique that employs high pressure gas injected into the soil for the purpose of driving the entrapped oil into the wells.

HP.

Horsepower. Unit of power.

IN-FILL DRILLING.

Additional wells or side tracks drilled following the initial development drilling program.

KICK-OFF.

The point at which the angle of a well trajectory is altered to meet directional parameters e.g. build up of angle from vertical at the top of a well, build up of angle from deviated to horizontal in a reservoir, etc.

MLLW.

Mean Lower Low Water. Lowest level of the sea at a designated location. Used as a reference datum.

MSDS.

Material Safety Date Sheet. The written listing of data for a chemical substance.

MUD.

Fluid circulated through the drill string and back up in the well while drilling to remove cuttings from the well and lubricate the drill string.

NORMS.

Naturally occurring radioactive materials.

PBU.

Prudhoe Bay Unit.

PIG.

Device inserted in a pipeline and used to provided information on the inside condition, or for the purpose of pushing and / or separating fluids transported in the pipeline. The pig is called "intelligent" if it is provided with electronic equipment and is used to determine internal corrosion, or for providing information on the vertical and horizontal position of a pipeline.

POLYELECTROLYTE.

Substance added to the filter system of a facility for the purpose of improving the efficiency of the filters. It acts by giving the sand particles an electrical charge and increasing their separation.

PSIG.

Pounds per square inch gauge.

PVT.

Pressure-volume-temperature

RISER(S).

Vertical pipe segments connected to the outfall through which the discharge of wastewater will take place. The upper end of the risers is capped by means of specially designed, replaceable nozzles for diffusing the wastewater in the surrounding water.