CHUKCHI SEA
TRANSPORTATION FEASIBILITY
AND
COST COMPARISON

JOINT INDUSTRY STUDY UPDATE

INTEC JOB NO. H-046.4

JULY 1991

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EXECUTIVE SUMMARY

In preparation for Chukchi Lease Sale 126 scheduled for mid-1991, INTEC Engineering was contracted by ARCO Alaska, BP Exploration, Chevron, Conoco, Mobil, MMS, and Texaco to update the Chukchi Sea Transportation Feasibility and Cost Comparison Joint Industry Study prepared by INTEC in 1986.

The updated study results indicate that while no changes were required with regard to the environmental database, tanker design, terminal selection and design, and pipeline design from the 1986 study, current material and contracting market changes had influenced tanker, terminal, and pipeline costs. Construction cost of arctic tankers increased approximately 8 percent, while operating and maintenance costs increased 30 to 60 percent. Far East built tankers remained 50 to 60 percent lower than U.S. built tankers. Construction costs for both offshore, nearshore, and trans-shipment tanker terminals increased by approximately 5 percent and operating and maintenance costs increased by approximately 13 percent. Pipeline material and construction costs increased by as much as 30 percent assuming the use of conventional pipeline trenching equipment. However, the development and use of a linear trenching system could significantly reduce pipeline construction costs.

The study also determined that a direct offshore pipeline from the Chukchi Sea to a storage facility and nearshore terminal at Unimak Pass was not only feasible, but is also a cost effective option.

In conclusion, the study recommends the following crude oil transportation scenarios:

- A pipeline from the Chukchi Sea to the existing Trans-Alaskan Pipeline System is the most economical solution for transporting up to 200 MBPD of crude oil from the Chukchi Sea.

- A pipeline to tanker scenario from the Chukchi Sea to a trans-shipment terminal and storage facility at Unimak Pass is the most economical solution for transporting from 200 up to 400 MBPD of crude oil from the Chukchi Sea.

- A direct offshore pipeline from the Chukchi Sea to a storage facility and nearshore terminal at Unimak Pass is the most economical solution for transporting greater than 400 MBPD of crude oil from the Chukchi Sea.

The development and use of a linear trencher can significantly reduce the cost of offshore arctic pipelines that require more than 35 miles of relatively deep trenching.

In recent meetings with the MMS and other regional participants, it was indicated that the direct pipeline may be the only politically viable solution in transporting crude from the region. This is due to the increasing fear of oil tanker transportation in the region, the numerous state controls for onshore/near shore oil pipelines, and the future availability of the Trans-Alaskan Pipeline System.

UPDATE OF THE CHUKCHI SEA

TRANSPORTATION FEASIBILITY AND

COST COMPARISON

JOINT INDUSTRY STUDY UPDATE

CHAPTER 1

INTRODUCTION AND SUMMARY

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1.1 INTRODUCTION

INTEC Engineering was contracted in November 1990 to update the original Chukchi Sea Transportation Feasibility and Cost Comparison Joint Industry Study completed in May of 1986. The update was requested in anticipation of Lease Sale Number 126 scheduled for July 1991. The lease sale will include areas within the central and northern portions of the Chukchi Sea.

The study update is primarily intended to support lease sale bid preparation. Specific objectives include:

- Establish the technical feasibility for transporting Chukchi Sea hydrocarbons by pipelines, tanker/terminal systems or combinations of these methods
- Prepare cost estimates for selected scenarios in a building block format which facilitates further optimization and investigation of development options by the Study Participants
- Prepare a matrix of recommended transportation systems for a range of throughput rates and area ice conditions

1.2 SUMMARY

The study report is organized into eight chapters plus appendices. The first chapter contains an introduction and a brief summary of the report organization and contents. Study conclusions and recommendations are presented in Chapter 2.

Chapter 3 summarizes environmental design criteria affecting pipeline, tanker and terminal design and system performance within the study area. Meteorological conditions addressed include wind, air temperature and visibility. Oceanographic conditions (waves, currents and tides), soil conditions and available seafloor ice scour data are also summarized. Sea ice conditions important to the design of transportation facilities in the Lease Sale 126 area and the operation of ice-breaking tankers along potential tanker routes are described in Section 3.3. Detailed summaries of sea ice conditions are presented in the Chukchi Sea Ice Concentration Study by D.F. Dickins contained in Appendix A.

Chapter 4 discusses the design, performance and costs of icebreaking tankers. The principal design characteristics for 100,000, 150,000 and 200,000 deadweight ton ice Class 4, 6 and 8 tankers are described in Section 4.2. Tanker transit simulations, tanker routes and transit times are summarized in Sections 4.3 through 4.5. Icebreaking tanker capital and operating costs are developed in Sections 4.6 and 4.7 based on U.S. built tankers.

Tanker terminal design, operation and costs are presented in Chapter 5. The design, performance and costs for an offshore crude oil storage structure and separate tanker loading structure at the central offshore field location are contained in Section 5.2. Costs were also developed for other offshore field locations, crude oil production rates and storage volumes. The design and costs for a nearshore tanker loading terminal located at Kivalina are presented in Section 5.3. Applicable costs for terminal locations at Wainwright and Nome are also included. The cost for a trans-shipment terminal at Unimak Pass and at Valdez are presented in Sections 5.4 and 5.5.

Chapter 6 describes pipeline design, construction methods and pipeline costs. Major pipeline design considerations are addressed in Section 6.2. Important design parameters are defined for trunklines between the central offshore field location and shore, and for the tanker loading lines. Open water and ice-based pipeline installation methods are addressed in Section 6.3. Feasible trenching methods are described, and their capabilities, limitations, and production rates are presented in Section 6.4. Pipeline construction costs and schedules for the central field location are summarized in Sections 6.5 and 6.6. The major cost components include materials, installation and trenching. Operating and maintenance costs for pipelines and decommissioning costs are summarized in Sections 6.7 and 6.8. Section 6.9 presents the pipeline costs for the southern and northern field locations.

Chapter 7 discusses a direct offshore pipeline from the central Chukchi Sea Field location to Unimak Pass. Preliminary flow analyses for a direct pipeline are presented in Section 7.2. Pipeline routes and design parameters are presented in Sections 7.3 and 7.4. Pipeline construction and costs are presented in Sections 7.5 through 7.7.

Individual crude oil transportation system components are combined and evaluated in Chapter 8. Fourteen transportation scenarios are defined in Section 8.2. The economic evaluation methodology is summarized in Section 8.3. Sections 8.4 and 8.5 summarize the economic evaluation for the 14 transportation scenarios and the direct offshore pipeline route. Recommended transportation scenarios are discussed in Section 8.6.

CHAPTER 2

CONCLUSIONS AND RECOMMENDATIONS

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2.1 CONCLUSIONS

Updated Chukchi Sea study results indicate no changes from the 1986 study with regard to the following:

- Environmental Data Base
- Tanker Designs
- Tanker Transit Simulations
- Terminal Designs
- Pipeline Designs

However, the updated study results do indicate the following changes:

- Arctic tanker construction costs increased approximately 8 percent.

- Tanker operating and maintenance costs increased approximately 30 percent.

- Terminal construction costs increased approximately 5 percent.

- Terminal operating and maintenance costs increased approximately 13 percent.

- Offshore pipeline costs were marginally increased. However, the development and use of a linear trencher system will significantly reduce the offshore pipeline costs.

- Pipeline operating and maintenance costs were marginally reduced.

- Onshore pipeline construction costs remain constant.

Based on these changes, the 1986 recommended transportation scenarios changed from an all tanker scenario for all flowrates to an all pipeline scenario for flowrates below 200 MBPD, a pipeline and tanker scenario for flowrates between 200 and 400 MBPD, and a direct offshore pipeline route for flowrates larger than 400 MBPD. These changes are discussed in more detail within each individual section of the report.

Conclusions for each major subject area addressed in this study are presented.

Chapter 3: Environmental Conditions

A detailed review of publicly available environmental data, issued since the completion of the 1986 study, and the preparation of an updated sea ice study by D.F. Dickens and Associates indicated that there are no changes to the environmental data base established during the 1986 study.

Sea ice conditions, soil conditions and maximum ice gouge depths remain the significant factors affecting transportation system costs. For example, the open water construction season defined for this study as 3/10 or 30 percent ice cover is approximately 10 to 13 weeks for the central field location. Maximum observed ice gouge depth is 15 feet recorded at a water depth of 125 feet. However, no ice gouges have been recorded in water depths greater than 190 feet. Surficial seafloor sediments generally range from silty sand nearshore to sandy clayey silt offshore. Beneath this thin surficial soil layer is a very stiff, erosion resistant soil.

Chapter 4: Arctic Tankers

A review of the previous arctic tanker design and proposed changes to CASPPR regulations indicated that there are no changes to the arctic tanker design which was based on the following:

- Tanker sizes of 100,000, 150,000 and 200,000 dwt
- Maximum ice thickness of 4, 6, and 8 feet; approximately corresponding to CASPPR Ice Classes 4, 6, and 8
- Double hull tanker construction

As there were no tanker design changes or changes in the environmental conditions, there were no changes to the tanker transit simulations performed in the 1986 study.

Only two U.S. shipyards, Newport News and National, expressed interest in building large arctic tankers. The cost of the U.S.-built tankers range from $144 million for a 100,000 dwt arctic Class 4 tanker to $280 million for a 200,000 dwt arctic Class 8 tanker. These costs remain 50 to 60 percent higher than costs for arctic tankers built in Far East shipyards.

Based on recent events in the Alaskan Coastal region and the oil tanker transportation industry, the cost of icebreaking support/oil spill tanker escort vessels were included. The annual operating and maintenance cost for an arctic tanker ranges from $23.75 million for a 100,000 dwt arctic Class 4 tanker to $53.16 million for a 200,000 dwt arctic Class 8 tanker.

Chapter 5: Tanker Terminals

As in the prior study, the offshore tanker terminal consists of a bottom founded monolithic storage structure located approximately three nautical miles from a bottom founded monolithic omni-directional SPM loading structure. The two structures are connected by a 48-inch diameter submarine pipeline.

U.S. and Far East fabricators which have built, or have an interest in building, arctic structures were contacted to obtain unit costs for structural steel, reinforced concrete and sand-infill. For study purposes, unit costs for reinforced concrete, structural steel and sand-infill are $1,125 per cubic yard, $2,500 per short ton and $15.85 per cubic yard, respectively.

Capital construction costs for offshore terminals have increased approximately 5 percent on average since the 1986 study. The costs range from $1.05 billion for a 2 million barrel storage terminal at the southern field location to $3.05 billion for an 18 million barrel storage terminal at the northern field location. Annual operating and maintenance costs have increased approximately 13 percent on average since the 1986 study. These costs range from $48.4 million for a 2 million barrel storage terminal at the southern field location to $78.4 million for a 18 million barrel storage terminal at the northern field location.

The nearshore tanker terminal consists of a bottom founded monolithic omni-directional SPM loading structure connected by a 5 mile long, 36-inch diameter pipeline to an onshore tank farm. Capital construction costs range from $567.8 million for a 2 million barrel storage facility and terminal at Nome to $740 million for a 20 million barrel storage facility and terminal at Wainwright. Annual operating and maintenance costs for a nearshore terminal range from $46.1 million for the 2 million barrel storage facility and terminal at Nome to $52.2 million for the 20 million barrel storage facility and terminal at Wainwright.

The capital construction cost of a trans-shipment terminal at Unimak Pass ranges from $950 million for a peak flowrate of 100,000 barrels per day to $1.7 billion for a peak flowrate of 600,000 barrels per day. Annual operating and maintenance costs are estimated at $32 million.

Capital construction costs of $400 million were assigned for upgrading the existing Valdez terminal to a trans-shipment terminal with annual operating costs of $20 million.

Chapter 6: Pipelines

Eight pipeline routes, which were components of the transportation scenarios considered in the 1986 study, were evaluated. Each pipeline route was designed and evaluated for flow rates of 100, 200, 400 and 600 MBPD.

Insulation is required for offshore pipelines in water depths less than 20 feet, and for all overland pipelines. Line pipe costs have increased from $760 per ton including delivery to the U.S. West Coast to $800 per ton F.O.B. steel mills in the Far East. The use of a direct sealift from Far East steel mills to Prudhoe Bay by means of oceangoing barges at a cost of $280 per ton may reduce material transportation costs from 50 percent of the total material cost to approximately 20 percent of the total material cost.

U.S. and Canadian onshore pipeline contractors were contacted to obtain costs for elevated and insulated overland pipelines constructed in Alaska. Their responses indicate that onshore pipeline costs have remained approximately constant, on a cost per mile basis, since the 1986 study.

Offshore pipeline installation would be performed by a third generation laybarge for pipeline segments in water depths exceeding 40 feet. Shallow water sections would be installed by the bottom-pull method.

Chukchi Sea pipelines will require trenching for ice gouge protection in water depths to 190 feet. Evaluation of an arctic linear trencher system has indicated the potential for significant pipeline trenching cost reductions, and therefore the linear trenching concept should be developed for Chukchi Sea pipeline installations.

Pipeline operating and maintenance costs have been calculated based on personnel and equipment requirements for pipeline control, operations, inspection, maintenance and repair. Pipeline annual operating costs also include taxation payments based on the initial capital expenditure for each overland pipeline, and for offshore pipeline sections within three miles of the Alaskan coastline.

Based on the development and use of a linear trencher, offshore pipeline capital costs range from $428.7 million for Pipeline P3 at 100 MBPD to $1.05 billion for Pipeline P2 at 600 MBPD.

The capital costs of onshore pipelines from the Alaskan coastline to the Trans-Alaska Pipeline System range from $1.4 billion for Pipeline P4 at 100 MBPD to $2.9 million for Pipeline P6 at 600 MBPD.

<u>Chapter 7: Direct Offshore Pipeline to Unimak Pass</u>

A preliminary analysis of a direct pipeline from the central Chukchi field location to Unimak Pass was evaluated upon request of the study participants. Based on a flow analysis, it was determined that a 56-inch diameter pipeline without pump stations can transport 635 MBPD of crude oil. If two pump stations are added, the peak flowrate could be increased to 1105 MBPD. For this study, a maximum of two pump stations, one at Prince of Wales and one at Nunivake Island were considered.

The construction of a direct offshore pipeline from the central field to Unimak Pass could continue throughout the year, thereby eliminating the need for expensive winter standby charges. This is accomplished by constructing the pipeline in segments whereby the northern most segments are constructed during the summer construction season and the southern segments constructed during the winter months. Therefore, the direct pipeline would require a three to four year construction period depending on the pipe diameter selected.

The capital construction cost for the direct offshore pipeline including a nearshore terminal at Unimak Pass and pump stations when required are summarized below:

CAPITAL CONSTRUCTION COST ($x10^9)			
PIPE DIAMETER	NO. OF PUMP STATIONS		
	0	1	2
48	5.02	5.90	6.27
52	6.35	7.40	7.72
56	8.61	9.95	10.42

Annual operating and maintenance costs are $26.75 million with no pump stations, $35.70 million with one pump station and $45.65 million with two pump stations.

Chapter 8: Transportation System Evaluation

Fourteen transportation scenarios, summarized in Tables 2.1 and 2.2, were identified in the 1986 study which can be grouped into four categories:

- All Pipeline (Scenarios 1, 2, and 3)
- All Tanker (Scenarios 12, 13, and 14)
- Tanker to Pipeline (Scenarios 7 and 8)
- Pipeline to Tanker (Scenarios 4, 5, 6, 9, 10, and 11)

Chapter 8 evaluates each transportation scenario by calculating the present value of the crude oil transportation cost per barrel at flowrates of 100, 200, 400, and 600 MBPD. This present value is based on a life of 20 years and an annual discount rate of 10 percent.

Each of the transportation scenarios was evaluated for the following five cases:

- Central field location, conventional dredging/trenching equipment used for pipeline trenching and no tanker escort vessels required
- Central field location, conventional dredging/trenching equipment used for pipeline trenching with tanker escort vessels required
- Central field location, linear trencher developed for pipeline trenching with tanker escort vessels required
- Southern field location, linear trencher developed for pipeline trenching with tanker escort vessels required
- Northern field location, linear trencher developed for pipeline trenching with tanker escort vessels required

For each case, Scenario 1 provides the lowest cost per barrel for flowrates of 100 and 200 MBPD and Scenario 10 provides the lowest cost per barrel for flowrates of 400 and 600 MBPD.

The average cost per barrel for each type of transportation scenario (all pipeline, all tanker, tanker to pipeline, and pipeline to tanker) are as follows:

COST PER BARREL (US$/BARREL)				
SCENARIO TYPE	MAXIMUM FLOWRATES (MBPD)			
	100	200	400	600
All Pipeline	7.45	5.20	3.69	3.58
Pipeline to Tanker	9.87	5.39	3.59	3.00
Tanker to Pipeline	14.46	7.62	4.48	3.43
All Tanker	11.19	6.21	4.56	3.93

The above per barrel costs are based on the central Chukchi Sea field location, development of a linear trencher for pipeline trenching, and the use of tanker escort vessels.

For peak flowrates less than 200 MBPD, Scenario 1, Drawing No. 201, is recommended. Scenario 1 consists of a 214-mile long offshore pipeline from the field location to an onshore pump station at Point Barrow and a pipeline (194 miles off-shore and 34 miles onshore) from Point Barrow to the Trans-Alaskan Pipeline System (TAPS) at Pump Station Number 1. The TAPS is then used to transport the crude oil to the existing tanker terminal at Valdez.

For peak flowrates of approximately 400 MBPD, Scenario 5, Drawing No. 202, is recommended. Scenario 5 consists of a 32-inch, 183 mile long offshore pipeline from the field to a pump station at Cape Lisburne. From Cape Lisburne, the crude is transported 57 miles to a nearshore tanker terminal at Kivalina via a 26-inch diameter onshore pipeline. From Kivalina, crude oil is then transported to a trans-shipment terminal at Unimak Pass using a fleet of three 200,000 dwt arctic Class 6 tankers.

Of the original 14 transportation scenarios, Scenario 6, Drawing No. 203, is recommended for peak flowrates of 600 MBPD. Scenario 6 consists of a 183-mile long, 38-inch diameter offshore pipeline from the field to a pump station at Cape Lisburne. From Cape Lisburne, the crude is transported 57 miles to a pump station at Kivalina via a 30-inch diameter onshore pipeline. From Kivalina, a 38-inch diameter pipeline (113 miles of offshore pipeline and 107 miles of onshore pipeline) transports the crude oil to a nearshore tanker terminal at Nome. From Nome, the crude oil is then transported to a trans-shipment terminal at Unimak Pass using a fleet of four 200,000 dwt arctic Class 4 tankers.

However, a 48-inch diameter direct offshore pipeline, Drawing No. 204, from the central field to Unimak Pass is recommended for peak flowrates of approximately 400 to 800 MBPD. In addition to reduced costs per barrel, this scenario also eliminates arctic tankers and arctic tanker terminals. For peak flowrates greater than 800 MBPD, a 52-inch or 56-inch diameter direct offshore pipeline is recommended depending on the required maximum peak flowrate.

1.2 RECOMMENDATIONS

Based on the findings of this study, an all pipeline system to Prudhoe Bay (TAPS PS1), which incorporates the existing TAPS system, is recommended for transporting peak flowrates equal to 200 MBPD or less. For peak flowrates greater than 400 MBPD, a direct offshore pipeline to Unimak Pass is recommended. For intermediate flowrates between 200 and 400 MBPD, a pipeline to Kivalina or Nome with tanker transportation to Unimak Pass is recommended.

- All pipeline scenario from the field location to TAPS PS1
- Pipeline to tanker scenarios that use arctic Class 4 or 6 tankers
- Direct offshore pipeline to Unimak Pass

It was indicated in recent meetings with the MMS and other participants in the region that a direct offshore pipeline from the Chukchi Sea to Unimak Pass could possibly be the only politically viable solution due to the following reasons:

- The increasing inability to obtain permits for overland pipelines in the region
- The political perception of oil tankers and their environmental impact to the region
- The availability of space in TAPS in the near future (10 - 20 years)

The two factors that will most likely influence the final method chosen for transporting crude oil from the Chukchi Sea will be the feasibility of locating a trans-shipment terminal at Unimak Pass or Valdez, and possible future governmental regulations affecting offshore pipeline and tanker operations in arctic regions.

TABLE 2.1

TRANSPORTATION SYSTEM SUMMARY

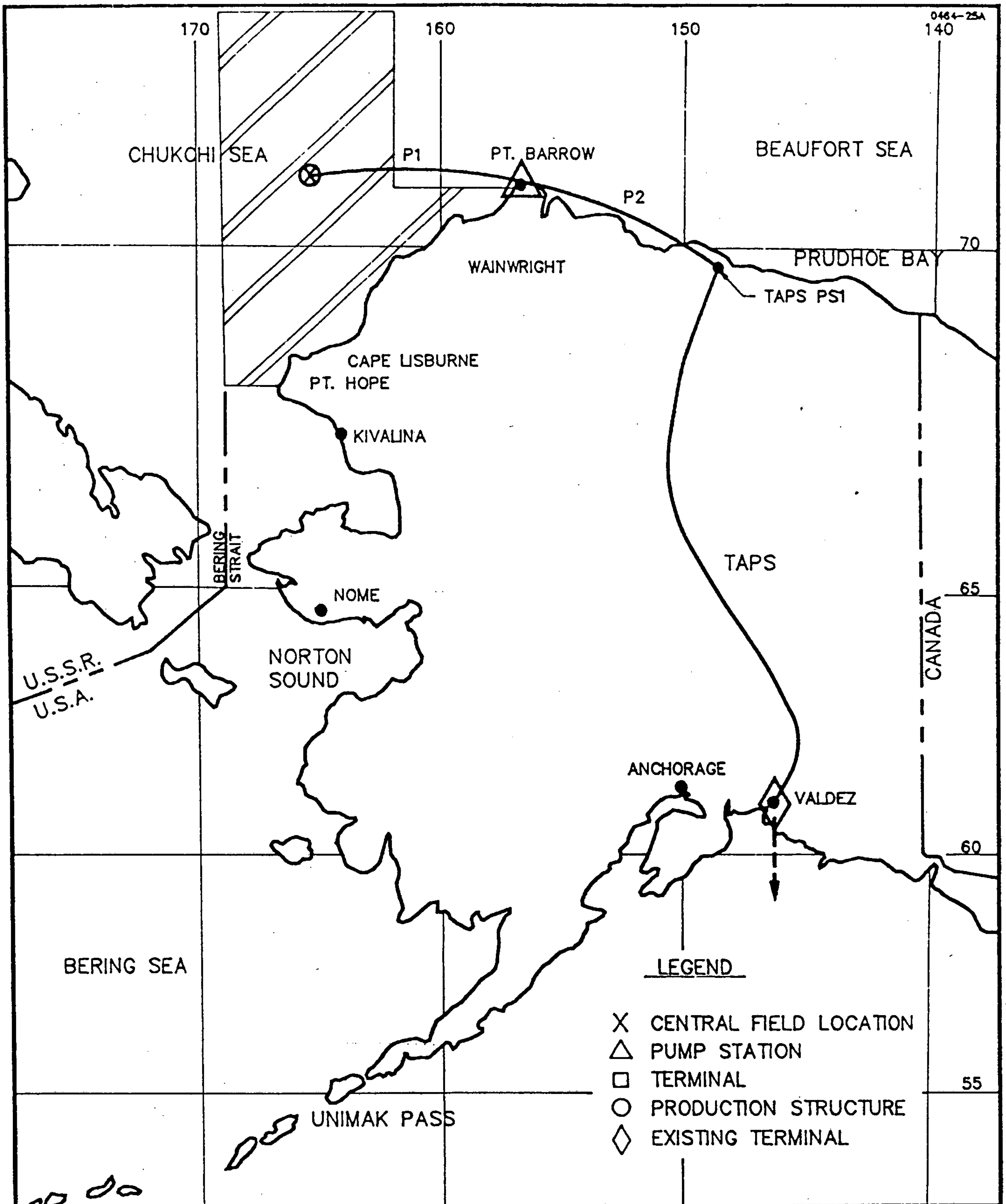
SCENARIO DESIGNATION		SCENARIO DESCRIPTION
1986 STUDY	1990 STUDY	
1A	1	All Pipelines (Drawing No. 801)
1B	2	All Pipelines (Drawing No. 802)
1C	3	All Pipelines (Drawing No. 803)
3A	4	Pipeline to Tanker (Drawing No. 804)
3B	5	Pipeline to Tanker (Drawing No. 805)
3C	6	Pipeline to Tanker (Drawing No 806)
4A	7	Tanker to Pipeline (Drawing No. 807)
4B	8	Tanker to Pipeline (Drawing No. 808)
6A	9	Pipeline to Tanker (Drawing No. 809)
6B	10	Pipeline to Tanker (Drawing No. 810)
6C	11	Pipeline to Tanker (Drawing No. 811)
2A	12	All Tankers (Drawing No. 812)
2B	13	All Tankers (Drawing No. 813)
5	14	All Tankers (Drawing No. 814)

TABLE 2.2

TRANSPORTATION SCENARIO COMPONENT SUMMARY

SCENARIO	PIPELINE ROUTES	TANKER ROUTES	TERMINAL TYPE			
			NEARSHORE	OFFSHORE	TRANS-SHIPMENT	PRODUCTION STRUCTURE
1	P1, P2	N/A	N/A	N/A	N/A	Yes
2	P3, P4	N/A	N/A	N/A	N/A	Yes
3	P5, P6	N/A	N/A	N/A	N/A	Yes
4	P3	T6	AT WAINWRIGHT	N/A	Yes	Yes
5	P5, P7	T8	AT KIVALINA	N/A	Yes	Yes
6	P5, P7 P8	T10	AT NOME	N/A	Yes	Yes
7	P4	T1	AT WAINWRIGHT	Yes	N/A	N/A
8	P6	T2	AT CAPE LISBURNE	Yes	N/A	N/A
9	P3	T7	AT WAINWRIGHT	N/A	N/A	Yes
10	P5, P7	T9	AT KIVALINA	N/A	N/A	Yes
11	P5, P7 P8	T11	AT NOME	N/A	N/A	Yes
12	N/A	T4	N/A	Yes	Yes	N/A
13	N/A	T5	N/A	Yes	N/A	N/A
14	N/A	T3, T10	AT NOME	Yes	Yes	N/A

N/A: Not Applicable

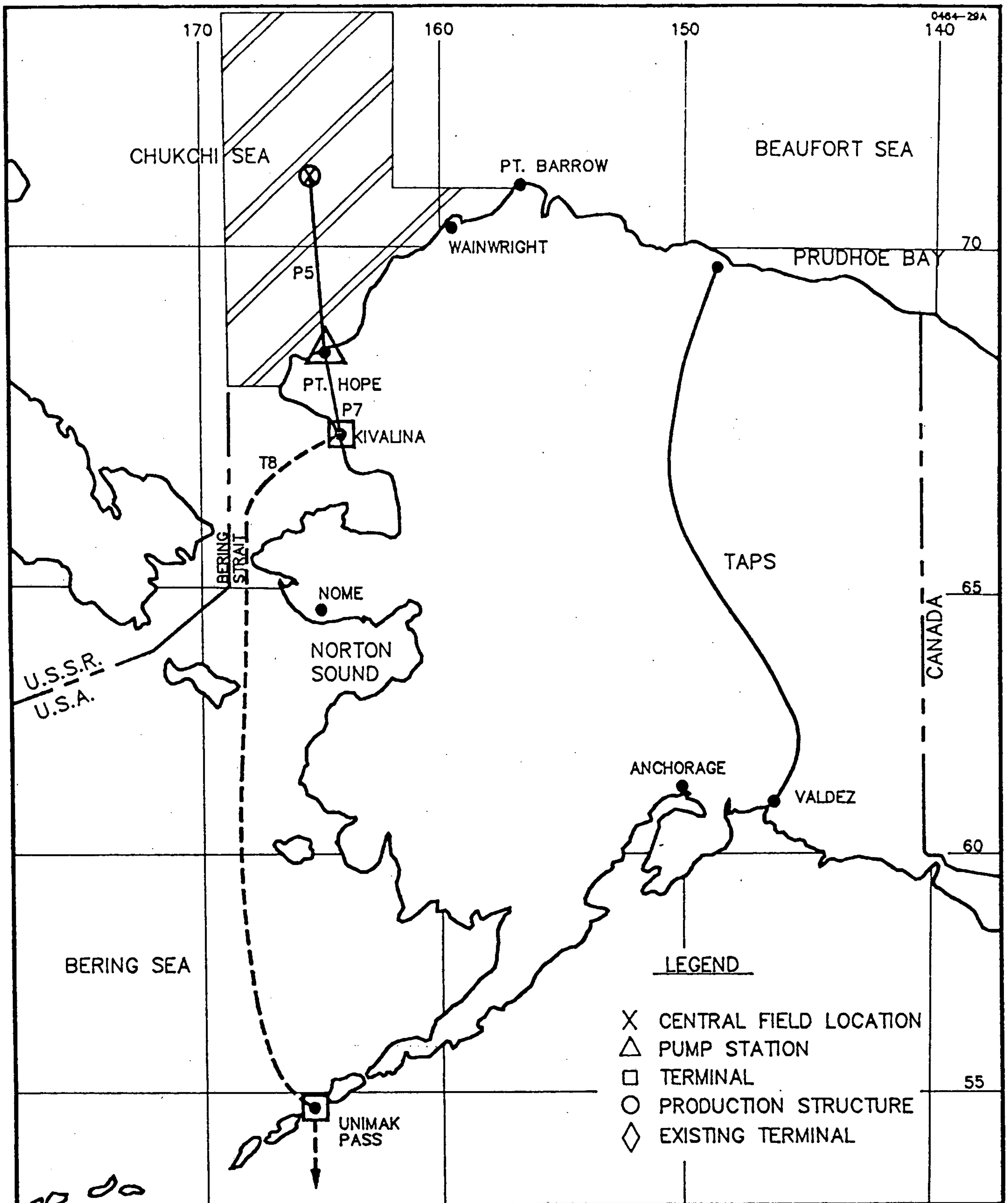


JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

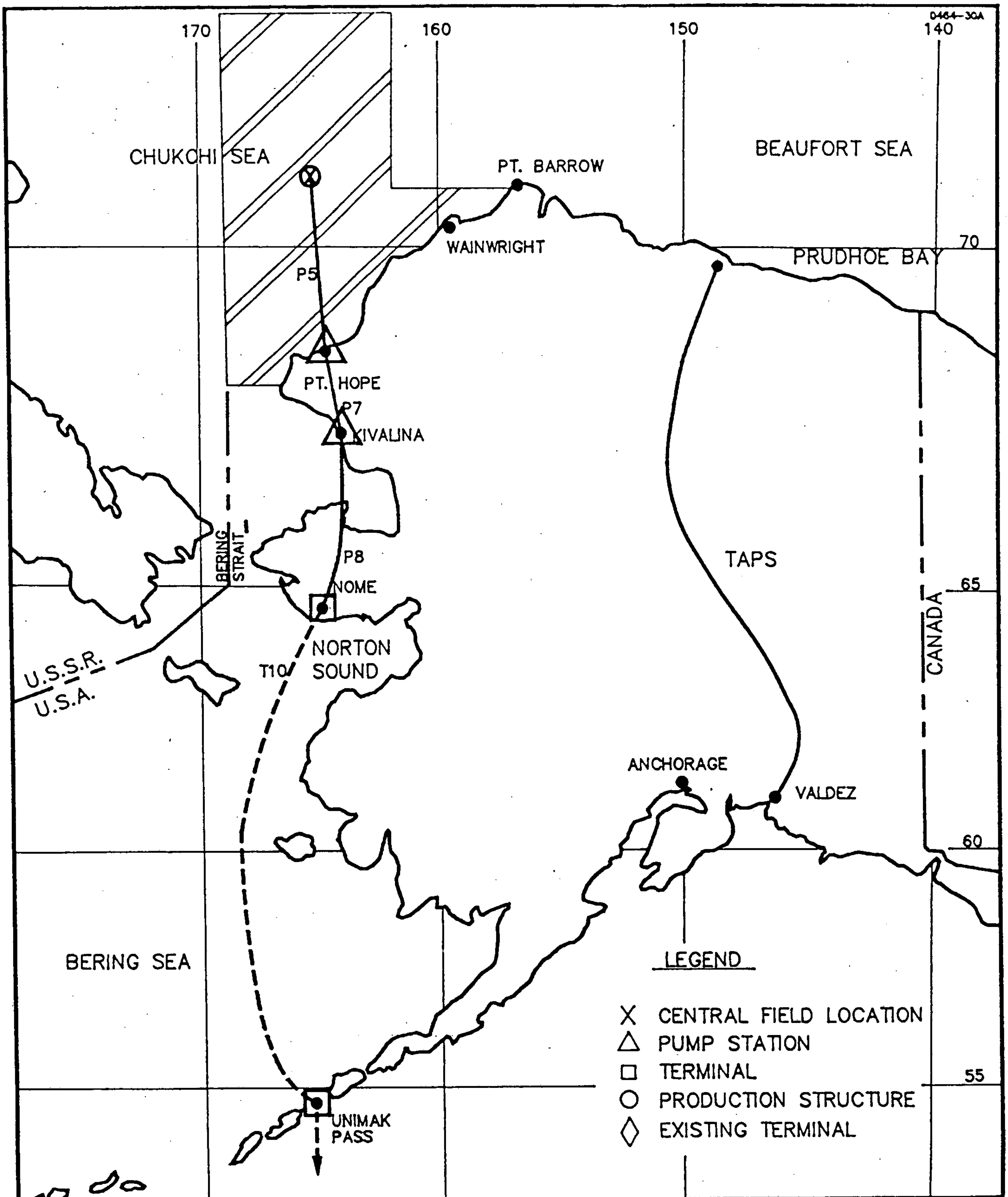
CHUKCHI SEA
TRANSPORTATION SCENARIO 1

INTEC ENGINEERING, INC.

SCALE	DRAWN BY	DRAWING NO.
NONE	KC	201
DATE	JOB NO.	
12-20-90	H-046.4	

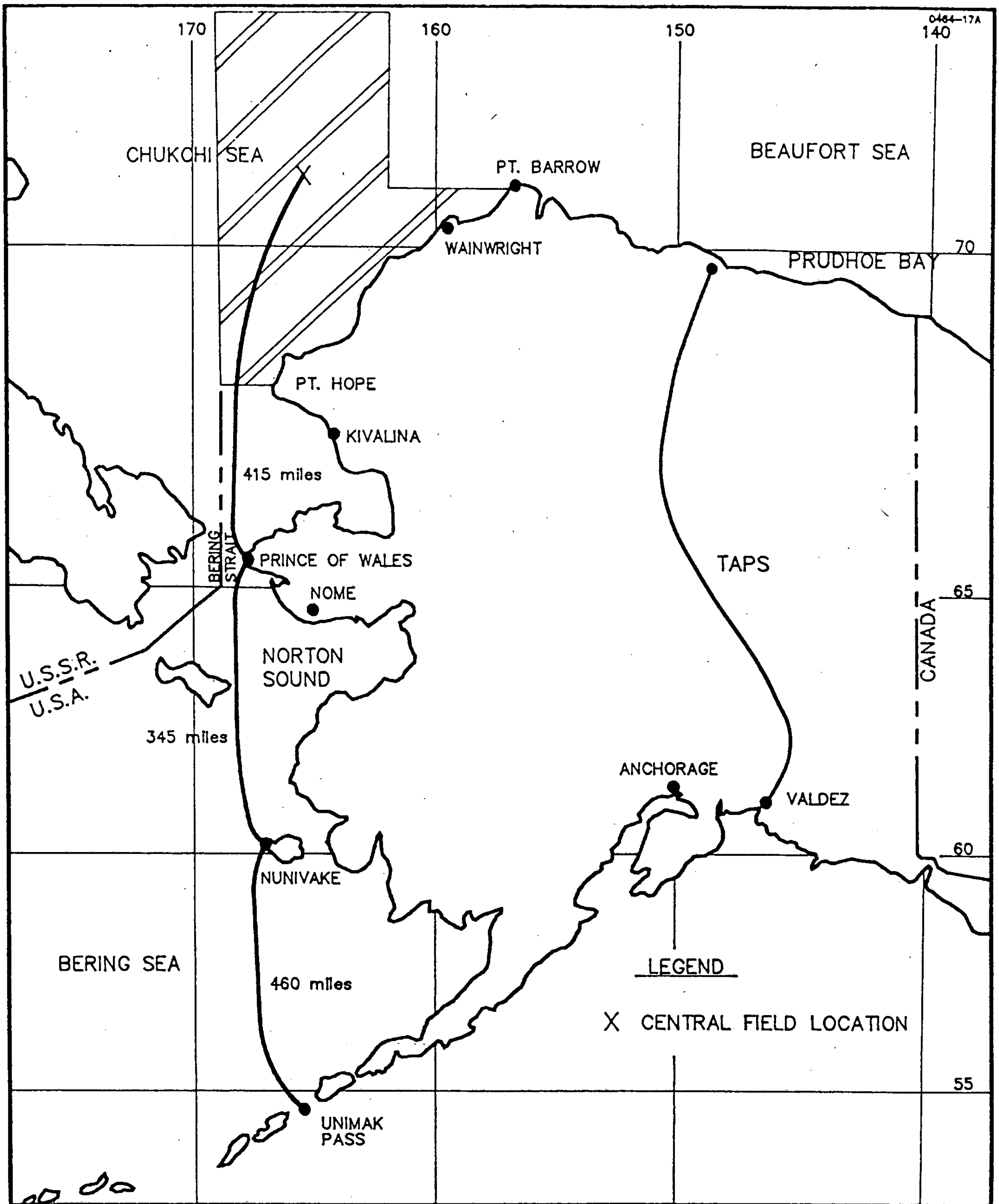


JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 5		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 202
	DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 6

INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 203
	DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA OFFSHORE PIPELINE WITH 2 PUMP STATIONS

INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 204
	DATE 1-9-91	JOB NO. H-046.4	

CHAPTER 3

ENVIRONMENTAL CONDITIONS

CHAPTER 3
ENVIRONMENTAL CONDITIONS

3.1 GENERAL

As stated in the 1986 transportation study, environmental conditions in the Lease Sale 126 area and along the potential crude oil transportation routes will have a major influence on the technical feasibility and costs for each proposed transportation system. The presence of sea ice is the single most important environmental consideration. However, the meteorological, oceanographic and geotechnical conditions will also affect the different components of each potential transportation system.

The objective of this chapter is to summarize the environmental conditions presented in the 1986 report and highlight any important changes to these conditions that would have a significant impact on the transportation system evaluations and conceptual designs. To achieve this objective, a detailed literature search of all publicly available research and data gathering programs was conducted. Numerous state and federal government agencies including state universities and other potential data sources were contacted to determine the extent of data gathering, data reduction and reported research results since the 1986 study. Data, if any, and results thereof were compared to the original data base developed for the 1986 study, and changes, if any, are noted in the following sections.

3.2 PHYSICAL DESCRIPTION OF LEASE SALE 126 AREA

The Lease Sale 126 area (Drawing No. 301) is located in the Chukchi Sea. As was the case with Lease Sale 109, it is bounded to the north by the 73rd parallel and to the south by a line extending westward from Point Hope. The boundary to the west is the USA-USSR Convention Line of 1867 (approximate longitude 169°W) The east boundary is the 162°W meridian extending down to latitude 71°N where the boundary traverses eastward until it reaches the three (3) mile state territorial limit off the Alaska coast.

Water depths in the lease sale area range from approximately 30 feet nearshore to 300 feet at the northern boundary. The seabed gradually slopes to the deeper water depths in the northwest portion of the lease sale area. At the western boundary, and for much of the central portion, the water depth is approximately 120 feet.

3.3 SEA ICE CONDITIONS

Sea ice conditions have a dominant effect on the design, construction and operation of crude oil transportation systems within the study area. Ice conditions important to the proposed offshore pipelines, tankers and terminals have been prepared by DF Dickins Associates, Ltd, and are presented in Appendix A.

The updated ice data which are contained in Appendix A provide an adequate basis for the preliminary design and construction/operation planning of pipelines, tankers and tanker terminals within the Lease Sale 126 area. Conditions summarized in the report include:

- Seasonal ice retreat and advance patterns
- Recurrent ice embayments during summer ice retreat

* Open water season durations based on several different criteria
* Multi-year ice conditions
* Winter contiguous ice zone extent

Sea ice conditions within the Lease Sale 126 area, and along potential tanker routes through the Bering Sea, are summarized for nine representative ice zones. Monthly tabulations present available data on total ice concentrations, multi-year ice concentrations, first year ice concentrations, level first year ice thicknesses, snow depths and pressure ridge heights and frequencies. Additional data to support tanker transit simulations is summarized in the report by DF Dickins and includes:

* Recurring flaw polynyas and lead systems
* Tanker routing through leads and thin first year ice
* Ice roughness
* Ice motions
* Ice floe sizes

3.4 METEOROLOGICAL CONDITIONS

In summary, the meteorological design conditions for the lease sale area have not changed since the previous study.

3.4.1 Wind

Wind condition summaries are presented in Tables 3.1 through 3.3. These are based on meteorological observations reported by international vessels operating in the Chukchi Sea, and observations at coastal weather stations.

3.4.2 Air Temperature

Air temperatures in the Lease Sale 126 area are tabulated in Table 3.4

3.4.3 Visibility

The average observed frequencies of reduced visibility and a record of the persistency of low visibility in the Lease Sale 126 area are presented in Table 3.5.

3.5 OCEANOGRAPHIC CONDITIONS

In summary, the oceanographic design conditions for the lease sale area have not changed since the previous study.

3.5.1 Waves

Table 3.6 presents the significant wave heights as a function of occurrence by month, and the predicted extreme significant and maximum wave heights are presented in Table 3.7.

3.5.2 Currents

In the Bering Strait, strong northward currents occur on the east side near Cape Prince of Wales, and in the uppermost 100 feet of the water column. Velocities of 3.4 feet per second are common, but 10 feet per second northward currents have been observed. Over the south Bering Shelf where wind stresses and tidal forces are dominant, current velocities of 1 foot per second are common with current velocities of 2 feet per second being rare in occurrence. Currents flowing through the Aleutian passes infrequently reach 3.4 feet per second.

Extreme current events in the Lease Sale 126 area are associated with storm surges. Along the northeast Chukchi Sea coast, significant surge events are produced during the occurrence of west and northwest winds of several hours duration. Wind drift current and geostrophic storm surge current velocities (Ichiye, 1969) were calculated for extreme wind speeds having average return periods of 2, 10, 25 and 100 years. The resulting current velocities are presented in Table 3.8.

3.5.3 Sea Water Temperature

The minimum, average and maximum monthly sea water temperatures in the Chukchi Sea are presented in Table 3.9.

3.5.4 Tidal Conditions

The predicted extreme combined storm surge and astronomical tides are presented in Table 3.10.

3.6 SOIL CONDITIONS

In summary, the design soil conditions for the Lease Sale Area have not changed since the 1986 study. However, it should be noted that Fugro-McClelland have conducted a soil boring investigation of the area, but the results are only available to those companies who sponsored the investigation.

3.6.1 Surficial Sediments

As described in the previous study, sediment gradations in the Chukchi Sea range from sandy gravel nearshore to sandy clayey silt offshore. Between Cape Lisburne and Point Barrow, the entire nearshore area consists of sand with sandy gravel coastal barrier islands.

Coarse sediments consisting mainly of sand and gravel are also found on, and around, Herald Shoal in the Central Chukchi Shelf. Herald Shoal is bordered on the east and west by narrow channels mantled with clayey silty sand. Seaward from the Alaskan coast, sediments gradually become progressively finer, consisting of mainly clayey sandy silt. The sediments with a predominant silt fraction cover large offshore areas west of Point Hope and northwest of Point Barrow.

Drawings No. 302 to 305 indicate that grain size is related to water depth and that sandy, clayey silts are mainly deposited in water depths greater than 150 feet. Drawings Nos. 302, 303 and 304 indicate the soil weight percentage of sand, silt and clay, respectively. Drawing No. 305 provides the mean size distribution of sediments in the Chukchi Sea shelf.

3.6.2 Stratigraphy

Most of the Lease Sale 126 area is a very flat continental shelf with limited sediment input from rivers or other sources. There is only a thin veneer of recently deposited sediment covering the underlying, older Cretaceous age strata.

In portions of the nearshore area west of Point Barrow, the Alaska coastal current has eroded the surficial sediment exposing outcrops of the erosion-resistant Cretaceous strata (Phillips and Reiss, 1985). A thin cover of sediment (less than 3 feet) may surround these outcrops and in some areas this layer thickens to approximately 33 feet. Apparent northwest dipping Cretaceous strata are identified throughout the nearshore area from sub-bottom profiles.

Further southwest, along the coast to Blossom Shoals (offshore of Icy Cape), varying thicknesses of younger Quaternary sediments have been observed. A maximum sand thickness of over 50 feet is reported in Blossom Shoals. Locally, thick Quaternary sediments may also be found in areas where old channels had been cut in the Cretaceous strata.

The underlying erosion-resistant Cretaceous strata has been described as "bedrock" where it outcrops near Point Barrow (Phillips and Reiss, 1985). Geotechnical properties of samples obtained from five deep soil borings in the offshore portion of the Lease Sale 126 area are presented on Drawing Nos. 306 and 307 (Winters and Lee, 1984). Based on this information, the underlying soil throughout the Lease Sale 126 area is assumed to vary from very stiff cohesive to dense granular soil.

3.6.3 Ice Gouges

As stated in the previous report, Barnes and Reimnitz (1974) reported that surficial sediment on the entire shelf of the Chukchi Sea, including shore areas, appears to be dominated by ice processes during the winter season. This observation was confirmed by the U.S. Geological Survey reconnaissance survey (Toimil, 1978) of ice gouges in the eastern Chukchi Sea. The survey concluded the following:

- Maximum ice gouge depths were generally observed between water depths of 115 and 165 feet.

- A maximum ice gouge depth of 15 feet was encountered at water depths of between 115 and 130 feet near Hanna Shoal.

- In water depths greater than 165 feet, gouge densities were generally less than 80 gouges per mile.

- The maximum water depth at which an ice gouge was observed is 190 feet.

During the survey, it was also observed that ice gouge density increases with decreasing water depth, increasing seabed slope gradient and decreasing latitude, and that ice gouging occurs at least as far south as Cape Prince of Wales.

The areal distribution of maximum ice gouge densities for complete survey route segments are plotted on Drawing No. 308. Maximum observed ice gouge depths within the lease sale area are shown on Drawing No. 309.

3.7 DESIGN CRITERIA SUMMARY

Based on a review of the 1986 report, and recent environmental studies which have indicated no significant changes in environmental conditions, the following 100-year average return period environmental design criteria were used:

Oceanographic	
Water Depth, MLLW (feet)	140
Significant Wave Height (feet)	29
Maximum Wave Height (feet)	54
Significant Wave Period (seconds)	12.2
Maximum Surface Current (feet/second)	5
Maximum Near Bottom Current (feet/second)	2.3
Rise in Sea Level	
Storm Surge (feet)	6.5
Astronomical Tide (feet)	0.5
Total Rise (feet)	7
Maximum Wind Speed	
3-Second Gust (knots)	106
1 Minute Sustained (knots)	90
Temperature	
Maximum Air Temperature (°F)	80
Minimum Air Temperature (°F)	-56
Maximum Water Temperature (°F)	53
Minimum Water Temperature (°F)	28.5
Visibility	
Maximum Duration of Visibility of Less Than 2 miles (hours)	96

The environmental operating criteria for the Lease Sale 126 area have not changed and are summarized in Table 3.11, based on a 2-year return period and 140 foot water depth, and are extreme values for the month that controls. The maximum values are exceeded approximately one percent of the time while the minimum values are exceeded 99 percent of the time.

TABLE 3.1

AVERAGE PERCENTAGE FREQUENCY OF OCCURRENCE OF

WIND DIRECTION BY MONTH

LEASE SALE 126 AREA

MONTH	WIND DIRECTION ± 22.5 DEGREES								
	N	NE	E	SE	S	SW	W	NW	CALM
JAN*	4	17	22	13	9	10	12	11	2
FEB*	8	22	24	7	7	10	12	8	2
MAR*	8	23	23	10	5	10	11	7	2
APR*	8	25	26	10	8	8	7	7	1
MAY*	8	22	32	12	6	6	6	6	1
JUN*	8	16	36	10	5	7	10	7	1
JUL	11	21	20	6	7	10	14	7	4
AUG	9	16	24	9	7	7	13	11	4
SEP	8	14	24	7	4	7	14	17	5
OCT*	6	32	25	15	13	6	6	6	1
NOV*	4	22	29	13	11	7	7	6	1
DEC*	6	24	21	9	9	10	11	7	3
ANNUAL	8	20	26	10	8	8	10	8	2

NOTES:

* Estimates based on Barrow, Alaska data.
(1)Data after Brower et al., 1977

TABLE 3.2

AVERAGE PERCENTAGE FREQUENCY OF OCCURRENCE OF

WIND SPEED GROUPS BY MONTH

LEASE SALE 126 AREA

	WINDS SPEED GROUPS (KNOTS)								
MONTH	CALM	1-6	7-10	11-16	17-21	22-27	28-33	34-40	> 41	AVG
JAN*	2	26	34	23	10	4	1	0	0	10.3
FEB*	2	33	35	19	7	3	1	0	0	9.2
MAR*	2	25	38	24	8	2	1	0	0	9.9
APR*	1	24	37	26	4	3	0	0	0	10.0
MAY*	1	22	36	31	8	2	0	0	0	10.1
JUN*	1	17	39	32	7	1	0	0	0	10.1
JUL	4	20	30	29	10	5	2	1	0	11.0
AUG	4	24	26	27	10	6	2	1	0	10.9
SEP	5	17	21	16	14	10	3	1	1	13.1
OCT*	1	11	28	32	14	9	3	1	1	14.1
NOV*	1	20	29	28	14	7	1	0	0	11.8
DEC*	3	32	31	22	8	3	1	0	0	9.5
ANNUAL	2	23	32	27	10	5	1	0	0	10.8

NOTES:

* Estimates based on Barrow, Alaska data.
(1)Data after Brower et al., 1977

TABLE 3.3

PREDICTED ANNUAL EXTREME WIND SPEEDS

OCCURING IN THE LEASE SALE 126 AREA (KNOTS)

	WIND DURATION				
AVERAGE RETURN PERIOD (YRS)	3 SEC GUSTS	1 MIN	2 HOURS	4 HOURS	6 HOURS
2	51	43	33	31	30
5	61	52	40	38	36
10	71	60	46	43	41
25	83	70	55	51	48
100	106	90	69	65	62

NOTE: Wind speeds predicted for 30 foot height above water surface.

TABLE 3.4

CHUKCHI SEA AIR TEMPERATURE[1]

MONTH	AIR TEMPERATURES		
	MINIMUM[2]	MEAN	MAXIMUM[3]
JAN-FEB	- 40	- 13	30
APR	- 22	1	34
JUL-AUG	28	42	59
OCT	0	19	37
ESTIMATED 100 YEAR EXTREMES[4]	- 56		80

NOTES:

[1]Sector center point coordinates: 70°N, 166°W
[2]Based on 99th percentile of exceedence
[3]Based on 1st percentile of exceedence
[4]Reference Brower et al, 1977

TABLE 3.5

AVERAGE FREQUENCY OF REDUCED VISIBILITY AND PERSISTENCY OF LOW VISIBILITY IN THE LEASE SALE 126 AREA

MONTH	AVERAGE FREQUENCY OF OCCURRENCE OF REDUCED VISIBILITY(1)(2)			PERSISTENCE OF LOW VISIBILITY EVENTS(3) (HOURS)		
	< 1/2 NAUTICAL MILES	< 1 NAUTICAL MILES	< 2 NAUTICAL MILES	< 1/2 NAUTICAL MILES	< 1 NAUTICAL MILES	< 2 NAUTICAL MILES
JAN	8	13	18	12	19	27
FEB	7	11	15	12	19	27
MAR	7	11	15	11	17	24
APR	6	10	14	8	13	18
MAY	6	10	14	7	11	15
JUN	6	10	14	7	11	15
JUL	7	11	15	7	11	15
AUG	7	11	15	7	11	15
SEP	5	8	11	7	11	16
OCT	5	8	11	6	11	14
NOV	8	12	17	12	19	27
DEC	8	12	17	11	17	24
ANNUAL	7	11	15	-	-	-

NOTES:

(1) Percentage of observations with visibility less than distance are noted.
(2) Frequency of observation of < 1/2 mile and < 1 mile visibility events are approximately 45% and 70%, respectively, of indicated < 2 mile visibility event frequencies.
(3) Based on 95th percentile, 95 percent of the events (occasions with visibility less than 2 miles) have durations less than the persistence indicated.

TABLE 3.6

AVERAGE PERCENTAGE FREQUENCY OF OCCURENCE OF

SIGNIFICANT WAVE HEIGHTS BY MONTH

LEASE SALE 126 AREA

	WAVE HEIGHT (FEET)						
	0 - 2	2 - 4	4 - 6	6 - 8	8 - 10	10-15	15+
JUN	100	0	0	0	0	0	0
JUL	70	15	8	4	2	1	0
AUG	42	31	14	8	3	1	1
SEP	25	29	20	14	7	3	2
OCT	23	32	20	14	7	3	1
NOV	100	0	0	0	0	0	0
JUL-OCT AVERAGE	30	31	18	12	6	2	1

NOTES:

Ice edge assumed to be located in mean position for years on record.

Sea ice rapidly attenuates wave conditions. Therefore, wave height percentages of occurrence are considered valid only for areas and years when large areas of open water exist.

TABLE 3.7

PREDICTED EXTREME WAVE HEIGHTS

OCCURRING IN THE LEASE SALE 126 AREA

(WATER DEPTH > 140 FEET)

AVERAGE RETURN PERIOD (YEARS)	SIGNIFICANT WAVE HEIGHT (FEET)	SIGNIFICANT WAVE PERIOD (SEC)	MAXIMUM WAVE HEIGHT[1] (FEET)
2	16.0	9.0	29.5
5	18.0	9.6	33.5
10	20.0	10.2	37.0
25	22.5	10.8	42.0
50	25.5	11.5	47.5
100	29.0	12.2	54.0

NOTE:

[1]Maximum wave height = 1.86 x significant wave height.

TABLE 3.8

PREDICTED EXTREME CURRENT VELOCITIES ALONG CHUKCHI SEA COAST

WATER DEPTH (FEET)	AVERAGE RETURN PERIOD (YEARS)	RESULTANT CURRENT (FT/SEC)	
		NEAR BOTTOM	SURFACE
30	2	2.2	3.0
30	10	3.9	4.8
30	25	5.4	6.4
30	100	7.9	9.0
75	2	1.0	2.2
75	10	1.8	3.3
75	25	2.6	4.3
75	100	4.1	6.0
100	2	0.7	2.1
100	10	1.3	3.1
100	25	1.9	3.9
100	100	3.0	5.3
140	2	0.5	2.1
140	10	1.0	3.0
140	25	1.5	3.7
140	100	2.3	5.0

TABLE 3.9

CHUKCHI SEA MONTHLY SEA WATER TEMPERATURES (°F)

SITE: 70°N, 166°W, WATER DEPTH 150 FEET

MONTH	MINIMUM	AVERAGE	MAXIMUM
JAN	28	28	29
FEB	28	28	29
MAR	28	28	29
APR	28	28	29
MAY	28	28	29
JUN	28	32	34
JUL	28	34	49
AUG	28	37	52
SEP	28	32	50
OCT	28	29	43
NOV	28	29	30
DEC	28	28	29

TABLE 3.10

PREDICTED EXTREME COMBINED STORM SURGE AND ASTRONOMICAL TIDES FOR CHUKCHI SEA COAST

AVERAGE RETURN PERIOD (YEARS)	SHORELINE (FEET)	140 FOOT WATER DEPTH CONTOUR (FEET)
2	4.6	2.1
5	6.2	3.3
10	7.7	4.0
25	10.5	5.4
50	13.0	6.2
100	15.5	7.0

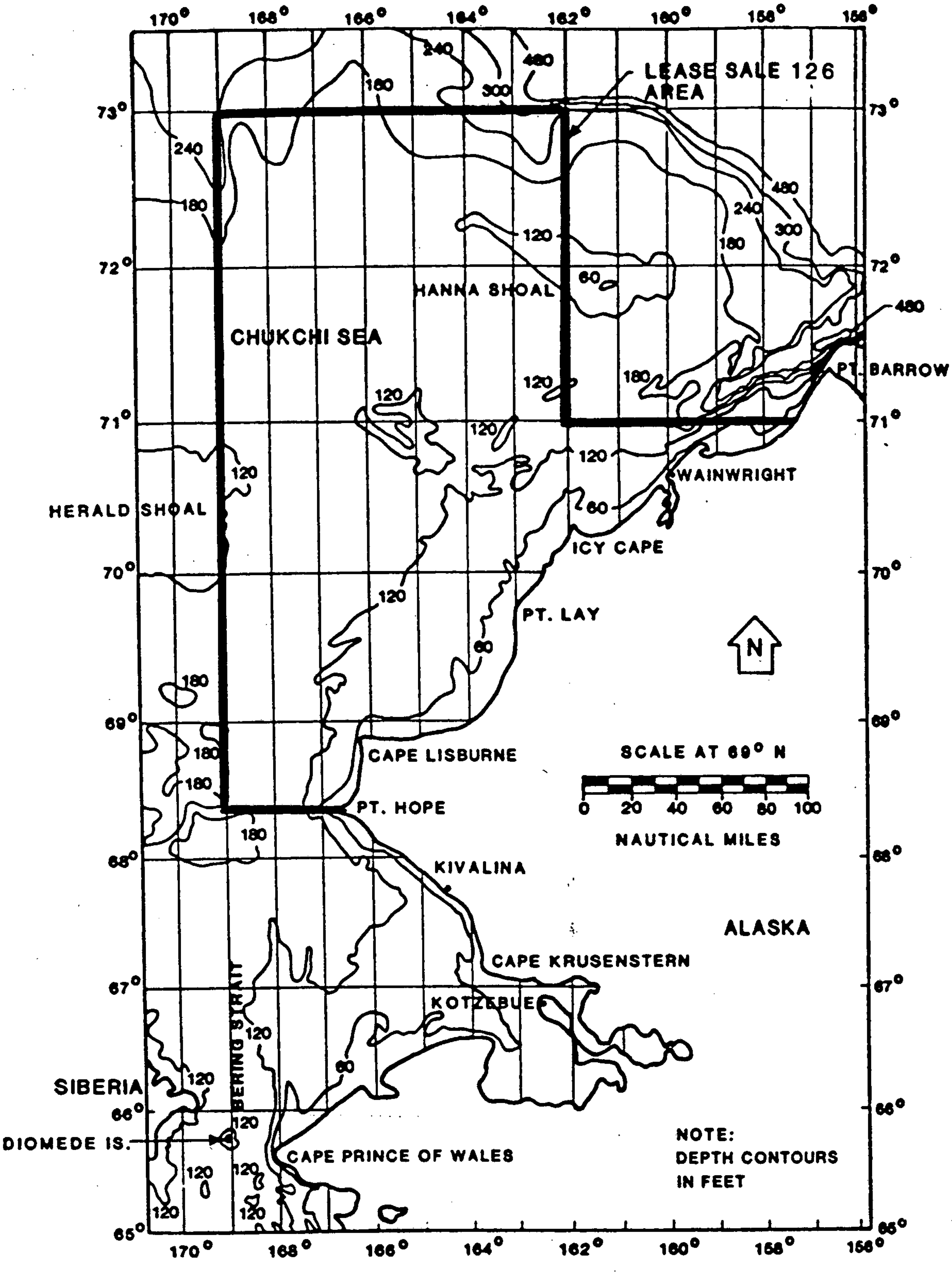
NOTE:

Tidal datum is Mean Lower Low Water (MLLW).

TABLE 3.11

ENVIRONMENTAL OPERATING CRITERIA

	DEC - FEB	MAR - MAY	JUN - AUG	SEP - NOV
OCEANOGRAPHIC				
% Freq. of Occurrence of Significant Wave Heights, H_s > 10 ft	0	0	2	6
% Freq. of Occurrence of Gale Force Winds (> 28 knots)	1	1	3	5
AIR TEMPERATURE				
99th Percentile (°F)	30	30	59	48
1st Percentile (°F)	-36	-36	28	-20
VISIBILITY				
Max. Duration of Visibility Less Than 1 Mile (hrs)	54	48	27	72
Freq. of Observation of Visibility < 2 miles (%)	18	15	15	17

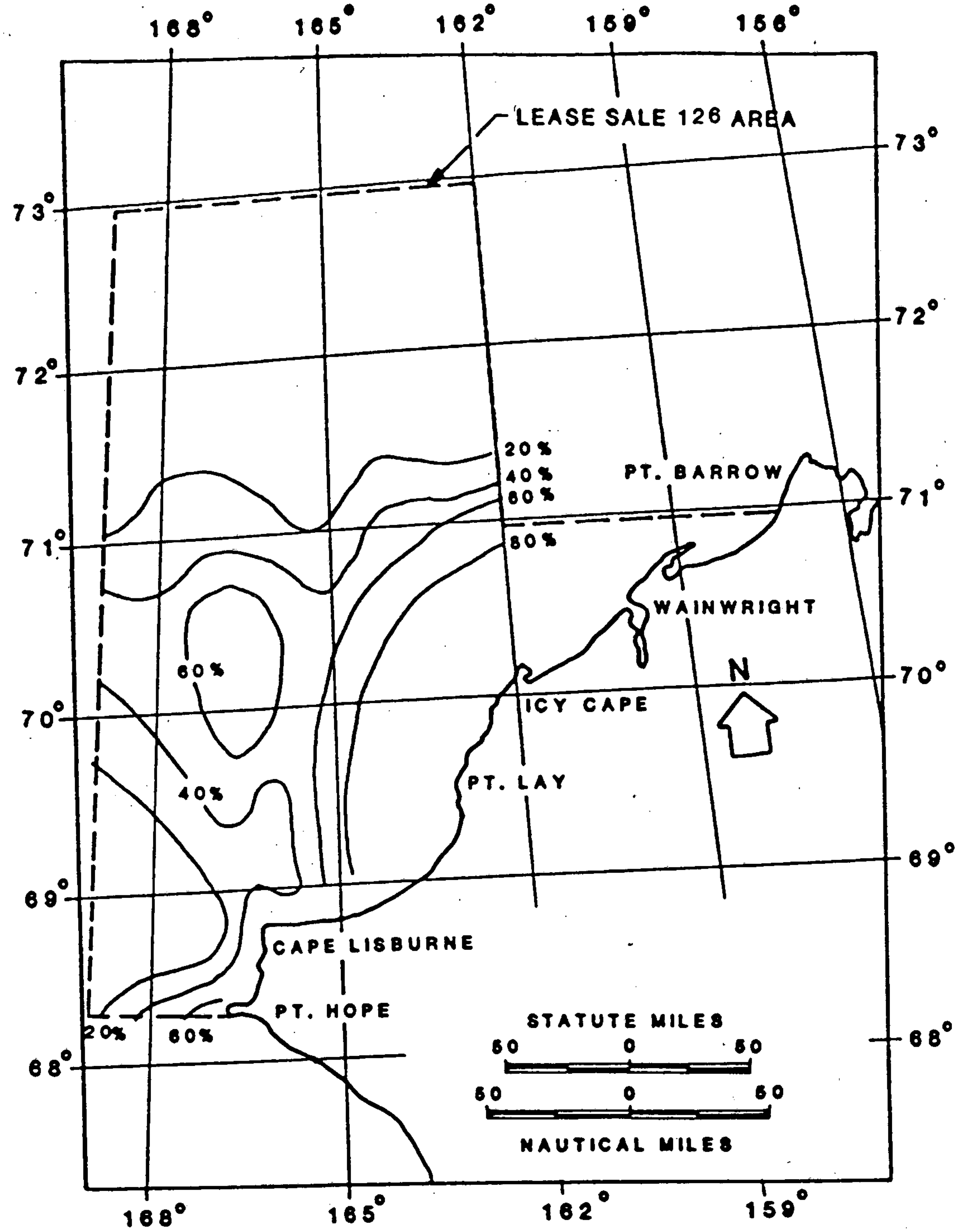


JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

LEASE SALE 126 AREA

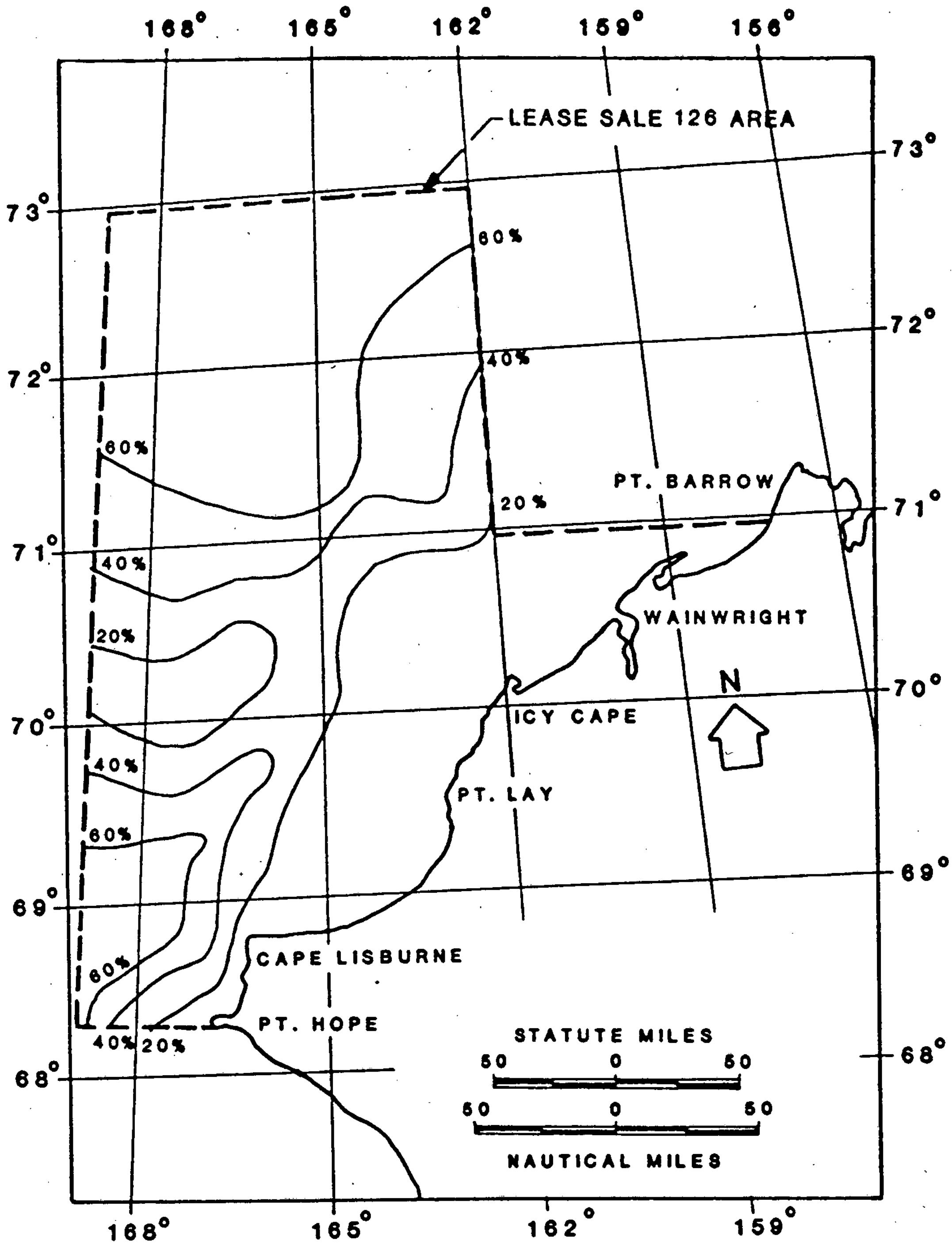
INTEC ENGINEERING, INC.

SCALE	DRAWN BY	DRAWING NO.
NONE	MN	301
DATE	JOB NO.	
1-18-91	H-046.4	



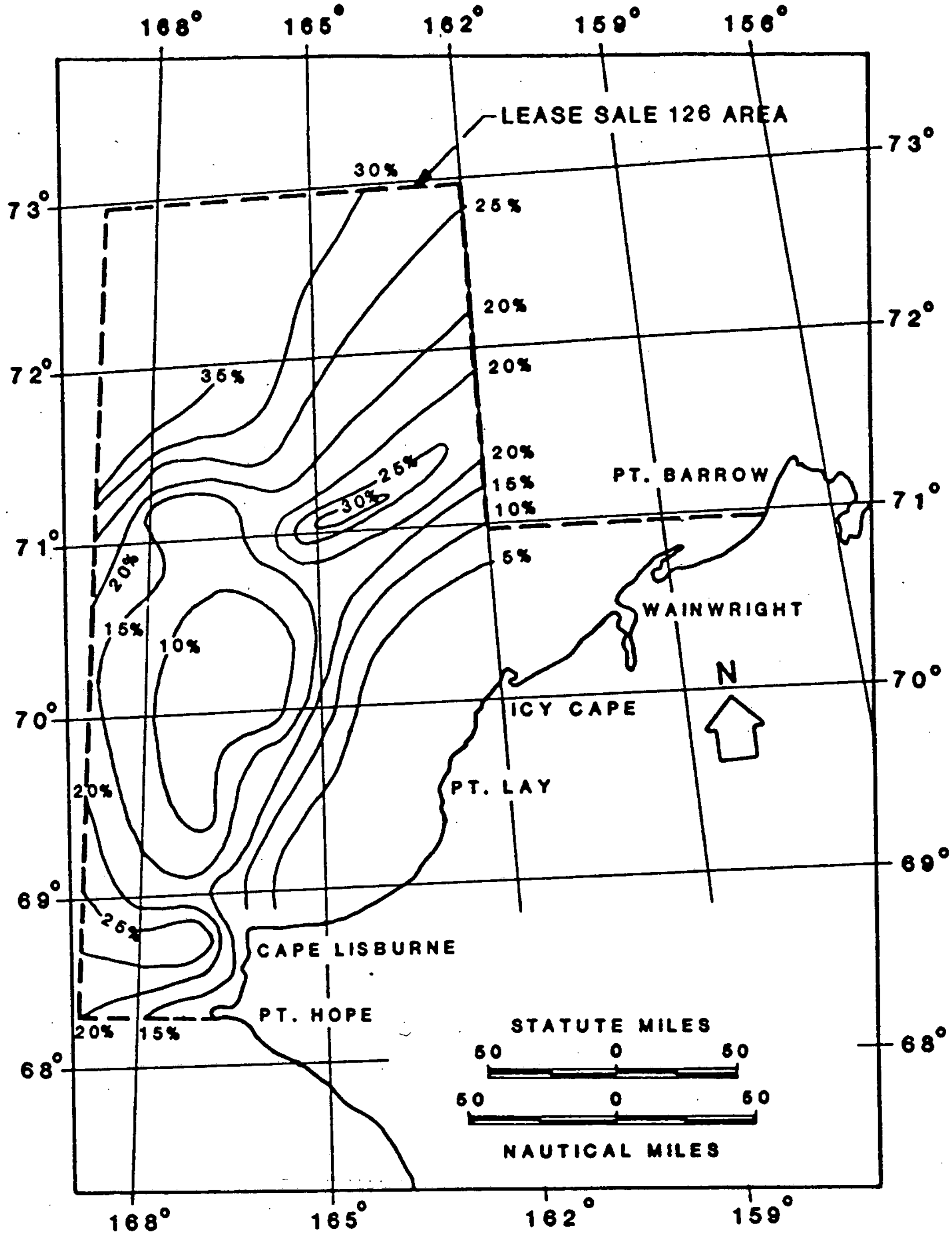
DATA AFTER: SHARMA 1979

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	WEIGHT PERCENT SAND IN SEDIMENTS		
INTEC ENGINEERING, INC.	SCALE 1:3,900,000 DATE 1-7-91	DRAWN BY MN JOB NO. H-046.4	DRAWING NO. 302



DATA AFTER: SHARMA 1979

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	WEIGHT PERCENT SILT IN SEDIMENTS		
INTEC ENGINEERING, INC.	SCALE 1:3,900,000 / DATE 1-7-91	DRAWN BY MN / JOB NO. H-046.4	DRAWING NO. 303



DATA AFTER: SHARMA 1979

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	WEIGHT PERCENT CLAY IN SEDIMENTS		
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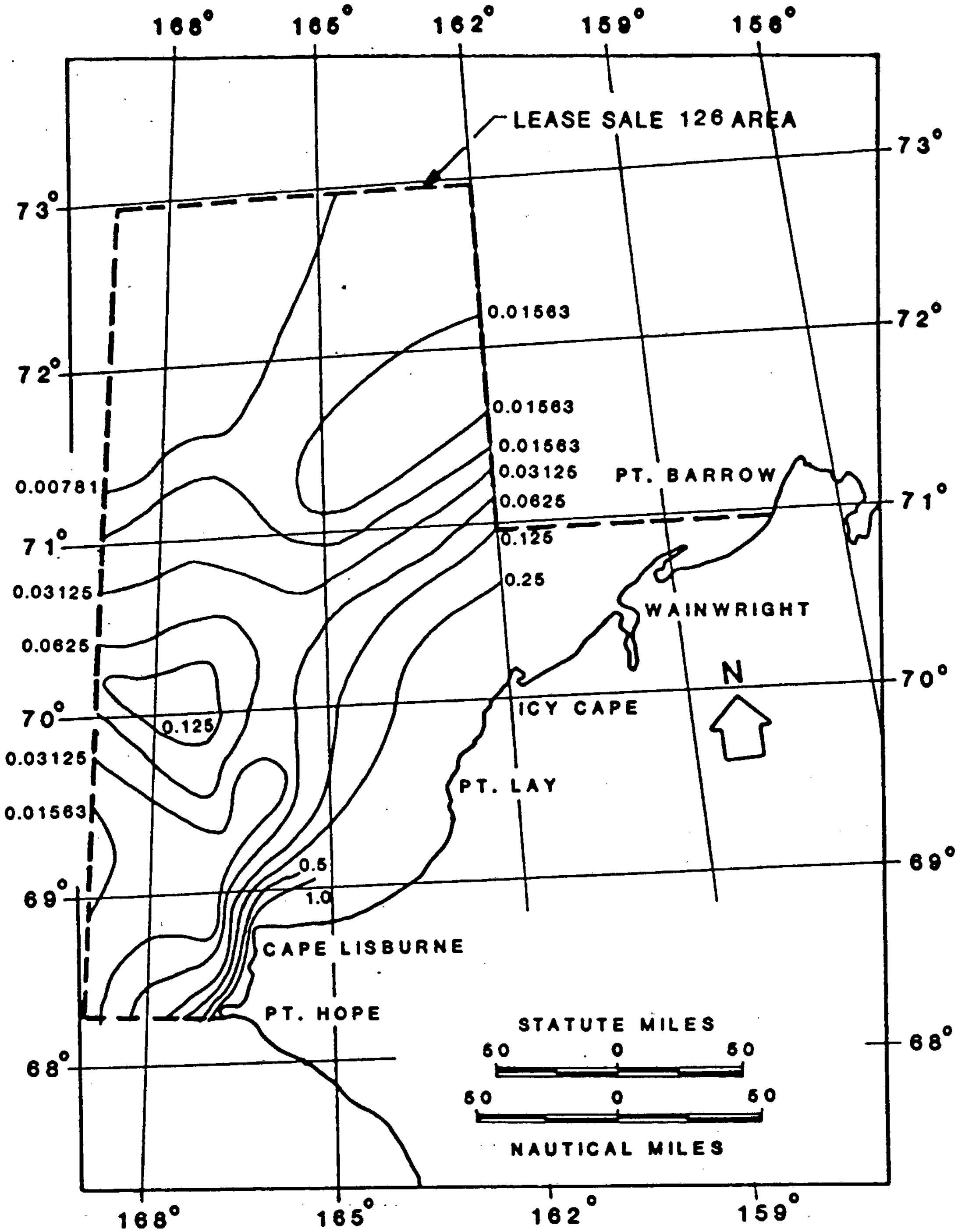
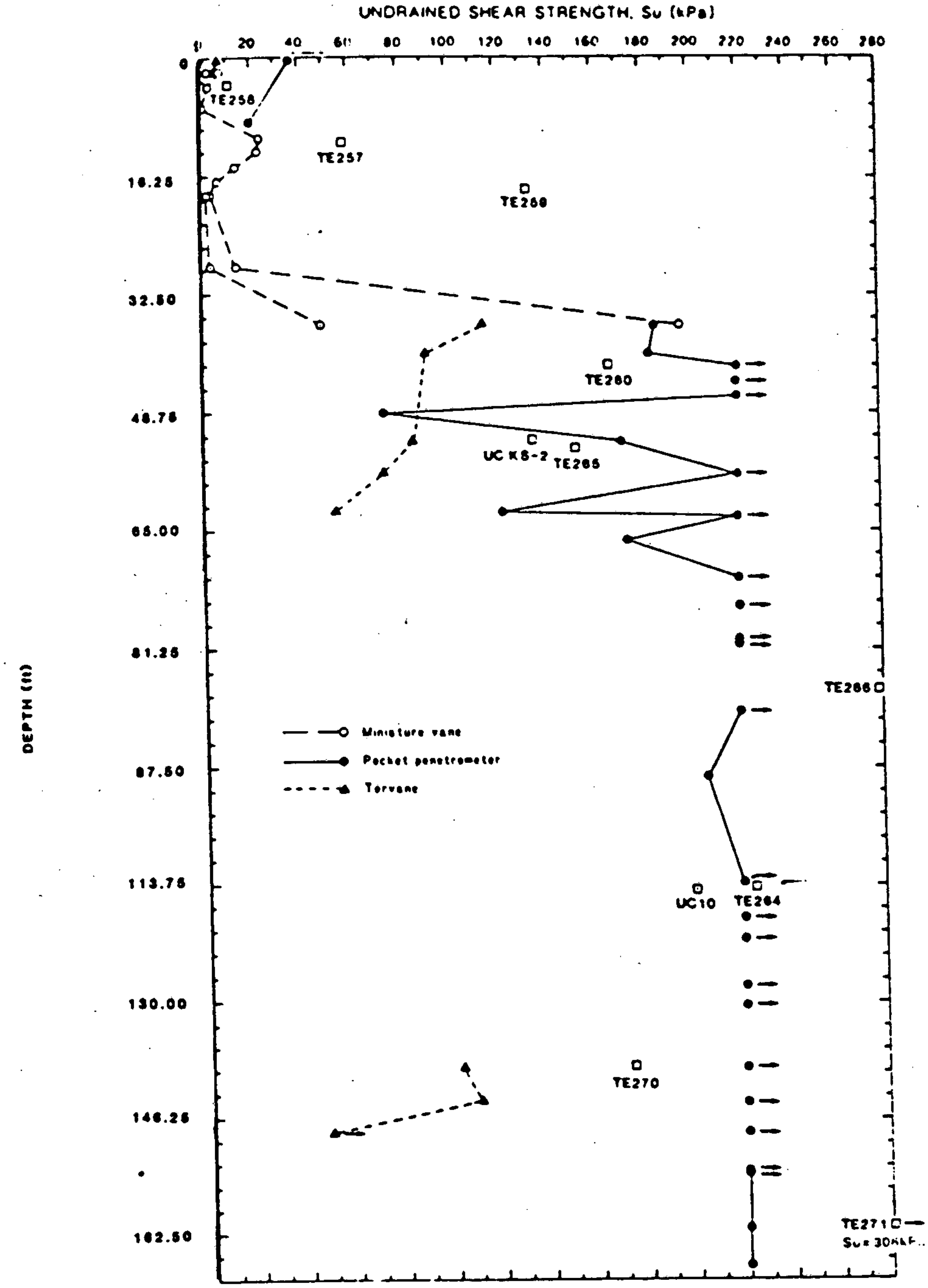
	DATE 1-7-91	JOB NO. H-046.4	



MEAN SIZE IN MILLIMETERS

DATA AFTER: SHARMA 1979

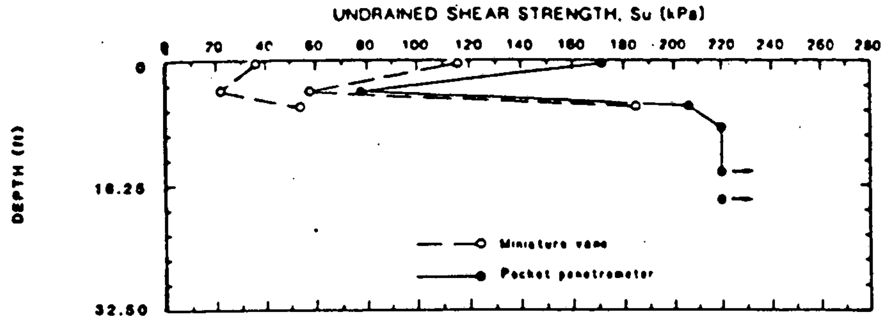
JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	SEDIMENT MEAN SIZE DISTRIBUTION		
INTEC ENGINEERING, INC.	SCALE 1: 3,900,000	DRAWN BY MN	DRAWING NO. 305
	DATE 1-7-91	JOB NO. H-046.4	



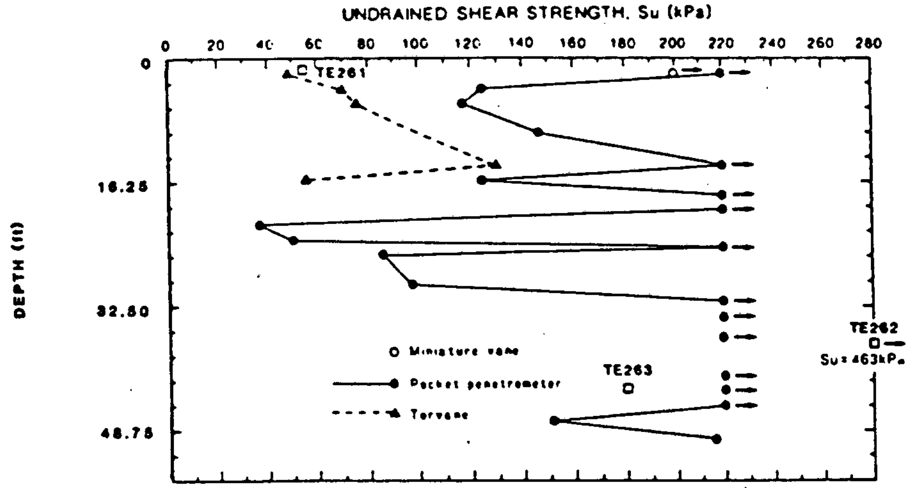
SOIL BORINGS 2 AND 3

DATA AFTER: WINTERS AND LEE, 1984

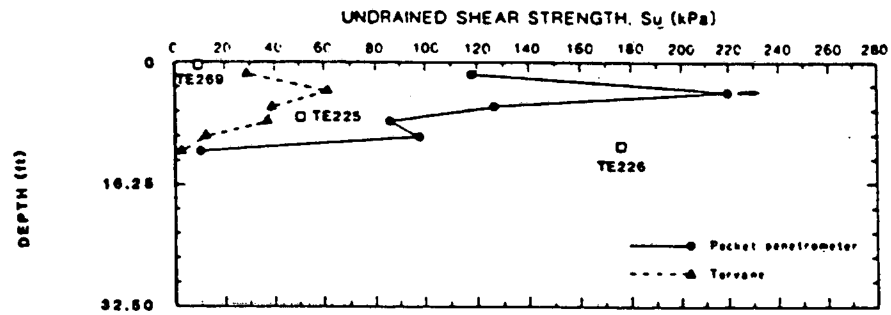
JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	UNDRAINED SHEAR STRENGTH VS. BORING DEPTH		
INTEC ENGINEERING, INC.	SCALE NONE DATE 1-7-91	DRAWN BY MN JOB NO. H-046.4	DRAWING NO. 306



SOIL BORING 4



SOIL BORING 7

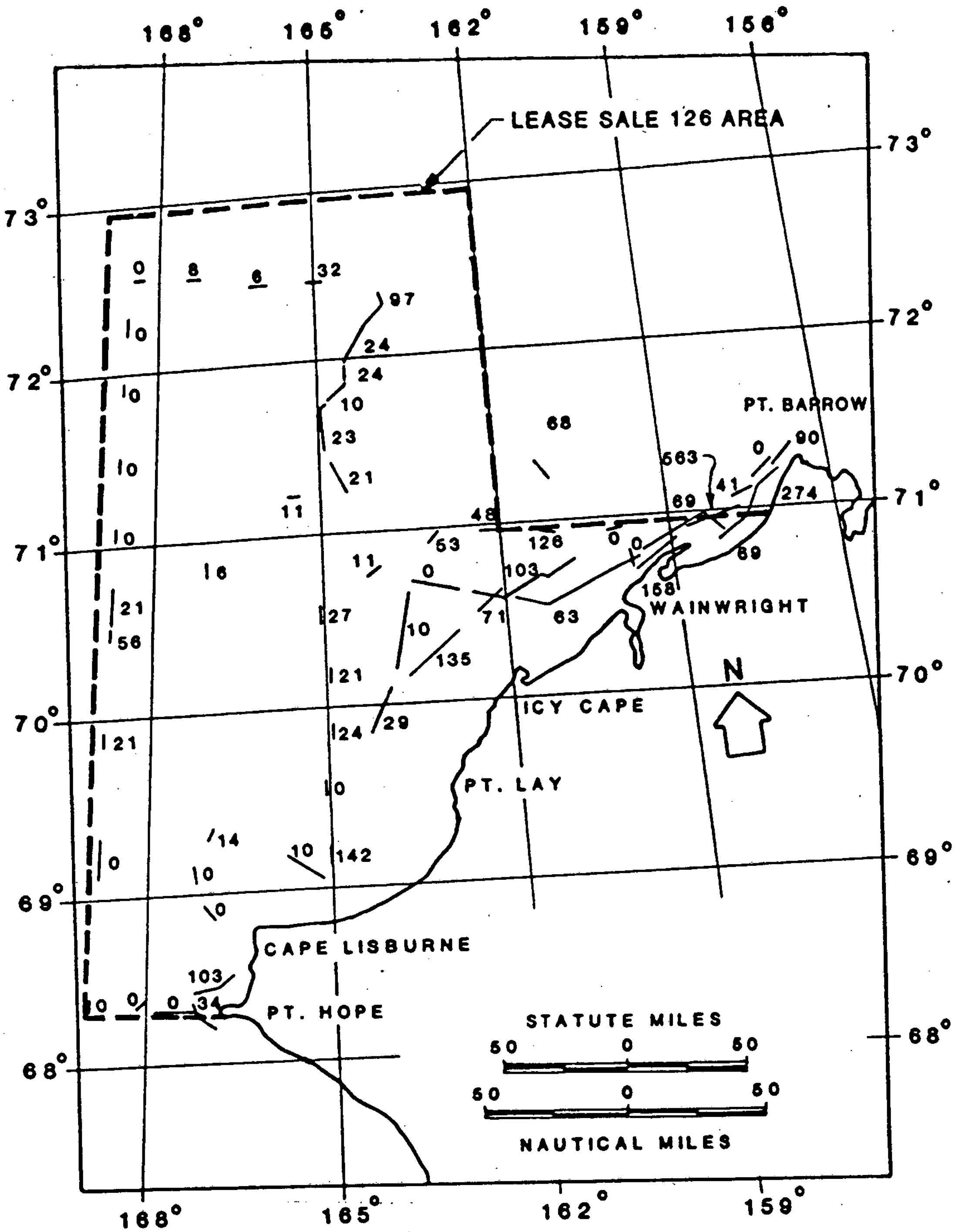


SOIL BORING 8

DATA AFTER: WINTERS AND LEE, 1984

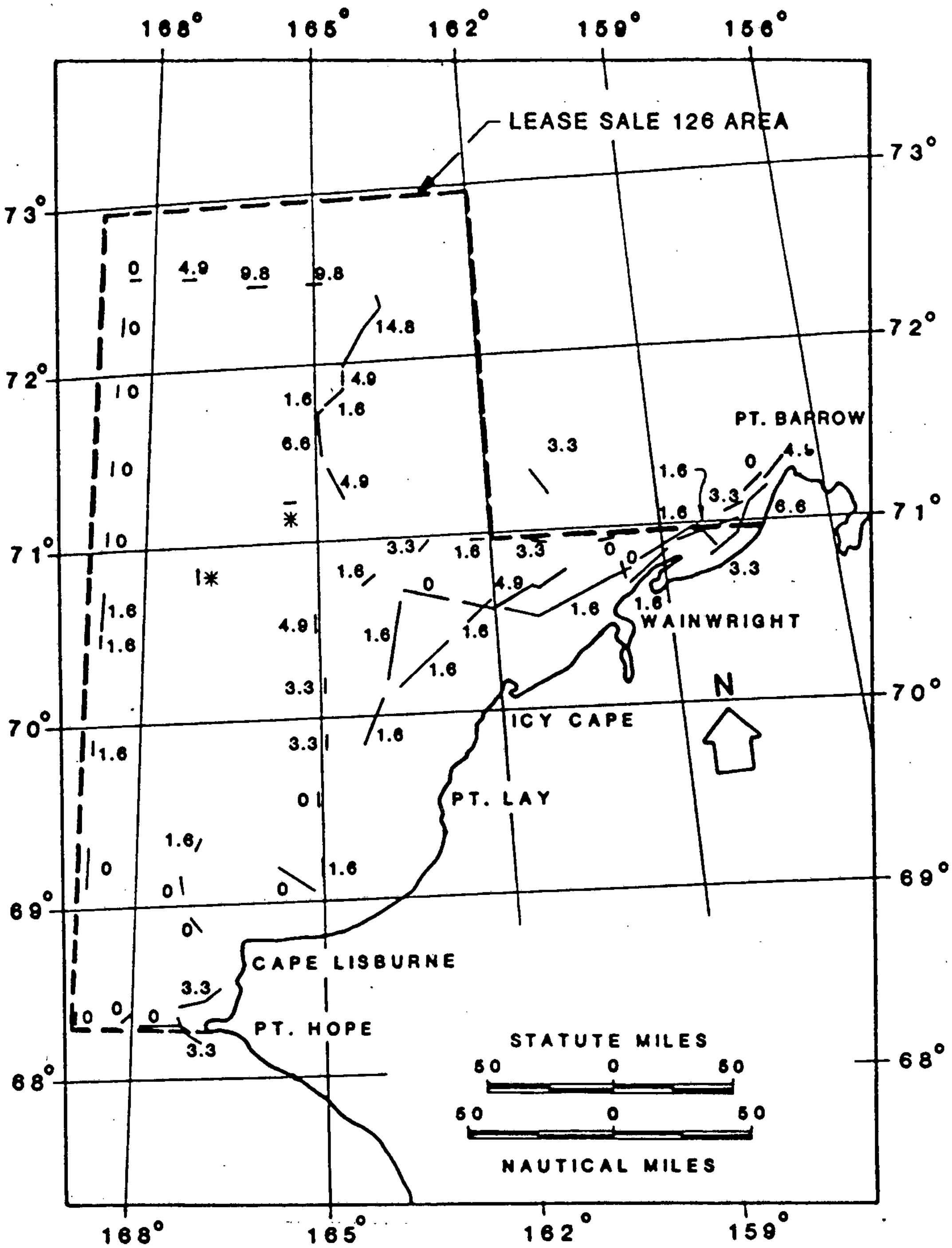
JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	UNDRAINED SHEAR STRENGTH VS. BORING DEPTH

INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY MN	DRAWING NO. 307
	DATE 1-7-91	JOB NO. H-046.4	



NOTE: 17 INDICATES 1974 USGS SURVEY TRACKLINE AND NUMBER OF GOUGES PER MILE

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	MAXIMUM NUMBER OF ICE GOUGES PER MILE		
INTEC ENGINEERING, INC.	SCALE 1:3,900,000	DRAWN BY MN	DRAWING NO. 308
	DATE 1-7-91	JOB NO. H-046.4	



NOTE: ⁀1.6 INDICATES 1974 USGS SURVEY TRACKLINE AND MAXIMUM OBSERVED GOUGE DEPTH (FEET)

✱ INDICATES NO DATA AVAILABLE

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	MAXIMUM OBSERVED ICE GOUGE DEPTH

INTEC ENGINEERING, INC.	SCALE 1: 3,900,000	DRAWN BY MN	DRAWING NO. 309
	DATE 1-7-91	JOB NO. H-046.4	

CHAPTER 4

ARCTIC TANKER DESIGN AND TRANSIT SIMULATION

CHAPTER 4
ARCTIC TANKERS

4.1 GENERAL

This chapter discusses the design, operation and cost of ice-breaking tankers. The objectives of this chapter are to:

- Summarize the principal design characteristics for the icebreaking tankers
- Summarize the Arctic Tanker Transit Simulations
- Describe the various tanker route scenarios
- Summarize possible future arctic tanker requirements
- Estimate capital and operating costs for icebreaking tankers

4.2 ARCTIC TANKER DESIGN

Based on a review of proposed changes to the CASPPR regulations and discussions with CASPPR representatives, it was determined that the proposed changes did not affect the tanker design prepared for the 1986 study. Therefore, the Arctic Tanker Design was not changed from the previous report which was based on the following assumptions/ requirements:

- Tanker sizes of 100,000, 150,000 and 200,000 dwt
- One hundred (100) percent segregated ballast and constant vessel draft
- Maximum tanker draft of 65 feet due to shallow water areas near the Bering Straits and nearshore terminals
- Use of direct-drive diesel propulsion systems
- Maximum ice thicknesses of 4, 6 and 8 feet approximately corresponding to Canadian CASPPR Ice Classes 4, 6 and 8

- Double hull tanker
- Vessel length/beam ratio = 6.5
- Beam/draft ratio = 2.5
- Draft ratio = 1
- Block coefficient = 0.65
- Minimum metacentric height = 6.6 ft
- Power reserve factor = 1.25
- Cargo specific gravity = 0.89 sg (56 lb/ft^3)
- Sea water specific gravity = 64 lb/ft^3

The calculated characteristics for the arctic tankers, based on these assumptions/requirements, are summarized in Tables 4.1 through 4.3, with a typical arctic tanker shown on Drawing No. 401.

4.3 TANKER TRANSIT SIMULATION

As a result of no changes to the design of the arctic tanker, and no significant changes to the environmental conditions, as discussed earlier, no changes in the tanker transit simulations were required. Therefore, the results of the previous tanker transit simulation for the 150,000 dwt tankers are summarized in Tables 4.4 through 4.6.

4.4 TANKER ROUTE SCENARIOS

Eleven different tanker routes were identified in the previous study. These routes are shown on Drawing No. 402 and summarized in Tables 4.7 and 4.8.

These tanker routes, combined with pipeline scenarios identified in Chapter 6 and terminal scenarios identified in Chapter 5, are used in various combinations to develop the overall transportation scenarios identified in Chapter 8.

4.5 TANKER ROUTE TRANSIT TIMES

Based on the 150,000 dwt tanker transit simulations and the tanker route scenarios, a tanker route transit time calculation was performed for each route. The results are presented on Drawings No. 403 through 413.

The number and size of tankers required for each route at each flowrate for the central, northern and southern field locations were calculated based on the tanker route simulation results and the following equation:

$$T = \frac{Q\ (R)\ F}{V}$$

where:

T = number of tankers required rounded up to the next higher integer;

Q = crude oil throughput rate in barrels per day;

R = round trip tanker transit time during the worst month ice conditions in days;

F = factor for reducing the maximum number of tankers required for the worst month by storing oil at the tanker terminal (F = 0.9 for the study evaluation); and

V = volume of crude oil transported per tanker trip in barrels.

The results of this analysis are presented in Tables 4.9 through 4.11.

4.6 ARCTIC TANKER CAPITAL CONSTRUCTION COST ESTIMATE

Table 4.12 summarizes the response from various worldwide shipyards contacted during the course of this study. Based on the responses from U.S. shipyards, capital construction costs were calculated for each of the arctic tanker ice classes and sizes. The estimated capital construction costs for arctic tankers are presented in Table 4.13.

4.7 TANKER OPERATING AND MAINTENANCE COSTS

The estimated operating and maintenance costs for the various classes and sizes of tanker are presented in Tables 4.14 through 4.16.

The operating costs include a support/oil spill escort vessel for each tanker on each trip. This is not a regulatory requirement at the present time, but was considered by the sponsors of this study to possibly become a requirement in the future. Therefore, this cost was included in the tanker operating cost estimates.

TABLE 4.1[1]

ARCTIC TANKER PRINCIPAL CHARACTERISTICS SUMMARY

(100,000 dwt)

ICE CLASS[2]	4	6	8
Length Between Perpendiculars (ft)	950	950	950
Beam (ft)	144.3	144.3	147.6
Molded Depth (ft)	91.8	91.8	91.8
Draft (ft)	50.8	52.5	55.0
Shaft Horsepower (hp)	46,930	103,260	134,100
Propeller Thrust (kips)	900	1570	2250
Number of Propellers	2	2	3
Number of Nozzles	---	---	1
Vessel Steel Weight (metric tons)[3]	28,000	34,000	41,000
Vessel Light Weight (metric tons)[3]	32,000	39,000	48,000
Vessel Displacement (metric tons)[3]	132,000	139,000	148,000

Notes:

(1) Tanker propulsion is based on direct drive diesels. Number of engines per propeller shaft, total horsepower per shaft, engine manufacturer and model number to be determined as part of tanker detail design.

(2) Ice class approximately as per Canadian Arctic Shipping Pollution Prevention Regulations

(3) 1 metric ton = 2205 pounds

TABLE 4.2[1]

ARCTIC TANKER PRINCIPAL CHARACTERISTICS SUMMARY

(150,000 dwt)

ICE CLASS[2]	4	6	8
Length Between Perpendiculars (ft)	1070	1080	1100
Beam (ft)	167.3	167.3	170.6
Molded Depth (ft)	105.0	108.2	108.2
Draft (ft)	55.0	59.0	62.3
Shaft Horsepower (hp)	50,960	113,980	151,530
Propeller Thrust (kips)	1010	1750	2580
Number of Propellers	2	2	3
Number of Nozzles	---	---	2
Vessel Steel Weight (metric tons)[3]	40,000	49,000	56,000
Vessel Lite Weight (metric tons)[3]	45,000	55,000	63,000
Vessel Displacement (metric tons)[3]	195,000	205,000	213,000

Notes:

(1) Tanker propulsion is based on direct drive diesels. Number of engines per propeller shaft, total horsepower per shaft, engine manufacturer and model number to be determined as part of tanker detail design.

(2) Ice class approximately as per Canadian Arctic Shipping Pollution Prevention Regulations

(3) 1 metric ton = 2205 pounds

TABLE 4.3[1]

ARCTIC TANKER PRINCIPAL CHARACTERISTICS SUMMARY

(200,000 dwt)

ICE CLASS[2]	4	6	8
Length Between Perpendiculars (ft)	1150	1180	1200
Beam (ft)	177.1	180.4	187.0
Molded Depth (ft)	111.5	114.8	118.1
Draft (ft)	65.6	65.6	65.6
Shaft Horsepower (hp)	54,980	119,350	162,260
Propeller Thrust (kips)	1080	1860	2790
Number of Propellers	2	2	3
Number of Nozzles	---	---	1
Vessel Steel Weight (metric tons)[3]	45,000	56,000	66,000
Vessel Lite Weight (metric tons)[3]	51,000	64,000	75,000
Vessel Displacement (metric tons)[3]	251,000	264,000	275,000

Notes:

(1) Tanker propulsion is based on direct drive diesels. Number of engines per propeller shaft, total horsepower per shaft, engine manufacturer and model number to be determined as part of tanker detail design.

(2) Ice class approximately as per Canadian Arctic Shipping Pollution Prevention Regulations

(3) 1 metric ton = 2205 pounds

TABLE 4.4

150,000 DWT CLASS 8 ARCTIC TANKER TRANSIT SPEED (knots)

MEAN YEAR ICE CONDITIONS

ICE ZONE	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
2	20.0	20.0	15.4	12.6	11.5	10.9	12.2	20.0	20.0	20.0	20.0	20.0
3	20.0	20.0	15.0	10.3	9.3	9.1	9.1	20.0	20.0	20.0	20.0	20.0
4	20.0	20.0	12.1	9.9	7.8	5.8	5.6	8.6	20.0	20.0	20.0	20.0
5	20.0	14.6	11.9	11.3	10.1	10.7	9.1	12.2	20.0	20.0	20.0	20.0
6	20.0	14.0	8.6	6.2	5.6	7.6	7.2	8.9	20.0	20.0	20.0	20.0
7	20.0	11.9	5.1	4.3	3.9	3.9	3.7	6.4	20.0	20.0	20.0	20.0
8	20.0	10.9	4.3	3.7	3.3	3.3	3.1	3.1	5.1	8.4	11.5	20.0
9	20.0	13.4	7.0	5.1	4.1	4.1	3.7	3.7	20.0	20.0	20.0	20.0

WORST YEAR ICE CONDITIONS

ICE ZONE	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	20.0	20.0	20.0	20.0	10.7	10.5	13.8	20.0	20.0	20.0	20.0	20.0
2	20.0	12.2	13.4	11.7	10.7	9.7	8.2	8.6	20.0	20.0	20.0	20.0
3	20.0	12.8	13.8	9.7	8.6	8.2	6.8	6.4	20.0	20.0	20.0	20.0
4	20.0	11.3	11.5	9.7	7.6	5.6	5.1	4.1	20.0	20.0	20.0	20.0
5	11.1	14.0	11.9	11.3	9.9	10.1	8.9	6.0	4.7	20.0	20.0	20.0
6	11.3	13.6	8.4	6.2	5.6	7.2	6.8	5.1	3.1	3.1	3.5	20.0
7	10.3	11.9	5.1	4.3	3.9	3.7	3.5	3.5	3.1	4.3	5.4	20.0
8	9.3	10.9	4.5	3.7	3.3	3.3	3.1	3.1	2.9	3.1	3.3	7.0
9	20.0	13.2	8.7	5.1	4.1	4.1	3.7	3.3	3.1	3.3	20.0	20.0

Note:
Tanker speed in open water is 20 knots.

TABLE 4.5

150,000 DWT CLASS 6 ARCTIC TANKER TRANSIT SPEED (knots)

MEAN YEAR ICE CONDITIONS

ICE ZONE	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
1	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
2	18.0	18.0	12.6	9.5	7.8	7.4	9.1	18.0	18.0
3	18.0	18.0	12.2	6.6	5.8	6.2	6.4	18.0	18.0
4	18.0	18.0	8.7	6.4	4.9	4.5	4.5	7.2	18.0

WORST YEAR ICE CONDITIONS

ICE ZONE	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
1	18.0	18.0	18.0	18.0	7.6	6.4	10.1	18.0	18.0
2	18.0	10.3	11.3	8.6	7.0	6.0	4.7	4.7	18.0
3	18.0	10.1	11.1	6.3	5.1	5.1	4.1	3.1	18.0
4	18.0	8.2	8.2	6.2	4.9	4.5	3.9	3.1	18.0

Note:
Tanker speed in open water is 18 knots. July, August and September are open water months.

TABLE 4.6

150,000 DWT CLASS 4 ARCTIC TANKER TRANSIT SPEED (knots)

MEAN YEAR ICE CONDITIONS

ICE ZONE	NOV	DEC	JAN	FEB	MAR	APR	MAY
1	16.0	16.0	16.0	16.0	16.0	16.0	16.0
2	16.0	9.5	6.8	5.6	5.4	7.4	16.0
3	16.0	9.3	4.7	4.1	4.3	4.9	16.0

WORST YEAR ICE CONDITIONS

ICE ZONE	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
1	16.0	16.0	16.0	16.0	4.9	4.9	8.6	16.0	16.0	16.0
2	16.0	8.2	8.2	5.8	4.9	4.3	3.1	3.3	16.0	16.0
3	16.0	8.0	8.0	4.1	3.5	3.3	2.5	1.9	6.8	16.0

Note:
Tanker speed in open water is 16 knots. Months not shown above are open water periods.

TABLE 4.7

TANKER ROUTE SUMMARY

ROUTE	TERMINAL LOCATIONS	ICE CLASS [1]	TOTAL LENGTH (Naut. Miles)
T1	Central Chukchi to Wainwright	8	128
T2	Central Chukchi to Cape Lisburne	8	152
T3	Central Chukchi to Nome	8	507
T4	Central Chukchi to Unimak Pass	8	1108
T5	Central Field to Valdez	8	1940
T6	Wainwright to Unimak Pass	8	1102
T7	Wainwright to Valdez	8	1934
T8	Kivalina to Unimak Pass	6	865
T9	Kivalina to Valdez	6	1697
T10	Nome to Unimak Pass	4	647
T11	Nome to Valdez	4	1479

Note:
(1) Ice Class approximately as per Canadian Arctic Shipping Pollution Prevention Regulations

TABLE 4.8

TANKER ROUTE LENGTH SUMMARY

ROUTE	ROUTE LENGTH IN EACH ICE ZONE (Naut. Mile)										TOTAL LENGTH (N.M.)
	OPEN	1	2	3	4	5	6	7	8	9	
T1	0	0	0	0	0	0	15	113	0	0	128
T2	0	0	0	0	0	60	0	92	0	0	152
T3	0	0	0	115	157	143	0	92	0	0	507
T4	72	281	199	164	157	143	0	92	0	0	1108
T5	904	281	199	164	157	143	0	92	0	0	1940
T6	72	281	199	164	157	136	38	55	0	0	1102
T7	904	281	199	164	157	136	38	55	0	0	1934
T8	72	281	199	164	149	0	0	0	0	0	865
T9	904	281	199	164	149	0	0	0	0	0	1697
T10	72	281	199	95	0	0	0	0	0	0	647
T11	904	281	199	95	0	0	0	0	0	0	1479

TABLE 4.9

TANKER ROUTE VESSEL REQUIREMENTS

CENTRAL FIELD LOCATION

TANKER ROUTE	FLOWRATE (MBPD)							
	100		200		400		600	
	NO. OF VESSELS	SIZE (DWT x10^3)	NO. OF VESSELS	SIZE (DWT x10^3)	NO. OF VESSELS	SIZE (DWT x10^3)	NO. OF VESSELS	SIZE (DWT x10^3)
T1	2	100	2	100	2	150	2	200
T2	2	100	2	100	2	150	2	200
T3	2	100	2	150	3	200	4	200
T4	2	100	2	200	4	200	5	200
T5	2	150	3	150	5	200	7	200
T6	2	100	2	200	4	200	5	200
T7	2	100	2	200	4	200	6	200
T8	2	150	2	150	3	200	5	200
T9	2	100	2	200	4	200	6	200
T10	2	100	2	150	3	200	4	200
T11	2	100	2	200	4	200	6	200

TABLE 4.10

TANKER ROUTE VESSEL REQUIREMENTS

SOUTHERN FIELD LOCATION

TANKER ROUTE	FLOWRATE (MBPD)							
	100		200		400		600	
	NO. OF VESSELS	SIZE (DWT $x10^3$)	NO. OF VESSELS	SIZE (DWT $x10^3$)	NO. OF VESSELS	SIZE (DWT $x10^3$)	NO. OF VESSELS	SIZE (DWT $x10^3$)
T1	2	100	2	100	2	100	2	100
T2	2	100	2	100	2	100	2	100
T3	2	100	2	150	3	150	4	200
T4	2	100	2	150	3	200	5	200
T5	2	100	2	200	4	200	6	200
T6	2	000	2	200	4	200	5	200
T7	2	100	2	200	4	200	6	200
T8	2	100	2	150	3	200	5	200
T9	2	100	2	200	4	200	6	200
T10	2	100	2	150	3	200	4	200
T11	2	100	2	200	4	200	6	200

TABLE 4.11

TANKER ROUTE VESSEL REQUIREMENTS

NORTHERN FIELD LOCATION

TANKER ROUTE	FLOWRATE (MBPD)							
	100		200		400		600	
	NO. OF VESSELS	SIZE (DWT $x10^3$)	NO. OF VESSELS	SIZE (DWT $x10^3$)	NO. OF VESSELS	SIZE (DWT $x10^3$)	NO. OF VESSELS	SIZE (DWT $x10^3$)
T1	2	100	2	150	2	150	2	200
T2	2	100	2	150	2	150	2	200
T3	2	100	3	150	3	200	5	200
T4	2	100	2	200	4	200	6	200
T5	2	150	3	200	5	200	7	200
T6	2	100	2	150	4	200	5	200
T7	2	100	2	200	4	200	6	200
T8	2	100	2	150	3	200	5	200
T9	2	100	2	200	4	200	6	200
T10	2	100	2	150	3	200	4	200
T11	2	100	2	200	4	200	6	200

TABLE 4.12

SHIPYARD RESPONSE SUMMARY

SHIPYARD	LOCATION	PROVIDED COST DATA	
		1986	1991
U. S. Shipyards			
American Shipbuilding Co. Tampa Shipyards, Inc.	Tampa, FL	No	No
Avondale Industries, Inc. Shipyards Division	New Orleans, LA	No	No
Bethelehem Steel Corp. Baltimore Marine Division	Sparrows Point, MD	Yes	No[2]
Ingalls Shipbuilding, Inc.	Pascagoula, MS	[1]	No
National Steel Shipbuilding	San Diego, CA	Yes	Yes
Newport News Shipbuilding	Newport News, VI	Yes	Yes
Far East Shipyards			
Hitachi Zosen (USA) Ltd.	Tokyo, Japan	Yes	No
IHI Inc.	Tokyo, Japan	[1]	Yes
Mitsui Zosen (USA) Ltd.	Tokyo, Japan	Yes	No
Daewoo International	Seoul, Korea	[1]	Yes

Note:

(1) Shipyards were not contacted during 1986 Study.

(2) Shipyards no longer interested in ship construction, interested in ship repair only.

TABLE 4.13

ARCTIC ICEBREAKING TANKER

CAPITAL COST ESTIMATE SUMMARY

CAPITAL COST ESTIMATED (US$ $\times 10^6$)			
TANKER ICE CLASS (APPROXIMATE CASPPR)	DEAD WEIGHT TONNAGE		
	100,000	150,000	200,000
4	144	172	201
6	173	219	240
8	212	250	280

Note:
Cost estimates are based on U.S.-built tankers. Note that Far East built tankers would be approximately 55 percent less.

TABLE 4.14

100,000 DWT ARCTIC TANKER OPERATING COSTS ($/DAY)

COST ITEM	ICE CLASS 4	ICE CLASS 6	ICE CLASS 8
Crew	9,600	9,600	9,600
Maintenance and Repair	1,600	3,200	4,800
Insurance	12,165	16,275	19,400
Ice Reconnaissance	1,645	1,645	1,645
Miscellaneous Expenses	1,250	1,535	1,770
Support/Oil Spill Escort Vessel(1)	12,300	14,600	17,450
Subtotal	38,560	46,855	54,665
Fuel and Lubricants	26,500	49,750	69,200
Total	65,060	96,605	123,865
ANNUAL COST (x10^6$ /YEAR)	23.75	35.26	45.21

Note:
(1) Note that this significant cost item is not a regulatory requirement, and inclusion of same is therefore subject to user's prerogative.

TABLE 4.15

150,000 DWT ARCTIC TANKER OPERATING COSTS ($/DAY)

COST ITEM	ICE CLASS 4	ICE CLASS 6	ICE CLASS 8
Crew	9,600	9,600	9,600
Maintenance and Repair	1,600	3,200	4,800
Insurance	16,110	20,950	24,650
Ice Reconnaissance	1,645	1,645	1,645
Miscellaneous Expenses	1,450	1,770	2,035
Support/Oil Spill Escort Vessel[1]	12,300	14,600	17,450
Subtotal	42,705	51,775	60,190
Fuel and Lubricants	28,050	53,975	76,200
Total	70,755	105,750	136,390
ANNUAL COST (x10^6$ /YEAR)	25.83	38.60	49.78

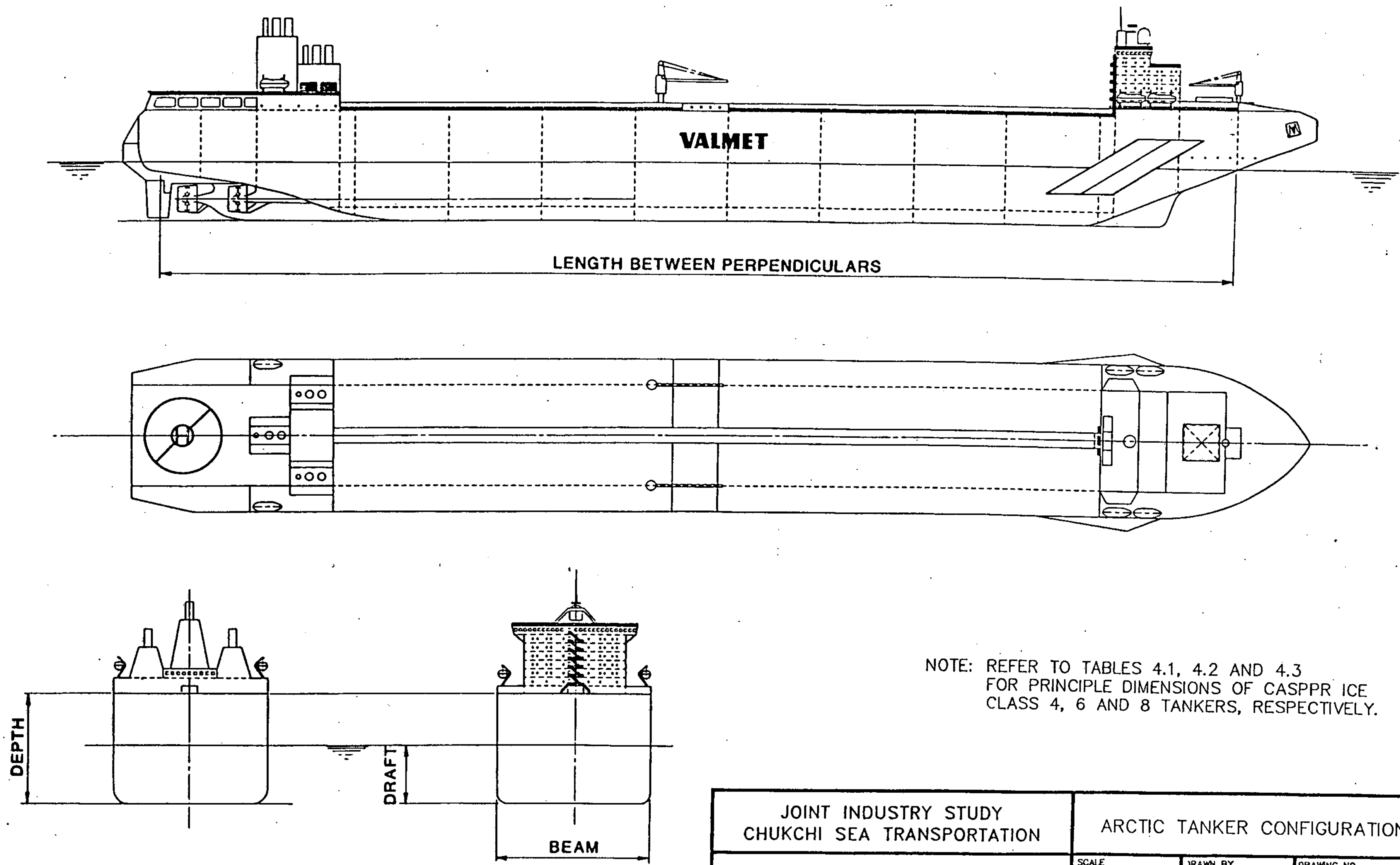
Note:
[1] Note that this significant cost item is not a regulatory requirement, and inclusion of same is therefore subject to user's prerogative.

TABLE 4.16

200,000 DWT ARCTIC TANKER OPERATING COSTS ($/DAY)

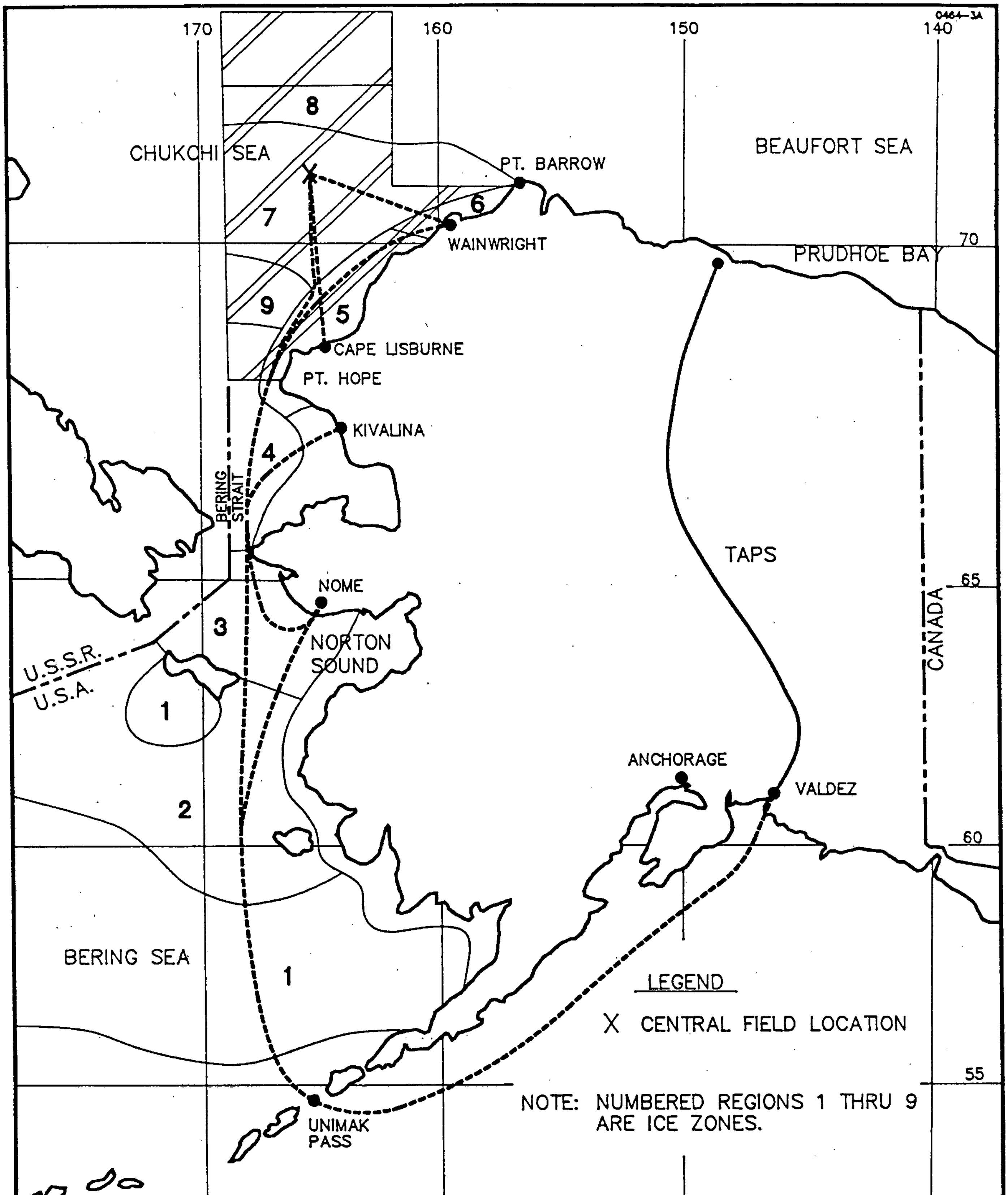
COST ITEM	ICE CLASS 4	ICE CLASS 6	ICE CLASS 8
Crew	9,600	9,600	9,600
Maintenance and Repair	1,600	3,200	4,800
Insurance	19,725	24,495	29,425
Ice Reconnaissance	1,645	1,645	1,645
Miscellaneous Expenses	1,630	1,950	2,275
Support/Oil Spill Escort Vessel(1)	12,300	14,600	17,450
Subtotal	46,500	55,490	65,195
Fuel and Lubricants	29,540	56,125	80,450
Total	76,040	111,615	145,645
ANNUAL COST (x10^6$ /YEAR)	27.75	40.74	53.16

Note:
(1) Note that this significant cost item is not a regulatory requirement, and inclusion of same is therefore subject to user's prerogative.



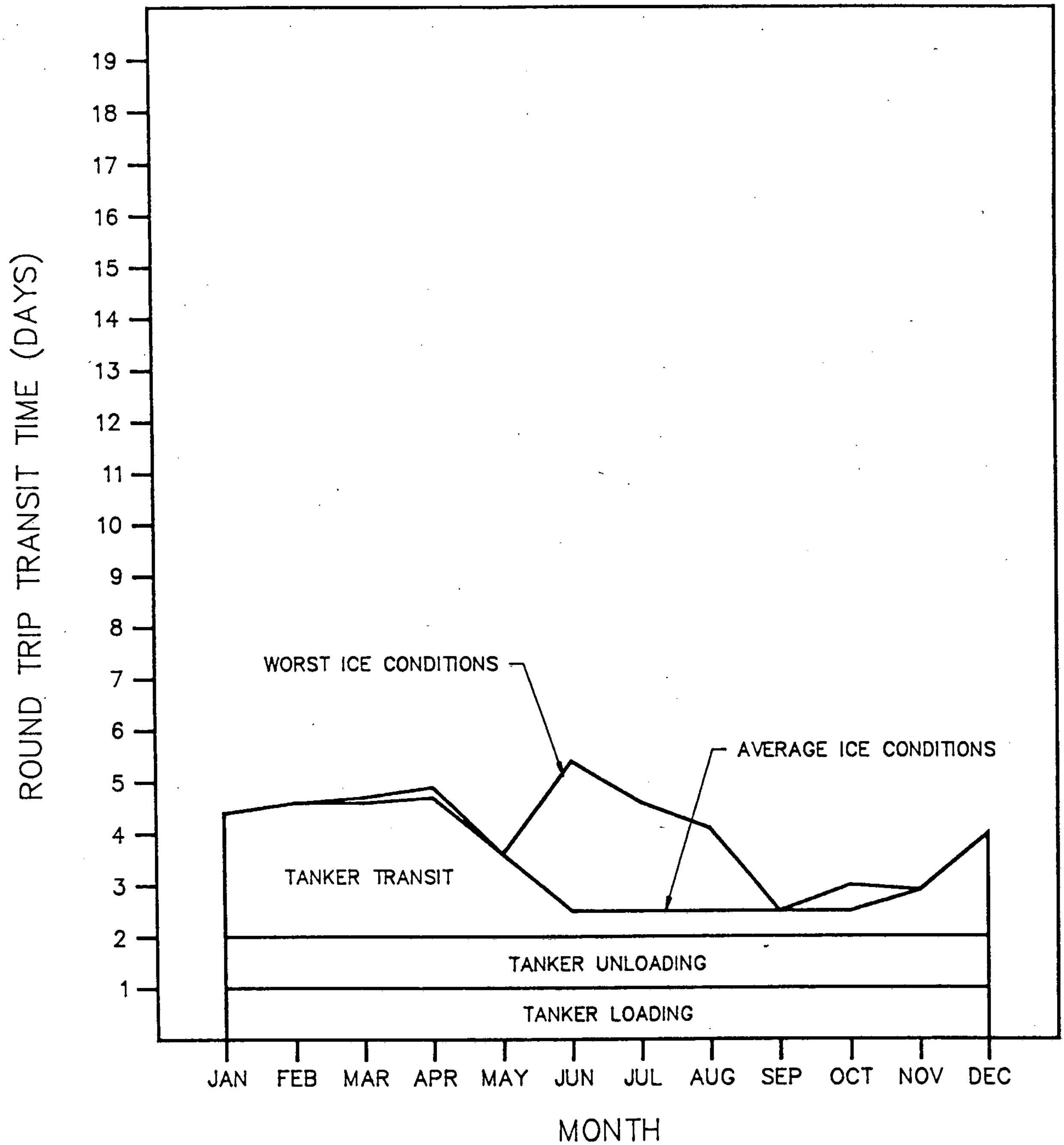
NOTE: REFER TO TABLES 4.1, 4.2 AND 4.3 FOR PRINCIPLE DIMENSIONS OF CASPPR ICE CLASS 4, 6 AND 8 TANKERS, RESPECTIVELY.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	ARCTIC TANKER CONFIGURATION		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY MN	DRAWING NO. 401
	DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTES		
INTEC ENGINEERING, INC.	SCALE: NONE	DRAWN BY: KC	DRAWING NO.: 402
	DATE: 1-7-91	JOB NO.: H-046.4	

0464-4A

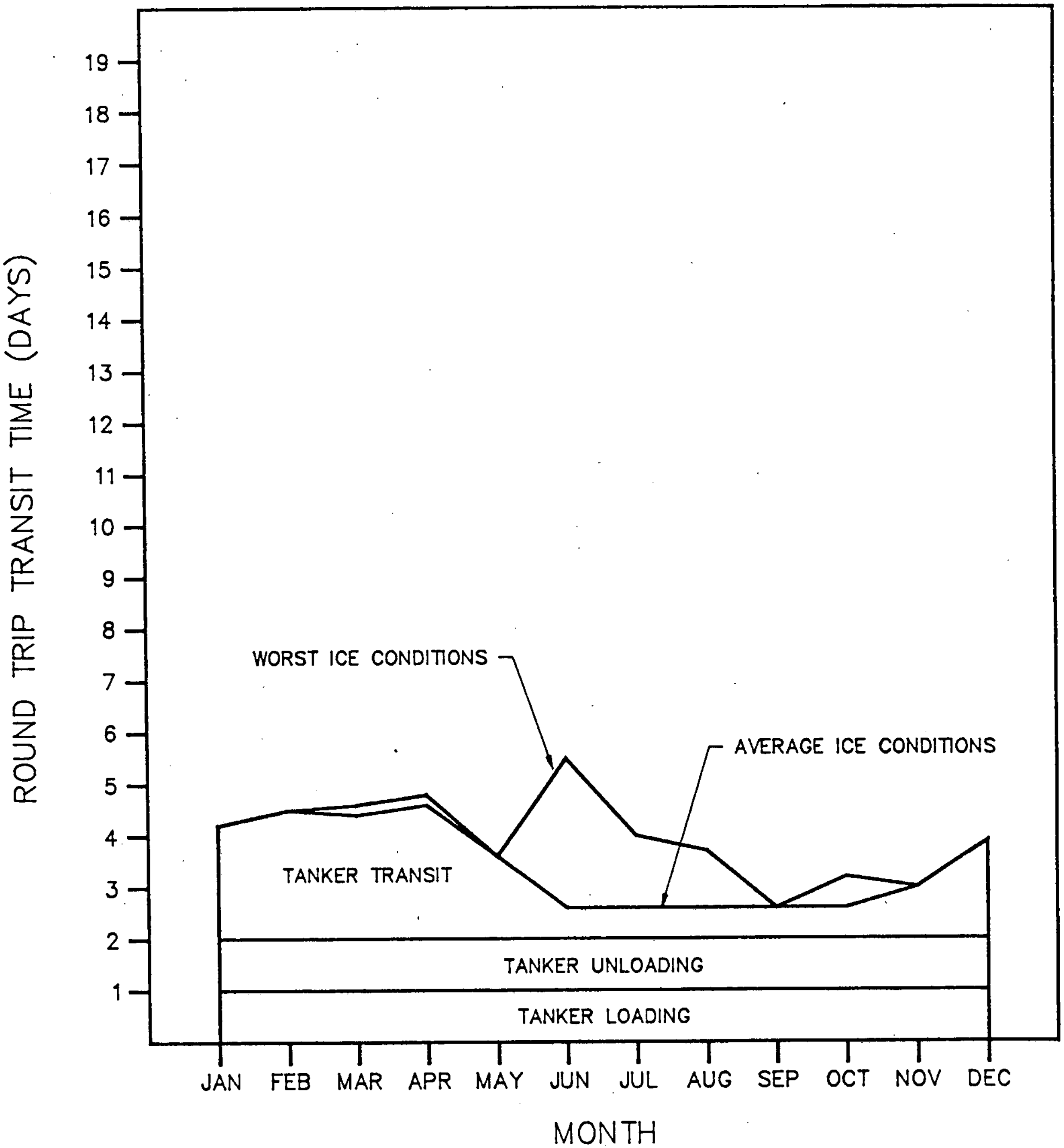


NOTES:

1. TANKER ROUTE 1 CONSISTS OF TANKERS TRANSITING BETWEEN CENTRAL CHUKCHI AND WAINWRIGHT.
2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 8 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 1 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE: NONE DATE: 1-7-91	DRAWN BY: KC JOB NO. H-046.4	DRAWING NO. 403

0464-5A

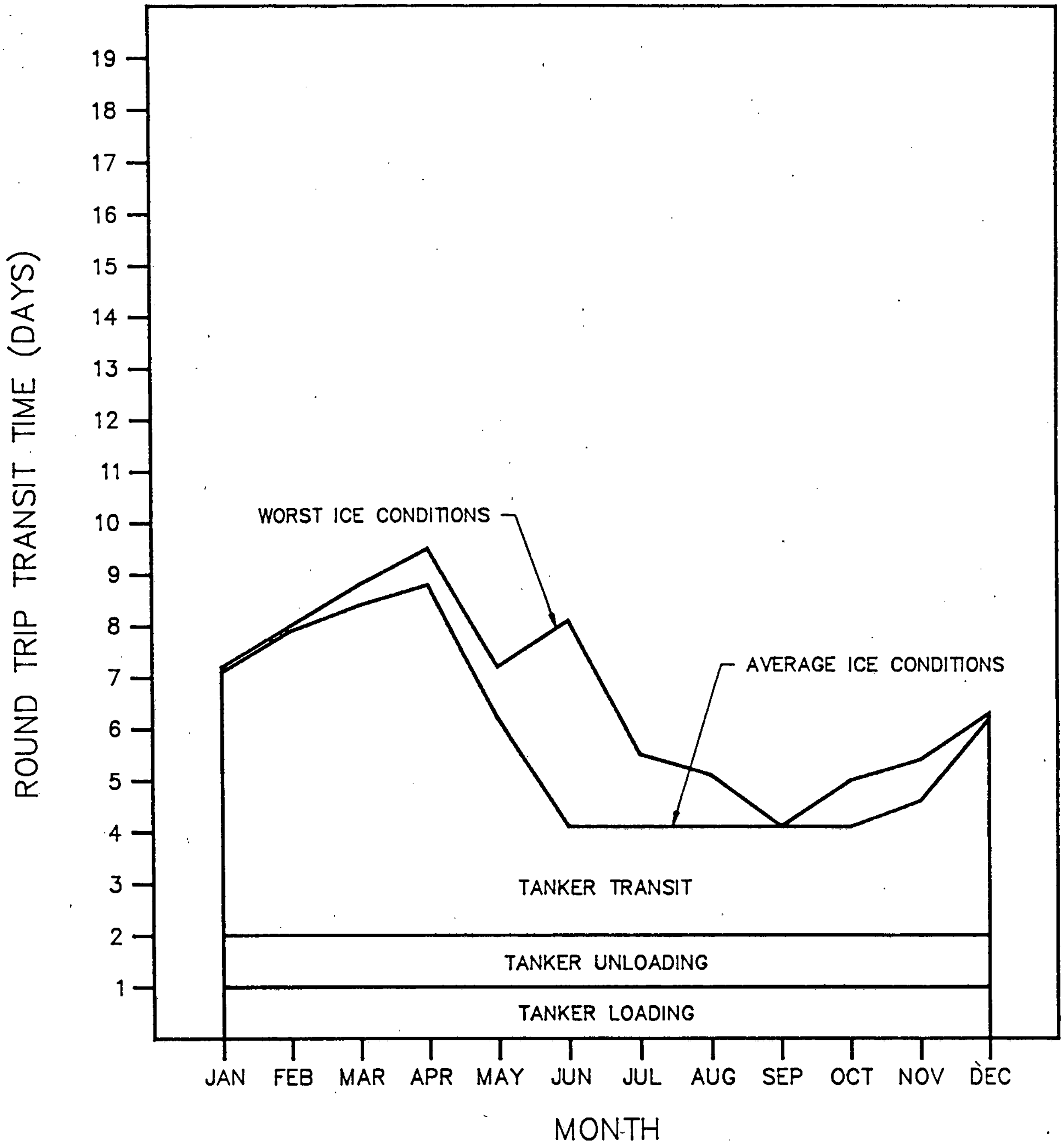


NOTES:

1. TANKER ROUTE 2 CONSISTS OF TANKERS TRANSITING BETWEEN CENTRAL CHUKCHI AND PT. HOPE.
2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 8 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 2 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 404
	DATE 1-7-91	JOB NO. H-046.4	

0464-6A



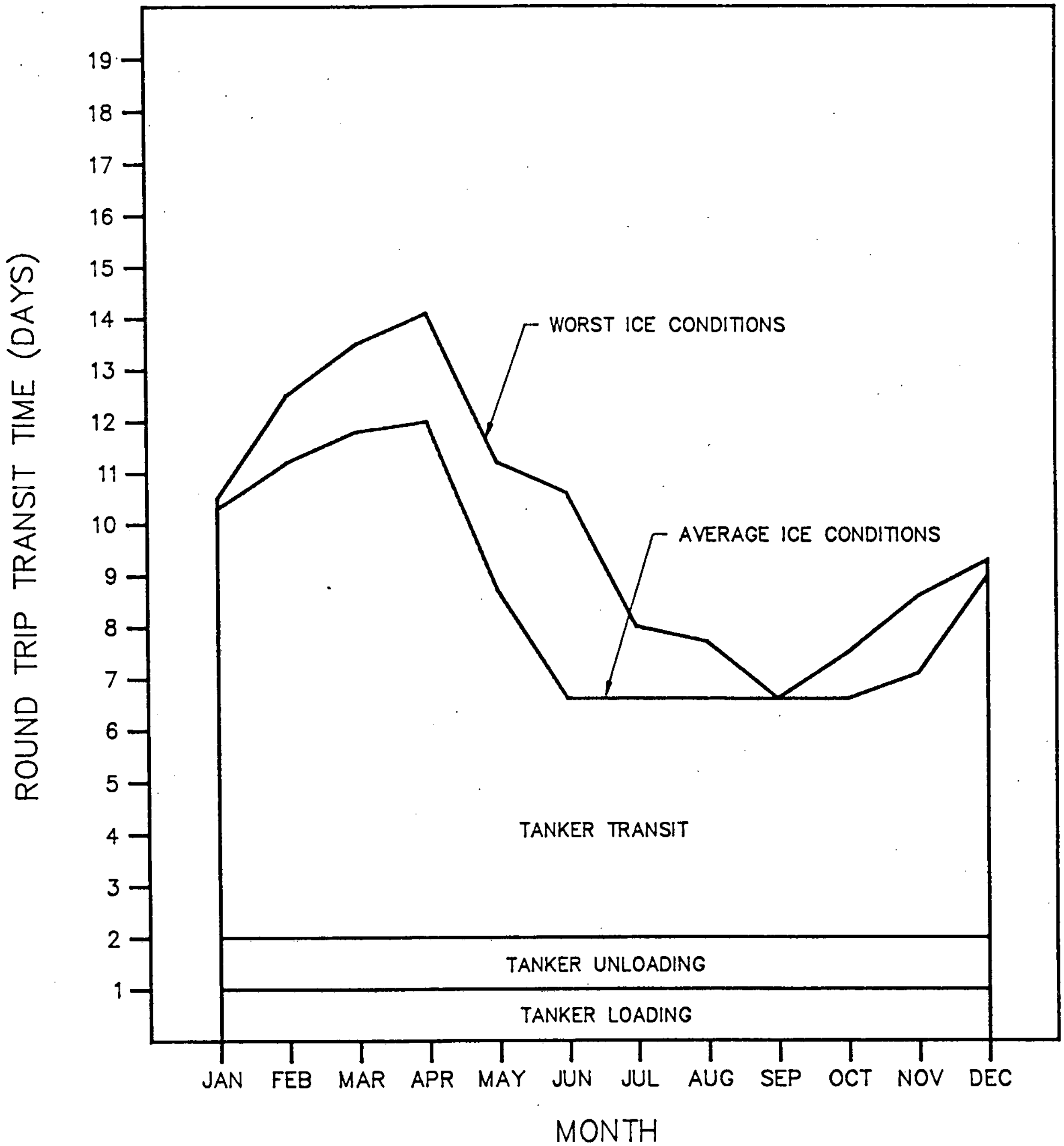
NOTES:

1. TANKER ROUTE 3 CONSISTS OF TANKERS TRANSITING BETWEEN CENTRAL CHUKCHI AND NOME.

2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 8 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 3 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 405
	DATE 1-7-91	JOB NO. H-046.4	

0464-7A



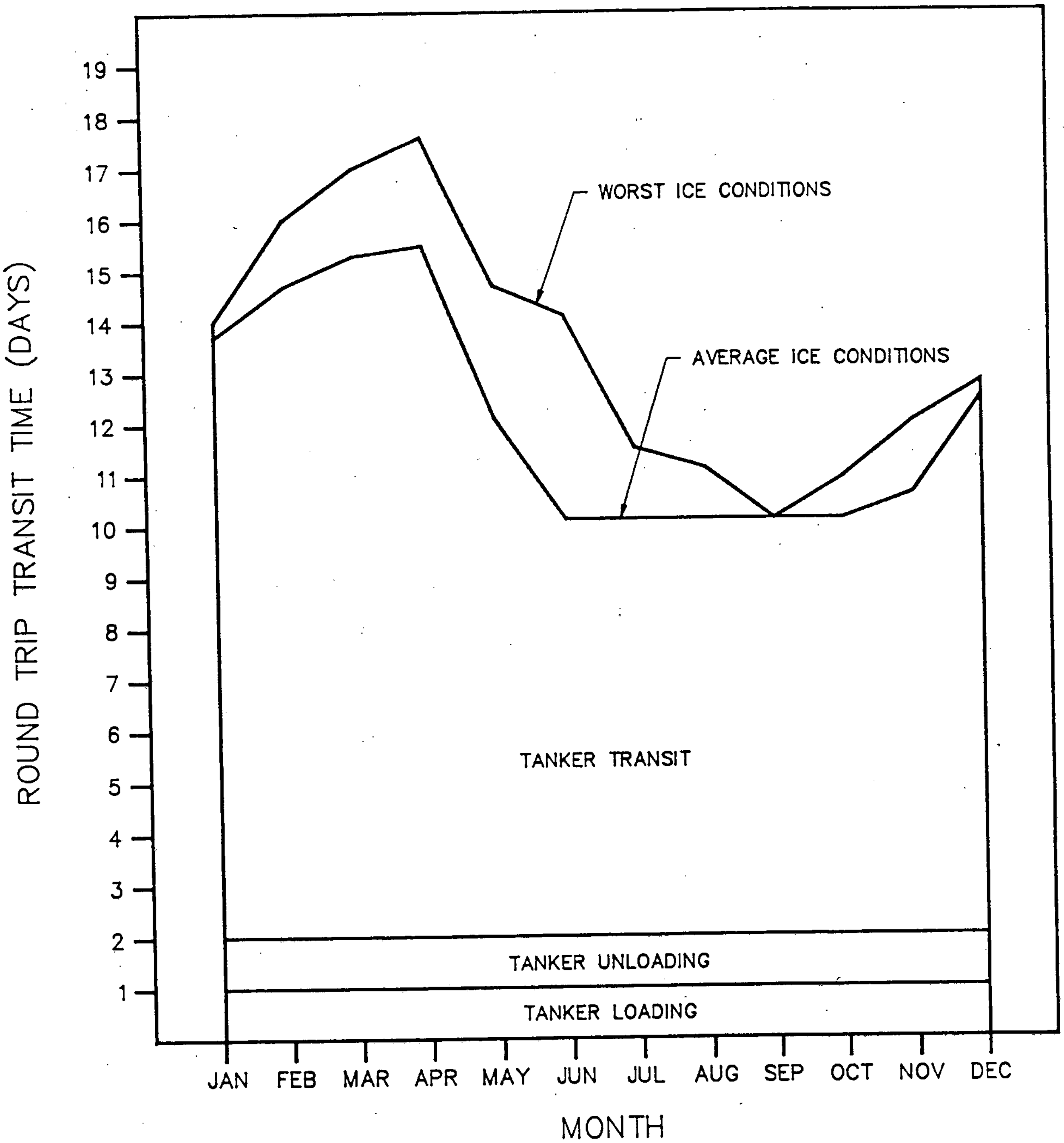
NOTES:

1. TANKER ROUTE 4 CONSISTS OF TANKERS TRANSITING BETWEEN CENTRAL CHUKCHI AND UNIMAKE PASS.

2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 8 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 4 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE: NONE DATE: 1-7-91	DRAWN BY: KC JOB NO. H-046.4	DRAWING NO. 406

0464-8A



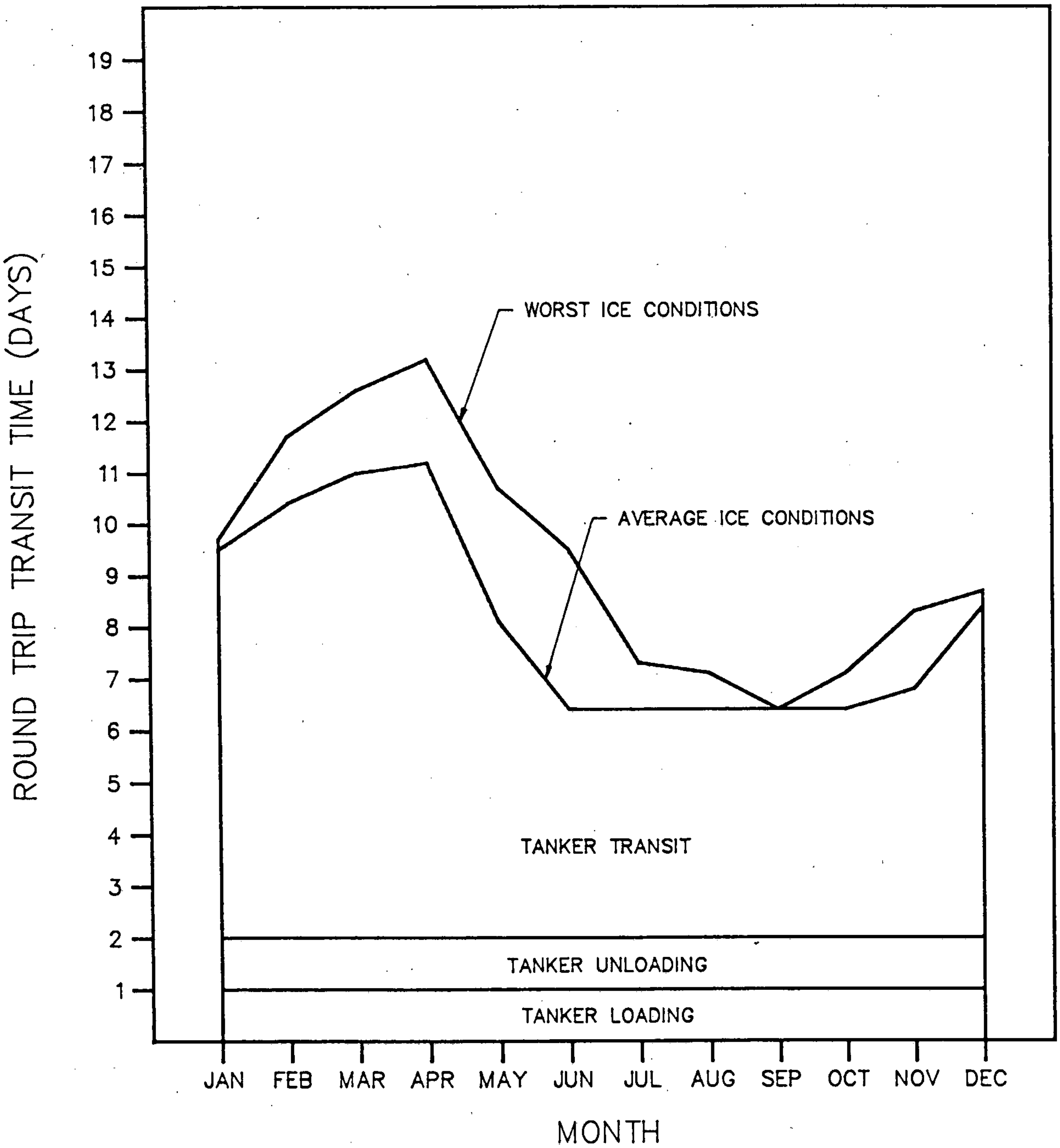
NOTES:

1. TANKER ROUTE 5 CONSISTS OF TANKERS TRANSITING BETWEEN CENTRAL CHUKCHI AND VALDEZ.

2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 8 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 5 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 407
	DATE 1-7-91	JOB NO. H-046.4	

0464-9A

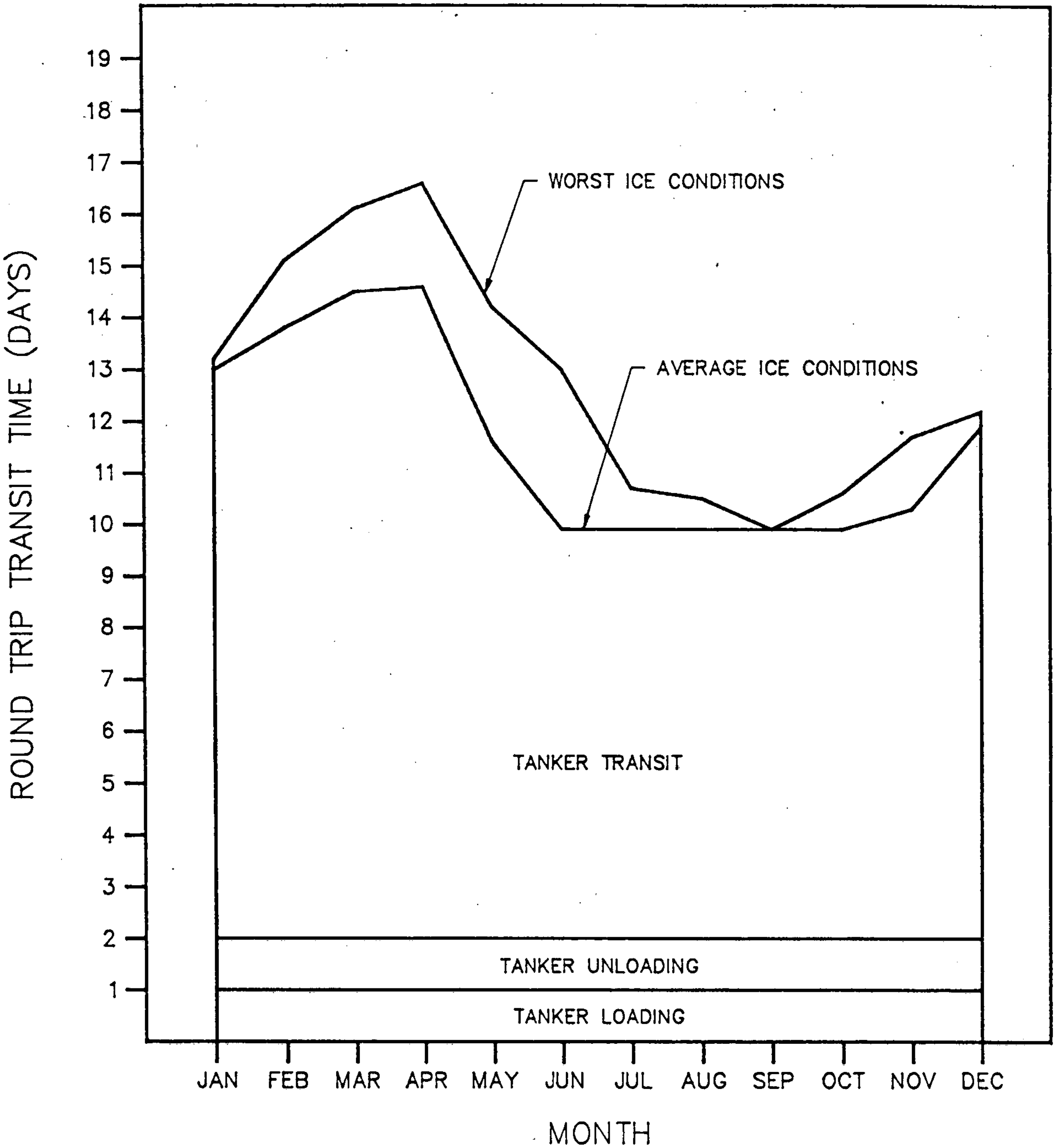


NOTES:

1. TANKER ROUTE 6 CONSISTS OF TANKERS TRANSITING BETWEEN WAINWRIGHT AND UNIMAKE PASS.
2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 8 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 6 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 408
	DATE 1-7-91	JOB NO. H-046.4	

0464-10A



NOTES:

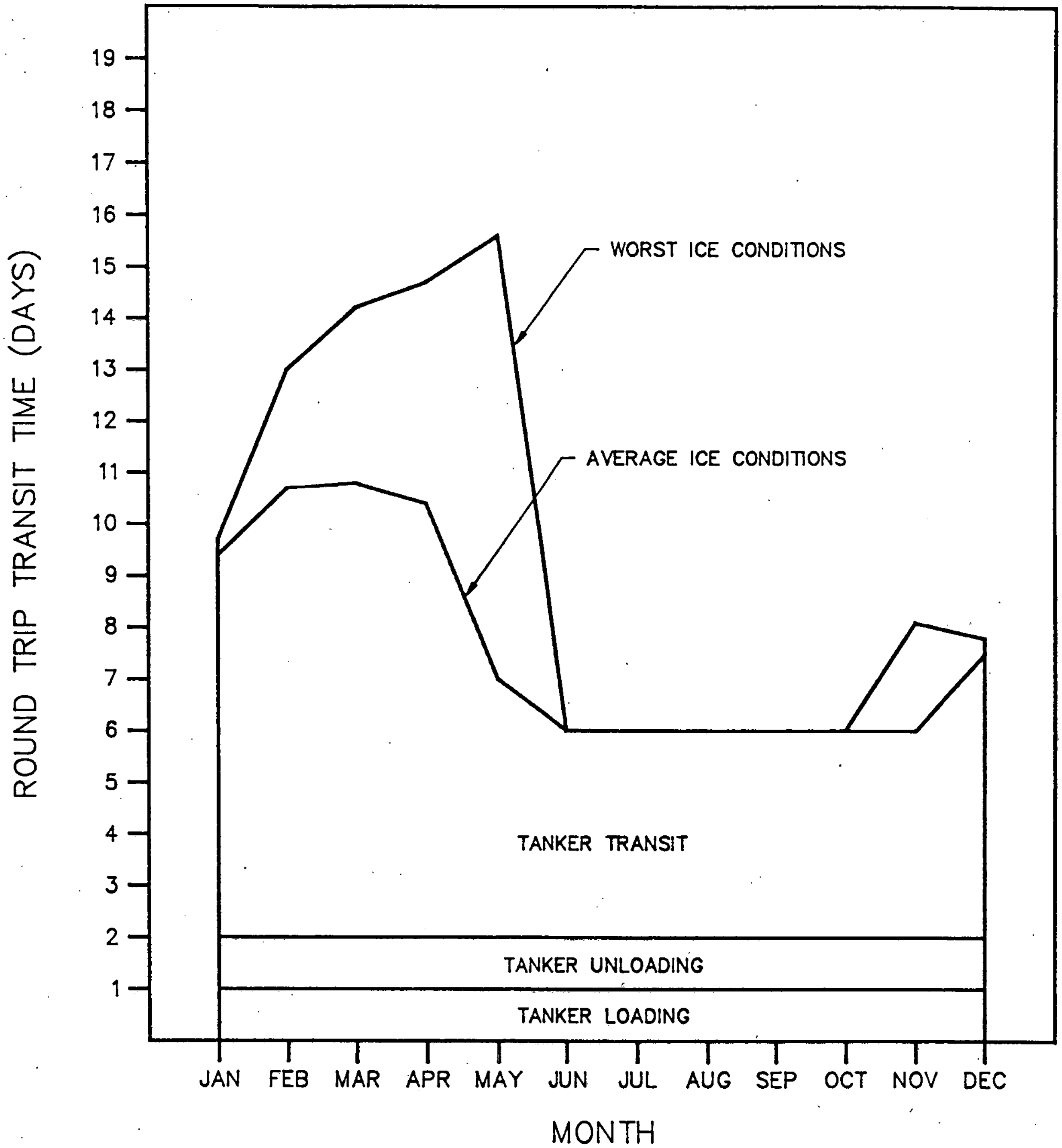
1. TANKER ROUTE 7 CONSISTS OF TANKERS TRANSITING BETWEEN WAINWRIGHT AND VALDEZ.

2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 8 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 7 TRANSIT TIME

	SCALE	DRAWN BY	DRAWING NO.
INTEC ENGINEERING, INC.	NONE	KC	409
	DATE 1-7-91	JOB NO. H-046.4	

0464-11A



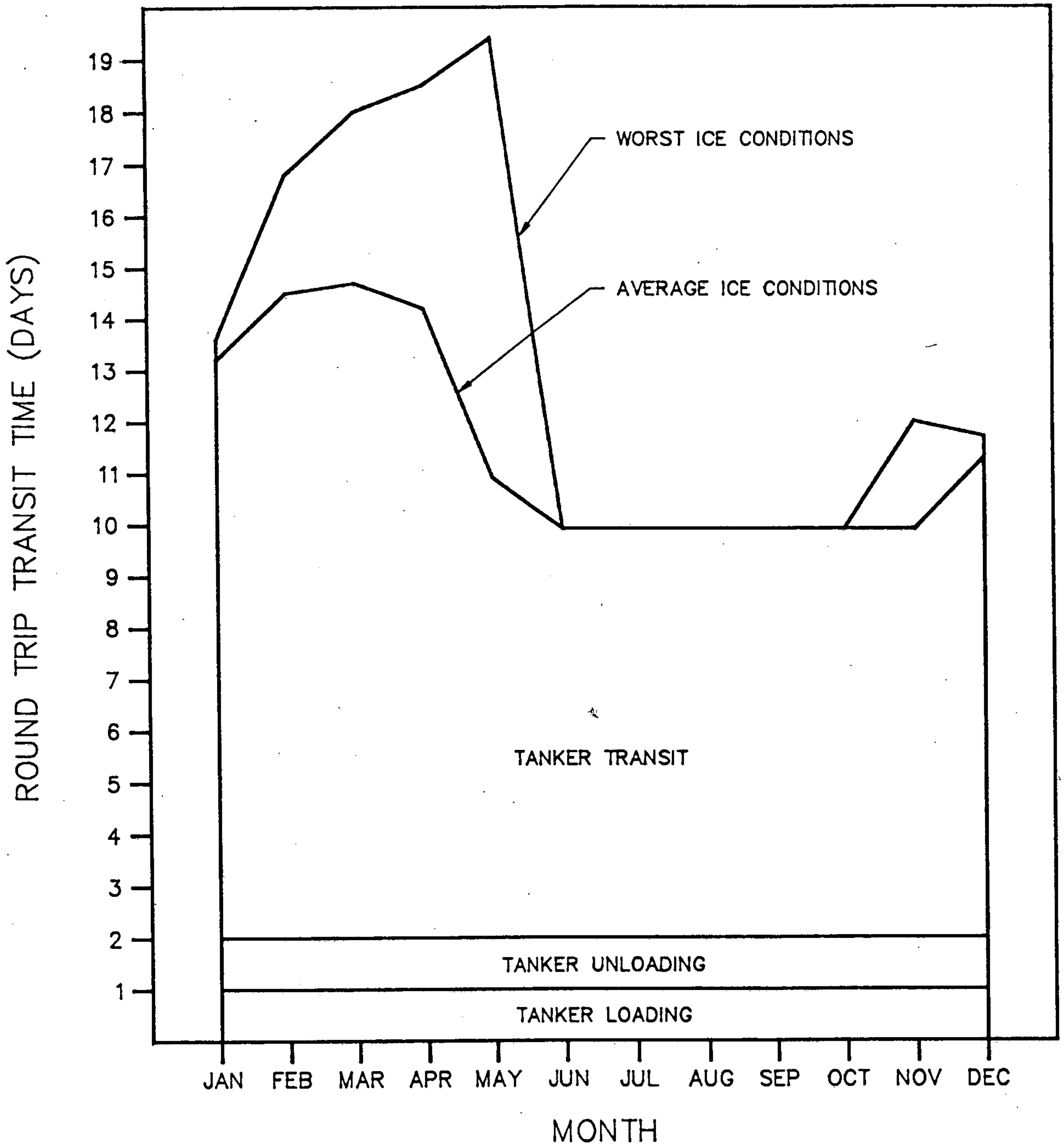
NOTES:

1. TANKER ROUTE 8 CONSISTS OF TANKERS TRANSITING BETWEEN KIVALINA AND UNIMAKE PASS.

2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 6 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 8 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 410
	DATE 1-7-91	JOB NO. H-046.4	

0464-12A



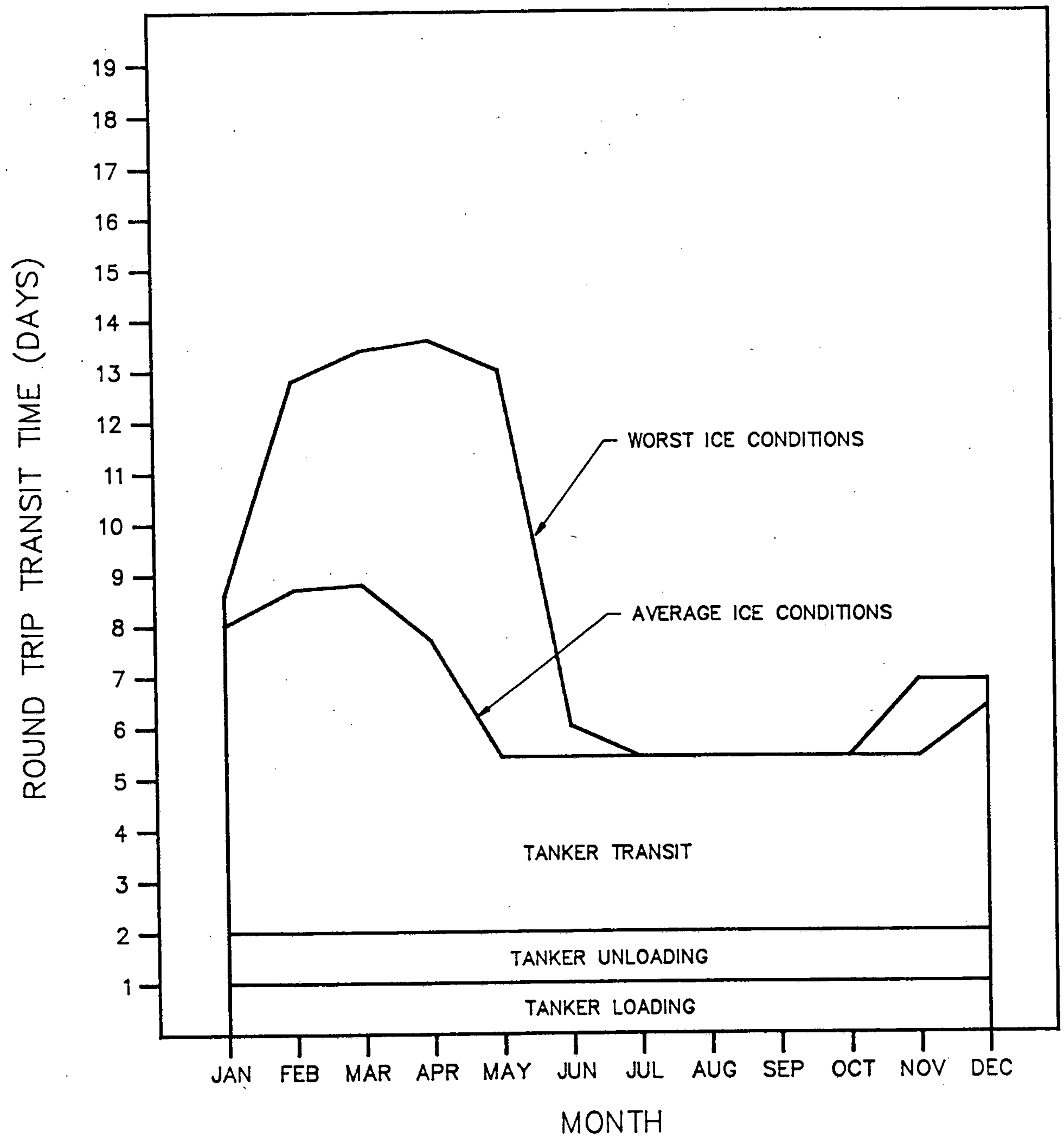
NOTES:

1. TANKER ROUTE 9 CONSISTS OF TANKERS TRANSITING BETWEEN KIVALINA AND VALDEZ.

2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 6 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 9 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 411
	DATE 1-7-91	JOB NO. H-046.4	

0464-134

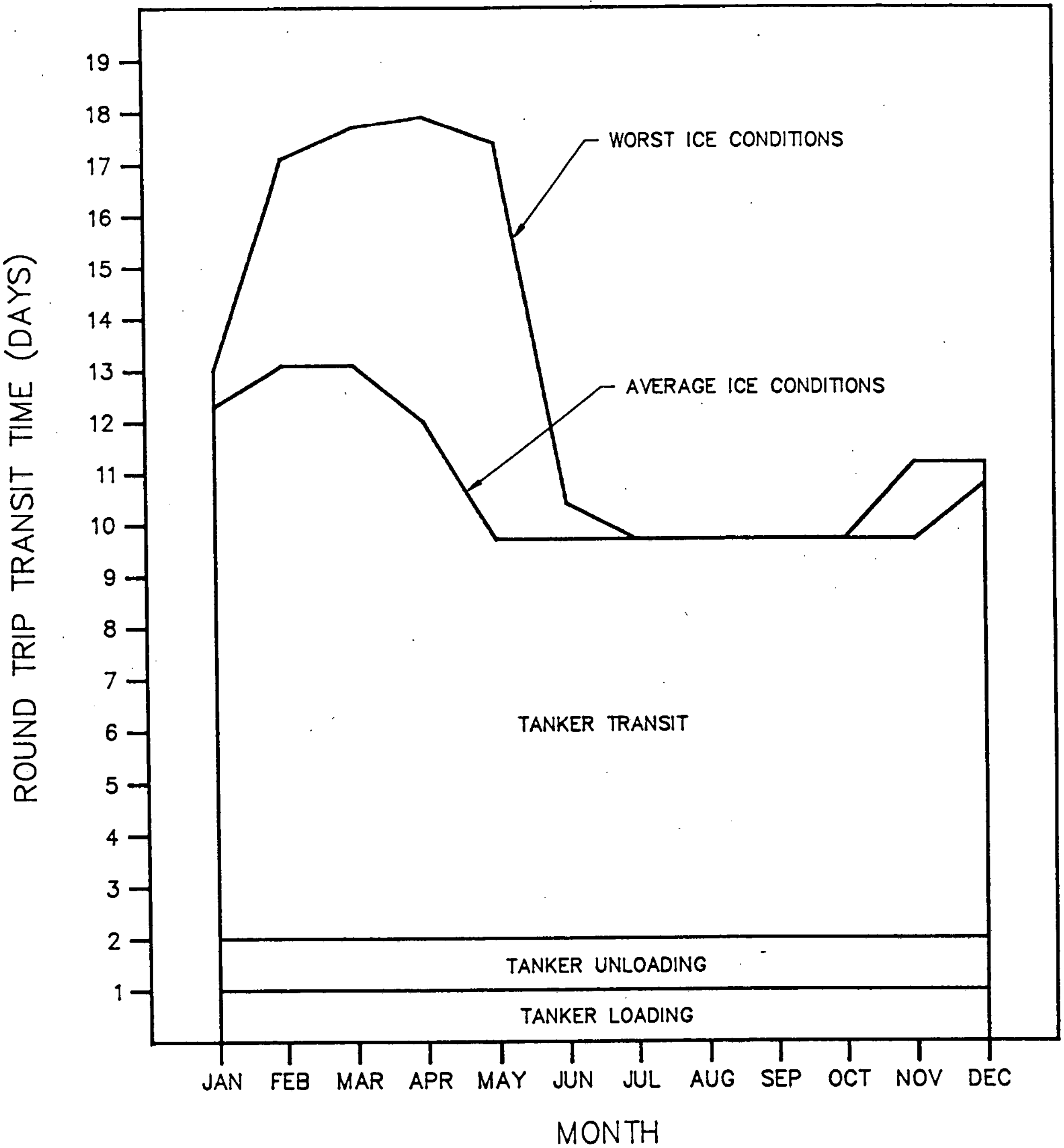


NOTES:

1. TANKER ROUTE 10 CONSISTS OF TANKERS TRANSITING BETWEEN NOME AND UNIMAKE PASS.
2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 4 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 10 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 412
	DATE 1-7-91	JOB NO. H-046.4	

0464-14A



NOTES:

1. TANKER ROUTE 11 CONSISTS OF TANKERS TRANSITING BETWEEN NOME AND VALDEZ.

2. TRANSIT TIME IS BASED ON A 150,000 DWT ARCTIC CLASS 4 TANKER.

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	TANKER ROUTE 11 TRANSIT TIME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 413
	DATE 1-7-91	JOB NO. H-046.4	

CHAPTER 5

TANKER TERMINALS

CHAPTER 5
TANKER TERMINALS

5.1 GENERAL

This chapter describes the two types of tanker terminals selected for the transportation scenarios and the associated cost of each. The two terminal types are an offshore terminal and a nearshore terminal. The chapter also outlines the costs associated with transshipment terminals at Unimak Pass and Valdez.

For the purposes of this study, an offshore terminal is defined as a crude oil storage and tanker loading facility associated with offshore drilling and production operations located at a considerable distance from the nearest land area. The costs associated with the production structure are not included due to the fact that they are considered a cost of production and not a transportation system cost. A near shore terminal is defined as a crude oil storage and tanker loading/offloading facility located a relatively short distance from shore and consisting of an onshore tank farm connected to a nearshore tanker loading structure by a short distance submarine pipeline.

The selection of terminal types will not be presented in this report, as it was presented in significant detail in the 1986 study, and the decisions as to the types of terminals were not changed in this study.

5.2 OFFSHORE TANKER TERMINAL

The offshore tanker terminal selected for cost estimating and scheduling purposes consists of a bottom founded monolithic storage structure located approximately three nautical miles from a bottom founded monolithic omni-directional SPM loading structure as shown on Drawing No. 501. A 48-inch diameter submarine pipeline connects the storage structure to the tanker loading structure. The three mile separation between the two structures minimizes adverse affects from rubble field buildup around the structures, and provides sufficient clearance between the structures to accommodate tanker approach, maneuvering and mooring operations at the omni-directional SPM loading structure.

The omni-directional SPM concept allows the tanker to moor in the open water slot behind the structure caused by break-up of the ice as it moves past the structure. The terminal configuration, conceptual design, operating parameters, budgetary cost estimates and construction schedule described in this section are based on the central Chukchi Sea location as shown on Drawing No. 502, with a water depth of 140 feet, and the 100-year return period environmental design criteria summarized in Chapter 3.

The estimated total tanker turnaround time at the offshore terminal is 22 to 24 hours based on the following:

Approach and Moor Tanker (hours)	3.5 - 4.0
Connect Loading Arm (hours)	1.0
Tanker Loading and Topping (hours)	15.5 - 16.5
Disconnect Loading Arm (hours)	0.5
Departure Time (hours)	1.5 - 2.0
TOTAL TURNAROUND TIME (hours)	22.0 - 24.0

The assumed crude oil properties are summarized in Chapter 6.

5.2.1 Offshore Terminal Location

As shown on Drawing No. 502, the offshore storage structure is located approximately three nautical miles from the loading structure which is surrounded by a 2.5 nautical mile radius tanker mooring and maneuvering area (MMA).

The loading structure is located southeast of the storage structure as it has been assumed that the preferred tanker route would approximately parallel the Alaskan coastline to take advantage of anticipated nearshore open water leads as evidenced by satellite imagery.

5.2.2 Offshore Terminal Structure Design

The offshore terminal consists of two major structures, the storage structure and the separate tanker loading structure. Both structures are bottom founded monolithic concrete structures with composite steel/concrete ice resistant exterior walls.

Considering the seasonal variations in ice conditions along proposed tanker routes and at the terminal location, and the corresponding variations in tanker transit speed; a storage volume at the storage facility equivalent to fifteen days of production was assumed for conceptual design purposes. Considering a base case production rate of 400 MBPD, the storage structure was designed for six million barrels of crude oil storage.

The largest existing and planned graving docks which would be available for structure construction have main dimensions of approximately 800 feet by 800 feet. Maximum structure dimensions will, therefore, be limited to approximately 600 feet by 600 feet. In order to accommodate six million barrel storage capacity in a water depth of 140 feet, the storage structure will consist of an individual structure approximately 600 feet square.

Storage Structure

The storage structure is designed with a composite steel/concrete ice resistant exterior wall (or ice wall) which is composed of 0.75-inch thick exterior and interior steel plate 24 inches apart with concrete infill. Three 0.75-inch thick steel stiffeners are equally spaced between 24-inch thick concrete bulkheads 12.5 feet apart. At the bulkheads, three 0.75 inch thick steel stiffeners are spaced 12 inches apart. A two feet thick, heavily reinforced, vertical framing system forms grids within the structure. Two feet thick by ten feet wide heavily reinforced horizontal framing systems are located at elevations -120 feet, -90 feet, -40 feet, +20 feet, +30 feet, +40 feet, +50 feet, and +95 feet. The top slab is 12-inch thick heavily reinforced concrete, and the bottom plate is 1-inch thick steel, stiffened in both directions by WT eight x eighty sections spaced ten feet apart. In order to effectively resist global ice loads, sand ballast is placed within the grids or spaces extending from the exterior ice wall to the interior vertical framing walls.

Loading Structure

The loading structure is located approximately three nautical miles from the storage structure and has an octagonal shape, as shown on Drawing No. 501, and a composite steel/concrete ice resistant exterior wall. The exterior profile, and horizontal and vertical framing systems are identical to the storage structure. To effectively resist severe ice loads in the central Chukchi Sea, the interior of the structure is filled with sand ballast, and sixteen 96-inch diameter by three-inch wall, spud piles are driven approximately 100 feet below the mudline.

Materials

For cost estimating purposes, high yield strength, low temperature structural and reinforcement steel and concrete prestressing tendons are assumed to be used. Concrete compressive strengths of eight ksi and six ksi respectively, were used to maintain concrete freeze and thaw durability, with six to eight percent air entrainment, a water-cement ratio of less than 0.45, and a cement factor of greater than eight sacks per cubic yard.

Major facilities/equipment located on the storage structure includes:

- Control center
- Personnel accommodations
- Recreational complex
- Fresh water supply
- Maintenance shop
- Material storage
- Heliport
- Crude oil transfer/loading pumps
- Meters and prover systems
- Crude piping system
- Communication systems

- Fire protection
- SCADA system

Major terminal facilities and equipment on the loading structure include:

- Personnel accommodations
- Loading arm and helideck
- Loading control center
- Crude oil piping system
- Communication systems
- Navigational aids including fog horn
- General alarm and fire protection system
- Mooring hawser deployment/storage system

Crude oil is transferred between the storage structures and the loading structure through a 48-inch diameter submarine pipeline at the rate of 100,000 to 120,000 barrels per hours.

Loading Arm

The loading arm shown on Drawing No. 504 consists of a 200-feet long boom supported by a pedestal tower on torsion free spherical bearings. The boom is capable of rotating in any direction on a large slewing gear. The boom provides support for the piping, mooring hawser, control center and two 24-inch diameter insulated and heat traced pipe runs which carry crude oil from the rotating fluid swivel located at the structure center and along the boom to the vertical loading arm.

Mooring and Loading Operations

As the tanker enters the mooring and maneuvering area (MMA), which extends 2.5 nautical miles from the loading structure, tanker speed is reduced to between one knot and two knots to maintain effective control of the vessel. Terminal approach time due to reduced tanker speed is approximately two hours. If excessive rubble field and/or ridges block access to the loading structure, a multi-purpose arctic Class 8, terminal support vessel assigned to the terminal will break up the rubble and ridges prior to tanker arrival at the terminal. Time required for mooring the tanker to the loading structure is approximately 1.5 hours. Time required for connecting the loading arm is one hour.

5.2.3 Seasonal Limitation and Weather Downtime

The following terminal operating criteria based on worldwide offshore terminal experience have been assumed for the offshore tanker loading terminal:

Tanker Mooring and Loading Limits

	Mooring	Loading
Wind (1 minute sustained, knots)	40	50
Significant Wave Height (ft)	12	15
Current (knots)	1.5	2
Visibility (nautical miles)	<0.5	<0.1

structure fabrication schedule. In either case, the first season is utilized to prepare foundation berms. During the second season, the storage structure is towed to site and installed. The loading structure is installed during the third open water season. Alternatively, all component structures can be towed out and installed in the same season provided the foundation berms have been completed during the previous season(s). This can be accomplished by fabricating all structures simultaneously.

A representative construction schedule showing the major engineering, procurement, fabrication, towing and installation activities for the offshore terminal is shown on Drawing No. 505. As indicated by this schedule, total construction time from design engineering through structure installation requires approximately six years.

5.2.5 Offshore Terminal Capital Construction Cost Estimate

The offshore terminal cost estimate includes construction and installation, major facilities and equipment, interconnecting pipeline, an icebreaking terminal support vessel, and a helicopter. As indicated by the required structure material listed in Table 5.2, the concrete and steel required for the offshore terminal structures is comparable to the largest North Sea gravity based structures.

Unit Costs

To obtain realistic unit costs for the reinforced concrete, structural steel and sand infill required for the fabrication of the terminal structures, both U.S. and Far East fabricators which have built, or have an interest in building, arctic structures were furnished with sufficient information to allow them to prepare reasonable budgetary unit costs and total concrete and steel cost estimates for each structure. A list of these fabricators, along with the unit cost information provided by each, are presented in Table 5.3.

For cost estimating purposes, a concrete unit cost of $1,125 per cubic yard, a fabricated steel offshore unit cost of $2,500 per short ton, and a sand infill unit cost of $15.85 per cubic yard were selected.

Cost estimates for major facilities, equipment, and piping materials were obtained from manufacturers and suppliers. Equipment day rates, fuel consumption rates and offshore construction costs were obtained from experienced arctic marine contractors to the extent available.

Terminal Capital Cost Estimate

Based on material unit rates and structure material quantities, vendor cost estimates, marine contractor day rates for towing, costs for site survey, foundation berm construction, structure installation, sand ballasting, and unit pipeline costs developed in Chapter 6; the estimated total direct construction cost for the base case offshore terminal is approximately $862.25 million. The total offshore terminal capital cost including fifteen percent contingency, five percent engineering services, ten percent project management, U.S.-built icebreaking terminal support vessel and a Boeing 234 helicopter is approximately $1.417 billion. The base case offshore terminal construction cost estimate for the central field is summarized in Table 5.4.

5.2.6 Annual Operating and Maintenance Cost Estimate

The base case offshore terminal operating and maintenance costs summarized in Table 5.5 are approximately $53.95 million per year.

Operating Costs

Offshore terminal operating costs include personnel, logistics, quartering, helicopter fuel and an ice-breaking terminal support vessel operating cost. The annualized personnel cost of $12.2 million is based on a twelve hour work day, seven day work week and four week rotation period with a total work force of 86 men, 43 per rotation. Annual estimated logistics and quartering costs are $1.2 million and $3.5 million, respectively.

Helicopter fuel costs based on six hours of operation per day and a consumption rate of 910 pounds per hour is $1.0 million. The annual operating cost for an arctic Class 8 icebreaking terminal support vessel is $14.8 million.

Maintenance Costs

Estimated annual offshore terminal maintenance cost of $21.25 million is based on one and one-half (1.5) percent of the installed terminal capital cost.

5.2.7 Application to Alternate Transportation Scenarios

To determine cost sensitivity to variations in storage volume and terminal location, costs for the base case storage structure with storage of six million barrels, at the central field location, were first adjusted to reflect a range of storage volumes from two million to twenty million barrels. These costs were then adjusted to reflect sensitivity to variations in location and corresponding water depths. The results of this analysis are presented in Tables 5.6 and 5.7 for capital construction costs and operating and maintenance costs, respectively.

5.3 NEARSHORE TANKER TERMINAL

The nearshore tanker terminal considered for cost estimating and scheduling purposes consists of a bottom founded monolithic omni-directional SPM loading structure and onshore tank farm facilities as shown on Drawings No. 506 and 507. The omni-directional SPM loading structure is very similar to the offshore tanker terminal loading structure, but does not require spud piles due to the reduced ice loads resulting from less severe ice conditions nearshore.

A 36-inch diameter submarine pipeline extends approximately five miles from the onshore tank farm to the loading structure. The terminal configuration, conceptual design, operating parameters, budgetary cost estimates and construction schedule described in this section are based on a water depth of 110 feet and 100-year return period environmental design criteria summarized in Chapter 3. The loading structure design is based on an ice pressure of 920 psi and a global ice load of 600 kips/foot.

The loading structure is designed for mooring 100,000 to 200,000 dwt arctic Class 4 and six crude oil tankers as described in Chapter 4. It should be noted that the nearshore terminal loading rate is 60,000 barrels per hours compared to 100,000 barrels per hour at the offshore terminal. Due to less severe ice conditions at the nearshore terminal, the emphasis for minimizing tanker turnaround time is reduced. The reduced loading rate also permits the use of a 36-inch diameter pipeline instead of a 48-inch diameter pipeline as required for the 100,000 barrel per hour loading rate.

5.3.1 Nearshore Terminal Location

The nearshore terminal site should be selected based on a thorough review of Alaskan coastal topographic maps and hydrographic charts. Primary factors considered in site evaluation and selection include the following:

- Minimum distance from the 100 feet water depth contour to the coastal shoreline to minimize offshore pipeline costs
- Optimization of the onshore pipeline route to the coastal site with emphasis on avoiding mountainous terrain, major river crossings, and coastal marshlands
- Presence of a relatively flat area large enough to accommodate onshore tank farm facilities with a minimum of site improvement
- Preferable coastline/shore profile to minimize environmental impact and costs associated with the pipeline shore crossing

The nearshore terminal loading structure located approximately five miles from shore is surrounded by a 2.5 mile radius tanker mooring and maneuvering area (MMA). The perimeter of the MMA should be slightly beyond the 100 feet water depth contour. This is considered to be the minimum operating water depth for arctic tankers maneuvering in or about nearshore regions during severe ice conditions.

Estimated total tanker turnaround time at the terminal is 29 to 31 hours based on the following:

Approach and Moor Tanker (hours)	3.5 - 4.0
Connect Loading Arm (hours)	1.0
Tanker Loading and Topping (hours)	22.0 - 23.0
Disconnect Loading Arm (hours)	0.5
Terminal Departure Time (hours)	1.5 - 2.0
TOTAL TURNAROUND TIME (hours)	28.5 - 30.5

Crude oil properties are summarized in Chapter 6.0.

5.3.2 Nearshore Terminal Design

The nearshore tanker terminal includes onshore tank farm facilities as shown on Drawing No. 506, and an offshore tanker loading structure as shown on Drawing No. 507. The offshore storage terminal conceptual design was based on a storage volume equivalent to fifteen days of production. However, because of the longer open water season duration and less severe ice conditions at the nearshore terminal, a storage volume equivalent to ten days of production is used for the nearshore terminal. Therefore, considering a base case production rate of 400,000 BPD, the tank farm storage volume is designed for four million barrels and consists of eight 500,000 barrel tanks.

Tank Farm

Each tank is located on a foundation berm surrounded by a containment berm. The capacity of the containment berm equals 100 percent of the total tank volume to also allow for rain water and snow melt within the berm. Each tank is 250 feet in diameter and 62 feet high. Fixed cone roofs are specified for the tanks because heavy snowfall and icing problems will adversely affect floating roof tanks. The tanks are welded steel, each containing mixers to prevent crude oil stratification and a level alarm which warns against low crude oil level or overfilling. Low temperature steel is required for the extreme low temperatures at the terminal location.

The onshore facilities include:

- Oil storage tanks
- Meters and prover systems
- Crude oil loading pumps
- Diesel fuel topping plant
- Oil vapor recovery system
- Incineration and sewage treatment plant
- Power generation system
- Maintenance shop and storage buildings
- Personnel accommodations
- Control center
- Potable water storage system
- Heliport and aircraft landing site
- Communication facilities

Loading Structure

When a tanker arrives at the loading structure, stored crude oil is pumped from the tank farm through a 36-inch diameter submarine pipeline to the loading structure at the rate of 60,000 barrels per hour.

The nearshore terminal loading structure shown on Drawing No. 507 is located approximately five miles offshore in a water depth of 110 feet. The structure has an octagonal shape and a composite steel/concrete ice resistant exterior wall. Composition of the ice resistant exterior wall and the horizontal and vertical framing systems are similar to the offshore structures. To effectively resist global ice load, sand ballast is used to fill the spaces within the structure. However, spud piles are not required because of reduced global ice loads. The nearshore structure materials are basically the same as described in the previous section, for an offshore structure.

Minimal facilities and equipment located on the loading structure include:

- Personnel accommodations
- Loading boom and heliport
- Communication systems
- Navigational aids including fog horn
- General alarm and fire control system
- Service crane

<u>Loading Boom</u>

The nearshore terminal loading boom is the same as the offshore terminal loading boom described in Section 5.2.2, and shown on Drawing No. 504.

Mooring and Loading Operations

Tanker mooring and loading operations are also basically the same as for the offshore terminal with the exception of a longer tanker loading time due to the reduced loading rate. However, it should be noted that the loading rate can be increased by increasing the pipeline diameter and pumping equipment capacity.

5.3.3 Seasonal Limitation and Weather Downtime

The nearshore terminal operating criteria are based on worldwide offshore terminal experience, and are the same as for the offshore tanker loading terminal described in Section 5.2.3.

Estimated annual weather downtime for the nearshore terminal, based on the frequency of occurrence of wind, wave, current and visibility conditions (reference Chapter 3) which exceed the assumed terminal shutdown limits are as follows:

- Wave conditions will prevent mooring and loading operations for approximately 97 hours annually. Annual weather downtime due to excessive current conditions is expected to be minimal. Visibility conditions which limit mooring operations occur 206 hours annually. In summary, total nearshore annual weather downtime due to wind, wave, current and visibility is 303 hours or 12.6 days.

- A 9.5 tenths multi-year ice concentration at the terminal site has been assumed to be the limiting criterion for tanker operations. Based on this assumption and a review of multi-year ice concentrations for the study area, it was determined that the 9.5 tenths multi-year ice condition does not occur in the nearshore areas. Therefore, the terminal is not subject to ice-related weather downtime.

5.3.4 Nearshore Terminal Construction Schedule

To determine construction feasibility and a realistic construction schedule, fabricators with the capability of constructing onshore tank farms and/or offshore arctic structures were contacted. Fabricators contacted in addition to those listed in Section 5.3.4 included Chicago Bridge and Iron (CBI), Houston, Texas. It should be noted that CBI fabricated and installed the tank farm at the Valdez terminal.

Equipment and materials in sufficient quantities to support construction operations for a nine month period, including facilities for 125 men will be moved to shore. Cargo lightening to shore from larger vessels anchored offshore may be required. Access roads and an aircraft landing site 3,000 feet long will be constructed to facilitate mobility within the construction area and airlifting of personnel and supplies during winter months.

Fabrication of the loading structure will not require special fabrication procedures as the loading structure dimensions are similar to structures which have been built for Beaufort Sea exploration. Fabrication will be initiated in a graving dock until the structure reaches a predetermined draft after which the structure is floated out and construction completed in sheltered waters near the graving dock. The overall construction schedule for the nearshore terminal shown on Drawing No. 508 will require approximately five years.

5.3.5 Nearshore Terminal Capital Construction Cost Estimate

The nearshore terminal direct construction cost was estimated based on material unit rates and required structure material quantities, vendor cost estimates for major structure facilities and equipment, marine contractor day rates for towing, and unit pipeline costs developed in Chapter 6.

The estimated total direct construction cost for the nearshore terminal is $312.11 million. The total nearshore terminal capital cost including fifteen percent contingency, five percent engineering services, ten percent project management, U.S.-built arctic Class 6, icebreaking terminal support vessel and a Bell 213 helicopter is approximately $597.77 million. The base case nearshore terminal construction cost estimate summary is presented in Table 5.8.

5.3.6 Annual Operating and Maintenance Cost Estimate

The base case nearshore terminal annual operating and maintenance cost estimate summarized in Table 5.9 is $47.8 million per year.

Operating Costs

Nearshore terminal annual operating cost includes personnel, logistics, quartering, helicopter fuel and icebreaking terminal support vessel operating costs. Annual personnel cost of $19.01 million is based on a twelve hour work day, seven day work week and two week rotation for a total work force of 134 men, 67 per rotation. Annual estimated logistics and quartering costs are \$3.21 million and \$5.45 million, respectively. Helicopter fuel cost based on six hours of operation per day and a consumption rate of 700 pounds per hour is \$0.8 million. The annual operating cost for a Class 6, 30,000 hp icebreaking terminal support vessel is estimated at \$10.36 million.

Maintenance Costs

Estimated annual nearshore terminal maintenance cost of \$8.97 million is based on one and on-half (1.5) percent of the installed terminal capital cost.

5.3.7 Application to Alternate Transportation Scenarios

Three possible tanker loading terminal sites include Wainwright, Kivalina, and Nome. The base case nearshore terminal cost estimate described above was based on a crude oil storage volume of four million barrels at the Kivalina location.

To determine the sensitivity of cost to variations in storage volume and terminal location, costs for the base case were first adjusted to reflect a range of storage volumes from two million barrels to twenty million barrels. These costs were then adjusted to reflect sensitivities due to change in terminal location from Kivalina to Wainwright and Nome. The results of this analysis for both capital construction costs and operating and maintenance costs are presented in Tables 5.10 and 5.11, respectively.

5.4 TRANSSHIPMENT TERMINAL AT UNIMAK PASS

Based on the nearshore terminal and existing transshipment terminals around the world, the estimated capital construction costs of a transshipment terminal at Unimak Pass are:

Flow Rate (MBPD)	Capital Construction Costs (USD $\times 10^6$)
100	950
200	950
400	1170
600	1655

The annual operating and maintenance costs of a transshipment terminal were estimated at $32 million.

5.5 VALDEZ TRANSSHIPMENT TERMINAL

A capital construction cost of $400 million was assigned for upgrading of the Valdez terminal for transshipment of crude oil into Valdez, with an annual operating cost of $20 million.

TABLE 5.1

OFFSHORE TERMINAL ANNUAL WEATHER DOWNTIME

(Ice Conditions Not Included)

	WIND (Hrs)	WAVE (Hrs)	CURRENT (Hrs)	VISIBILITY (Hrs)	TOTAL (Hrs)
Jan	0	0	0	59	59
Feb	0	0	0	49	49
Mar	0	0	0	49	49
Apr	0	0	0	46	46
May	0	0	0	46	46
Jun	0	0	0	46	46
Jul	8	8	8	49	73
Aug	8	8	8	49	73
Sep	8	22	8	36	74
Oct	8	22	8	36	74
Nov	0	0	0	56	56
Dec	0	0	0	56	56
TOTAL	32	60	32	577	701 Hrs 29.2 Days

TABLE 5.2

MATERIAL QUANTITY SUMMARY

OFFSHORE TERMINAL STRUCTURES

(Base Case)

STRUCTURE	CONCRETE (cu yd)	STRUCTURAL STEEL (s tons)	REINFORCING STEEL (s tons)	SAND INFILL (cu yd)
Storage Structure (6×10^6 barrels storage)	318,000	42,000	42,000	547,000
Loading Structure	84,000	17,000	11,000	60,000
TOTAL	402,000	59,000	53,000	607,000

TABLE 5.3

ARCTIC STRUCTURE MATERIAL COST

RESPONSE SUMMARY TABLE

NAME	LOCATION	INPLACE REINFORCED CONCRETE	FABRICATED STRUCTURAL STEEL ($/ton)	SAND INFILL ($/cu yard)
Bouygues Offshore	France	1,125.00	2,325.00	15.95
Concrete Tech. Corp.	Tacoma, WA	510.51	3,063.00	
Daewoo	Korea		1,100.75	
Hyudai Corp.	Korea	1,620.00	3,610.00	
IHI	Japan	1,400.00	2,722.16	
Kiewit	Omaha, NB	1,500.00	3,750.00	
Mitsubishi	Japan	700.00	2,356.20	
Mitsui Shipbuilding	Japan	544.45	1,843.34	
Morrison Knudsen	Boise, ID	712.20	2,400.00	15.75
Nippon Steel	Japan	1,487.78	2,034.20	
Mean		956.10	2,520.46	15.85
Median		700.00	2,356.20	-
Maximum Value		1,500.00	3,750.00	15.95
Minimum Value		510.51	1,100.75	15.75
Standard Deviation		419.34	763.16	0.10
VALUE SELECTED FOR COST ESTIMATING PURPOSES		960.00	2,500.00	15.85

TABLE 5.4

OFFSHORE ARCTIC TERMINAL

CAPITAL COST ESTIMATE SUMMARY

(Base Case)

ITEM DESCRIPTION	COST (US$ $x10^6$)
Storage Structure (6 $x10^6$ barrels storage)	471.40
Loading Structure	144.85
Towing	29.76
Site Survey	5.40
Foundation Preparation	6.75
Installation	90.76
Pipeline	81.21
Facilities	8.70
Equipment	23.42
TOTAL DIRECT CONSTRUCTION COST	862.25
Contingencies (15%)	129.34
SUB-TOTAL	991.59
Engineering Services (5%)	49.58
Project Management (10%)	99.16
TOTAL STRUCTURE CAPITAL COST	1,140.33
Icebreaking Terminal Support Vessel (U. S. Built)	270.25
Helicopter	6.50
TOTAL TERMINAL CAPITAL COST	1,417.08

TABLE 5.5

OFFSHORE ARCTIC TERMINAL

ANNUAL OPERATING AND MAINTENANCE COST ESTIMATE SUMMARY

(Base Case)

ITEM DESCRIPTION	COST (US$ x10^6)
Personnel	12.20
Logistics	1.20
Quartering	3.50
Helicopter Fuel	1.00
Icebreaking Terminal Support Vessel	14.80
TOTAL ANNUAL OPERATING COSTS	32.70
Annualized Maintenance Cost (1.5% of Construction)	21.25
TOTAL TERMINAL OPERATING AND MAINTENANCE COST	53.95

TABLE 5.6

OFFSHORE ARCTIC TERMINAL

CAPITAL CONSTRUCTION COST ESTIMATE

SENSITIVITY ANALYSIS SUMMARY

OFFSHORE ARCTIC CONSTRUCTION COSTS (USD $x10^6$)			
STORAGE VOLUME (mmbbl)	FIELD LOCATION		
	SOUTHERN	CENTRAL	NORTHERN
2	1046.1	1133.7	1388.4
4	1098.0	1190.3	1405.7
6	1187.1	1417.1	1554.4
8	1483.9	1657.7	1818.4
10	1602.6	1771.4	1947.4
12	2003.9	2182.3	2811.4
14	2248.4	2593.3	2889.6
16	2389.7	2706.6	2967.7
18	2529.7	2805.9	3045.8

TABLE 5.7

OFFSHORE ARCTIC TERMINAL

ANNUAL OPERATING AND MAINTENANCE COST ESTIMATE

SENSITIVITY ANALYSIS SUMMARY

OFFSHORE ARCTIC OPERATING AND MAINTENANCE COSTS (USD x10^6)			
STORAGE VOLUME (mmbbl)	FIELD LOCATION		
	SOUTHERN	CENTRAL	NORTHERN
2	48.4	49.7	53.5
4	49.2	50.6	53.8
6	50.5	54.0	56.0
8	55.0	57.6	60.0
10	56.7	59.3	61.9
12	62.8	65.4	74.9
14	66.4	71.6	76.0
16	68.5	73.3	77.2
18	70.6	74.8	78.4

TABLE 5.8

NEARSHORE ARCTIC TERMINAL

CAPITAL COST ESTIMATE SUMMARY

(Base Case)

ITEM DESCRIPTION	COST (US$ $x10^6$)
Loading Structure	167.85
Site Survey	3.60
Site Preparation	21.70
Containment Berm	14.20
Storage Tanks	20.00
Pipeline	42.15
Facilities	9.58
Equipment	33.03
TOTAL DIRECT CONSTRUCTION COST	312.11
Contingencies (15%)	46.82
SUB-TOTAL	358.93
Engineering Services (5%)	17.95
Project Management (10%)	35.89
TOTAL STRUCTURE CAPITAL COST	412.77
Icebreaking Terminal Support Vessel (U.S. Built)	178.50
Helicopter	6.50
TOTAL TERMINAL CAPITAL COST	597.77

TABLE 5.9

NEARSHORE TERMINAL

ANNUAL OPERATING AND MAINTENANCE COST

(Base Case)

ITEM DESCRIPTION	USx10^6$
Personnel	19.01
Logistics	3.21
Quartering	5.45
Helicopter Fuel	0.80
Icebreaking Terminal Support Vessel	10.36
TOTAL ANNUAL OPERATING COST	38.83
Annual Maintenance Cost (1.5% of Construction)	8.97
TOTAL OPERATING AND MAINTENANCE COST	47.80

TABLE 5.10

NEARSHORE ARCTIC TERMINAL

CAPITAL CONSTRUCTION COST ESTIMATE

SENSITIVITY ANALYSIS SUMMARY

NEARSHORE ARCTIC TERMINAL CAPITAL CONSTRUCTION COSTS			
STORAGE VOLUME (mmbbl)	LOCATION		
	WAINWRIGHT	KIVALINA	NOME
2	621.26	583.79	567.80
4	634.46	597.77	581.00
6	647.66	610.19	594.20
8	660.86	623.39	607.40
10	674.06	636.59	620.60
12	687.26	649.79	633.80
14	700.46	662.99	647.00
16	713.66	676.19	660.20
18	726.86	689.39	673.40
20	740.06	702.59	686.60

TABLE 5.11

NEARSHORE ARCTIC TERMINAL

ANNUAL OPERATING AND MAINTENANCE COST ESTIMATE

SENSITIVITY ANALYSIS SUMMARY

NEARSHORE ARCTIC TERMINAL OPERATING AND MAINTENANCE COSTS (USD $x10^6$)			
STORAGE VOLUME (mmbbl)	LOCATION		
	WAINWRIGHT	KIVALINA	NOME
2	50.38	47.59	46.10
4	50.58	47.80	46.30
6	50.77	47.98	46.49
8	50.97	48.18	46.69
10	51.17	48.38	46.89
12	51.37	48.58	47.09
14	51.57	48.77	47.29
16	51.76	48.97	47.48
18	51.96	49.17	47.68
20	52.16	49.37	47.88

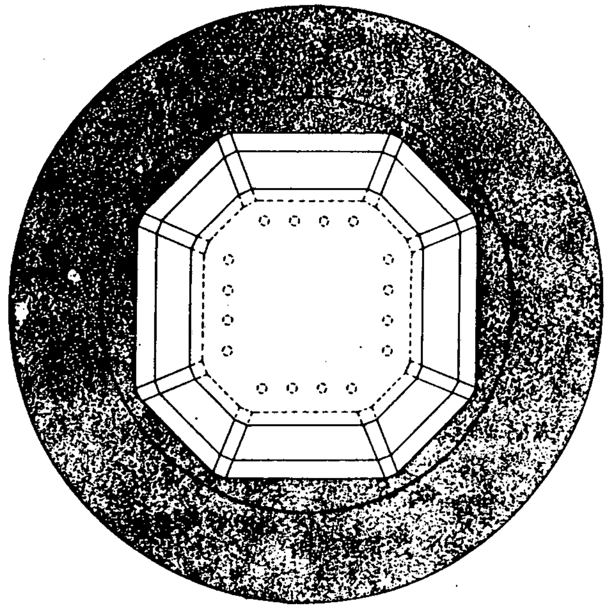
TABLE 5.12

PRODUCTION STRUCTURE

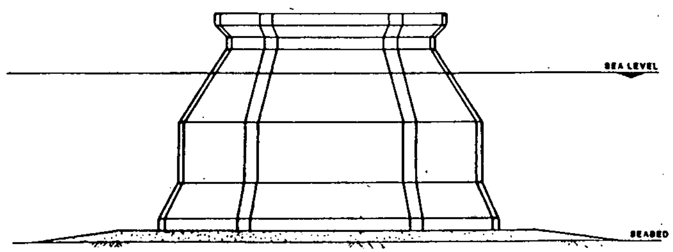
CAPITAL COST ESTIMATE SUMMARY

(Central Field Location)

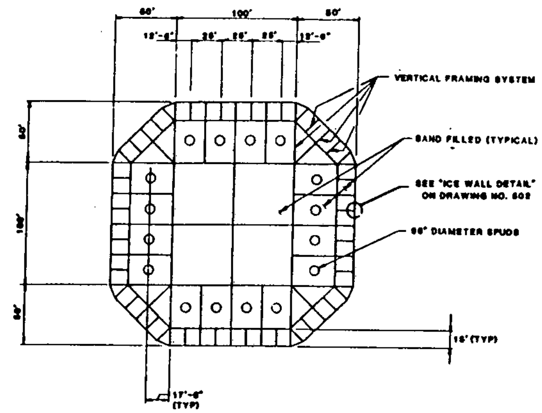
ITEM DESCRIPTION	COST (US$ x10^6)
Production Structure	300.08
Towing	11.30
Site Survey	2.52
Foundation Preparation	2.35
Installation	30.50
Facilities	6.50
Equipment	14.10
TOTAL DIRECT CONSTRUCTION COST	367.35
Contingencies (15%)	55.10
SUB-TOTAL	422.45
Engineering Services (5%)	21.12
Project Management (10%)	42.25
TOTAL STRUCTURE CAPITAL COST	485.82
Helicopter	6.50
TOTAL TERMINAL CAPITAL COST	492.32



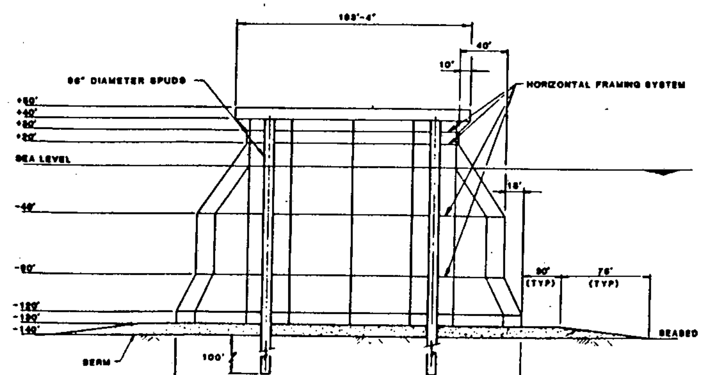
PLAN VIEW
Scale 1" = 50'



ELEVATION
Scale 1" = 50'

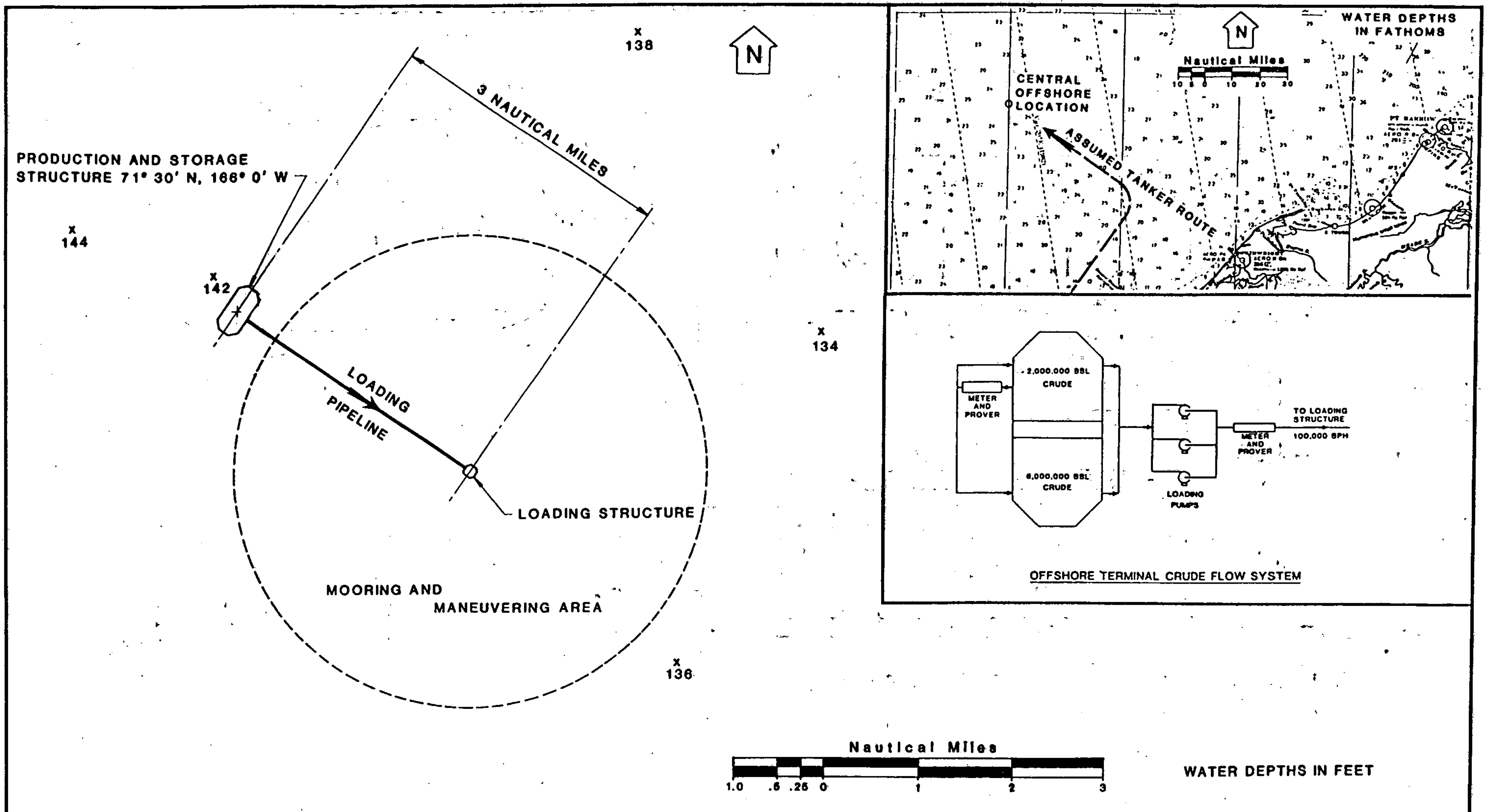


PLAN AT SEA LEVEL
Scale 1" = 50'

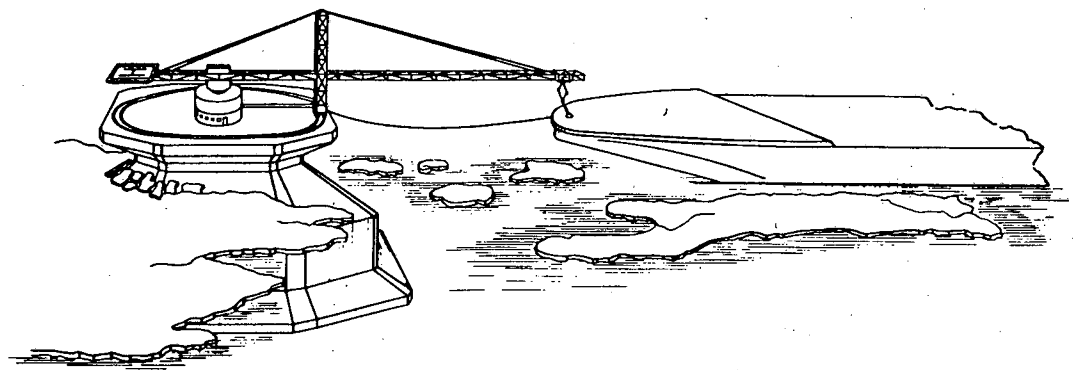


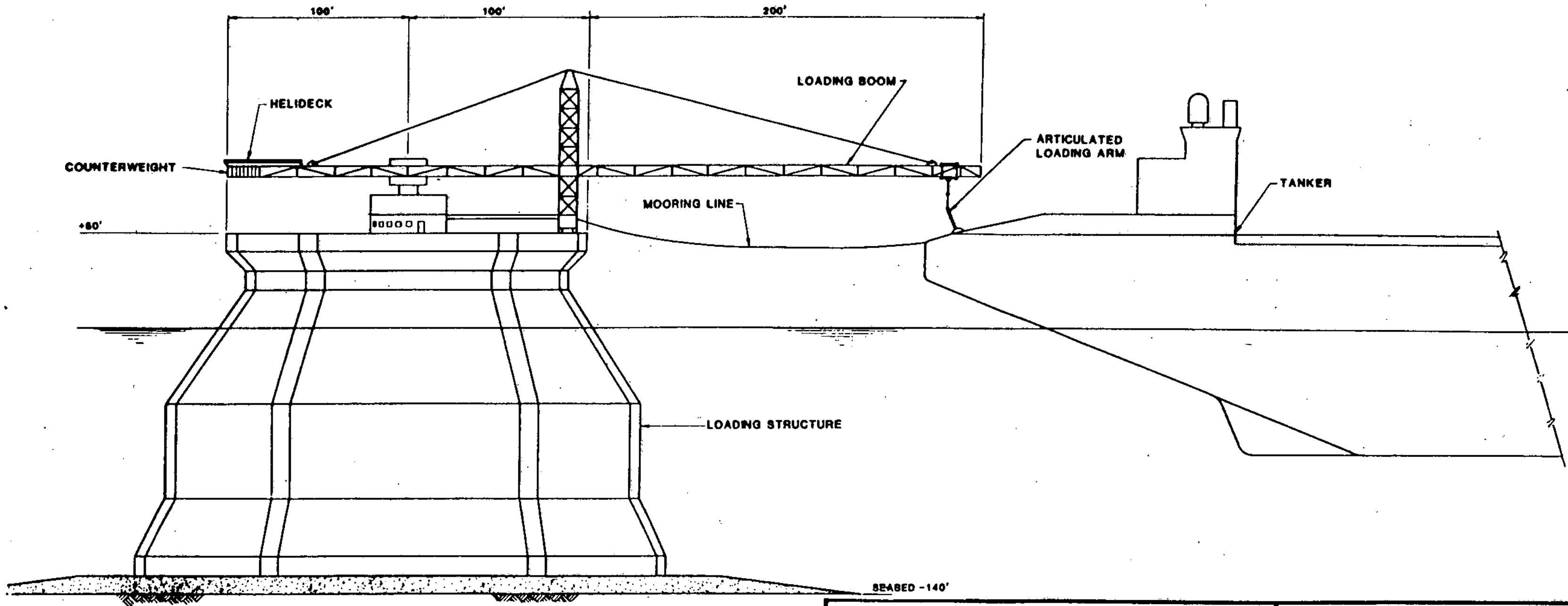
TYPICAL SECTION
Scale 1" = 80'

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	OFFSHORE LOADING STRUCTURE CONCEPT			
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 501	
	DATE 1-17-91	JOB NO. H-046.4		

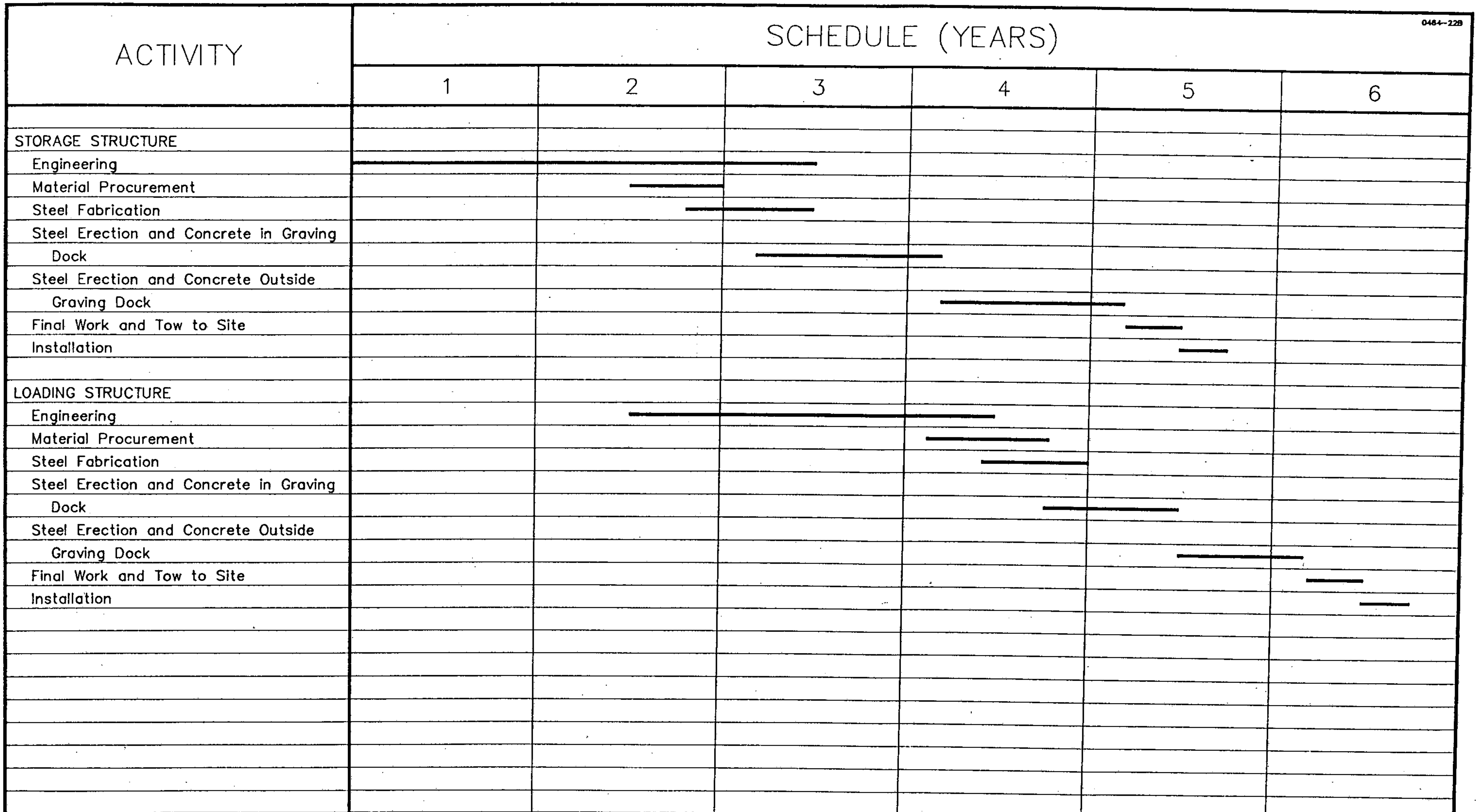


JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	OFFSHORE TERMINAL CONCEPTUAL SITE PLAN		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 502
	DATE 1-17-91	JOB NO. H-046.4	





JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	LOADING ARM CONCEPT		
INTEC ENGINEERING, INC.	SCALE NONE DATE 1-17-91	DRAWN BY KC JOB NO. H-046.4	DRAWING NO. 504



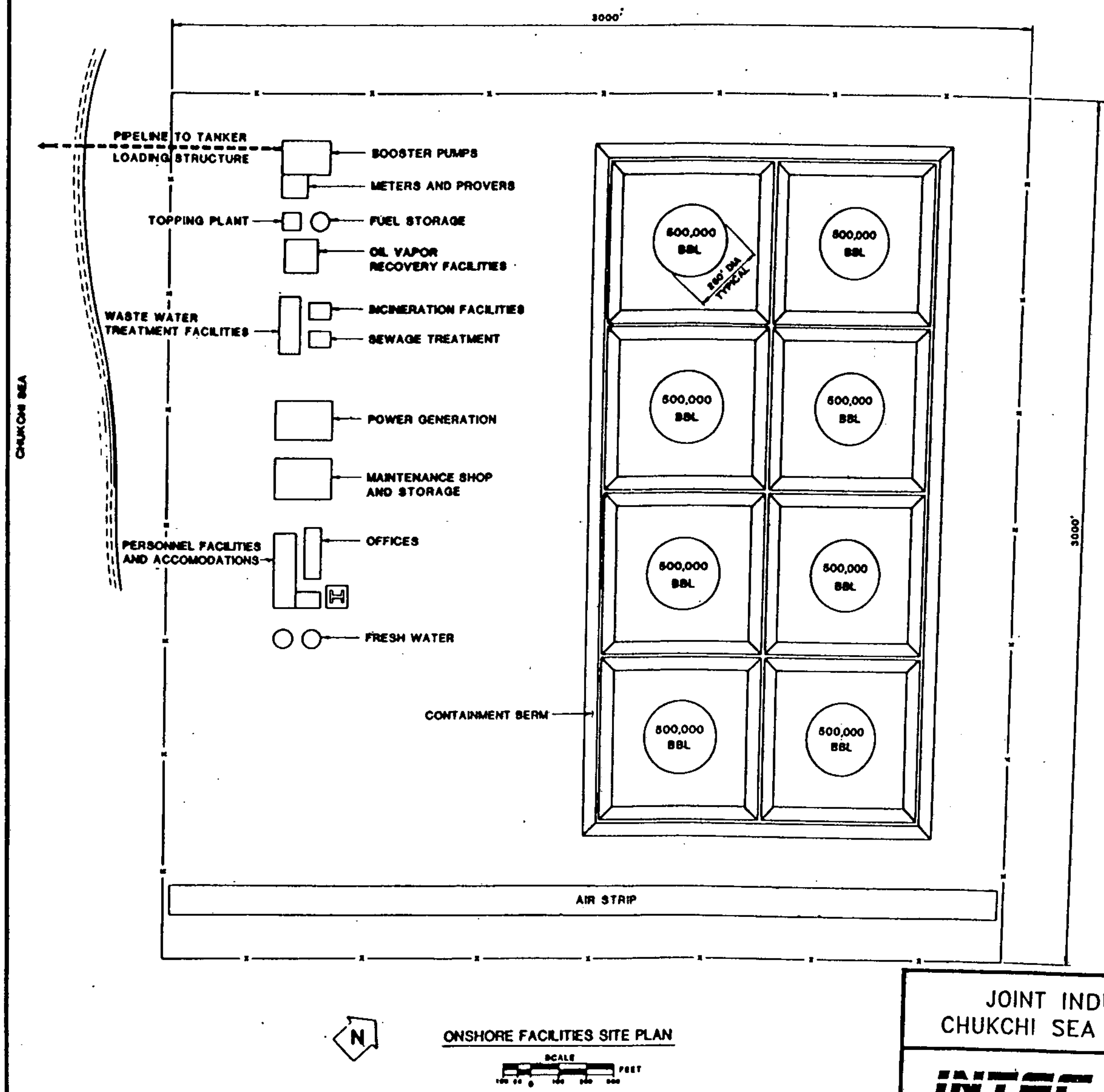
NOTE: FABRICATION AND HOOK-UP OF DRILLING AND PRODUCTION FACILITIES (NOT SHOWN) WILL BE IN YEARS 4 AND 5 AND MAY ADD ONE YEAR TO THE PRODUCTION/STORAGE STRUCTURE CONSTRUCTION SCHEDULE.

JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

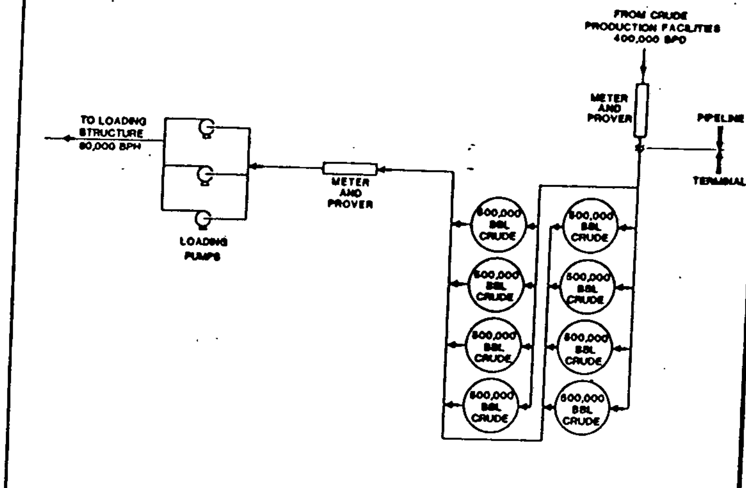
INTEC ENGINEERING, INC.

OFFSHORE TERMINAL
CONSTRUCTION SCHEDULE

SCALE	DRAWN BY	DRAWING NO.
NONE	KC	505
DATE 3-1-91	JOB NO. H-046.4	



ONSHORE FACILITIES SITE PLAN



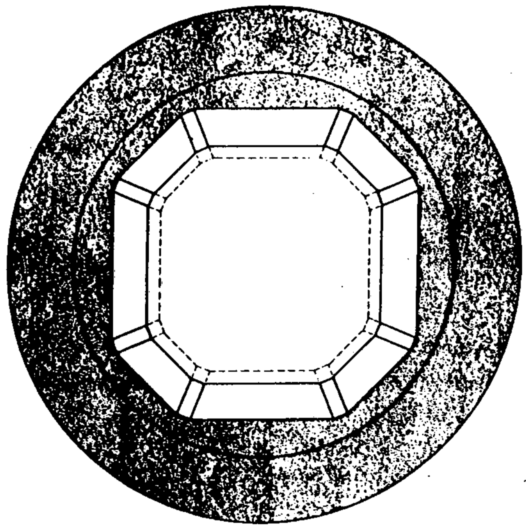
NEARSHORE TERMINAL CRUDE FLOW SYSTEM

JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

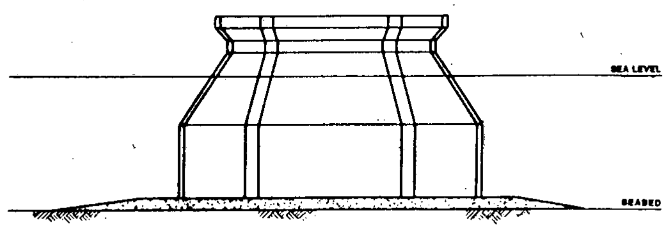
ONSHORE FACILITIES
SITE PLAN

INTEC ENGINEERING, INC.

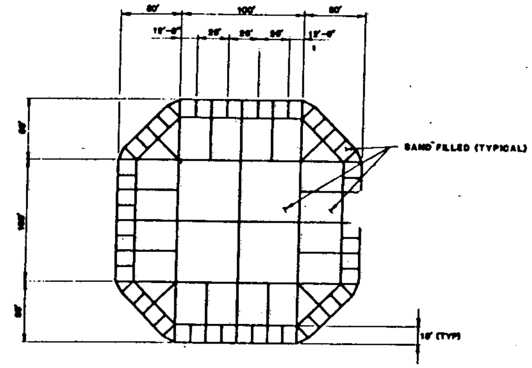
SCALE	DRAWN BY	DRAWING NO.
NONE	KC	506
DATE 1-17-91	JOB NO. H-046.4	



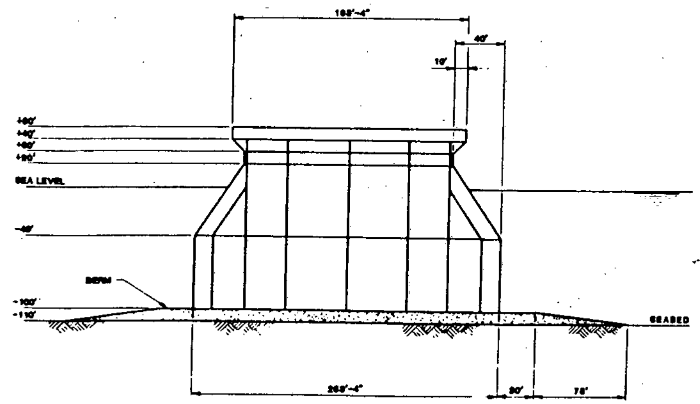
PLAN VIEW



ELEVATION

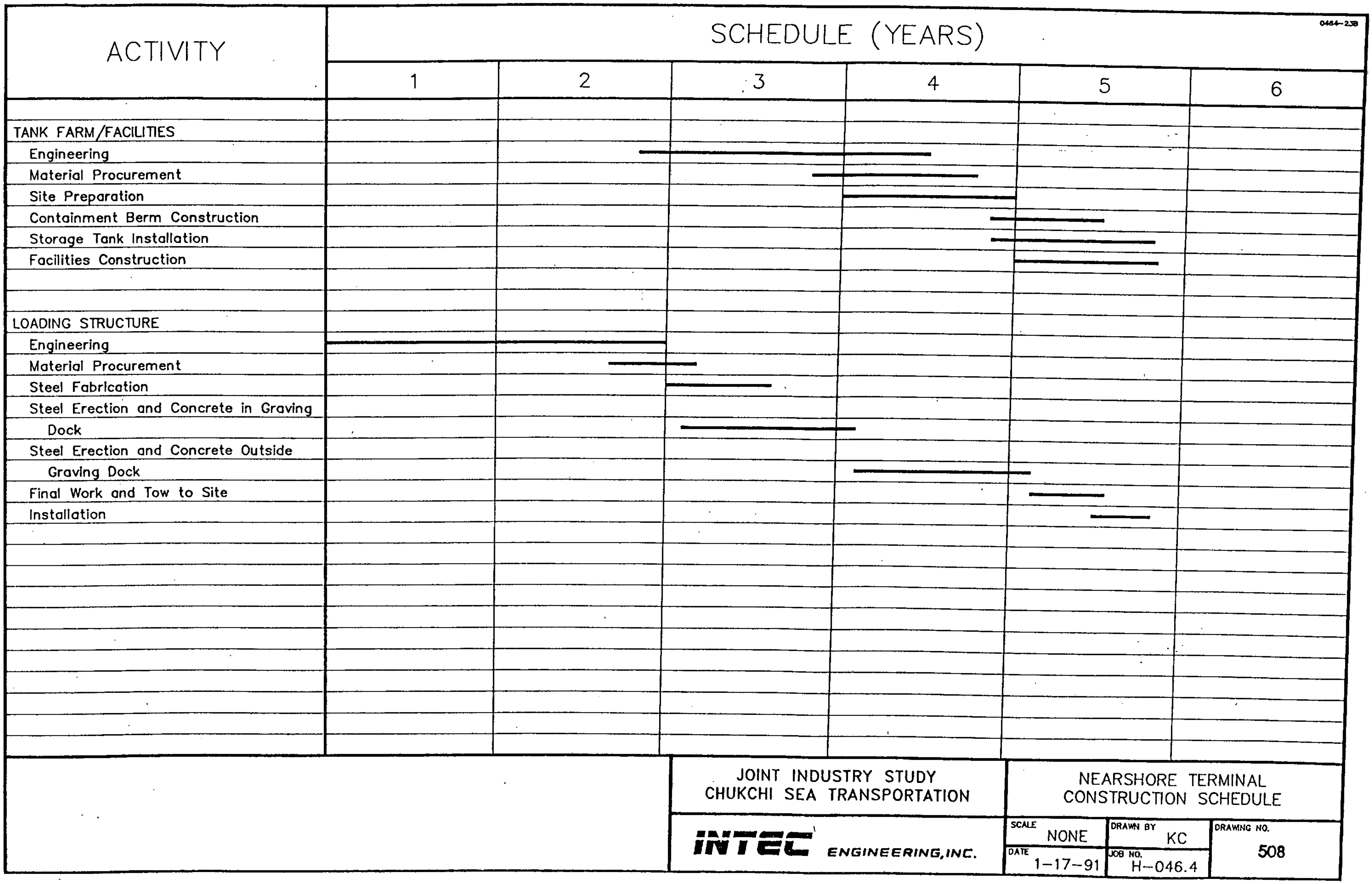


PLAN AT SEA LEVEL



TYPICAL SECTION

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	NEARSHORE LOADING STRUCTURE CONCEPT
INTEC ENGINEERING, INC.	SCALE NONE; DRAWN BY KC; DRAWING NO. 507 DATE 1-17-91; JOB NO. H-046.4


0464-238
ACTIVITY
SCHEDULE (YEARS)
1
2
3
4
5
6
TANK FARM/FACILITIES
Engineering
Material Procurement
Site Preparation
Containment Berm Construction
Storage Tank Installation
Facilities Construction
LOADING STRUCTURE
Engineering
Material Procurement
Steel Fabrication
Steel Erection and Concrete in Graving Dock
Steel Erection and Concrete Outside Graving Dock
Final Work and Tow to Site
Installation
JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION
INTEC ENGINEERING, INC.
NEARSHORE TERMINAL
CONSTRUCTION SCHEDULE
SCALE NONE
DRAWN BY KC
DRAWING NO. 508
DATE 1-17-91
JOB NO. H-046.4

CHAPTER 6

PIPELINES

CHAPTER 6
PIPELINES

6.1 GENERAL

The objectives of this chapter are to:

- Establish preliminary pipeline design requirements for eight pipeline routes
- Evaluate pipeline installation methods appropriate for Chukchi Sea trunklines and loading lines
- Evaluate pipeline trenching methods and select those most appropriate for developments in the Chukchi Sea
- Provide preliminary cost estimates for pipeline materials, trenching, installation, pump stations and annual operating and maintenance costs
- Evaluate the sensitivity of pipeline capital construction costs with respect to crude oil flow rates, and field location

6.2 PIPELINE DESIGN

6.2.1 Pipeline Route Selection

Eight alternative pipeline routes have been evaluated. These routes were part of eleven transportation scenarios developed for the 1986 study, each of which required one or more pipelines. The eight pipelines routes have been denoted P1 through P8, as shown on Drawing No. 601, and identified in Table 6.1.

Route P1 (Central Field Location to Point Barrow)

Pipeline P1 is a 214 mile trunkline from the central field location (71°30' N, 166°W) to a pump station at Point Barrow (71°19' N, 156°38' W), as shown on Drawing No. 602. One hundred and eighty miles of route P1 require trenching. The remaining thirty four miles of the pipeline are in water depths exceeding 200 ft where trenching is not required.

Route P2 (Point Barrow to Prudhoe Bay)

Pipeline P2 starts from an onshore pump station at Point Barrow and is routed through the Beaufort sea, running approximately parallel to the shoreline. The pipe line makes a shore crossing at Oliktok Point and travels overland to TAPS Pump Station No. 1 at Prudhoe Bay (71°16' N, 148°37' W). The offshore and onshore portions of route P2 are 164 and 34 miles, respectively, as shown on Drawing No. 603. Trenching is required along all of the offshore portion of the trunkline. Permafrost may be encountered within the upper thirty feet of the seabed soils in the Beaufort Sea and is expected to be continuous in water depths of less than five feet. Permafrost is discontinuous in deeper waters. The preliminary design of pipeline P2 assumes that insulation to prevent permafrost degradation is required in water depths of less than twenty feet. Insulation is, therefore, required along 105 miles of the pipeline.

Route P3 (Central Field Location to Wainwright)

Pipeline P3 is an offshore trunkline from the central field location to a pump station and/or terminal near Wainwright (70° 30' N, 160° 27' W). Pipeline P3 requires trenching along its entire 143 mile length as shown on Drawing No. 604.

Route P4 (Wainwright to TAPS PS3)

Pipeline P4 is an elevated overland pipeline which extends 309 miles from a pump station near Wainwright to TAPS Pump Station No. 3. Onshore pipelines must be elevated to prevent permafrost degradation, and require insulation over their entire length.

Route P5 (Central Field Location to Cape Lisburne)

Pipeline P5 is an offshore trunkline from the central field location to a pump station at Cape Lisburne (68° 51' N, 163° 31' W). Trenching is required along the entire 183 mile length of the pipeline. The depth of cover varies from six to fourteen feet, as outlined on Drawing No. 605.

Route P6 (Cape Lisburne to TAPS PS3)

Pipeline P6 is an onshore trunkline extending east from a pump station at Cape Lisburne to TAPS PS3, a distance of 396 miles.

Route P7 (Cape Lisburne to Kivalina)

Pipeline P7 is a 57 mile onshore pipeline extending from a pump station at Cape Lisburne to a tanker terminal and/or pump station near Kivalina (68°2' N, 165°23' W).

Route P8 (Kivalina to Nome)

Pipeline P8 consists of a 113 mile offshore pipeline section extending south from a pump station near Kivalina to a shore crossing at Cape Lowenstern. The onshore pipeline section is 107 miles long and ends at a tanker terminal at Nome (64°51' N, 165°10' W), as shown on Drawing No. 606.

6.2.2 Pipeline Design

Preliminary pipeline analyses were performed to define parameters which significantly affect the technical feasibility and cost of the offshore pipelines.

Crude Oil Properties

Crude oil properties similar to those for Prudhoe Bay (Sadlerochit) were assumed as follows:

- Gravity : 26.4 degrees API
- Specific Gravity: 0.89 at 35° F
- Viscosity : 0.00073 ft^2/sec at 35°F
- Pour Point : 0° F

Pipe Diameter Selection

Trunkline external diameters were selected to ensure that the downstream discharge pressure for a given pipeline length and crude oil flow rate was not less than 50 psig. Pressure drops were calculated using Darcy's Law. Each pipeline route was sized for crude oil flow rates of 100, 200, 400 and 600 thousand barrels per day (MBPD).

concrete density of 190 pounds per cubic foot (pcf) are shown in Table 6.2.

Pipeline Insulation

Pipeline preliminary designs assume that insulation of offshore trunklines is required in water depths of less than twenty feet. The insulation system considered for cost estimating purposes in shallow water is a pipe within a pipe, with a polyurethane foam filled annulus of 2.75 inches. Structural and watertight bulkheads of Type C, as shown on Drawing No. 607, were selected, as they eliminate the need to make a complex field joint on the laybarge.

Onshore trunklines require insulation over their entire length. The onshore pipeline insulating system is a 2.75-inch thickness of polyurethane foam enclosed by a crimped steel jacket.

Cathodic Protection

For cost estimating purposes, zinc bracelet anodes were selected to provide cathodic protection. Zinc anode requirements were determined using the following equation:

zw = (pipe OD x π/12) x (pipeline length) x (% flaws) x (current density) x (consumption rate) x (design life)

where:

- zw = required weight of zinc (lb/mile)

- Pipe OD = pipeline outside diameter (inches)
- Pipeline length = 1 mile x 5280 ft/mile
- % flaws = percentage of flaws in corrosion coating = 2/100
- Current density = 11 mA/ft^2 x (1/1000) A/mA (DNV design code)
- Consumption rate= 25 lb/(amp.yr)
- Design life = 25 years

Zinc anode requirements for a range of pipeline diameters are summarized in Table 6.2.

6.2.3 Pipe Selection

Table 6.3 lists the pipe diameter required for each pipeline route for four different flow rates. The diameters have been designed to ensure a downstream discharge pressure of not less than fifty psig in each case.

6.3 RECOMMENDED INSTALLATION METHOD

This section summarizes the selected methods of installation for Chukchi Sea trunklines and loading lines based on the 1986 study. Possible pipeline installation methods and evaluation criteria are presented in Table 6.4.

For trunklines in water depths exceeding forty feet, a third generation laybarge operating in Ice Condition A is recommended. Ice Condition A is the least severe, with total concentrations of less than 3/10, or a level, uniform ice thickness of less than eight inches. The average annual duration of Ice Condition A at the central field location is approximately eight weeks. Further south, thirteen weeks are typical for Wainwright and approximately eighteen weeks at Cape Lisburne. Ice conditions are summarized in Table 6.5.

A typical third generation laybarge with double joint capabilities is shown on Drawing No. 608. Estimated effective installation rates for both a second generation and third generation laybarge are presented in Table 6.6. Second generation laybarge installation rates are approximately fifty percent of the third generation laybarge rates and have been included for purposes of comparison only. Third generation laybarges are considered practical in Ice Condition A with appropriate ice management support. The laybarge method of pipelaying is compatible with all pipeline trenching methods.

For pipeline segments in less than forty feet of water depth, the bottom pull method is recommended. Bottom pull pipeline installation rates are shown in Table 6.6. A bottom pull barge can operate in approximately nine feet of water, which is within 0.5 miles of the coastline. Pulling in Ice Condition A can be conducted with one icebreaker support vessel. The bottom pull method is considered applicable for pipelines with lengths of less than approximately twenty miles.

Loading Lines

For the nearshore loading lines, the bottom pull method is recommended. The offshore loading lines are relatively short and favor the bottom tow method of installation. In the bottom tow method, an anchored pull barge is used to pull the pipeline into sufficient water depth for accessibility by a large tug. Once the tug is connected, the pull barge is released and the pipe is towed into position. A three-mile long pipe string could be launched and towed a distance of 180 miles in approximately four to five days.

6.4 TRENCHING REQUIREMENTS AND METHODS

This section summarizes trenching requirements for pipelines in the Chukchi Sea. Recommended trenching methods are identified based on technical feasibility and performance criteria.

6.4.1 Trenching Requirements

As stated in the 1986 Chukchi Sea transportation study, pipelines installed in the Chukchi Sea will require trenching for ice gouge protection. Due to the importance of trenching requirements in determining pipeline installation costs, three procedural methods were used to determine depth of cover requirements. These methods are based on the following:

- Maximum observed ice gouge depths along the pipeline corridor
- Beaufort Sea pipeline trenching requirements
- Statistical analysis of Chukchi Sea ice gouge data

Comparison of the three procedures for determining trenching requirements indicates considerable variation between methods. Depth of cover requirements based on the use of Chukchi Sea ice gouge data are generally between those derived by the other two methods. South of 72° N latitude, Chukchi Sea ice gouge data has been used to determine depth of cover requirements. North of 72° N latitude, the Beaufort Sea ice gouge analysis method was used.

Pipeline depths of cover for the five offshore trunklines are provided on Drawings No. 602 through

606. The recommended depths of cover for Chukchi Sea loading lines are fourteen feet at the central field location, six feet at or near Kivalina and six feet at or near Nome.

6.4.2 Recommended Trenching Methods

Dredging equipment is considered to be the primary excavation method for the Chukchi Sea, due to the length and depth of cover requirements for the off-shore pipeline routes. Evaluation of a trailing suction hopper dredge and a preliminary linear trencher concept clearly indicates the economic advantage of the linear trencher for trench lengths greater than thirty to thirty-five miles.

The linear trencher concept is depicted on Drawing No. 609, and would be purpose-built for the soil types and water depths encountered in the Lease Sale 126 area of the Chukchi Sea. It combines the favorable aspects of both cutter suction and trailing suction hopper dredges, and is capable of operation in water depths of between 30 feet and 200 feet. In water depths of less than 30 feet, a cutter suction dredge would be used for pipeline trenching. The linear trencher is towed to the dredging site and positioned over the pipeline route, and could excavate a 12-foot deep trench at an effective production rate of 0.8 miles per day. The trench would be dredged to the required depth by means of several box cut passes. Each box cut pass removes a volume of soil that is rectangular in cross-section. The cross-sectional area of each box cut becomes progressively smaller as the trench is deepened. A twelve feet to fourteen feet deep trench would require three box cut passes. The linear trencher would also perform a clean-up sweep of the entire trench length prior to installation of the pipeline. Costs associated with the proposed linear trencher are shown in Table 6.13.

A conceptual or preliminary design exists for the linear trencher, but would require approximately two years for completion of detailed design and construction.

Post trenching equipment may be used for trench maintenance operations, pipe stabilization or span corrections. Use of a mechanical trencher in combination with the linear trencher is competitive, but less economic than using the linear trencher alone. The use of a post trenching plow in a predredged trench is considered to be too expensive because of the need for establishing a 30-foot trench bottom width to minimize the possibility of plow sidewall interference during post trenching of the pipeline.

6.5 PIPELINE CONSTRUCTION SCHEDULE

A typical construction schedule for Chukchi Sea offshore pipelines is depicted on Drawing No. 610.

Preliminary engineering and surveying/route selection would take place during the first two years. Detailed engineering would commenced midway through Year Two. Materials procurement and transportation to site would commence after the detailed engineering phase and would take place until the end of Year Four. Three seasons are allocated for predredging/trenching of the pipeline route, using the linear trencher described in Section 6.4. A 150 to 200-mile pipeline could then be installed in two seasons with a third generation laybarge.

6.6 CAPITAL CONSTRUCTION COSTS

6.6.1 Material Costs

General

Unit costs for materials are summarized in Tables 6.7 through 6.9. An allowance of three percent of the value of materials is included for material surplus.

Line Pipe

API grade 5LX-65 line pipe was assumed for all pipelines at a unit cost of $800/ton. This cost is f.o.b. steel mills in the Far East.

Corrosion Coating

Fusion Bonded Epoxy (FBE) coating is used on all pipelines to provide corrosion protection. A 30-mil (0.03-inch) thickness is applied at a unit cost of $1.65/ft^2.

Concrete Weight Coating

Concrete weight coating would be applied where required on offshore pipelines to provide hydrodynamic stability prior to trenching. A concrete density of 190 pcf is assumed at a unit cost of $0.09/lb.

Cathodic Protection Anodes

Zinc anode bracelets were assumed for all offshore pipelines at a unit cost of $2.00/lb.

Insulation

Insulation is provided by a 2.75-inch thickness of 2.5 pcf polyurethane foam. Insulation costs are shown in Table 6.10.

6.6.2 Transportation Costs

Arctic Transportation Ltd. (ATL) has indicated the feasibility of transporting line pipe from steel mills in the Far East directly to Prudhoe Bay, Alaska. Transportation would be by means of oceangoing barges which would proceed to the ice edge in the vicinity of Wainwright, Alaska. Line pipe would then be transferred to local tugs and transported to Prudhoe Bay.

The estimated cost of transportation, lightening and offloading of the line pipe is $180 per ton. A further allowance of $100 per ton has been included for transportation of line pipe from the receiving dock to the pipe coating plant, and onward to the construction site.

6.6.3 Installation Costs

Installation spread day rates for offshore pipeline construction are shown in Table 6.10. Day rates for alternative pipeline installation methods, in Ice Condition A, are shown below:

INSTALLATION METHOD	DAY RATE ($k)
2nd Generation Laybarge	385
3rd Generation Laybarge	660
Bottom Tow	139
Bottom Pull	210

Effective pipeline installation rates are shown in Table 6.6.

The estimated cost of constructing onshore facilities to support bottom pull pipeline installation is $15 million per offshore pipeline. The bottom pull method is used for installation of pipelines in water depths of less than forty feet.

Onshore pipeline installation costs based on quotes from pipeline contractors are summarized in Table 6.11.

Structure approach and shore crossing costs used in capital cost evaluations are summarized in Table 6.12.

6.6.4 Mobilization/Demobilization Costs

Mobilization/demobilization costs for a third generation laybarge are based on a distance of 16,500 nautical miles from Rotterdam to the Chukchi Sea area, via Cape Horn, at a vessel transit speed of seven knots. A mobilization/demobilization day rate equal to fifty percent of the operating day rate is assumed for pipeline capital cost calculations.

The cost of mobilizing and demobilizing installation and trenching support vessels is estimated to be $5 million per construction season.

6.6.5 Trenching Costs

Costs associated with the proposed linear trencher are summarized in Table 6.13. A linear trencher excavation rate of 0.8 miles per day was used in trenching cost calculations.

A cutter suction dredge would be subject to a mobilization/demobilization cost of $3 million, a fixed cost per year of $4.7 million, a daily cost of $55,000 and a cost per mile of approximately $18,500 for replacement of high maintenance items. A cutter suction dredge trenching rate of 0.18 miles per day was used in trenching cost calculations.

Trenching costs were also calculated assuming that the linear trencher was not developed, and that trailing suction hopper dredges were used in lieu of a linear trencher. Trailing suction hopper dredges would be mobilized/demobilized at a cost of $4 million per dredge. Each dredge would also incur a fixed cost of $12.25 million per year, a daily operating cost of $65,600 and a cost per mile of approximately $13,500. An effective linear trenching rate of 0.15 miles per day was used for trailing suction hopper dredges.

All trenching costs include a twenty percent miscellaneous cost to allow for uncertainties in soil conditions, trench profiles and equipment downtime.

6.6.6 Pump Stations

Where pump stations are required, a capital cost of \$1200 per horsepower is used. This includes pumps, turbines, facilities and topping plant. Table 6.14 shows the pump capacity required at the downstream end of Pipelines P1 through P8 to produce a pipeline inlet pressure of 1800 psig. Pump horsepower requirements were determined using the following equation:

$$HP = (\Delta P) \times (BPD/1000) \times .022$$

where:

HP	=	pump capacity required, (horsepower)
ΔP	=	difference between desired pressure (1800 psig) and pressure losses over line length (psi)
BPD	=	crude oil flowrates (barrels per day)
0.022	=	factor derived from a pump efficiency of 80 percent and a gear efficiency of 97 percent

6.6.7 Project Costs

The cost of engineering, project management and materials procurement for Chukchi Sea pipelines is estimated to be ten percent of the combined total of material and installation costs.

Project insurance is typically five percent of material and installation costs. These project costs have been included in the pipeline scenario cost estimates.

6.6.8 Pipeline Scenario Cost Estimates

Capital costs were estimated for Pipelines P1 through P8 at flow rates of 100, 200, 400 and 600 thousand barrels per day (MBPD), and are presented in Tables 6.15(a) and 6.15(b). An allowance of fifteen percent for contingencies and omissions was included.

Tables 6.16(a) and 6.16(b) summarize the estimated cost of Pipeline P1, at the central field location, with a peak flowrate of 100 MBPD.

6.7 OPERATING AND MAINTENANCE COSTS

6.7.1 Pipeline Operating Personnel

Offshore Structure Based Personnel

There is no requirement for dedicated full or part-time personnel on the central field structure who are directly assigned to operation of the offshore crude oil pipelines. Thus, there are no additional labor costs associated with the existence of the offshore crude oil export lines in excess of those already required for operation of the offshore facilities.

Shore Based Personnel

Pipelines P1, P3 and P5 each require a shore based Pipeline Operations Department to control oil flows and pressures throughout the pipeline system. The Pipeline Operations Department is manned on a continuous basis. The department could also be responsible for other functions such as offshore facilities emergency coordination and contingency response. Minimum personnel levels to achieve this are as follows:

- Eight (8) full-time pipeline operators
- One (1) pipeline operations department head

Additional shore based personnel required to support operation of offshore Pipelines P1, P3 and P5 are as follows:

- One (1) pipeline operations department head
- One (1) pipeline operations superintendent
- One (1) pipeline engineer
- One (1) corrosion technician
- One (1) operations technician
- One (1) secretary

Salary, taxes, overheads and benefits for shore based personnel are as follows:

POSITION	SALARY (USD)	TOTAL (USD)
Pipeline Operations Department Head	1 @ 100,000	100,000
Pipeline Operators	8 @ 65,000	520,000
Operations Department Head	1 @ 100,000	100,000
Operations Superintendent	@ 90,000	90,000
Pipeline Engineer	1 @ 75,000	75,000
Corrosion Technician	1 @ 65,000	65,000
Operations Technician	1 @ 50,000	50,000
Secretary	1 @ 25,000	25,000
SUB-TOTAL		1,025,000
Taxes Benefits and Overheads @ 45%		461,250
TOTAL (USD) PER YEAR		1,486,250

Existence of the offshore facilities will generate the need for an onshore logistics and supply base. However, the existence of the offshore pipelines creates no additional supply base related costs in excess of those required to support the offshore production facilities.

Additional shore based personnel are required to support the operation of Pipelines P4, P6 and P7; and the onshore sections of Pipelines P2 and P8.

Pipelines P4 and P6 are both in excess of 300 miles in length, and would each require the following operations support personnel:

- One (1) pipeline operations superintendent
- Two (2) pipeline engineers
- Three (3) corrosion technicians
- Three (3) operations technicians
- Two (2) secretaries

Pipelines P2, P7 and P8 would each require the following operations support personnel:

- One (1) pipeline operations superintendent
- One (1) pipeline engineer
- One (1) corrosion technician
- One (1) operations technician
- One (1) secretary

6.7.2 Pipeline Inspection Costs

Inspection costs for Chukchi Sea offshore pipelines are based on an initial ROV inspection two years after the pipeline is commissioned, with inspections every five years thereafter.

ROV inspection costs for offshore pipelines are shown below, and are based on the following:

- A six mile per day inspection rate, exclusive of a thirty percent weather downtime allowance and a five percent mechanical downtime allowance
- Mobilization/demobilization cost of $100,000 each way, assuming a U.S. west coast port
- Inspection cost of $20,000/day
- Post processing and reporting cost of $40,000

PIPELINE ROUTE	LENGTH	ROV INSPECTION COST(1)
P1	214 miles	$1,320,000
P2	164 miles	$1,081,000
P3	143 miles	$ 960,000
P5	183 miles	$1,160,000
P8	113 miles(2)	$ 820,000

Notes:
(1)ROV inspection cost is after two years and then every five years thereafter.
(2)P8 length shown is the offshore section of Pipeline P8.

Onshore pipelines would be inspected visually approximately every two weeks. Inspections would be performed aerially by means of a fixed wing aircraft. An allowance of $7,000,000 per year for visual inspection is included for Pipelines P4, P6 and P7. The onshore section of pipeline could be inspected using the aircraft whose cost is included in the inspection cost for Pipeline P8. The onshore section of Pipelines P2 need not be inspected aerially, due to its relatively short length (34 miles) and its proximity to existing support facilities at Prudhoe Bay.

6.7.3 Cathodic Protection Potential Measurement Costs

Approximately one-third of the offshore pipeline length should be surveyed each year, using a locally acquired vessel. Cathodic protection potential measurement costs for the offshore pipelines are shown below, and are based on the following:

- A nine mile per day inspection rate, exclusive of a thirty percent weather downtime allowance and a five percent mechanical downtime allowance
- Mobilization/demobilization cost of $5000 each way
- Inspection cost of $15,000/day
- Post processing and reporting cost of $15,000

PIPELINE ROUTE	LENGTH	CATHODIC PROTECTION MEASUREMENT COST(1)
P1	214 miles	$ 205,000
P2	164 miles	$ 175,000
P3	143 miles	$ 145,000
P5	183 miles	$ 190,000
P8	113 miles(2)	$ 130,000

Notes:
(1)Cathodic Protection Potential Measurement cost is annual.
(2)P8 length shown is for the offshore section of Pipeline P8.

6.7.4 Intelligent Pigging Costs

Costs are based on surveying the entire length of the pipeline every five years. Spread costs are as follows:

- Mobilization/demobilization cost of $20,000 each way
- A rate per mile of $1100
- Incidentals cost of $50,000

Intelligent pigging costs for each pipeline route are shown below:

PIPELINE ROUTE	LENGTH	INTELLIGENT PIGGING COSTS[1]
P1	214 miles	$ 325,000
P2	198 miles	$ 308,000
P3	143 miles	$ 247,000
P4	309 miles	$ 430,000
P5	183 miles	$ 291,000
P6	396 miles	$ 526,000
P7	57 miles	$ 153,000
P8	220 miles	$ 332,000

Note:

[1] Intelligent pigging costs are once every five years.

6.7.5 Maintenance and Repair Costs

The cost of maintaining a pipeline system is subject to extensive variations which are a function of the quality of materials and installation work, as well as the environmental and operating conditions to which the pipeline may be exposed during its operating life. Normal maintenance could include the following:

- Replacement of span supports
- Replacement of anodes
- Placement of stable backfill in areas of scour or erosion
- Repair of riser clamps and riser coating

To assign a figure to this category of maintenance costs, assume that every two years a diving support vessel is required for a duration of one month at a daily rate of $75,000 plus twenty days mobilization and demobilization at a daily rate of $45,000, to perform the required tasks. In addition, assume a cost of $350,000 for materials and consumables. The associated cost is therefore estimated at $3.5 million two years, or $1.75 million per year.

Another possible cost is for repair of pipeline or pipeline appurtenance damage. This cost category is even more difficult to estimate since the cause and type of damage is more difficult to predict or assume. The most exposed portions of the offshore pipelines are the shore approach and structure risers. If a pipeline section needed to be replaced due to damage from whatever cause, this would represent a major cost. For the purpose of this study, assume a $10 million repair project is required every five years, resulting in a cost of $2 million on an annual basis.

Due to the uncertainty as to the nature and frequency of damage to onshore pipelines, no annual costs have been included for repair of Pipelines P4, P6 and P7.

6.7.6 Operation, Maintenance and Repair Cost Summary

The operation, maintenance and repair costs identified in the previous sections are summarized in Table 6.17.

6.7.7 Taxation

The annual operating cost of the pipelines considered in this study should also include a tax equal to one (1) percent of the initial capital expenditure for each overland pipeline, and one (1) percent of the value of the sections of each offshore pipeline that are within three miles of the coastline.

Annual taxation expenses for each pipeline are shown in Table 6.18.

6.8 PIPELINE DECOMMISSIONING

Decommissioning and removal is not typically required for offshore oil and gas pipelines. Therefore, the economic evaluations presented in Chapter 8 do not include the cost of removing the offshore pipelines.

It is uncertain at this time whether any of the onshore pipelines considered in this study will require decommissioning and removal. Future legislation regarding the environmental impact of pipelines could make onshore pipeline removal mandatory. However, no costs have been included in this study for the removal of onshore pipelines at the end of their operational life.

The present value of a year twenty removal cost equal to fifty percent of the initial pipeline installation cost, excluding materials, is shown in Table 6.19 for each onshore pipeline and the onshore sections of pipelines P2 and P8, at a central field location. The present value figure was calculated using a ten percent discount rate.

6.9 ALTERNATIVE FIELD LOCATIONS

A variation in the offshore field location from the central field to northern or southern fields will only alter the costs of Pipelines P1, P3 and P5. The material and installation costs for these three pipeline routes were adjusted to reflect the change in pipeline length for the northern and southern locations. Table 6.20 presents capital costs for Pipelines P1, P3 and P5 at the northern and southern field locations.

Annual operating and maintenance costs, including taxation, are shown for these three pipelines, at the alternative field locations, in Table 6.21.

TABLE 6.1

TRANSPORTATION SCENARIO PIPELINE ROUTES

PIPELINE DESIGNATION	ROUTE DESCRIPTION	PIPELINE LENGTH (mile)		NO. OF STRUCTURE APPROACHES	NO. OF SHORE CROSSINGS	INSULATED LENGTH (mile)	TRENCHED LENGTH (mile)
		OFFSHORE	ONSHORE				
P1	Central Field location to Point Barrow	214	N/A	1	1	1	171 miles @ 14 ft 9 miles @ 7 ft
P2	Point Barrow to Prudhoe Bay (TAPS PS1)	164	34	N/A	2	105	95 miles @ 10 ft 69 miles @ 7 ft
P3	Central Field location to Wainwright	143	N/A	1	1	1	72 miles @ 13 ft 71 miles @ 8 ft
P4	Wainwright to TAPS PS3	N/A	309	N/A	N/A	309	N/A
P5	Central Field location to Cape Lisburne	183	N/A	1	1	1	35 miles @ 14 ft 70 miles @ 8 ft 78 miles @ 6 ft
P6	Cape Lisburne to TAPS PS3	N/A	396	N/A	N/A	396	N/A
P7	Cape Lisburne to Kivalina	N/A	57	N/A	N/A	57	N/A
P8	Kivalina to Nome	113	107	N/A	2	113	113 miles @ 6 ft

Note:
TAPS PS represents Trans-Alaska Pipeline System Pump Station

TABLE 6.2

PIPELINE DESIGN SUMMARY

PIPELINE DIAMETER (inches)	WALL THICKNESS (inches)[1]	CONCRETE WEIGHT COATING THICKNESS (inches)[2]	ZINC ANODE REQUIREMENTS (lb/mile)[3]
16	0.318	1.01	3,041
18	0.375	1.07	3,421
20	0.406	1.23	3,801
22	0.438	1.38	4,181
24	0.469	1.53	4,562
26	0.500	1.70	4,942
28	0.562	1.75	5,322
30	0.625	1.80	5,702
32	0.625	2.05	6,482
34	0.688	2.10	6,462
36	0.750	2.14	6,842
38	0.750	2.40	8,223
42	0.812	2.71	7,983
44	0.875	2.76	8,363

Notes:
[1] API standard line pipe wall thicknesses.
[2] Weight coating provides S.G. of 1.10 when empty.
[3] Based on current density of 11 mA/ft^2 and 25 year design life.

TABLE 6.3

PIPE DIAMETER REQUIRED AT

ALTERNATIVE CRUDE OIL FLOW RATES

PIPELINE ROUTE	PIPE DIAMETERS (inches)			
	FLOW RATES (MBPD)			
	100	200	400	600
P1	20	26	34	38
P2	20	26	32	38
P3	20	24	30	36
P4	22	28	36	42
P5	20	26	32	38
P6	24	30	38	44
P7	16	20	26	30
P8	20	26	34	38

Note:
Pipe diameters have been selected to ensure a downstream discharge pressure of not less than 50 psig.

TABLE 6.4

EVALUATION SUMMARY FOR INSTALLATION METHODS

EVALUATION CRITERIA	2ND GENERATION LAYBARGE	3RD GENERATION LAYBARGE	BOTTOM TOW	BOTTOM PULL
Diameter Limitations	None	None	None	None
Equipment Availability	Gulf of Mexico	North Sea	W. Coast	W. Coast
Experience	Extensive	Moderate	Limited	Moderate
Water Depth Limitations (ft)	17-360	25-360	26-360	9-360
Tolerance to Ice Interference	Low	Low	Moderate	Moderate
Ice Management Support Req'ments	Significant	Significant	Low	Moderate
Limiting Significant Wave Height (ft)	9	12	12	8
Applicability to Insulated Pipeline	Note 1	Note 1	Note 2	Note 2
Economic Pipeline Lengths (mi)	50-100	75-320	0-15	0-20
Compatibility With Trenching Methods	Good	Good	Fair	Fair

Notes:
(1) Most efficient with use of insulated pipe joint design shown on Drawing No. 607 Figure C.
(2) Can be used with all insulated joint configurations depicted on Drawing No. 607.

TABLE 6.5

DESCRIPTION OF ICE CONDITIONS AND CONSTRUCTION SEASON DURATIONS

ICE CONDITION PARAMETERS	DESIGNATION		
	A	B	C
Total Ice Concentration	≤ 3/10	≤ 8/10	≥ 8/10
Maximum Uniform Ice Thickness (ft)	0.7	3	5
Maximum Sail Height for First Year Ridges (ft)	None	3	5
Multi-Year Ice Concentration	Trace	1/10	2/10
Season Duration at Central Site (weeks)(1)	8	12	14

Note:
(1)Season durations noted represent average year conditions.

TABLE 6.6

EFFECTIVE PIPELINE INSTALLATION RATES (MILES/WEEK)

PIPE DIAMETER (inch)	2ND GENERATION LAYBARGE	3RD GENERATION LAYBARGE	BOTTOM TOW(2)	BOTTOM PULL(3)
16 - 20	9.4	18.8	5.0	3/1
22 - 26	7.9	15.8	5.0	3/1
28 - 32	6.7	13.4	5.0	3/1
34 - 38	5.9	11.8	5.0	3/1
40 - 44	5.3	10.6	5.0	3/1
46 - 48	4.7	9.4	5.0	3/1
Installation Rate Factors				
Weather Downtime	0.90	0.95	0.97	0.94
Mechanical Downtime	0.80	0.80	0.95	0.95

Notes:
(1)Effective installation rates do not include mechanical or weather related downtime.
(2)Rate is for towing 3 mile long interfield lines approximately 180 miles from shore.
(3)Lower rates for interfield lines approximately 180 miles from shore. Higher rate is for pipelines within 50 miles from the shoreline.

TABLE 6.7

MATERIAL UNIT COSTS

MATERIAL	UNIT COST
Line Pipe (5LX-65)	$800/ton
Fusion Bonded Epoxy Coating (30 mils)	$1.65/ft^2
Concrete Weight Coating (190 pcf)	$0.09/lb
Zinc Anodes	$2.00/lb
Material Transportation	$280/ton

Note:
All costs are in US$.

TABLE 6.8

PIPELINE MATERIAL COST SUMMARY

PIPE DIAMETER (inches)	UNIT COSTS (USx10^3$/mile)			
	LINE PIPE[1]	CORROSION COATING[2]	CONCRETE COATING[3]	ZINC ANODES[4]
16	105.7	36.5	33.8	6.1
18	140.1	41.0	40.2	6.8
20	168.6	45.6	51.4	7.6
22	200.2	50.2	63.6	8.3
24	234.0	54.9	77.0	9.1
26	270.2	59.3	92.8	9.9
28	326.8	63.8	102.5	10.6
30	389.2	68.5	112.8	11.4
32	415.6	73.0	137.5	12.2
34	485.8	77.5	149.3	12.9
36	560.4	82.1	160.8	13.7
38	592.2	86.6	191.0	14.4
42	708.9	95.8	238.7	16.0
44	799.7	100.3	254.2	16.7

Notes:
(1)Line Pipe = \$800/ton
(2)FBE Corrosion Coating = \$1.65/ft^2
(3)Concrete Coating = \$0.09/lb
(4)Zinc Anodes = \$2/lb

TABLE 6.9

INSULATED PIPELINE COSTS

PIPE DIAMETER (inches)	INSULATION FOAM AND CRIMPED STEEL JACKET (USx10^3$/mile)[1]	OFFSHORE PIPELINES OUTER PIPE[2] (USx10^3$/mile)	BULKHEADS AND SPACERS FOR OFFSHORE INSULATION (USx10^3$/mile)[3]
16	97.2	101.2	51.7
18	109.3	125.9	54.9
20	121.4	136.4	58.1
22	133.6	147.0	61.2
24	145.7	157.6	64.4
26	157.9	168.3	67.6
28	170.0	178.8	70.8
30	182.2	189.4	73.9
32	194.3	249.2	77.1
34	206.4	262.5	80.3
36	218.6	303.7	83.4
38	230.7	318.3	86.6
42	255.0	347.5	92.9
44	267.2	410.3	96.1

Notes:
(1)Offshore and onshore pipelines, 2.75-inch thickness of 2.5 pcf polyurethane foam.
(2)Outer pipes have minimum API wall thicknesses, $800/ton
(3)Cost is determined by: $/mile = 5,280 * (5 + 0.3 * OD (in).

TABLE 6.10

SUPPORT VESSEL REQUIREMENTS AND COST DATA FOR PIPELINE INSTALLATION

VESSEL NOTE[1]	UNIT COST ($US\$ \times 10^3$/Day)	INSTALLATION METHOD			
		2ND GENERATION LAYBARGE	3RD GENERATION LAYBARGE	BOTTOM TOW	BOTTOM PULL
Anchor Handling Tug	30.5	2	2	N/A	1
Survey Vessel	33.5	1	1	1	1
Supply Vessel	33.5	1	1	1	1
Tie-in/Pull Barge	40.0	N/A	N/A	1	2
Icebreakers[1]	32.0	1	1	1	1
Laybarge	Note [2][3]	1	1	N/A	N/A

Notes:
N/A = Not applicable
(1) Ice Condition A requires Class 2 icebreaker vessel, other support vessels correspond to CASPPR 1A.
(2) 2nd generation laybarge vessel day rate = \$225,000
3rd generation laybarge vessel day rate = \$500,000
(3) 3rd generation laybarge wintering cost between each construction season is \$7,500,000.

TABLE 6.11

ONSHORE PIPELINE INSTALLATION COSTS

PIPE DIAMETER	INSTALLATION COST (USx10^6$/mile)[1]
16	2.560
18	2.790
20	2.900
22	3.080
24	3.240
26	3.250
28	3.360
30	3.450
32	3.520
34	3.672
36	3.744
38	3.800
42	4.032
44	4.048

Note:
[1]Estimates include labor, equipment, consumables and supplies.
[2]Does not include construction of temporary or permanent haul road and costs of permanent materials, permits and rights-of-way.

TABLE 6.12

SHORE CROSSING AND STRUCTURE APPROACH COSTS

PIPE DIAMETER (inches)	STRUCTURE APPROACH	SHORE CROSSING
16	$140,000	$390,000
18	$150,000	$395,000
20	$155,000	$400,000
22	$160,000	$405,000
24	$165,000	$410,000
26	$170,000	$420,000
28	$175,000	$430,000
30	$180,000	$435,000
32	$185,000	$440,000
34	$190,000	$450,000
36	$193,000	$455,000
38	$195,000	$460,000
42	$200,000	$470,000
44	$205,000	$475,000

Note:
Additional laybarge time is required for shore crossings and structure approaches as follows:

- Shore crossing: 5 days at installation spread cost of $660,000/day
- Structure approach: 7 days at installation spread cost of $660,000/day

TABLE 6.13

LINEAR TRENCHER COSTS

ITEM	COST ($)
Mobilization/Demobilization[1]	6,000,000
Fixed Cost per Season[2]	6,000,000
Daily Operating Cost[3]	97,000
Cost per Mile of Trench Length[4]	35,000
Construction Cost Assigned to Pipeline [5]	39,000,000

Notes:
(1)Assumes Gulf of Mexico construction.
(2)Includes winterization, repairs, maintenance, insurance, labor, fuel, lube, interest, depreciation, assembly/disassembly of floating pipeline.
(3)Spread includes one trencher, two ice strengthened tugs, floating pipeline, dumping pontoon and tug, survey and positioning.
(4)Based on a fixed cost of $0.20 per cubic yard of soil volume which includes replacement costs for high maintenance items such as suction tubes, pump impellers and cutter head assembly.
(5)65 percent of $60,250,000 construction cost assigned to first pipeline trenching project.

TABLE 6.14

PIPELINE ROUTE PUMP HORSEPOWER REQUIREMENTS

PIPELINE ROUTE	PUMP HORSEPOWER REQUIREMENTS (HP)			
	FLOW RATES (MBPD)			
	100	200	400	600
P1	3,586	6,635	12,294	21,846
P2	3,335	6,173	15,215	20,328
P3	2,398	6,538	15,145	19,193
P4	3,271	6,767	13,561	19,364
P5	3,067	5,676	13,992	18,678
P6	2,759	6,279	13,235	19,932
P7	2,779	6,340	11,898	18,586
P8	3,687	6,824	12,637	22,466

Note:
HP requirements refer to pump capacity needed at downstream end of pipeline to increase pressure to 1800 psig.

TABLE 6.15(a)

PIPELINE CAPITAL CONSTRUCTION COSTS

CENTRAL FIELD LOCATION

PIPELINE ROUTE	(US$x10^6) FLOW RATE (MBPD)			
	100	200	400	600
1	524.627	601.544	766.892	835.638
2	713.834	799.578	928.457	1,046.636
3	428.706	469.458	543.822	616.666
4	1,449.694	1,659.019	1,980.855	2,208.618
5	479.224	544.934	635.299	731.106
6	1,972.358	2,222.675	2,593.357	2,904.561
7	217.827	257.284	305.455	344.332
8	828.439	946.886	1,157.117	1,243,282

Note:
Assumes development of linear trencher.

TABLE 6.15(b)

PIPELINE CAPITAL CONSTRUCTION COSTS

CENTRAL FIELD LOCATION

PIPELINE ROUTE	(US$x10^6) FLOW RATE (MBPD)			
	100	200	400	600
P1	863.465	940.382	1,105.730	1,174.476
P2	857.434	943.179	1,072,057	1,190.236
P3	687.335	728.086	802.450	875.295
P4	1,449.694	1,659.019	1,980.855	2,208.618
P5	754.259	819.969	910.335	1,006.141
P6	1,972.358	2,222.675	2,593.357	2,904.561
P7	217.827	257.284	305.455	344.332
P8	910.790	1,029.236	1,239.468	1,325.632

Note:
Assumes use of conventional dredging equipment.

TABLE 6.16(a)

CAPITAL CONSTRUCTION COST, PIPELINE P1

CENTRAL FIELD LOCATION, 100 MBPD

20-INCH DIAMETER

CATEGORY	ITEM	ITEM COST ($)	CATEGORY TOTAL ($)
Materials			
	Line Pipe	36,080,400	
	Corrosion Coating	9,758,400	
	Concrete Coating	10,999,600	
	Zinc Anodes	1,626,400	
	Outer Line Pipe	136,400	
	Bulkheads/Spacers	58,100	
	Insulation	121,400	
	Surplus	1,763,421	60,544,121
Mobilization/ Demobilization			
	Laybarge	50,000,000	
	Linear Trencher	6,000,000	
	Support Vessels	10,000,000	
	Cutter Suction Dredge	3,000,000	69,000,000
Fixed Costs			
	Linear Trencher Annual Cost	36,000,000	
	Cutter Suction Dredge Annual Cost	4,700,000	
	Laybarge Wintering	7,500,000	48,200,000
Installation			
	Pipelaying	69,741,000	
	Trenching	73,967,000	
	Shore Crossing	3,700,000	
	Structure Approach	4,775,000	152,183,000
Infrastructure			
	Pump Station	4,303,200	
	Onshore Facilities	15,000,000	19,303,200
Construction Cost			
	Linear Trencher		39,000,000
Transportation			
	Materials		12,628,280
Project Costs			
	Engineering		
	Project Management		
	Procurement		
	Project Insurance	15%	55,339,000
Contingency		15%	68,430,000
TOTAL CAPITAL COST (US$)			524,627,601

Note:
Assumes development of linear trencher.

TABLE 6.16(b)

CAPITAL CONSTRUCTION COST, PIPELINE P1

CENTRAL FIELD LOCATION, 100 MBPD

20-INCH DIAMETER

CATEGORY	ITEM	ITEM COST ($)	CATEGORY TOTAL ($)
Materials	Line Pipe	36,080,400	
	Corrosion Coating	9,758,400	
	Concrete Coating	10,999,600	
	Zinc Anodes	1,626,400	
	Outer Line Pipe	136,400	
	Bulkheads/Spacers	58,100	
	Insulation	121,400	
	Surplus	1,763,421	60,544,121
Mobilization/ Demobilization	Laybarge	50,000,000	
	Trailing Suction Hopper Dredges	16,000,000	
	Support Vessels	10,000,000	
	Cutter Suction Dredge	3,000,000	79,000,000
Fixed Costs	Trailing Suction Hopper Dredge Annual Cost	232,750,000	
	Cutter Suction Dredge Annual Cost	4,700,000	
	Laybarge Wintering	7,500,000	244,950,000
Installation	Pipelaying	69,741,000	
	Trenching	162,427,000	
	Shore Crossing	3,700,000	
	Structure Approach	4,775,000	240,643,000
Infrastructure	Pump Station	4,303,200	
	Onshore Facilities	15,000,000	19,303,200
Transportation	Materials		12,628,280
Project Costs	Engineering		
	Project Management		
	Procurement		
	Project Insurance	15%	93,771,000
Contingency		15%	112,626,000
TOTAL CAPITAL COST (US$)			863,465,601

Note:
Assumes use of conventional dredging equipment.

TABLE 6.17

OPERATION, MAINTENANCE AND REPAIR COST SUMMARY

CENTRAL FIELD LOCATION

TYPE OF COST	US$x10^6							
	PIPELINE ROUTE							
	P1	P2	P3	P4	P5	P6	P7	P8
ROV or Visual Inspection	0.264	0.216	0.192	7.000	0.232	7.000	7.000	0.164
Cathodic Protection Potential Measure-ment	0.205	0.175	0.145	N/A	0.190	N/A	N/A	0.130
Pigging	0.065	0.062	0.049	0.086	0.058	0.105	0.306	0.066
Maintenance and Repair	3.750	3.750	3.750	N/A	3.750	N/A	N/A	3.750
Personnel	1.486	0.442	1.486	0.921	1.486	0.921	0.442	0.442
TOTAL	5.770	4.645	5.622	8.007	5.716	8.026	7.748	4.552

Notes:
(1)N/A = Not applicable
(2)Costs shown are annualized averages.
(3)Pipelines P2, P4 and P6 will also require payment of a TAPS tariff of $3 per barrel.

TABLE 6.18

PIPELINE ANNUAL TAXATION COST

CENTRAL FIELD LOCATION

PIPELINE ROUTE	US$x10^6			
	FLOW RATE (MBPD)			
	100	200	400	600
P1	0.127	0.146	0.186	0.202
P2	2.488	2.786	3.236	3.647
P3	0.090	0.098	0.114	0.129
P4	14.497	16.590	19.809	22.086
P5	0.079	0.089	0.104	0.120
P6	19.724	22.227	25.934	29.046
P7	2.178	2.573	3.055	3.443
P8	4.255	4.864	5.943	6.386

Note:
Taxation cost is equal to one percent of initial capital cost of all onshore pipelines and offshore pipeline sections within three miles of the coastline.

TABLE 6.19

PIPELINE DECOMMISSIONING COSTS

PIPELINE ROUTE	US$x10^6			
	FLOW RATE (MBPD)			
	100	200	400	600
P1	N/A	N/A	N/A	N/A
P2	7.328	8.213	8.895	9.602
P3	N/A	N/A	N/A	N/A
P4	70.734	77.164	85.983	92.597
P5	N/A	N/A	N/A	N/A
P6	95.358	101.538	111.839	119.138
P7	10.845	12.285	13.768	14.615
P8	23.062	25.845	29.201	30.219

Note:
Cost shown is the present value of a Year Twenty decommissioning cost equal to 50 percent of the initial pipeline installation cost, excluding material. Calculation assumes a 10 percent discount rate. Applicable to onshore pipeline sections only.

TABLE 6.20

PIPELINE CAPITAL CONSTRUCTION COSTS

PIPELINE ROUTE	PIPELINE CAPITAL CONSTRUCTION COSTS (US$x10^6)							
	FLOW RATE (MBPD)							
	NORTHERN FIELD LOCATION				SOUTHERN FIELD LOCATION			
	100	200	400	600	100	200	400	600
P1	518.282	592.871	753.696	820.673	473.869	532.153	661.326	715.921
P3	402.675	436.698	499.088	559.076	344.105	362.989	398.437	429.496
P5	541.490	629.973	748.835	877.103	428.862	476.298	543.469	613.020

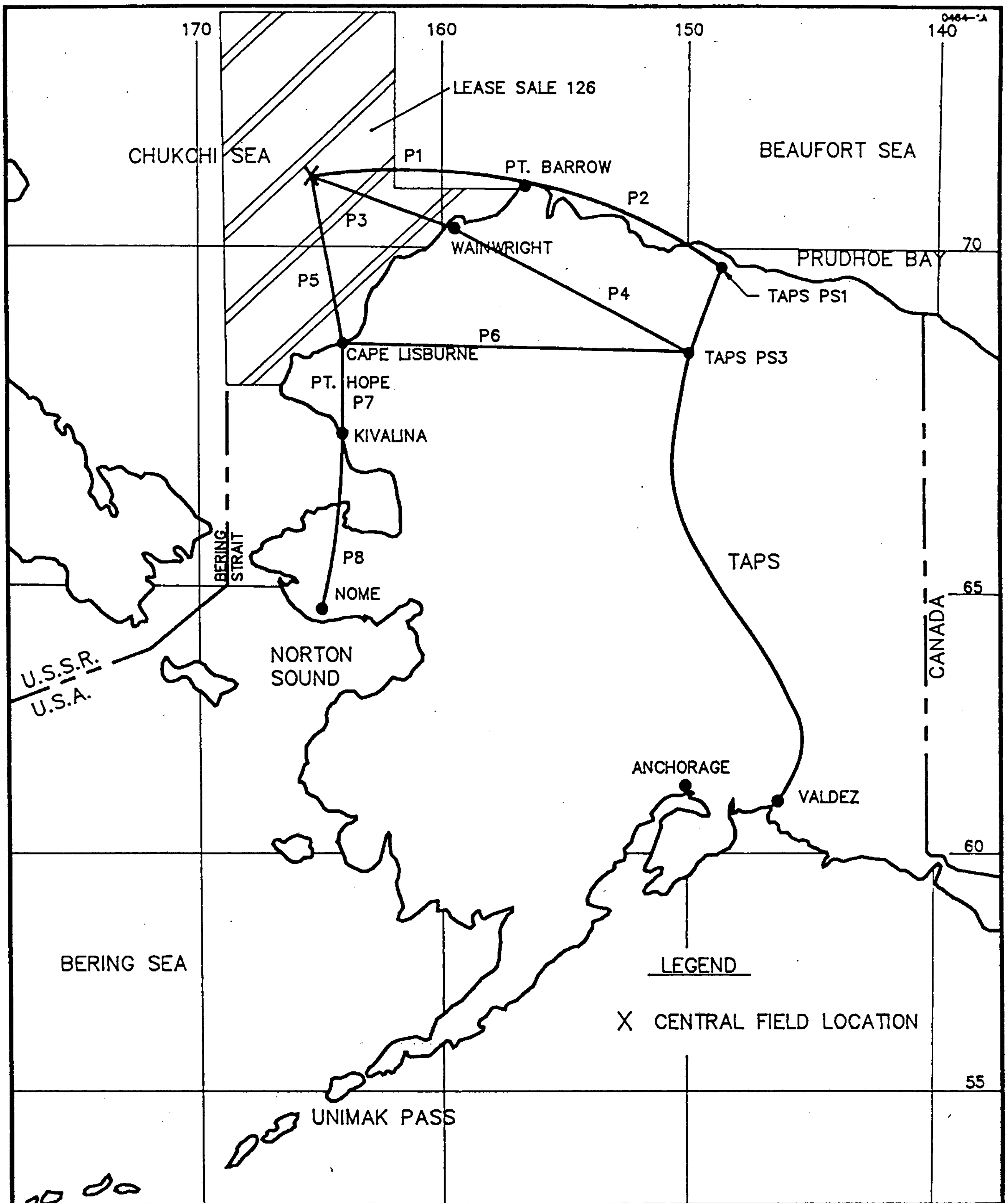
Notes:
(1)Capital costs for Pipeline Routes P2, P4, P6, P7 and P8 do not vary with field location and are shown in Table 6.15.
(2)Assumes development of linear trencher.

TABLE 6.21

OPERATION, MAINTENANCE AND REPAIR COSTS

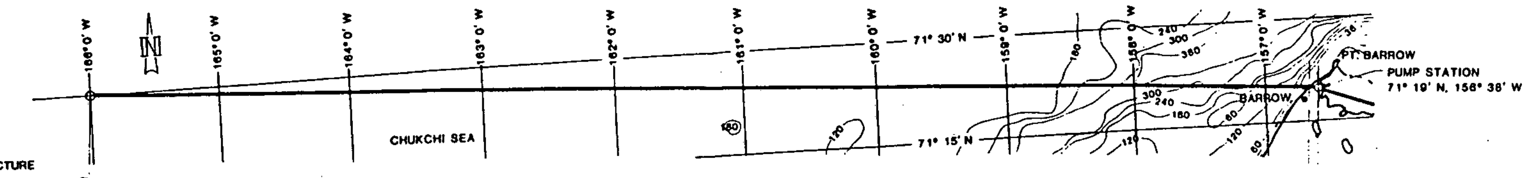
PIPELINE ROUTE	OPERATION, MAINTENANCE AND REPAIR COSTS ($US\$ \times 10^6$)	
	NORTHERN FIELD LOCATION	SOUTHERN FIELD LOCATION
P1	5.581	4.260
P3	4.521	2.044
P5	7.840	3.998

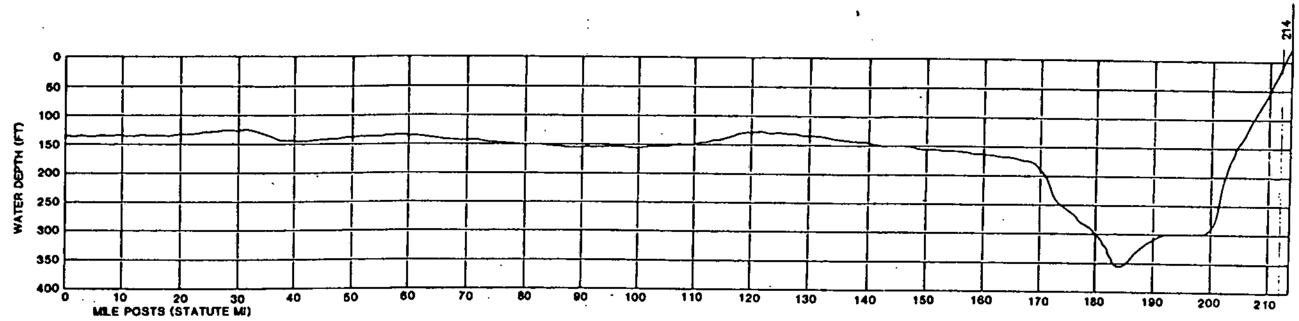
Notes:
(1) Costs shown are annualized averages.
(2) Operation, maintenance and repair costs for Pipeline Routes P2, P4, P6, P7 and P8 do not vary with field location and are shown in Table 6.17.



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	PIPELINE ROUTES FOR TRANSPORTATION SCENARIOS		
INTEC ENGINEERING, INC.	SCALE NONE DATE 12-20-90	DRAWN BY KC JOB NO. H-046.4	DRAWING NO. 601

PIPELINE P1 – CENTRAL FIELD
LOCATION TO PT. BARROW

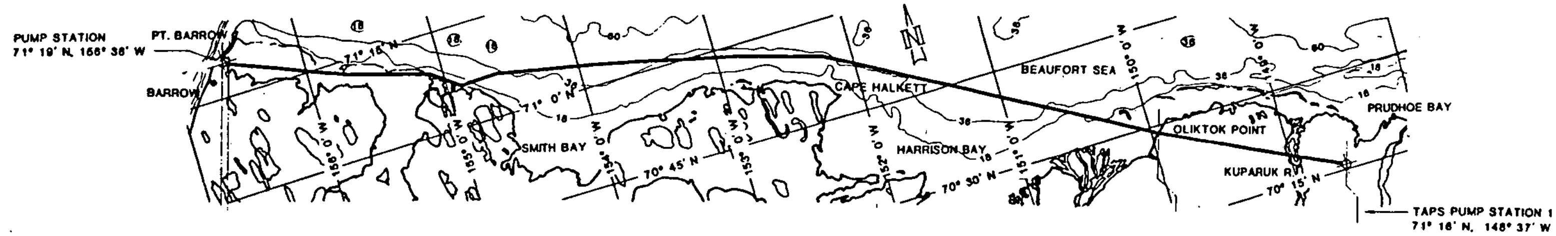


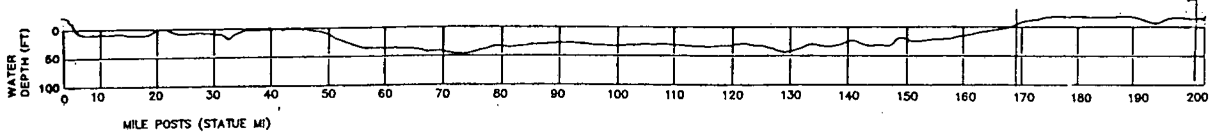


DEPTH OF COVER (ft)	14	7	0	14
SOIL CONDITIONS	0 – 10ft SOFT SANDY CLAYEY SILT OVER VERY STIFF COHESIVE OR DENSE GRANULAR SOILS		0 – 33ft SAND OVER EROSION RESISTANT STRATA	

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	PIPELINE P1 – CENTRAL FIELD LOCATION TO PT. BARROW		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 602
	DATE 1-2-91	JOB NO. H-046.4	

PIPELINE P2 – PT. BARROW TO PRUDHOE BAY



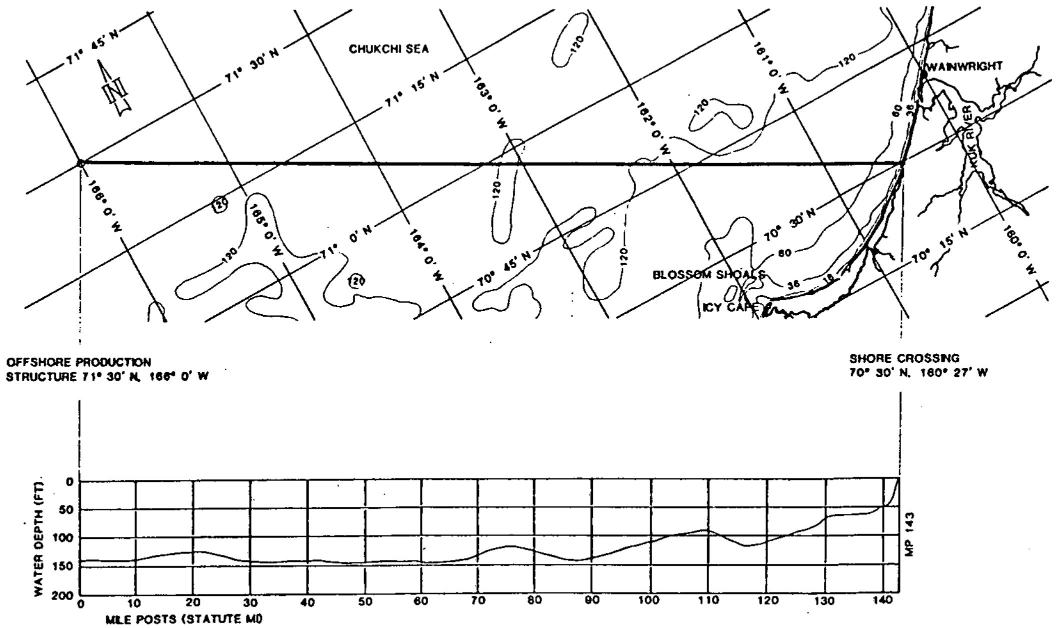


NOTE:
1) WATER DEPTHS IN FEET AT MEAN LOWER LOW WATER

DEPTH OF COVER (ft)	7	10	7	N/A
SOIL CONDITIONS	SAND, SILT AND CLAY			N/A
URETHANE FOAM INSULATION THICKNESS (IN)	2.75	NONE	2.75	

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	PIPELINE P2 – PT. BARROW TO PRUDHOE BAY		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY MN	DRAWING NO. 603
	DATE 2-4-91	JOB NO. H-046.4	

PIPELINE P3 – CENTRAL FIELD LOCATION TO WAINWRIGHT

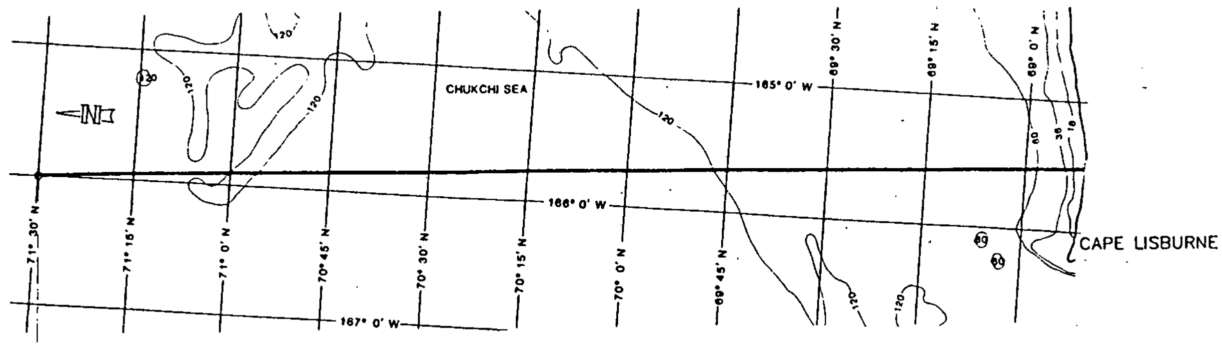


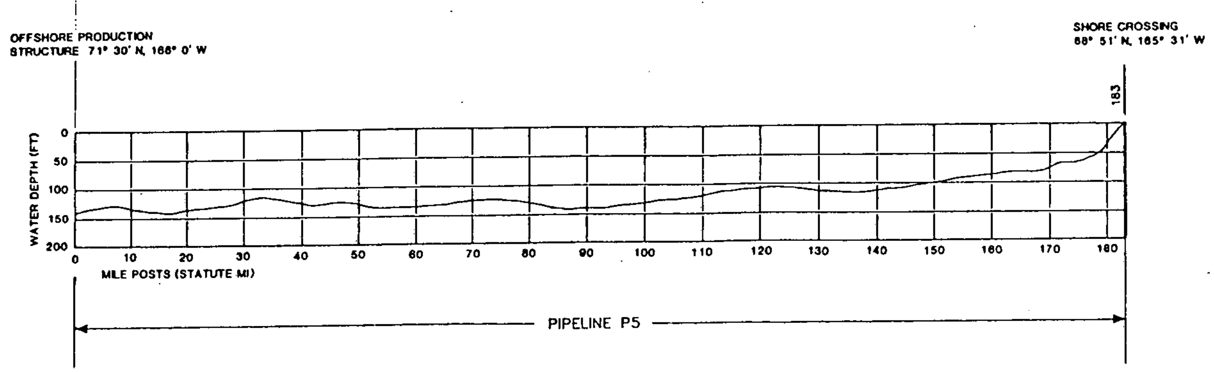
NOTE :
1) WATER DEPTHS IN FEET AT MEAN LOWER LOW WATER

DEPTH OF COVER (ft)	13	8
SOIL CONDITIONS	0 - 10ft SOFT SANDY CLAYEY SILT OVER VERY STIFF COHESIVE OR DENSE GRANULAR SOILS	8 - 13ft SILTY SAND OVER VERY STIFF COHESIVE OR DENSE GRANULAR SOILS

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	PIPELINE P3 – CENTRAL FIELD LOCATION TO WAINWRIGHT		
INTEC ENGINEERING, INC.	SCALE NONE DATE 1-2-91	DRAWN BY KC JOB NO. H-046.4	DRAWING NO. 604

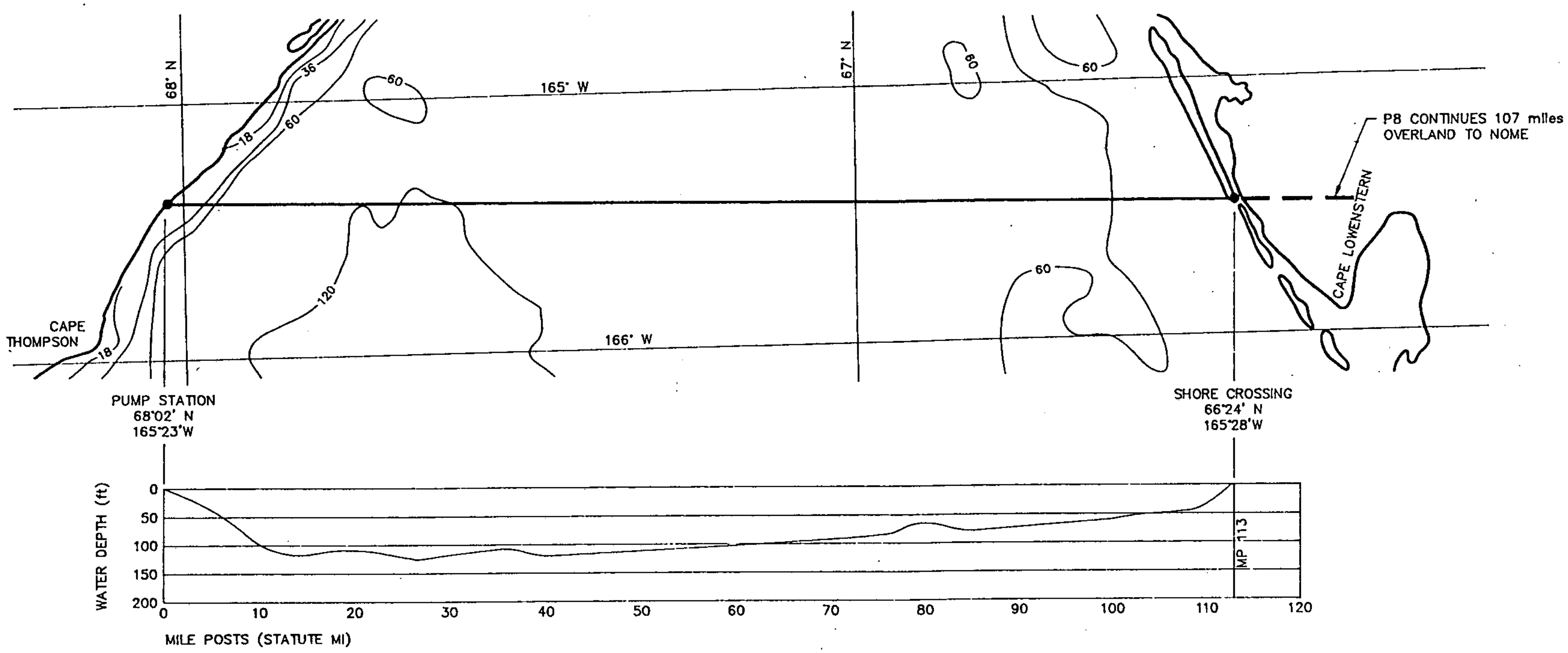
PIPELINE P5 – CENTRAL FIELD LOCATION TO CAPE LISBURNE





DEPTH OF COVER (ft)	14	8	6
SOIL CONDITIONS	0 – 10ft. SOFT SANDY CLAYEY SILT OVER VERY STIFF COHESIVE OR DENSE GRANULAR SOILS		6 – 13ft. SILTY SAND OVER VERY STIFF COHESIVE OR DENSE GRANULAR SOILS
URETHANE FOAM INSULATION THICKNESS (IN)	NONE		

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	PIPELINE P5 – CENTRAL FIELD FIELD LOCATION TO CAPE LISBURNE
INTEC ENGINEERING,INC.	SCALE NONE; DRAWN BY MN; DATE 2-4-91; JOB NO. H-046.4; DRAWING NO. 605



NOTE:

1. WATER DEPTH IN FEET AT MEAN LOWER LOW WATER

DEPTH OF COVER (ft)	6

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	PIPELINE P8 – KIVALINA LOCATION TO NOME		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 606
	DATE 1-7-91	JOB NO. H-046.4	

0464-158

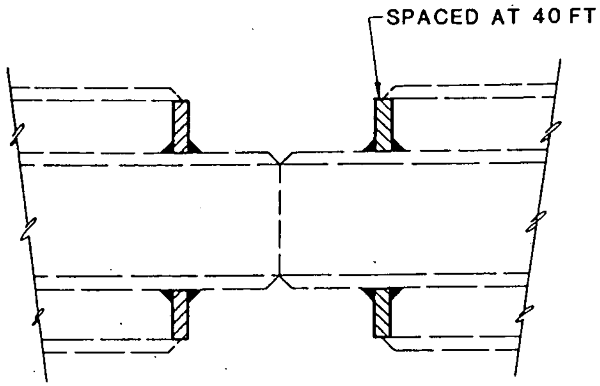


FIGURE A WELDED BULKHEAD TYPE A

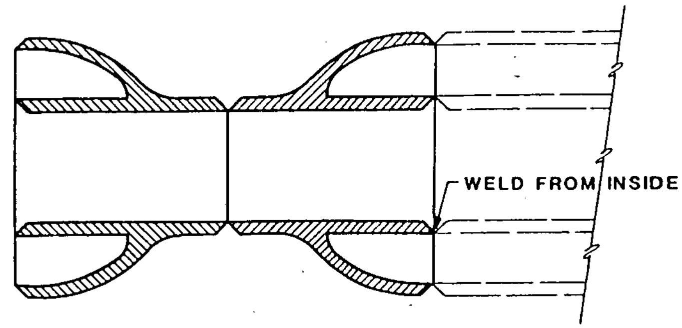


FIGURE C FORGED BULKHEAD TYPE A

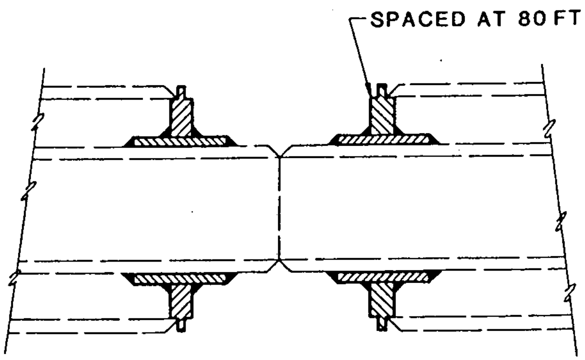


FIGURE B WELDED BULKHEAD TYPE B

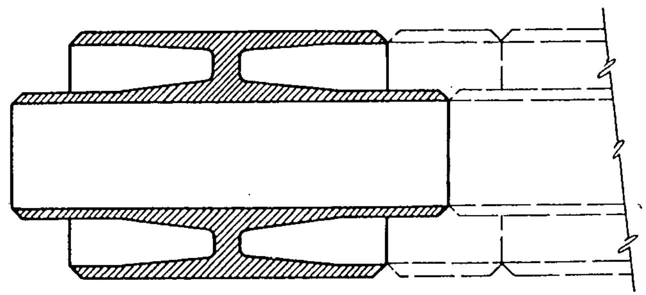
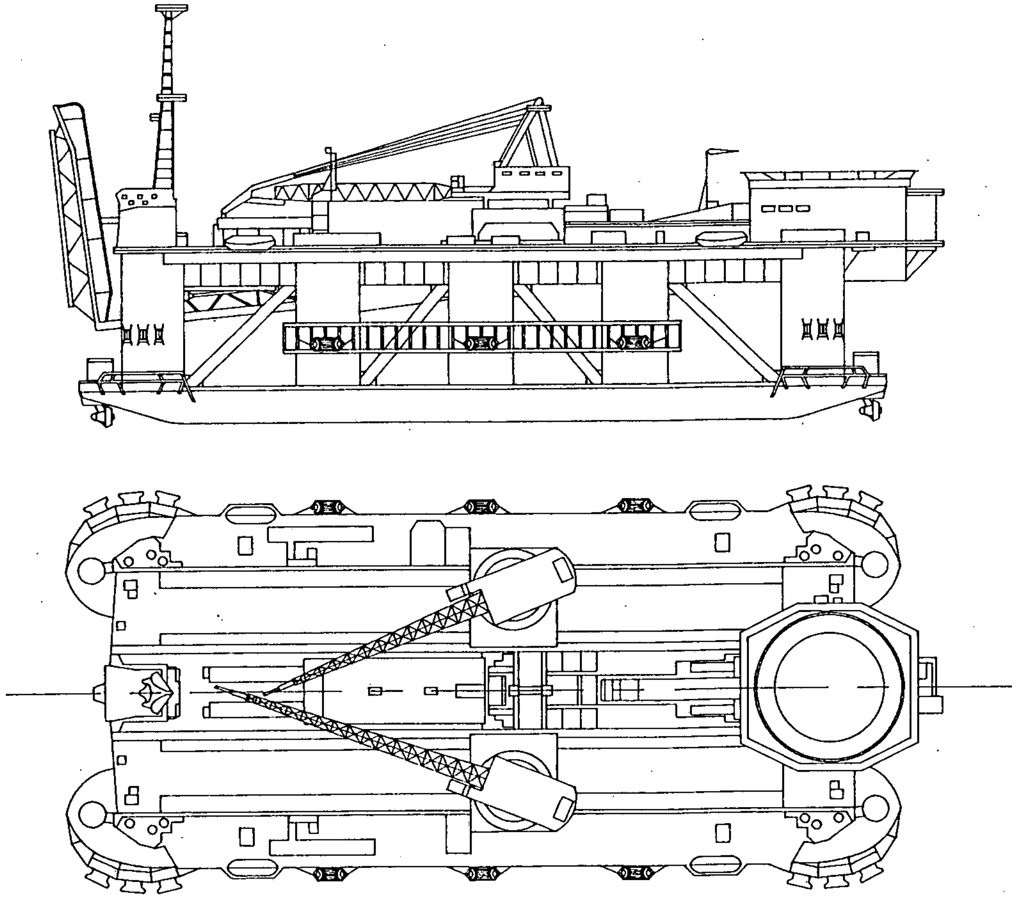


FIGURE D FORGED BULKHEAD TYPE B

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	BULKHEAD DESIGN CONCEPTS FOR INSULATED PIPELINES		
INTEC ENGINEERING, INC.	SCALE NONE DATE 1-8-91	DRAWN BY KC JOB NO. H-046.4	DRAWING NO. 607

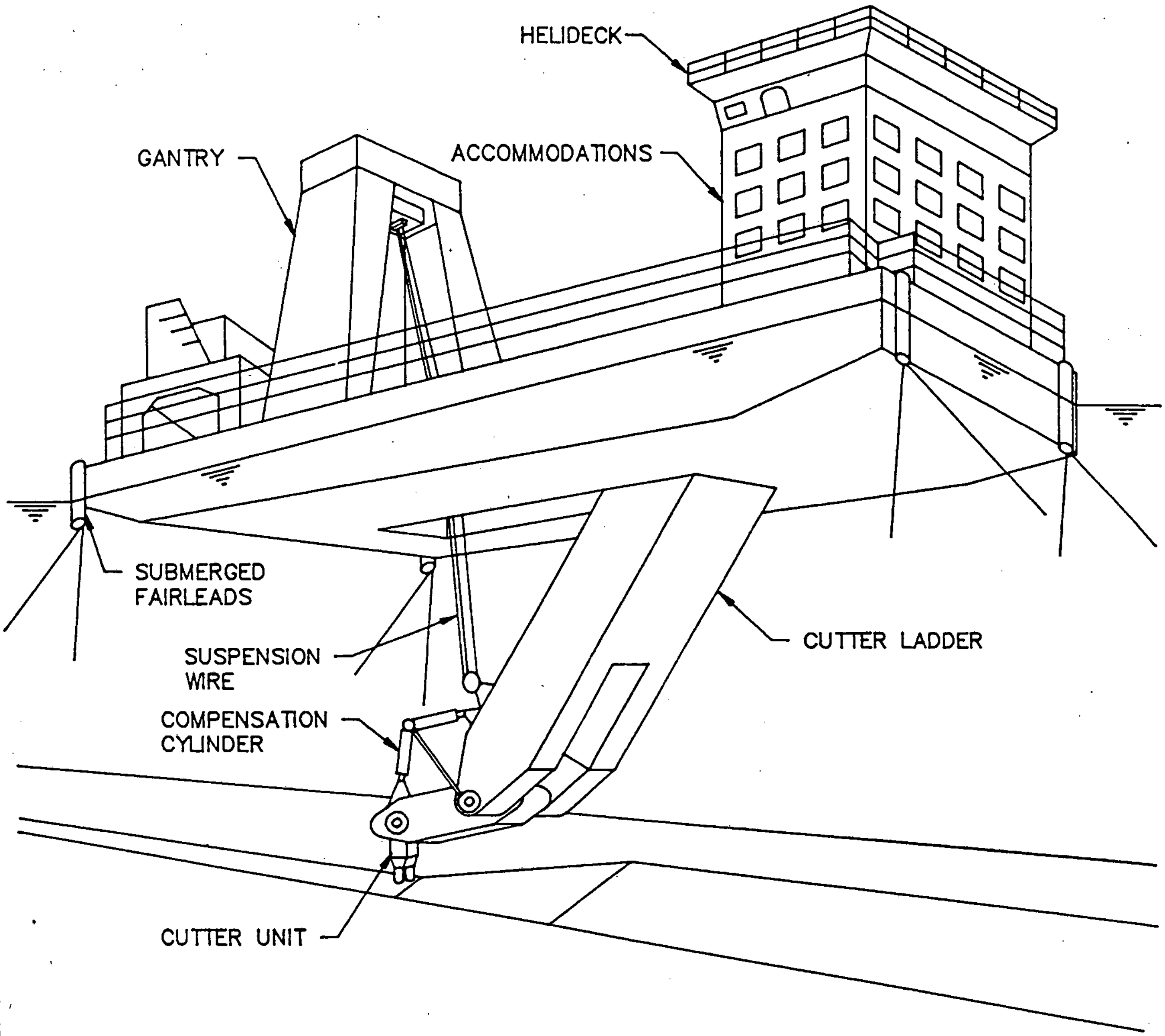
0464-208



PRINCIPAL CHARACTERISTICS

LENGTH:	497 FEET	OPERATING DRAFT:	46 FEET
WIDTH:	231 FEET	TOWING DRAFT:	33 FEET
DEPTH:	98 FEET	TRANSIT SPEED:	7.5 KNOTS

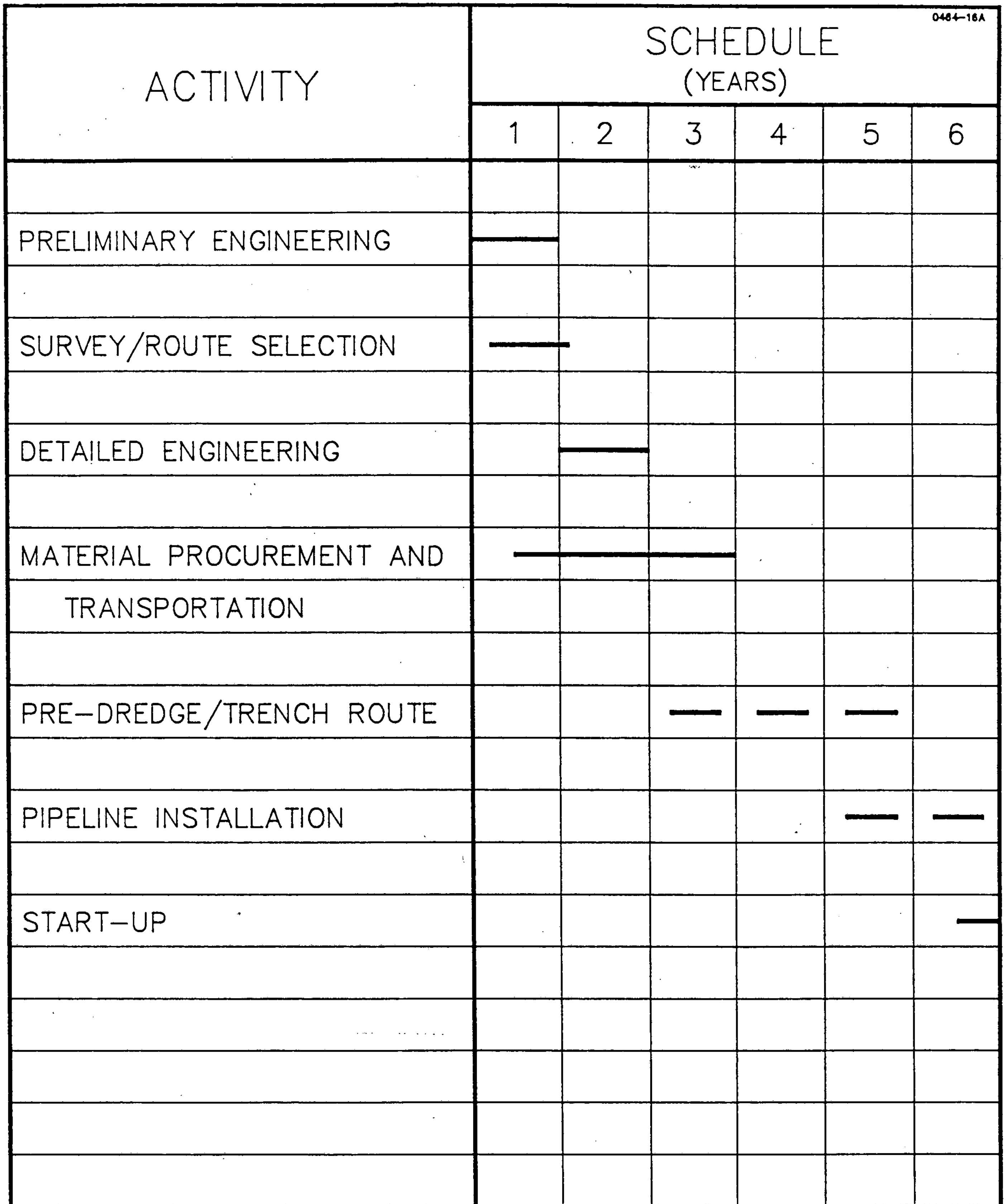
JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	THIRD GENERATION LAYBARGE CASTORO SEI		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 608
	DATE 1-10-91	JOB NO. H-046.4	



COURTESY OF VOLKER STEVIN

JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	LINEAR TRENCHER

	SCALE	DRAWN BY	DRAWING NO.
INTEC ENGINEERING, INC.	NONE	KC	609
	DATE 1-4-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

PIPELINE CONSTRUCTION SCHEDULE

INTEC ENGINEERING, INC.

SCALE NONE	DRAWN BY KC	DRAWING NO. 610
DATE 3-1-91	JOB NO. H-046.4	

24602

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CHAPTER 7

DIRECT PIPELINE TO UNIMAK PASS

CHAPTER 7
OFFSHORE PIPELINE TO UNIMAK PASS

7.1 GENERAL

This chapter evaluates the feasibility of an offshore pipeline from the central Chukchi Sea location to Unimak Pass. This type of transportation scenario would eliminate the need for arctic tankers, onshore pipelines, and/or TAPS-dependent tariffs.

The objectives of this chapter are to:

- Evaluate the maximum flowrates possible for variable route lengths, based on large diameter offshore pipelines
- Establish preliminary pipeline design criteria for a direct pipeline from the central Chukchi Sea location to Unimak Pass with no pump stations, one pump station and two pump stations
- Provide a preliminary schedule, and cost estimates, for an offshore pipeline from the central Chukchi Sea location to Unimak Pass

7.2 PIPELINE FLOW ANALYSIS

Preliminary pipeline flow analyses were performed using Darcy's Law and the parameters outlined in Chapter 6 to define the maximum flowrates for 48, 52 and 56-inch diameter pipelines. The results of these analyses are shown on Drawing No. 701 and indicate that a 56-inch diameter offshore pipeline from the central Chukchi Sea location to Unimak Pass could transport up to 635,000 barrels per day of crude oil without the use of any pump stations.

7.3 PIPELINE ROUTES

A series of pipeline routes from the central Chukchi Sea location (71.5°N, 166°W) to Unimak Pass (54.5°N, 164.3°W) were identified as shown on Drawings No. 702 through 704. The routes represent the variance in the number of pump stations along the route. It is also possible to select the routes so as to reduce an extensive amount of trenching based on the requirements necessitated by ice scours in the area. This would be accomplished by installing the pipeline in water depths greater than 190 feet where possible.

Peak crude oil flowrates versus pipe diameters for the various routes are shown on Drawing No. 705.

7.3.1 No Pump Stations

A direct offshore pipeline from the central Chukchi Sea location to Unimak pass with no pump stations is shown on Drawing No. 702. The approximate length of the 56-inch pipeline is 1,220 miles. If the peak flowrate of the pipeline is required to exceed 635 MBPD, an intermediate pump station would be required.

7.3.2 One Pump Station

A direct offshore pipeline route with one pump station is shown on Drawing No. 703. The most efficient location for the pump station is near the midpoint of the pipeline route; hence a pump station on St. Lawrence Island. The pipeline would consist of two segments, the first of which extends from the central Chukchi Sea location to the Northeast Cape of St. Lawrence Island (63.3°N, 169°W). The second segment extends from the Northeast Cape of St.

Lawrence Island to Unimak Pass. The second segment, which is 640 miles long, is the longer of the two segments and thus will limit the peak flowrates. If the required peak flowrate exceeds 918 MBPD, two pump stations will be required.

7.3.3 Two Pump Stations

A direct offshore pipeline route, with two pump stations is shown on Drawing No. 704. The most efficient location of the pump stations, are on Nunivake Island (60.8°N, 167.5 W) and at Prince of Wales (65.7°N, 68.3°W). This divides the route into three pipeline segments of 415, 345 and 460 miles, respectively, with the longest segment of 460 miles limiting the peak flowrates.

There are no viable locations for a pump station between Nunivake Island and Unimak Pass without the installation of an offshore platform. Therefore, it is not considered economically viable, at this time, to install more than two pump stations along a direct offshore pipeline route from the Chukchi Sea to Unimak Pass. This, therefore, limits the maximum flowrate for the direct offshore pipeline scenario to 1,107 MBPD.

7.4 PIPE DESIGN

The following pipeline design parameters are based on the standard design practices discussed in Chapter 6. The results are used for cost estimating purposes only.

7.4.1 Wall Thickness

Pipeline wall thicknesses were calculated using a maximum allowable operating pressure (MAOP) of 1,800 psig, API grade 5LX-65 line pipe, and the equation presented in Section 6.2.2. The wall thicknesses used are API standard wall thicknesses and are presented in Table 7.1.

7.4.2 Corrosion Protection

For cost estimating purposes, a thirty mil (0.03 inch) thick coating of fusion bonded epoxy (FBE) coating was assumed.

7.4.3 Concrete Weight Coating

Concrete weight coating thicknesses were selected to provide a pipeline specific gravity, when empty, of 1.10. This value is considered to be sufficient for cost estimating purposes. The required concrete weight coating thicknesses, based on a concrete density of 190 pcf, are shown in Table 7.1. It should be noted that, in a more detailed design phase, hydrodynamic stability calculations could adjust these requirements.

7.4.4 Pipeline Insulation

As discussed in the 1986 study, pipeline insulation is required in water depths of less than twenty feet which are subject to permafrost.

In a direct offshore route from the central Chukchi Sea to Unimak Pass, water depths of less than twenty feet are only encountered near shore approaches.

All shore approaches on the direct route would be in non-permafrost areas. Therefore, there was no allowance for insulation in the cost estimate.

7.4.5 Cathodic Protection

Conventional zinc anodes were used for cathodic protection calculations. Based on the equations presented in Section 6.2.2, zinc anode requirements, in pounds per mile, are presented in Table 7.1.

7.5 PIPELINE CONSTRUCTION

The construction of the direct pipeline route is based on the use of a third generation laybarge using double jointed pipe. While a detailed evaluation of the installation procedure and schedule is beyond the scope of this study, it is a viable assumption that construction of a direct offshore pipeline, from the Chukchi Sea to Unimak Pass, could continue throughout the year, thereby eliminating the need for expensive seasonal standby costs. This could be done by constructing the pipeline in segments, with the northern most segments being constructed during the critical summer construction season, and the southern segments constructed during the winter months. Based on these assumptions, and the production rates outlined in Chapter 6, the installation of a direct pipeline is estimated to require three to four years depending on the selected pipeline diameter.

7.6 PIPELINE CAPITAL CONSTRUCTION COST ESTIMATE

Based on the material unit costs and installation equipment day rates presented in Chapter 6, and terminal costs presented in Chapter 5; capital construction cost estimates for a 48, 52, and 56-inch diameter pipeline with no pump station, one pump station, and two pump stations were described. The results are presented in Tables 7.2 through 7.4.

7.7 PIPELINE OPERATING AND MAINTENANCE COST ESTIMATE

The estimated annual operating and maintenance costs for the direct offshore pipeline scenarios based on the operating and maintenance costs presented in Chapters 5 and 6 are as follows:

- No Pump Stations : $\$26.75 \times 10^6$
- One Pump Station : $\$35.70 \times 10^6$
- Two Pump Stations: $\$45.65 \times 10^6$

TABLE 7.1

PIPE DESIGN SUMMARY

PIPE DIAMETER (in)	WALL THICKNESS (in)	CONCRETE THICKNESS (in)	ZINC ANODES (lbs/mi)
36	0.750	2.15	6,842
40	0.812	2.50	7,603
44	0.875	2.80	8,363
48	0.938	2.90	9,123
52	1.062	3.20	9,883
56	1.550	2.00	10,644

TABLE 7.2

CHUKCHI SEA OFFSHORE PIPELINE

WITH NO PUMP STATION

CAPITAL CONSTRUCTION COST ESTIMATE

ITEM	48-INCH ($)	52-INCH ($)	56-INCH ($)
PIPELINE CAPITAL COSTS			
MATERIALS	1,781,646,550	2,149,983,700	2,875,253,240
MATERIAL TRANSPORTATION	425,173,570	521,026,060	812,872,860
MOB/DEMOBILIZATION	69,000,000	69,000,000	69,000,000
INSTALLATION			
PIPELAYING	632,657,150	708,576,000	885,720,000
TRENCHING(1)	144,500,000	168,000,000	192,200,000
RISERS	4,050,000	4,575,000	5,050,000
SHORE CROSSINGS	5,620,000	6,450,000	7,280,000
PROJECT COSTS (15%)	285,271,060	455,637,700	594,825,490
CONTINGENCY (15%)	502,187,750	612,487,270	816,330,240
SUB-TOTAL	3,850,106,080	4,695,735,730	6,258,531,830
PUMP STATIONS	0	0	0
TRANS-SHIPMENT TERMINAL	1,170,000,000	1,655,000,000	2,356,000,000
TOTAL	5,020,106,080	6,350,735,730	8,614,531,830

(1) Based on development of linear trencher

TABLE 7.3
CHUKCHI SEA OFFSHORE PIPELINE
WITH ONE PUMP STATION
CAPITAL CONSTRUCTION COST ESTIMATE

ITEM	48-INCH ($)	52-INCH ($)	56-INCH ($)
PIPELINE CAPITAL COSTS			
MATERIALS	1,781,646,550	2,149,983,700	2,875,253,240
MATERIAL TRANSPORTATION	425,173,570	521,026,060	812,872,860
MOB/DEMOBILIZATION	69,000,000	69,000,000	69,000,000
INSTALLATION			
PIPELAYING	632,657,150	708,576,000	885,720,000
TRENCHING[1]	147,000,000	170,500,000	195,000,000
RISERS	4,050,000	4,575,000	5,050,000
SHORE CROSSINGS	5,620,000	6,450,000	7,280,000
PROJECT COSTS (15%)	385,646,060	456,012,700	595,245,490
CONTINGENCY (15%)	517,619,000	612,918,520	816,813,240
SUB-TOTAL	3,968,412,330	4,699,041,980	6,262,234,830
PUMP STATIONS	275,404,800	349,536,000	383,355,720
TRANS-SHIPMENT TERMINAL	1,655,000,000	2,356,000,000	3,306,000,000
TOTAL	5,898,817,130	7,404,577,980	9,951,590,550

(1) Based on development of linear trencher

TABLE 7.4

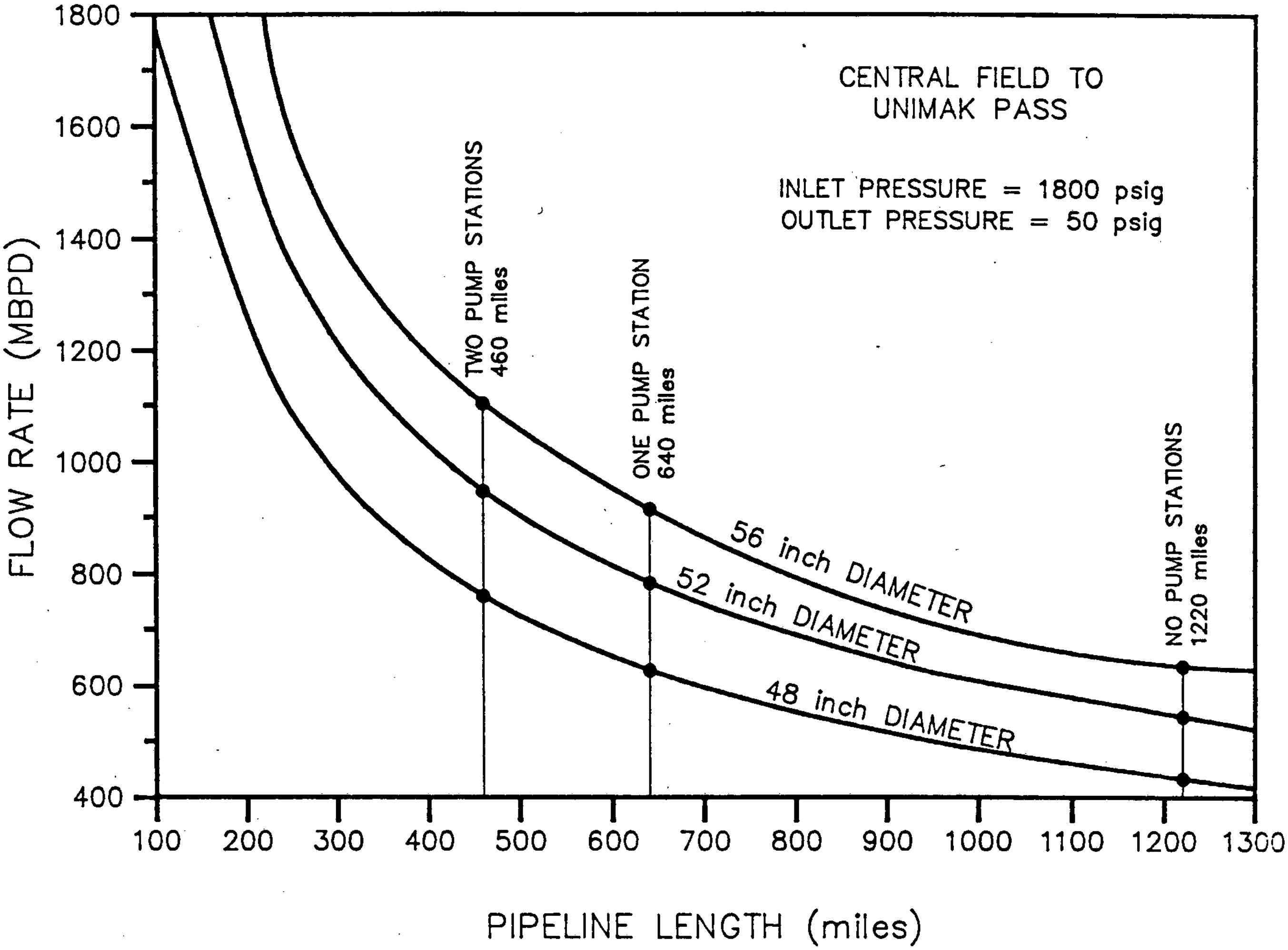
CHUKCHI SEA OFFSHORE PIPELINE

WITH TWO PUMP STATIONS

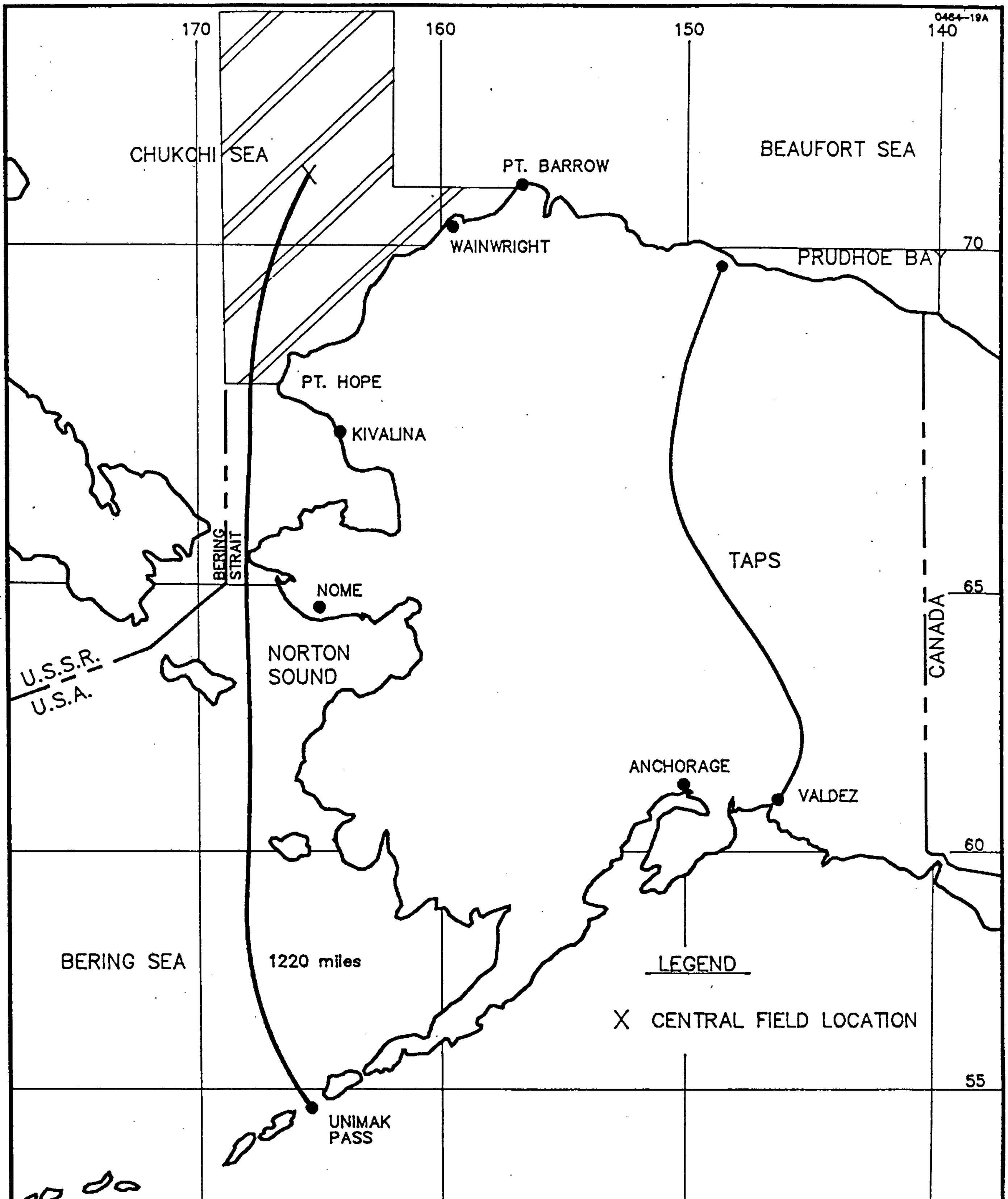
CAPITAL CONSTRUCTION COST ESTIMATE

ITEM	48-INCH ($)	52-INCH ($)	56-INCH ($)
PIPELINE CAPITAL COSTS			
MATERIALS	1,781,646,550	2,149,983,700	2,875,253,240
MATERIAL TRANSPORTATION	425,173,570	521,026,060	812,872,860
MOB/DEMOBILIZATION	69,000,000	69,000,000	69,000,000
INSTALLATION			
PIPELAYING	632,657,150	708,576,000	885,720,000
TRENCHING[1]	150,000,000	173,000,000	197,500,000
RISERS	4,050,000	4,575,000	5,050,000
SHORE CROSSINGS	5,620,000	6,450,000	7,280,000
PROJECT COSTS (15%)	386,096,050	456,387,700	595,620,490
CONTINGENCY (15%)	518,136,500	613,349,770	817,244,490
SUB-TOTAL	3,972,379,820	4,702,348,230	6,265,541,080
PUMP STATIONS	645,701,760	663,806,880	846,642,880
TRANS-SHIPMENT TERMINAL	1,655,000,000	2,356,000,000	3,306,000,000
TOTAL	6,273,081,580	7,722,155,110	10,418,183,960

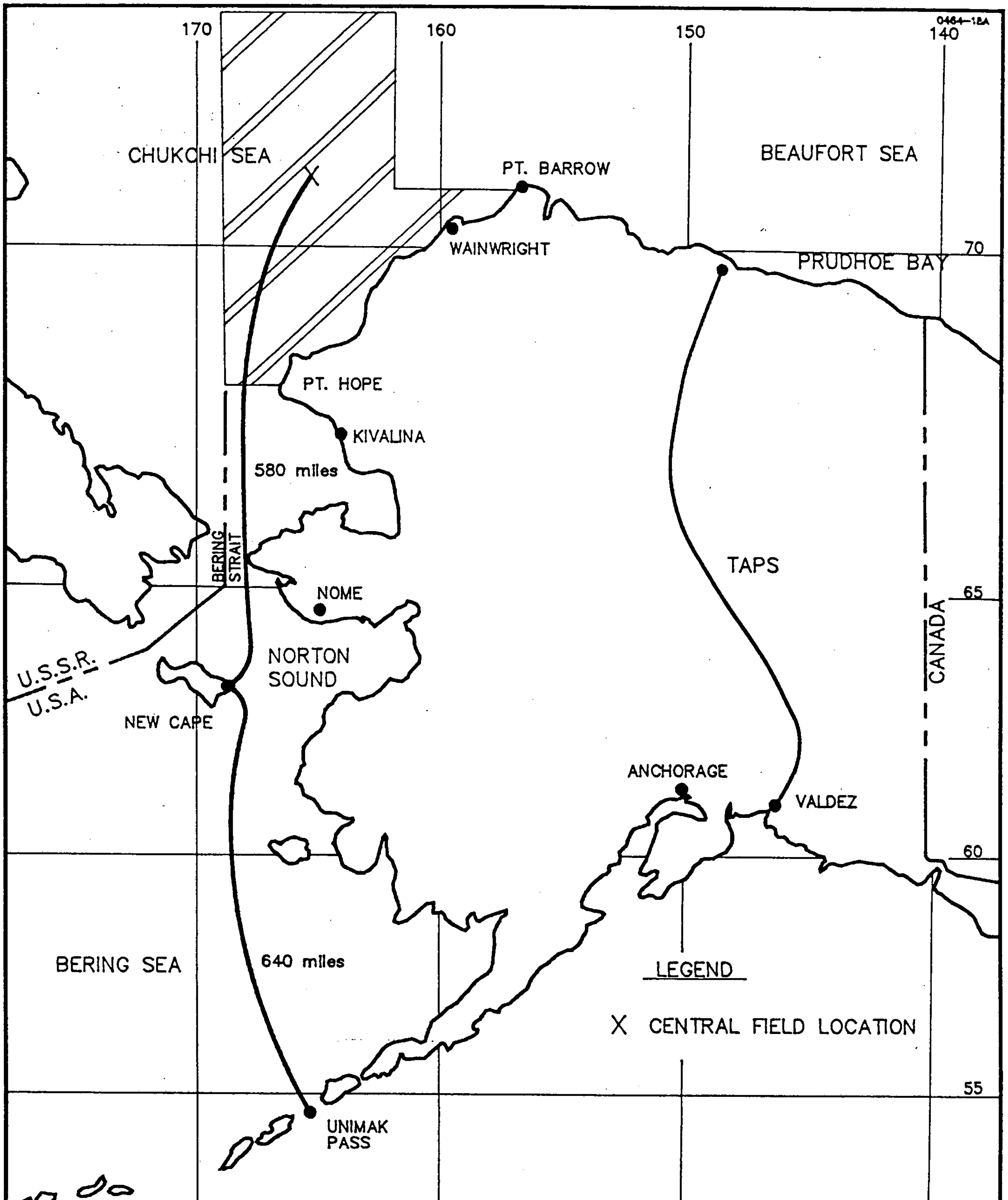
(1) Based on development of linear trencher



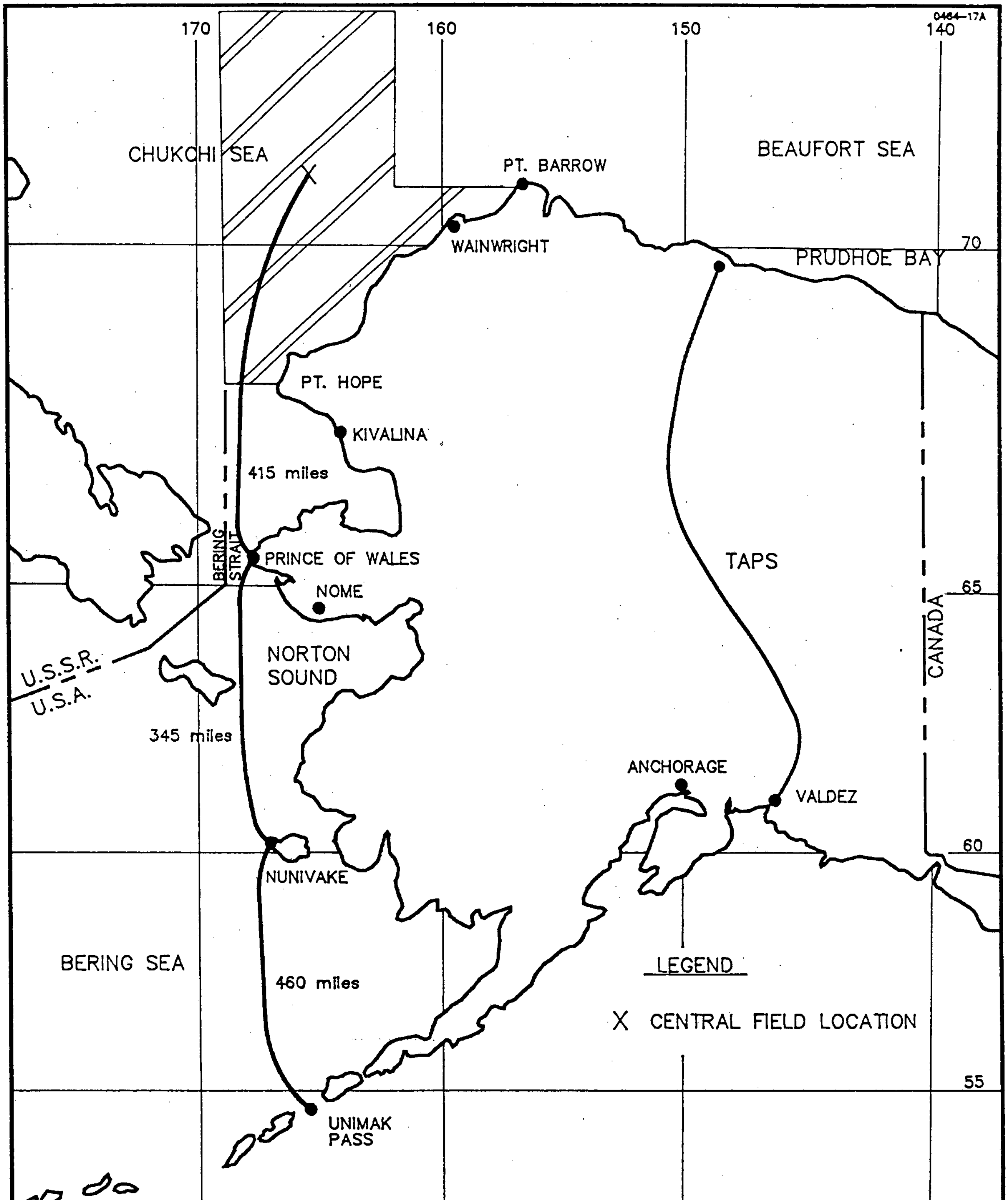
JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION		LARGE DIAMETER FLOW ANALYSIS	
INTEC ENGINEERING, INC.	SCALE NONE DATE 2-12-91	DRAWN BY MN JOB NO. H-046.4	DRAWING NO. 701



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA OFFSHORE PIPELINE WITH NO PUMP STATIONS		
INTEC ENGINEERING, INC.	SCALE NONE DATE 1-9-91	DRAWN BY KC JOB NO. H-046.4	DRAWING NO. 702



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA OFFSHORE PIPELINE WITH 1 PUMP STATION		
INTEC ENGINEERING, INC.	SCALE NONE DATE 1-9-91	DRAWN BY KC JOB NO. H-046.4	DRAWING NO. 703

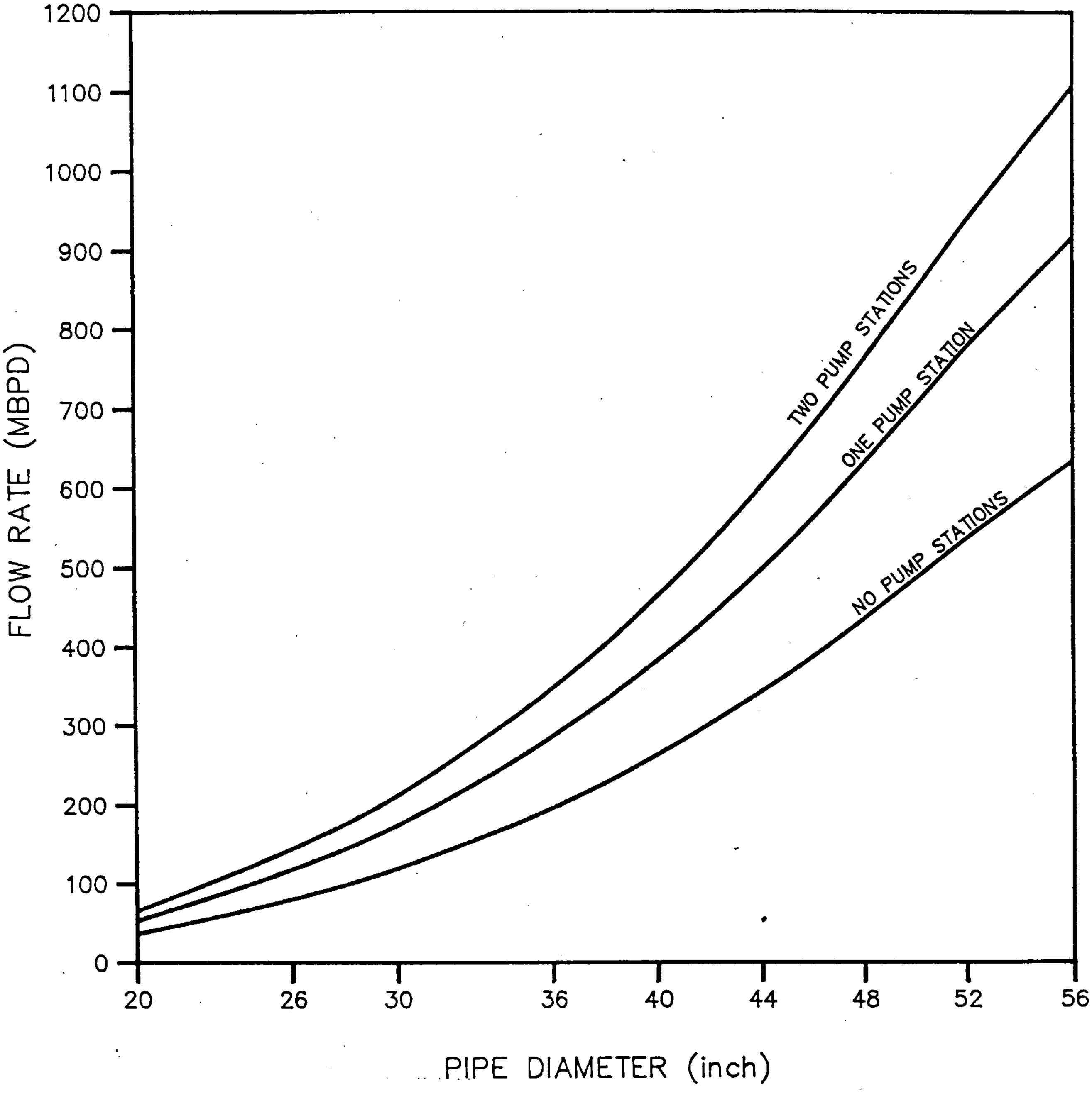


JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

CHUKCHI SEA OFFSHORE PIPELINE
WITH 2 PUMP STATIONS

INTEC ENGINEERING, INC.

SCALE	DRAWN BY	DRAWING NO.
NONE	KC	704
DATE 1-9-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CENTRAL FIELD TO UNIMAK PASS PEAK FLOWRATES		
INTEC ENGINEERING, INC.	SCALE NONE DATE 1-23-91	DRAWN BY KC JOB NO. H-046.4	DRAWING NO. 705

CHAPTER 8

TRANSPORTATION SYSTEM EVALUATION

CHAPTER 8

TRANSPORTATION SYSTEM EVALUATION

8.1 GENERAL

This chapter contains an updated economic evaluation of the fourteen transportation scenarios identified in the previous study, and also includes an economic evaluation of the direct offshore pipeline to Unimak Pass discussed in Chapter 7.

The objectives of this chapter are:

- Describe the fourteen transportation scenarios selected in the previous study for the central Chukchi Sea field location

- Describe and provide an economic evaluation model for comparing the fourteen transportation scenarios on a present value cost per barrel basis.

- Summarize and present the economic evaluations on a cost per barrel basis for the fourteen transportation scenarios at peak flowrates of 100, 200, 400, and 600 MBPD.

- Determine and summarize the cost per barrel for the direct offshore pipeline to Unimak Pass from the central Chukchi Sea field location.

- Provide a cost per barrel for the Northern and Southern field locations.

- Determine and present the recommended transportation scenarios for each flowrate.

8.2 TRANSPORTATION SCENARIO DESCRIPTIONS

Fourteen transportation scenarios described in this section are based on tanker, terminal and pipeline designs described in Chapters 4, 5 and 6, respectively. The scenarios have been numbered one through fourteen, and are shown on Drawings No. 801 through 814 and summarized in Tables 8.1 and 8.2. Each of the fourteen base case scenarios originate from the central Chukchi Sea field location. The sensitivity of each transportation scenario present worth to field location is examined by analyzing each transportation scenario for both the Northern and Southern field locations, as described in Section 8.4.

Transportation Scenario 1: (Drawing No. 801)

Scenario 1 transports the crude oil from the central field location to Point Barrow via Pipeline P1, were Pipeline P2 transports it from Point Barrow to TAPS PS1. The Trans-Alaska Pipeline System is then used to transport the crude oil to the existing terminal at Valdez.

Transportation Scenario 2: (Drawing No. 802)

Scenario 2 transports crude oil via Pipeline P3, from the central field to a pump station at Wainwright. Overland Pipeline P4 transports the crude oil from the pump station at Wainwright to TAPS PS3. The TAPS pipeline is then used to transport the crude oil to the existing terminal at Valdez.

Transportation Scenario 3: (Drawing No. 803)

Scenario 3 transports crude oil from the central field to Cape Lisburne via Pipeline P5, where Pipeline P6 transports the crude oil from Cape Lisburne to the Trans-Alaska Pipeline

System at TAPS PS3. The crude oil in then transported to the existing terminal at Valdez via the Trans-Alaska Pipeline.

Transportation Scenario 4: (Drawing No. 804)

Scenario 4 transports crude oil from the central field to a nearshore tanker terminal at Wainwright via Pipeline P3. Arctic Class 8 tankers then transport crude oil from Wainwright to a trans-shipment terminal at Unimak Pass along Tanker Route T6.

Transportation Scenario 5: (Drawing No. 805)

Scenario 5 transports crude oil from the central field to a nearshore tanker terminal at Kivalina via Pipelines P5 and P7. From Kivalina, Arctic Class 6 tankers using Route T8 transport oil to a trans-shipment terminal at Unimak Pass.

Transportation Scenario 6: (Drawing No. 806)

Scenario 6 transports crude oil from the central field to a nearshore terminal at Nome via Pipelines P5, P7, and P8. From Nome, Tanker Route T10 using Arctic Class 4 tankers, transports crude oil to a trans-shipment terminal at Unimak Pass.

Transportation Scenario 7: (Drawing No. 807)

Scenario 7 involves the transportation of crude oil from an offshore terminal at the central field, to a nearshore terminal at Wainwright using Arctic Class 8 tankers along Tanker Route T1. The crude oil is then transported to TAPS PS3 via Pipeline P4. The Trans-Alaska pipeline then transports the crude oil to the existing terminal at Valdez.

Transportation Scenario 8: (Drawing No. 808)

Arctic Class 8 tankers using Route T2 transport oil from an offshore terminal at the central field to a nearshore terminal at Cape Lisburne. Crude oil is then transported from Cape Lisburne to TAPS PS3 via Pipeline P6. The Trans-Alaska Pipeline System is then used to transport the oil to the existing terminal at Valdez.

Transportation Scenario 9: (Drawing No. 809)

Pipeline P3 is used to transport oil from the central field to a nearshore tanker terminal at Wainwright. Arctic Class 8 tankers are then used to transport oil from Wainwright to the existing terminal at Valdez along Tanker Route T7.

Transportation Scenario 10: (Drawing No. 810)

This scenario is similar to Scenario 5, in that oil is transported to a nearshore terminal at Kivalina via Pipelines P5 and P7. However, from Kivalina, Arctic Class 6 tankers transport crude oil along Route T9 to the trans-shipment terminal at Valdez.

Transportation Scenario 11: (Drawing No. 811)

Pipelines P5, P7 and P8 transport oil from the central field to a nearshore tanker terminal at Nome. Arctic Class 4 tankers then transport the crude oil from Nome to a trans-shipment terminal at Valdez along Tanker Route T11.

Transportation Scenario 12: (Drawing No. 812)

Scenario 12 does not involve the use of any pipelines. Arctic class 8 tankers transport oil directly from an offshore terminal at the central field to a transshipment terminal at Unimak Pass along Tanker Route T4.

Transportation Scenario 13: (Drawing No. 813)

This scenario is similar to Scenario 12, in that no pipelines are used. However, crude oil is transported from an offshore terminal at the central field directly to a trans-shipment terminal at Valdez using Arctic Class 8 tankers along Tanker Route T5.

Transportation Scenario 14: (Drawing No. 814)

Arctic Class 8 tankers transport crude oil from an offshore tanker terminal at the central field location to a nearshore transshipment terminal at Nome along Tanker Route T3. Oil is then loaded onto Arctic Class 4 tankers for transportation to a transshipment terminal at Unimak Pass along Route T10.

8.3 ECONOMIC EVALUATION METHODOLOGY

Each transportation scenario is evaluated by calculating the present value of the crude oil transportation cost per barrel at flowrates of 100, 200, 400, and 600 MBPD. The present value crude oil transportation scenario cost per barrel is calculated by dividing the total scenario present worth by the total field recoverable reserves in barrels.

The transportation scenario present worth is equal to the sum of the initial capital expenditure for tankers, terminals and/or pipelines, plus the present value of the annual operating, maintenance and taxation costs associated with each of the transportation system components.

Total recoverable reserves are calculated by assuming that the peak annual crude oil production rate is equal to 9.1

percent of the total recoverable reserves, based on the following relationship:

$$Q \times 365 = 9.1\% \times F$$

where:

Q = peak crude oil flow rate, thousands of barrels per day.
F = total field recoverable reserves, barrels.

This equation can also be expressed as:

$$F = \frac{Q \times 365 \times \text{Field Life (Years)}}{1.82}$$

The method for calculating total field recoverable reserves in barrels is the same method assumed for the 1986 report.

Based on a field life of twenty years and peak crude oil flow rates of 100, 200, 400 and 600 thousand barrels per day (MBPD), the total field recoverable reserves are as follows:

Peak Crude Oil Flow Rate (MBPD)	Total Field Recoverable Reserves (Barrels)
100	401,100,000
200	802,200,000
400	1,604,400,000
600	2,406,590,000

Major assumptions made in the economic evaluation of the fourteen transportation scenarios are summarized below:

- All costs are in constant 1991 U.S. Dollars. No estimates of future inflation or other cost escalation have been included.

- Costs associated with the annual operation and maintenance of pipelines, tankers and terminals are constant over the field life and are based on the peak crude oil production rate.

- The field life is twenty years.

- The economic life of all vessels and facilities is equal to the field life.

- Transportation scenarios which utilize the existing Trans-Alaska Pipeline System are assumed to require payment of a per barrel tariff of $3.00. This tariff is an estimated average value that would be paid over the twenty year life of the project. The anticipated decline in production for presently developed fields is expected to allow adequate capacity in TAPS for Chukchi Sea oil production.

- Tankers would be required to be constructed in the United States.

- Present worth calculations are based on an annual discount rate of ten percent.

- Transportation scenario capital costs include engineering, materials, fabrication and installation. Costs associated with construction financing, permitting and owner company overheads are not included.

- The costs associated with crude oil production shut-ins are not considered.

- Crude oil transportation costs per barrel do not include salvage values and decommissioning costs.

The economic evaluation procedures and assumptions used to calculate the crude oil transportation costs per barrel are judged to be adequate for the purpose of evaluating the transportation systems on a comparative basis within the scope of this study.

8.4 ECONOMIC EVALUATIONS

Based on the costs presented in Chapters 4 through 6 and the economic evaluation methodology presented in Sections 8.3, a cost per barrel for crude oil transportation was calculated for each of the fourteen transportation scenarios presented in Section 8.2 for the following five cases:

- Central field location, conventional dredging equipment used for pipeline trenching, and no tanker escort vessels required (Table 8.3)
- Central field location, conventional dredging equipment used for pipeline trenching, and tanker escort vessels required (Table 8.4)
- Central field location, linear trencher developed for pipeline trenching, and tanker escort vessels required (Table 8.5)
- Southern field location, linear trencher developed for pipeline trenching, and tanker escort vessels required (Table 8.6)
- Northern field location, linear trencher developed for pipeline trenching, and tanker escort vessels required (Table 8.7).

Case 1: Central Field Location, Conventional Dredging Equipment Used For Pipeline Trenching, and Tanker Escort Vessels Required

The first set of economic evaluations for the 14 transportation scenarios was based on a central Chukchi Sea field location, with the use of conventional dredging equipment for trenching the offshore pipelines, and no allowance for tanker escort vessels for the arctic tankers. The tabulated results of these evaluations are presented in Table 8.3. Based on these evaluations the following transportation scenarios have the lowest cost per barrel for Case 1:

Flowrate (MBPD)	Scenario No.	Cost Per Barrel ($/BBL)	Next Lowest ($/BBL)	Scenario Description
100	1	6.90	8.25	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 20%
200	1	4.82	5.00	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 4%
400	10	3.39	3.48	Pipeline to Kivalina with tankers to Valdez is least expensive by 3%
600	10	2.82	2.97	Pipeline to Kivalina with tankers to Valdez is least expensive by 5%

Case 2: Central Field Location, Conventional Dredging Equipment Used for Pipeline Trenching, and Tanker Escort Vessels Required

Due to recent events in the Alaskan Gulf Coast region and the oil tanker transportation industry, it was determined by the participants that within the foreseeable future tanker escort vessels may be required for tankers travelling near environmentally critical areas. Therefore, it was necessary to evaluate the transportation scenarios based on the use of a tanker escort vessel accompanying each tanker along the route. The tabulated results for this evaluation are presented in Table 8.4. Based on these evaluations, the following transportation scenarios have the lowest cost per barrel for Case 2:

Flowrate (MBPD)	Scenario No.	Cost Per Barrel ($/BBL)	Next Lowest ($/BBL)	Scenario Description
100	1	6.90	8.25	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 20%
200	1	4.82	5.14	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 7%
400	10	3.51	3.57	Pipeline to Kivalina with tankers to Valdez is least expensive by 2%
600	10	2.93	3.09	Pipeline to Kivalina with tankers to Valdez is least expensive by 5%

Case 3: Central Field Location, Linear Trencher Developed For Pipeline Trenching, and Tanker Escort Vessels Required

As discussed in Section 6.4.2, the use of conventional dredging/trenching equipment is not an efficient or economic solution for the large amount of trenching required for offshore Chukchi Sea pipelines. The use of a linear trenching system can and will reduce the time and capital required for constructing offshore Chukchi Sea pipelines. It was therefore necessary to evaluate the transportation scenarios based on the use of a linear trenching system. The tabulated results for this evaluation are presented in Table 8.5. Based on these evaluations, the following transportation scenarios have the lowest cost per barrel for Case 3:

Flowrate (MBPD)	Scenario No.	Cost Per Barrel ($/BBL)	Next Lowest ($/BBL)	Scenario Description
100	1	5.59	7.61	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 36%
200	1	4.16	4.82	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 16%
400	10	3.34	3.40	Pipeline to Kivalina with tankers to Valdez is least expensive by 2%
600	10	2.82	2.92	Pipeline to Kivalina with tankers to Valdez is least expensive by 4%

Case 4: Southern Field Location, Linear Trencher Developed for Pipeline Trenching, and Tanker Escort Vessels Required

Based on the assumptions used above for Case 3, a cost per barrel for the fourteen transportation scenarios was calculated for a southern Chukchi Sea field location to determine a cost sensitivity based on location for the transportation scenarios. The tabulated results of this evaluation are presented in Table 8.6. Based on these evaluations, the following transportation scenarios have the lowest cost per barrel for Case 4:

Flowrate (MBPD)	Scenario No.	Cost Per Barrel ($/BBL)	Next Lowest ($/BBL)	Scenario Description
100	1	5.43	7.32	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 35%
200	1	4.06	4.65	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 15%
400	10	3.27	3.33	Pipeline to Kivalina with tankers to Valdez is least expensive by 2%
600	10	2.76	2.87	Pipeline to Kivalina with tankers to Valdez is least expensive by 4%

Case 5: Northern Field Location, Linear Trencher Developed for Pipeline Trenching, and Tanker Escort Vessels Required

Based on the assumptions used above for Case 3, a cost per barrel for the 14 transportation scenarios was calculated for a northern Chukchi Sea field location to determine a cost sensitivity based on location for the transportation scenarios. The tabulated results for this evaluation are presented in Table 8.7. Based on these evaluations, the following transportation scenarios have the lowest cost per barrel for Case 5:

Flowrate (MBPD)	Scenario No.	Cost Per Barrel ($/BBL)	Next Lowest ($/BBL)	Scenario Description
100	1	5.57	7.52	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 35%
200	1	4.15	4.76	All pipeline to Prudhoe Bay (TAPS PS1) is least expensive by 15%
400	1/9/10	3.42	3.48	Scenarios 1, 9 and 10 are all estimated to cost $3.42/barrel with the next lowest cost only 2% greater
600	10	2.89	2.97	Pipeline to Kivalina with tankers to Valdez is least expensive by 3%

8.5 RECOMMENDED TRANSPORTATION SCENARIOS

The following recommended transportation scenarios are based on the central Chukchi Sea field location, with the use of a linear trenching system for pipeline trenching, with tanker escort vessels required. It is worth noting that the selection of the recommended transportation scenario for each peak flowrate would not change for the five cases analyzed in Section 8.4. The cost per barrel of the recommended transportation scenario might change but the selection of that scenario as the recommended transportation scenario would not change.

8.5.1 Peak Flowrate of 100 MBPD

The five lowest cost per barrel scenarios for a peak flowrate of 100,000 barrels per day are summarized in Table 8.11. The three pipeline route scenarios (1, 2, and 3) and two pipeline with tanker scenarios (9 and 10) are the five lowest cost per barrel scenarios.

The recommended scenario for a peak flowrate of 100,000 barrels per day is Transportation Scenario 1. This scenario transports crude oil from the central field location to a pump station at Point Barrow via a 214-mile long, 20-inch diameter offshore pipeline. From the pump station at Point Barrow, the crude oil is transported to Trans-Alaskan Pipeline Pump Station One (PS1) via a 20-inch diameter pipeline (194 miles of offshore pipeline and 34 miles of onshore pipeline). The crude oil is then transported to the existing Valdez terminal using the Trans-Alaskan Pipeline System.

The net present value of this scenario is sensitive to both offshore and onshore pipeline construction cost factors, onshore and offshore pipeline operating and maintenance costs and TAPS dependent tariffs.

8.5.2 Peak Flowrate of 200 MBPD

The five lowest cost per barrel scenarios for a peak flowrate of 200,000 barrels per day are summarized in Table 8.12. Two of the all pipeline route scenarios (1 and 2) and three of the pipeline with tanker scenarios (5, 9 and 10) are the lowest five cost per barrel scenarios.

The recommended scenario for a peak flowrate of 200,000 barrel per day is Transportation Scenario 1. This scenario transports crude oil from the central field location to a pump station at Point Barrow via a 214-mile long, 26-inch diameter offshore pipeline. From the pump station at Point Barrow, the crude oil is transported to Trans-Alaskan Pipeline Pump Station Number One (PS1) via a 26-inch diameter pipeline (194 miles of offshore pipeline and 34 miles of onshore pipeline). The crude oil is then transported to the existing Valdez terminal using the Trans-Alaskan Pipeline System.

The net present value of this scenario is sensitive to both offshore on onshore pipeline construction cost factors, onshore and offshore pipeline operating and maintenance costs and TAPS dependent tariffs.

8.5.3 Peak Flowrate of 400 MBPD

The five lowest cost per barrel scenarios for a peak flowrate of 400,000 barrels per day are summarized in Table 8.13. Four pipeline with tanker scenarios (5, 9, 10 and 11) and Transportation Scenario 1 are the five lowest cost per barrel scenarios.

The recommended scenario for a peak flowrate of 400,000 barrel per day is Transportation Scenario 5. Scenario 5 was selected instead of Scenario 10 because Transportation Scenario 10 requires the existing terminal at Valdez be upgraded to a transshipment terminal. It is believed that increased trafficking of oil tankers in and around Valdez will not be allowed due to the growing concern over crude oil tanker shipments in environmentally critical areas in the region.

At this time no such opposition seems to be present against transshipment terminals in the Aleutians. However if such opposition develops, Scenario 5 could become less viable thus causing Transportation Scenario 1 to be the optimum solution for a peak flowrate of 400,000 barrels per day.

Transportation Scenario 5 transports crude oil from the central field location to a pump station at Cape Lisburne via a 183-mile long, 32-inch diameter offshore pipeline. From the pump station at Cape Lisburne, the crude oil is transported 57 miles in a 26-inch onshore pipeline to a nearshore tanker terminal and storage facility at Kivalina. From Kivalina, crude oil is transported to a transshipment terminal at Unimak pass using a fleet of three 200,000 dwt Arctic Class 6 tankers.

The net present value of Scenario 5 is sensitive to:

- Offshore and onshore pipeline construction cost factors, and operating and maintenance costs
- Arctic tanker construction costs, and operating and maintenance costs
- Nearshore tanker terminal construction costs, and operating and maintenance costs
- Transshipment tanker terminal construction costs, and operating and maintenance costs

8.5.4 Peak Flowrate of 600 MBPD

The five lowest cost per barrel scenarios for a peak flowrate of 600,000 barrels per day are summarized in Table 8.14. The lowest five cost per barrel scenarios are all pipeline with tanker scenarios (5, 6, 9, 10 and 11).

The recommended scenario for a peak flowrate of 600,000 barrel per day is Transportation Scenario 6. Scenario 6 was selected instead of Scenarios 10, 11, and 9 because Transportation Scenarios 10, 11, and 9 require the existing terminal at Valdez be upgraded to a transshipment terminal. As stated earlier, it is believed that such increased trafficking of oil tankers in and around Valdez will not be allowed due to the growing concern over crude oil tanker shipments in environmentally critical areas in the region.

At this time, no such opposition seems to be present against transshipment terminals in the Aleutians. However if such opposition develops, Scenarios 6 and 5 could become improbable thus causing Transportation Scenario 1 to be the optimum solution for a peak flowrate of 600,000 barrels per day.

Transportation Scenario 6 transports crude oil from the central field location to a pump station at Cape Lisburne via a 183-mile long, 38-inch diameter offshore pipeline. From the pump station at Cape Lisburne, the crude oil is transported 57 miles via a 30-inch onshore pipeline to a pump station at Kivalina. From Kivalina, a 38-inch diameter pipeline, 113 miles of offshore pipeline and 107 miles of onshore pipeline, transports the crude oil to a nearshore tanker terminal and storage facility at Nome. From Nome, crude oil is transported to a transshipment terminal at Unimak pass using a fleet of four 200,000 dwt Arctic Class 4 tankers.

The net present value of Scenario 5 is sensitive to:

- Offshore and onshore pipeline construction cost factors, and operating and maintenance costs
- Arctic tanker construction costs, and operating and maintenance costs
- Nearshore tanker terminal construction costs, and operating and maintenance costs
- Transshipment tanker terminal construction costs, and operating and maintenance costs

8.6 DIRECT OFFSHORE PIPELINE TO UNIMAK PASS

Based on the data presented in Chapter 7 and the economic evaluation methodology presented in Section 8.3, a cost per barrel for crude oil from the central Chukchi Sea field location to Unimak Pass via a direct offshore pipeline was calculated. The results of these evaluations are presented in Tables 8.8 through 8.10. The cost per barrel of transporting crude oil via a direct offshore pipeline ranges from $2.11 to $3.45 with an average cost of $2.62 a barrel and a peak flowrate ranging from 440 to 1105 MBPD.

The direct pipeline from the central Chukchi Sea location to Unimak Pass is not only a feasible solution for transporting crude oil from the region to the Aleutians, but also the most economically viable for large flowrates. A direct offshore pipeline is recommended for flowrates greater than 400 MBPD. This scenario not only is the most economical, but also eliminates the need for crude oil tankers in environmentally sensitive arctic waters.

The pipe diameter selected for a particular application would be selected based on the maximum predicted flowrate for the field life. Pump stations could be added after original pipeline construction, therefore maintaining a lower initial capital construction cost if initial production is low. As production increases, pump stations can be added to meet the required peak flowrates.

TABLE 8.1

TRANSPORTATION SYSTEM SUMMARY

SCENARIO DESIGNATION		SCENARIO DESCRIPTION
1986 STUDY	1990 STUDY	
1A	1	All Pipelines (Drawing No. 801)
1B	2	All Pipelines (Drawing No. 802)
1C	3	All Pipelines (Drawing No. 803)
3A	4	Pipeline to Tanker (Drawing No. 804)
3B	5	Pipeline to Tanker (Drawing No. 805)
3C	6	Pipeline to Tanker (Drawing No 806)
4A	7	Tanker to Pipeline (Drawing No. 807)
4B	8	Tanker to Pipeline (Drawing No. 808)
6A	9	Pipeline to Tanker (Drawing No. 809)
6B	10	Pipeline to Tanker (Drawing No. 810)
6C	11	Pipeline to Tanker (Drawing No. 811)
2A	12	All Tankers (Drawing No. 812)
2B	13	All Tankers (Drawing No. 813)
5	14	All Tankers (Drawing No. 814)

TABLE 8.2

TRANSPORTATION SCENARIO COMPONENT SUMMARY

SCENARIO	PIPELINE ROUTES	TANKER ROUTES	TERMINAL TYPE			
			NEARSHORE	OFFSHORE	TRANS-SHIPMENT	PRODUCTION STRUCTURE
1	P1, P2	N/A	N/A	N/A	N/A	Yes
2	P3, P4	N/A	N/A	N/A	N/A	Yes
3	P5, P6	N/A	N/A	N/A	N/A	Yes
4	P3	T6	AT WAINWRIGHT	N/A	Yes	Yes
5	P5, P7	T8	AT KIVALINA	N/A	Yes	Yes
6	P5, P7 P8	T10	AT NOME	N/A	Yes	Yes
7	P4	T1	AT WAINWRIGHT	Yes	N/A	N/A
8	P6	T2	AT CAPE LISBURNE	Yes	N/A	N/A
9	P3	T7	AT WAINWRIGHT	N/A	N/A	Yes
10	P5, P7	T9	AT KIVALINA	N/A	N/A	Yes
11	P5, P7 P8	T11	AT NOME	N/A	N/A	Yes
12	N/A	T4	N/A	Yes	Yes	N/A
13	N/A	T5	N/A	Yes	N/A	N/A
14	N/A	T3, T10	AT NOME	Yes	Yes	N/A

N/A: Not Applicable

TABLE 8.3

NET PRESENT VALUE

TRANSPORTATION COST SUMMARY

CENTRAL FIELD LOCATION ($/Barrel)

SCENARIO	FLOW RATE (MBPD)			
	100	200	400	600
1	6.90**	4.82**	3.76	3.36
2	8.25	5.62	4.24	3.73
3	9.84	6.50	4.72	4.10
4	10.39	5.65	3.94	3.17
5	10.52	5.61	3.48	3.08*
6	12.26	6.55	3.99	3.14*
7	13.48	7.10	4.21	3.23*
8	14.89	7.87	4.62	3.54
9	9.10	5.00*	3.48*	2.97*
10	9.24	5.11*	3.39**	2.82**
11	10.97	6.06	3.80	3.00*
12	9.82	5.39	4.08	3.48
13	8.93	5.36	4.09	3.58
14	13.80	7.31	5.04	4.26

Notes:
Assumes use of conventional dredging equipment and no icebreaking support/oil spill escort vessel.
*Within 10% of lowest cost scenario.
**Lowest cost scenario.

TABLE 8.5

NET PRESENT VALUE

TRANSPORTATION COST SUMMARY

CENTRAL FIELD LOCATION ($/Barrel)

SCENARIO	FLOW RATE (MBPD)			
	100	200	400	600
1	5.59**	4.16**	3.43*	3.14*
2	7.61	5.30	4.08	3.62
3	9.15	6.16	4.55	3.99
4	10.02	5.46	3.91	3.18
5	10.07	5.38	3.40*	3.06*
6	11.45	6.14	3.81	3.04*
7	13.75	7.24	4.27	3.27
8	15.17	8.00	4.69	3.59
9	8.73	4.82	3.45*	3.00*
10	8.78	4.88	3.34**	2.82**
11	10.17	5.65	3.65*	2.92*
12	10.09	5.53	4.22	3.59
13	9.20	5.57	4.26	3.74
14	14.27	7.54	5.21	4.45

Notes:
Assumes development of linear trencher and icebreaking support/oil spill escort vessels.
* Within 10% of lowest cost scenario.
**Lowest cost scenario.

TABLE 8.6

NET PRESENT VALUE

TRANSPORTATION COST SUMMARY

SOUTHERN FIELD LOCATION ($/Barrel)

SCENARIO	FLOW RATE (MBPD)			
	100	200	400	600
1	5.43**	4.06**	3.36*	3.09
2	7.32	5.13	3.97	3.53
3	8.99	6.05	4.48	3.93
4	9.73	5.29	3.80	3.09
5	9.90	5.27	3.33	3.01*
6	11.29	6.04	3.75	2.99*
7	13.51	7.11	4.05	3.05
8	14.92	7.87	4.47	3.50
9	8.44	4.65	3.34*	2.91*
10	8.62	4.78	3.27**	2.76**
11	10.00	5.55	3.58*	2.87*
12	9.84	5.19	3.60*	3.51
13	8.56	4.75	3.64	3.33
14	14.02	7.41	4.94	4.37

Note:
Assumes development of linear trencher and icebreaking support/oil spill escort vessels.
*Within 10% of lowest cost scenario.
**Lowest cost scenario.

TABLE 8.7

NET PRESENT VALUE

TRANSPORTATION COST SUMMARY

NORTHERN FIELD LOCATION ($/Barrel)

SCENARIO	FLOW RATE (MBPD)			
	100	200	400	600
1	5.57**	4.15**	3.42*	3.13
2	7.52	5.25	4.04	3.60
3	9.35	6.29	4.63	4.05
4	9.93	5.41	3.88	3.15*
5	10.27	5.51	3.48*	3.13*
6	11.65	6.27	3.90	3.11*
7	14.47	7.54	4.39	3.57
8	15.88	8.30	4.80	3.88
9	8.64	4.76	3.42*	2.97*
10	8.98	5.01	3.42*	2.89**
11	10.37	5.78	3.73*	2.99*
12	10.80	5.83	4.33	4.22
13	9.91	6.18	4.37	4.04
14	14.98	8.43	5.32	5.08

Notes:
Assumes development of linear trencher and icebreaking support/oil spill escort vessels.
*Within 10% of lowest cost scenario.
**Lowest cost scenario.

TABLE 8.8

48-INCH DIRECT OFFSHORE PIPELINE

ECONOMIC EVALUATION SUMMARY

ITEM	PUMP STATIONS		
	0	1	2
Capital Construction Cost ($MM)	5,020.11	5,898.82	6,273.08
P.V. of Operating & Maintenance Cost ($MM)	164.37	219.36	280.50
TOTAL P.V. ($MM)	5,184.47	6,118.18	6,553.58
Peak Flow Rate (MBPD)[1]	440	640	775
Recoverable Barrels[2]	1.765 x 109	2.567 x 109	3.109 x 109
Dollars Per Barrel	$2.94	$2.38	$2.11

Notes:
[1]Based on Darcy Law.
[2]Based on a design factor of 1.82 peak flow, reference Section 8.3.

TABLE 8.9

52-INCH DIRECT OFFSHORE PIPELINE

ECONOMIC EVALUATION SUMMARY

ITEM	PUMP STATIONS		
	0	1	2
Capital Construction Cost ($MM)	6,350.74	7,404.58	7,722.16
P.V. of Operating & Maintenance Cost ($MM)	164.37	219.36	280.50
TOTAL P.V. ($MM)	6,515.10	7,623.94	8,002.65
Peak Flow Rate (MBPD)[1]	540	785	945
Recoverable Barrels[2]	2,165.93	3,148.63	3,790.38
Dollars Per Barrel	$3.01	$2.42	$2.11

Notes:
[1]Based on Darcy Law.
[2]Based on a design factor of 1.82 peak flow, reference Section 8.3.

TABLE 8.10

56-INCH DIRECT OFFSHORE PIPELINE

ECONOMIC EVALUATION SUMMARY

ITEM	PUMP STATIONS		
	0	1	2
Capital Construction Cost ($MM)	8,614.53	9,951.59	10,418.18
P.V. of Operating & Maintenance Cost ($MM)	164.37	219.36	280.50
TOTAL P.V. ($MM)	8,778.90	10,170.95	10,698.68
Peak Flow Rate (MBPD) (1)	635	915	1105
Recoverable Barrels (2)	2.55 x 109	3.67 x 109	4.43 x 109
Dollars Per Barrel	$3.45	$2.77	$2.41

Notes:
(1)Based on Darcy Law.
(2)Based on a design factor of 1.82 peak flow, reference Section 8.3.

TABLE 8.11

PRESENT VALUE COST SUMMARY

FOR CENTRAL FIELD 100 MBPD

LOWEST COST SCENARIOS

RANK	1	2	3	4	5
SCENARIO	1	2	9	10	3
TRANSPORTATION COMPONENT					
PIPELINES					
Capital Construction Cost ($mm)	1,199.46	1,878.40	428.71	697.05	2,451.58
P.V. of Annual O&M Cost ($mm)	1,043.17	1,172.45	48.63	133.84	1,217.82
TANKERS					
Capital Construction Cost ($mm)	0	0	497.44	395.06	0
P.V. of Annual O&M Cost ($mm)	0	0	769.80	600.38	0
TERMINALS					
Capital Construction Cost ($mm)	0	0	1,021.26	983.79	0
P.V. of Annual O&M Cost ($mm)	0	0	735.40	711.65	0
TOTAL PRESENT VALUE ($mm)	2,242,63	3,050.85	3,501.23	3,521.77	3,669.40
CRUDE OIL TRANSPORTATION COST ($/barrel)	5.59	7.61	8.73	8.78	9.15

*Total Recoverable Reserves equal 401,098,400 barrels.
*Assumes development of linear trencher and use of icebreaking support/oil spill escort vessels.

TABLE 8.12

PRESENT VALUE COST SUMMARY

FOR CENTRAL FIELD 200 MBPD

LOWEST COST SCENARIOS

RANK	1	2	3	4	5
SCENARIO	1	9	10	2	5
TRANSPORTATION COMPONENT					
PIPELINES					
Capital Construction Cost ($mm)	1,362.12	469.46	802.22	2,128.48	802.22
P.V. of Annual O&M Cost ($mm)	1,978.10	48.70	137.29	2,122.58	137.29
TANKERS					
Capital Construction Cost ($mm)	0	683.98	585.84	0	505.84
P.V. of Annual O&M Cost ($mm)	0	905.16	693.69	0	657.25
TERMINALS					
Capital Construction Cost ($mm)	0	1,021.26	983.79	0	1,533.79
P.V. of Annual O&M Cost ($mm)	0	735.40	711.65	0	677.59
TOTAL PRESENT VALUE ($mm)	3,340.22	3,863.96	3,914.47	4,251.05	4,313.98
CRUDE OIL TRANSPORTATION COST ($/barrel)	4.16	4.82	4.88	5.30	5.38

*Total Recoverable Reserves equal 802,197,800 barrels.
*Assumes development of linear trencher and use of icebreaking support/oil spill escort vessels.

TABLE 8.13

PRESENT VALUE COST SUMMARY

FOR CENTRAL FIELD 400 MBPD

LOWEST COST SCENARIOS

RANK	1	2	3	4	5
SCENARIO	10	5	1	9	11
TRANSPORTATION COMPONENT					
PIPELINES					
Capital Construction Cost ($mm)	940.75	940.75	1,656.35	543.82	2,058.87
P.V. of Annual O&M Cost ($mm)	141.52	141.52	3,846.74	48.83	230.87
TANKERS					
Capital Construction Cost ($mm)	1,171.68	878.76	0	1,367.96	938.04
P.V. of Annual O&M Cost ($mm)	1,387.37	1,040.53	0	1,810.32	945.01
TERMINALS					
Capital Construction Cost ($mm)	997.77	1,767.77	0	1,034.46	981.00
P.V. of Annual O&M Cost ($mm)	713.44	679.38	0	737.10	700.67
TOTAL PRESENT VALUE ($mm)	5,352.53	5,448.72	5,503.09	5,542.50	5,854.45
CRUDE OIL TRANSPORTATION COST ($/barrel)	3.34	3.40	3.43	3.45	3.65

*Total Recoverable Reserves equal 1,604,395,600 barrels.
*Assumes development of linear trencher and use of icebreaking support/oil spill escort vessels.

TABLE 8.14

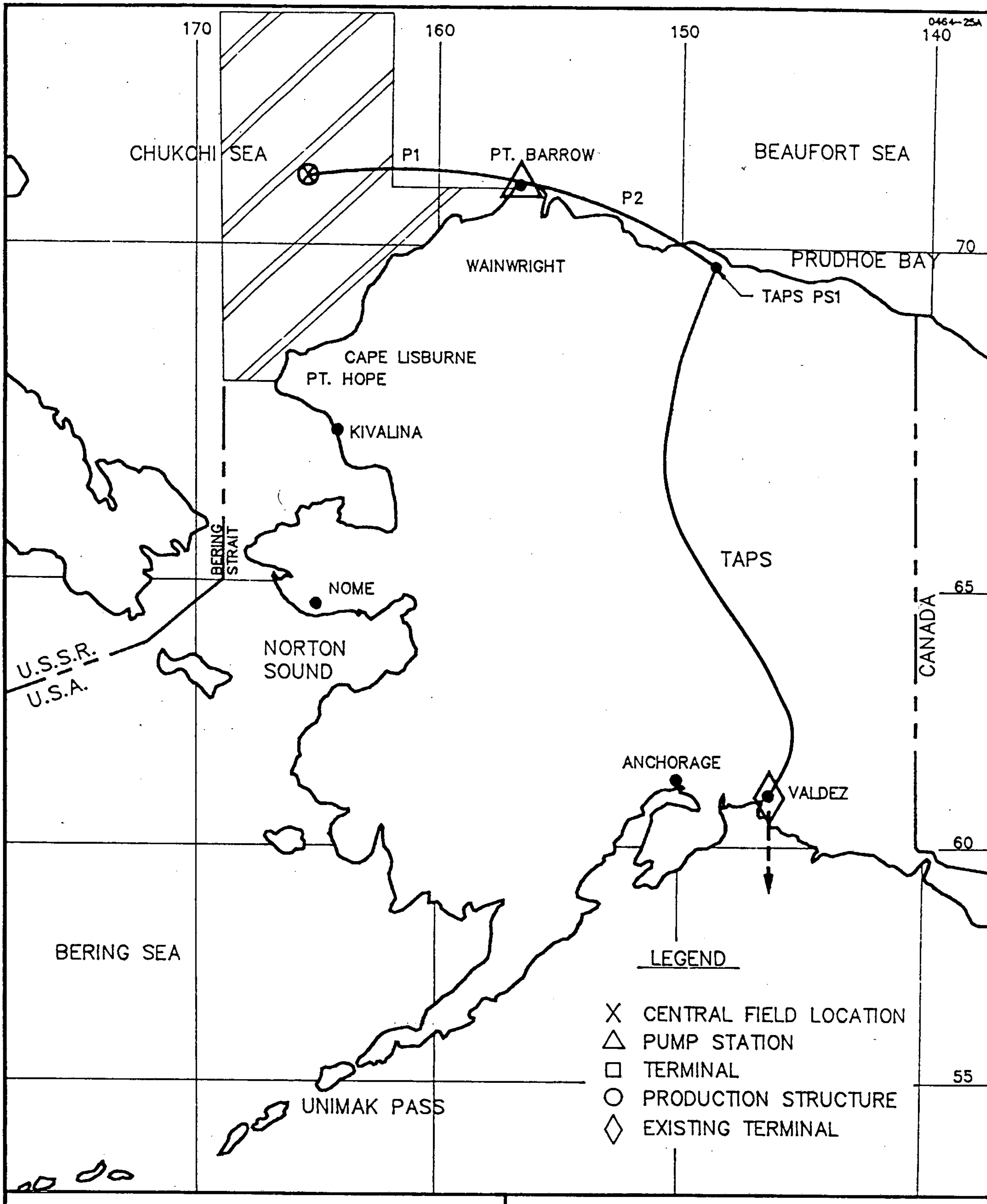
PRESENT VALUE COST SUMMARY

FOR CENTRAL FIELD 600 MBPD

LOWEST COST SCENARIOS

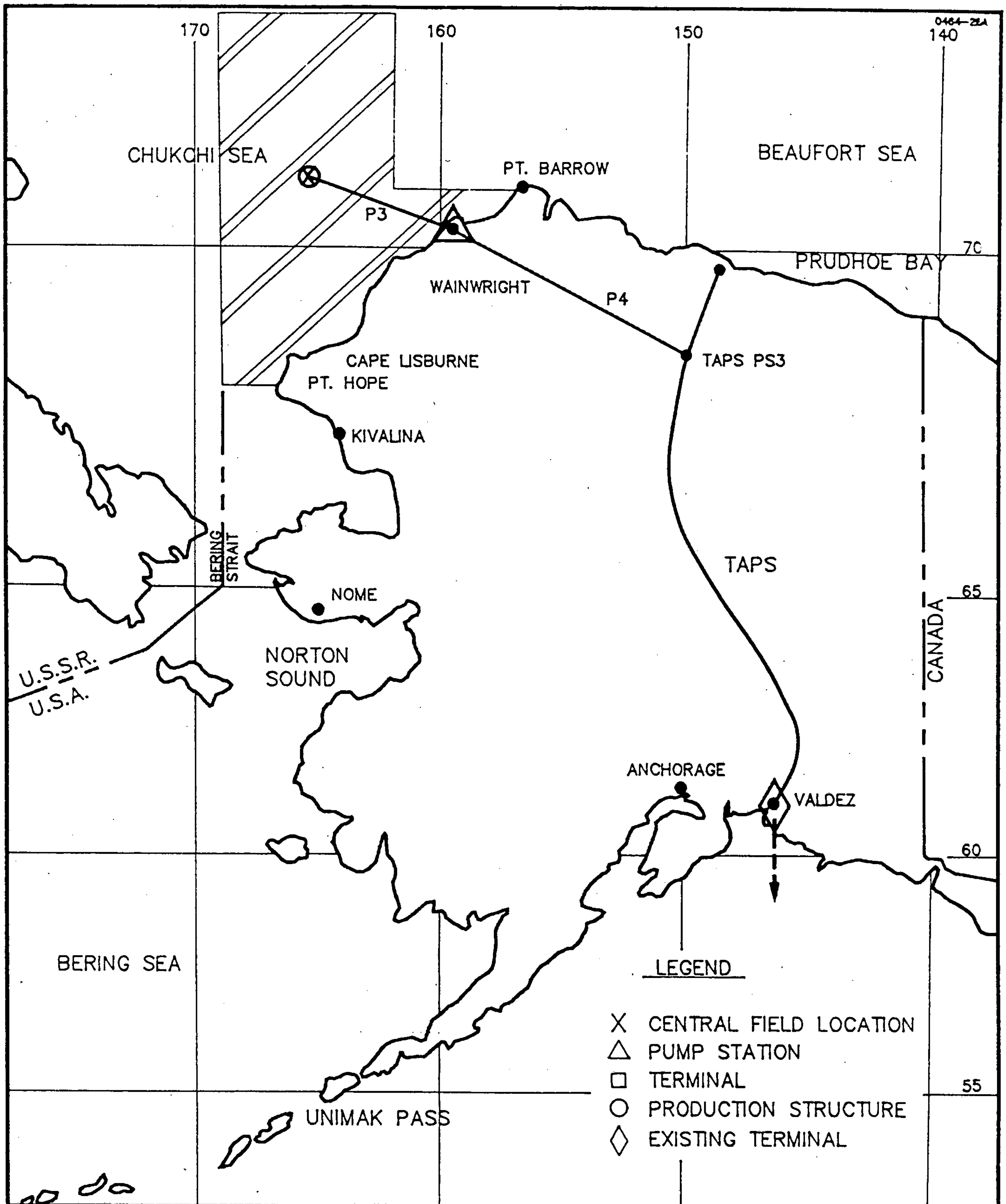
RANK	1	2	3	4	5
SCENARIO	10	11	9	6	5
TRANSPORTATION COMPONENT					
PIPELINES					
Capital Construction Cost ($mm)	1,075.44	2,279.72	616.67	2,279.72	1,075.44
P.V. of Annual O&M Cost ($mm)	144.96	238.08	48.96	238.08	144.96
TANKERS					
Capital Construction Cost ($mm)	1,757.52	1,407.06	2,051.94	938.04	1,464.60
P.V. of Annual O&M Cost ($mm)	2,081.05	1,417.51	2,715.49	945.01	1,734.21
TERMINALS					
Capital Construction Cost ($mm)	1,010.19	994.20	1,047.66	2,249.20	2,265.19
P.V. of Annual O&M Cost ($mm)	714.97	702.28	738.72	668.23	680.91
TOTAL PRESENT VALUE ($mm)	6,784.13	7,038.85	7,219.44	7,318.28	7,365.32
CRUDE OIL TRANSPORTATION COST ($/barrel)	2.82	2.92	3.00	3.04	3.06

*Total Recoverable Reserves equal 2,406,593,400 barrels.
*Assumes development of linear trencher and use of icebreaking support/oil spill escort vessels.



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 1

INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 801
	DATE 12-20-90	JOB NO. H-046.4	



JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

CHUKCHI SEA
TRANSPORTATION SCENARIO 2

INTEC ENGINEERING, INC.

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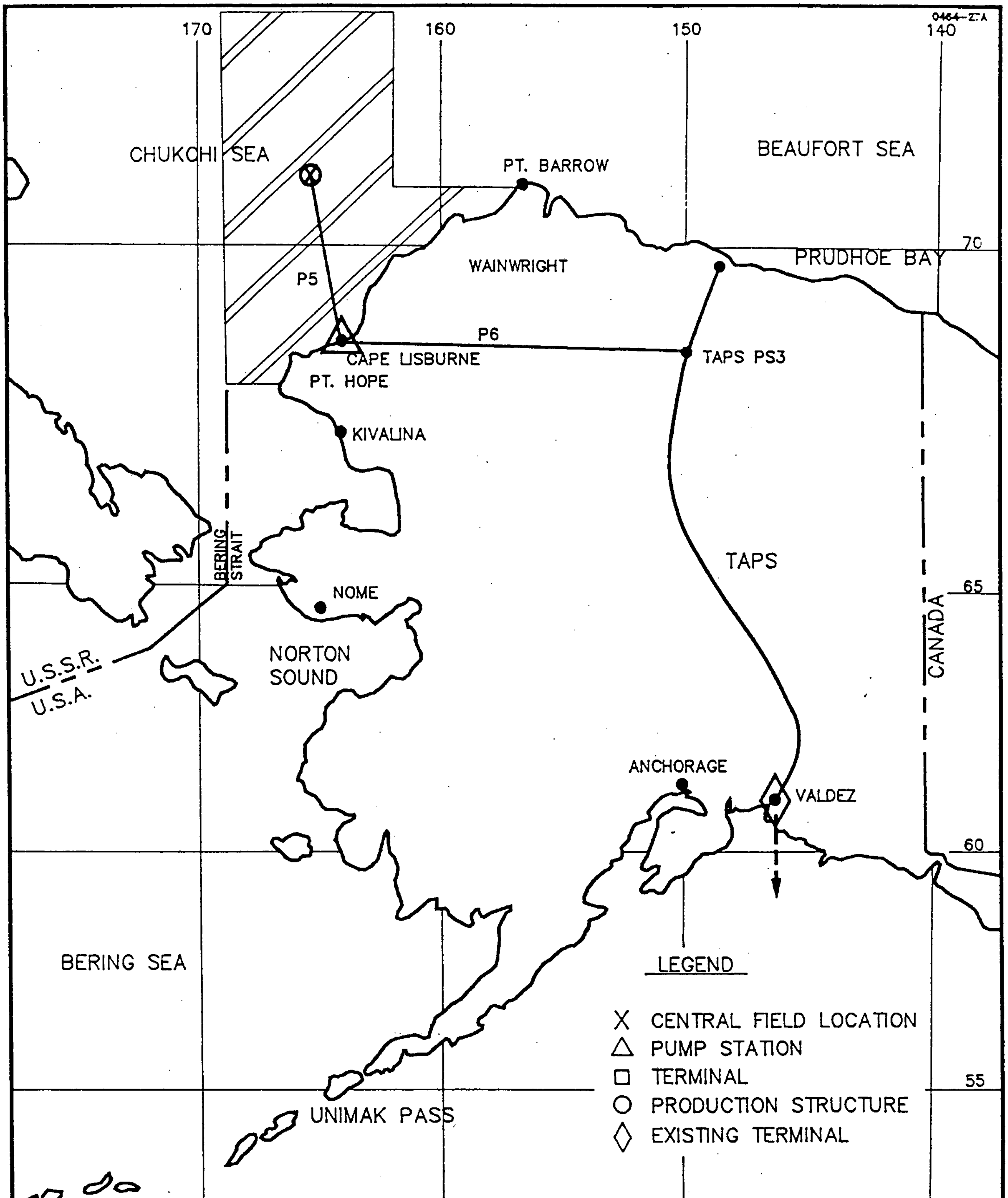
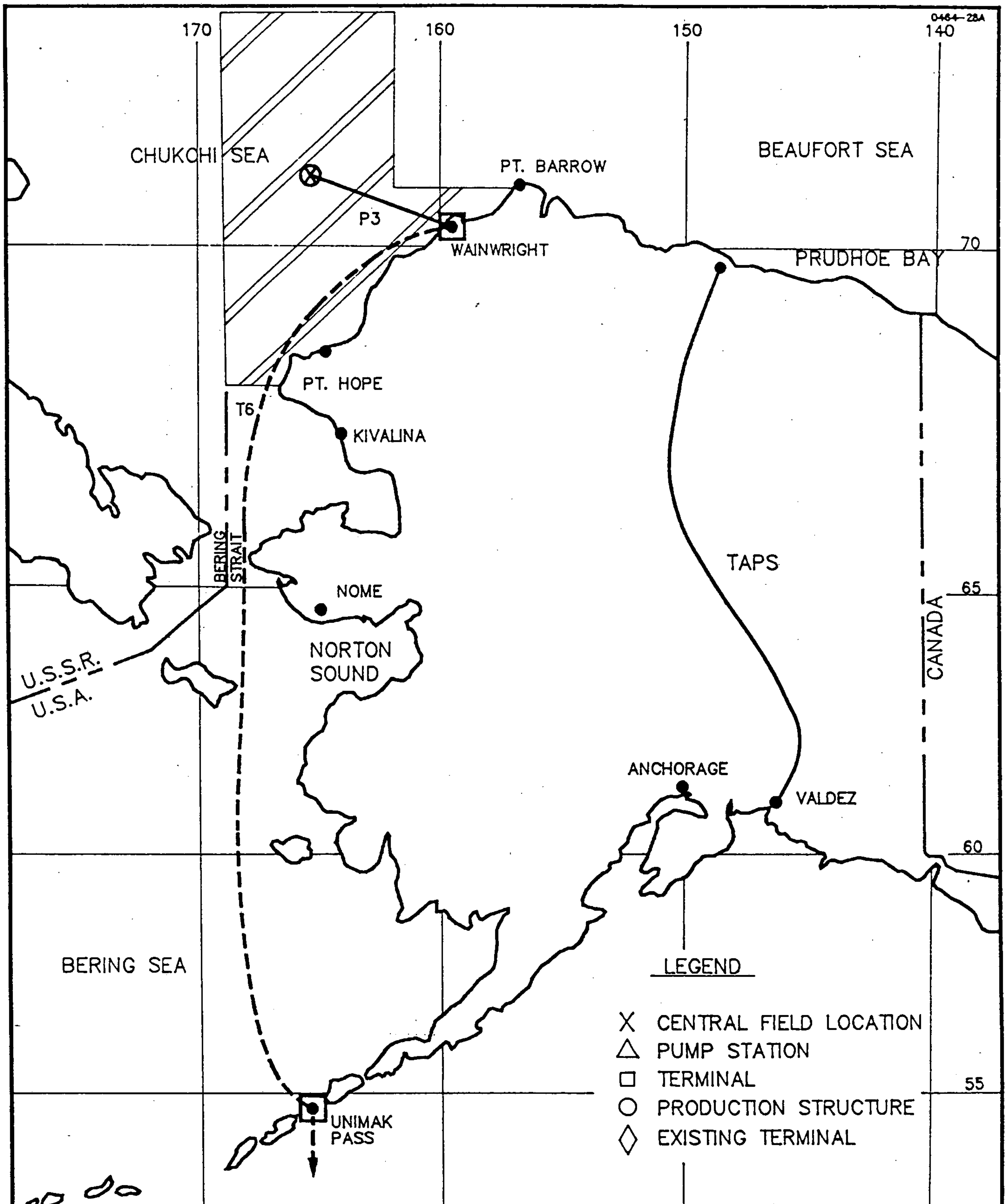
NONE	KC	802
DATE 12-20-90	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 3		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY KC	DRAWING NO. 803
	DATE 12-20-90	JOB NO. H-046.4	

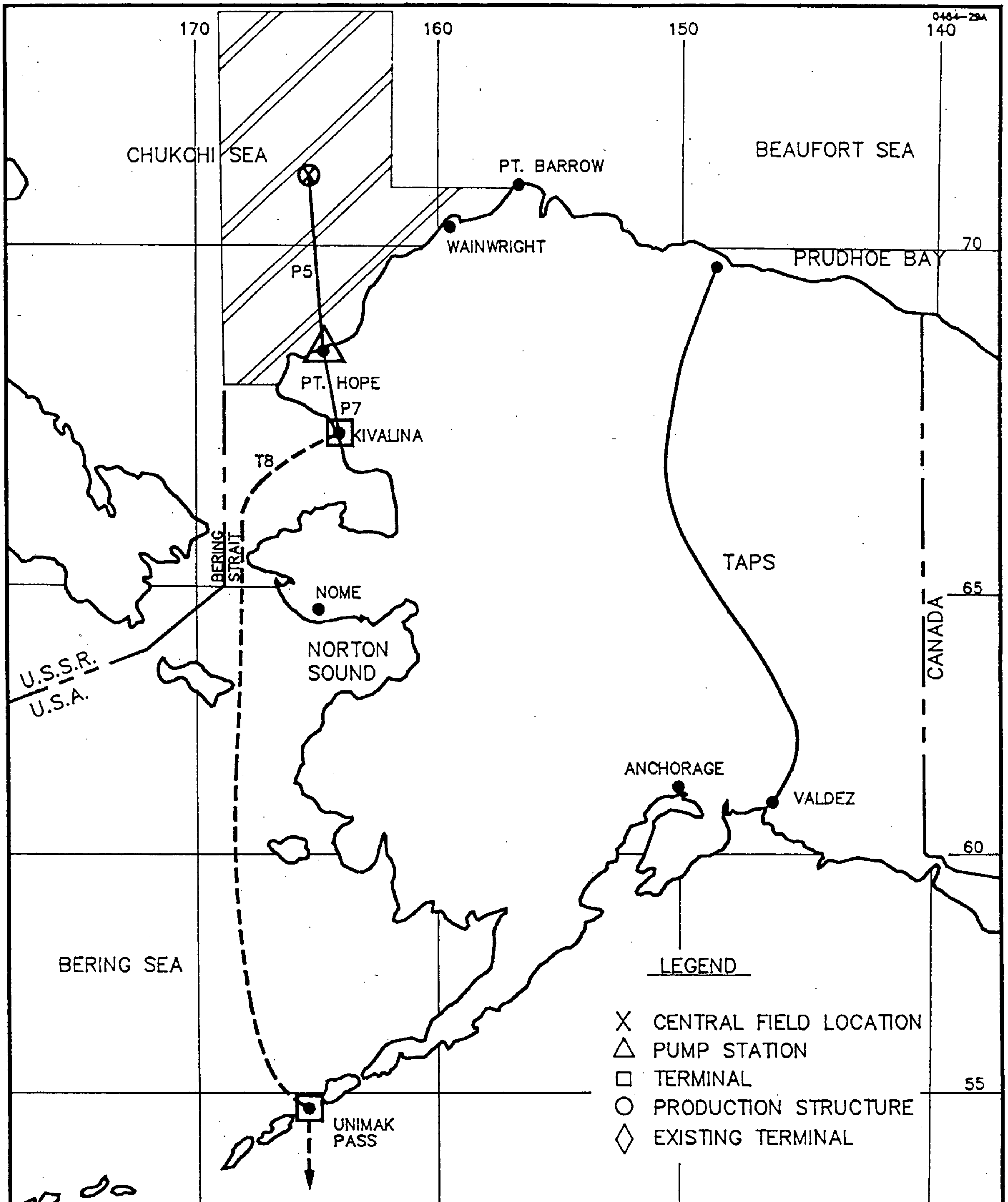


JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

CHUKCHI SEA
TRANSPORTATION SCENARIO 4

INTEC ENGINEERING, INC.

SCALE NONE	DRAWN BY KC	DRAWING NO. 804
DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 5		
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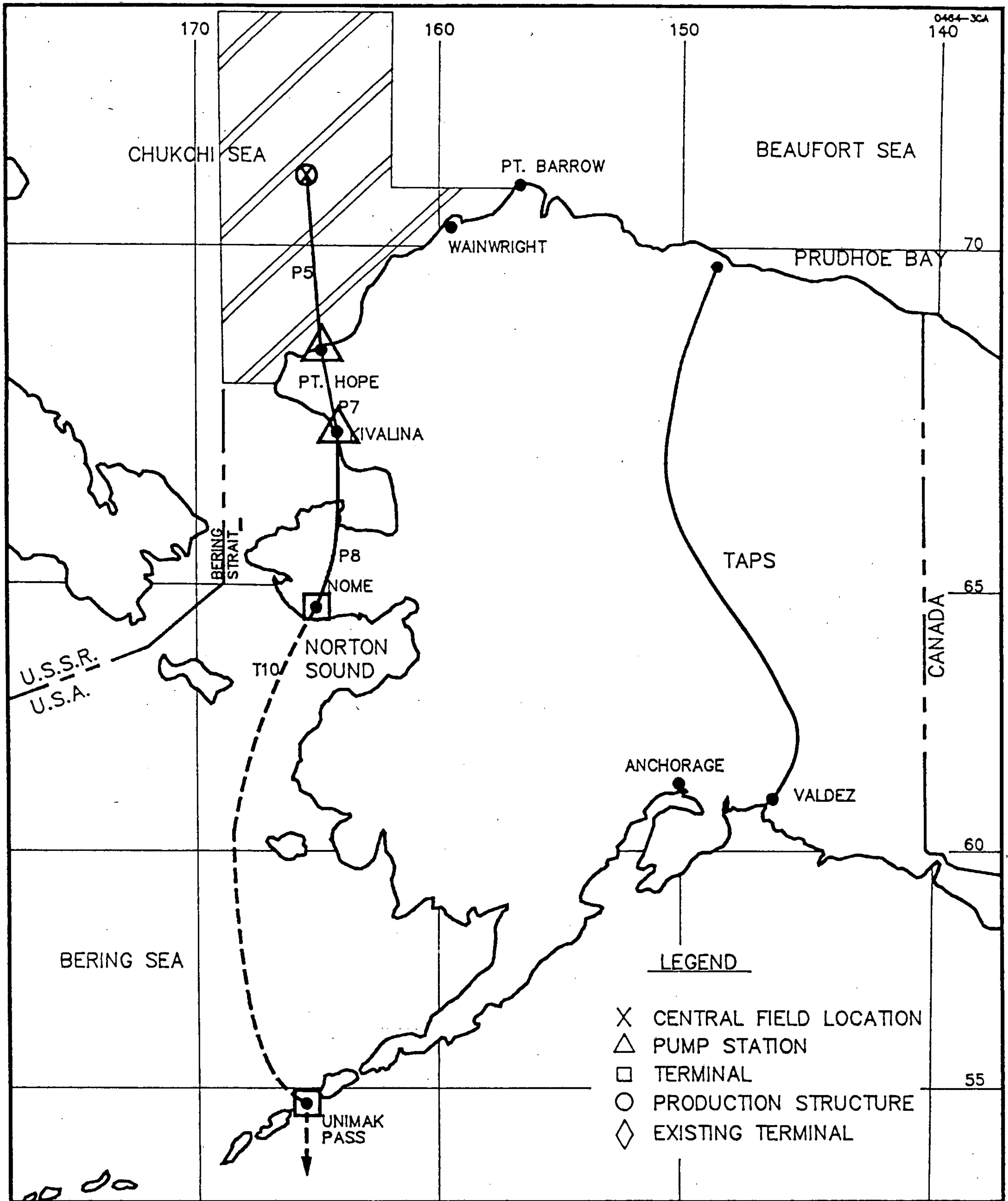
	DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 6		
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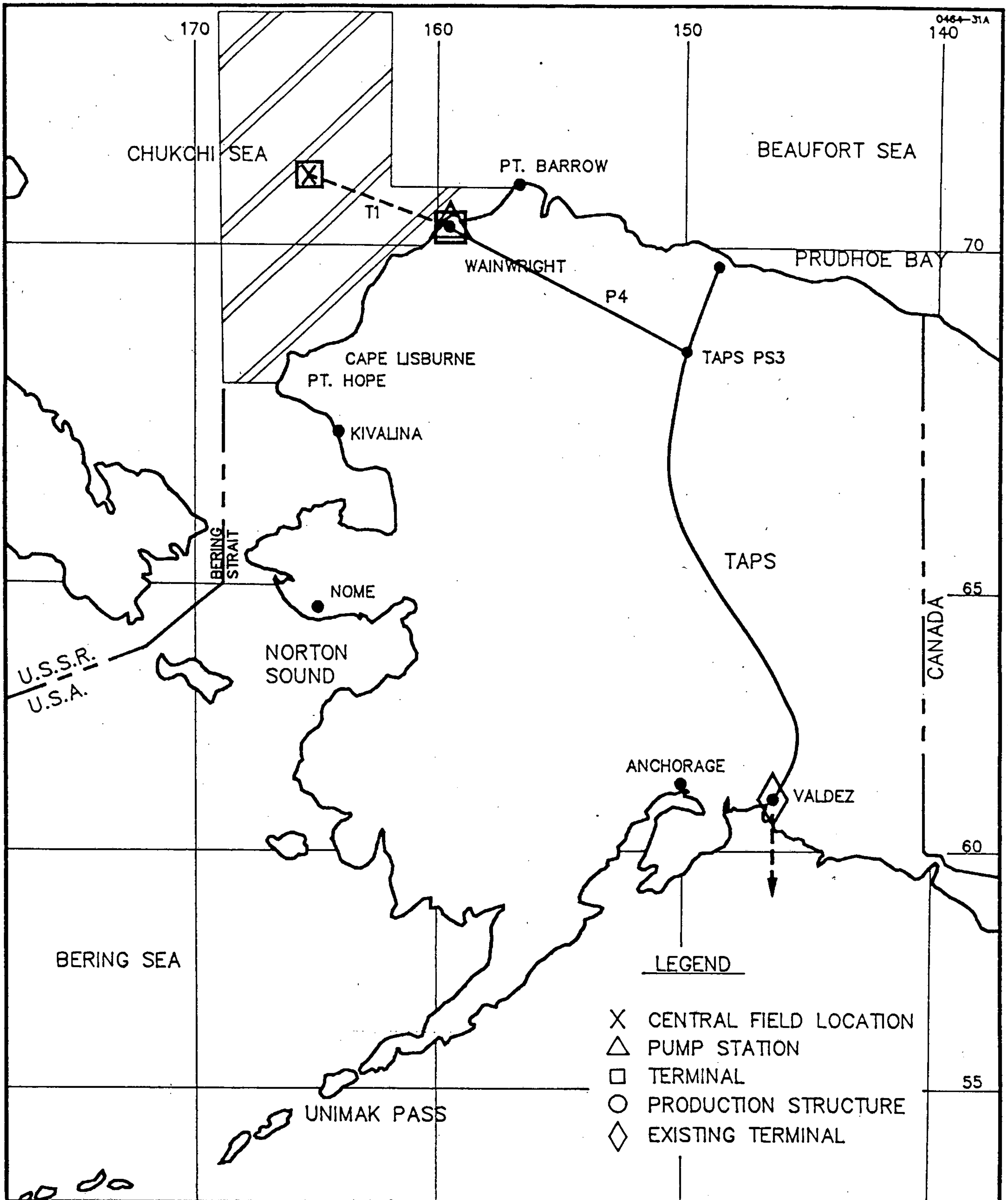
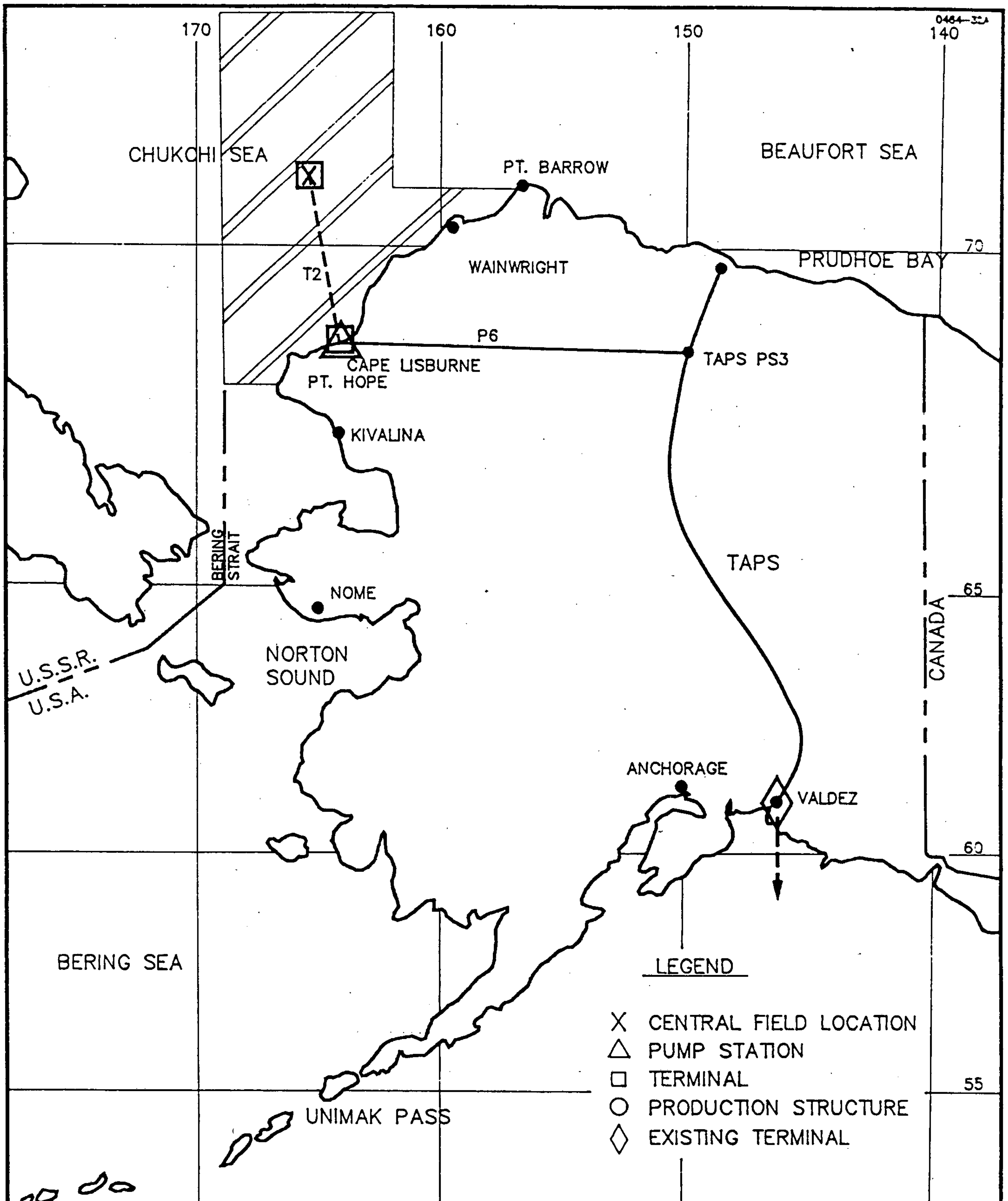
	DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 7

INTEC ENGINEERING, INC.

SCALE	DRAWN BY	DRAWING NO.
NONE	KC	807
DATE	JOB NO.	
12-20-90	H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 8		
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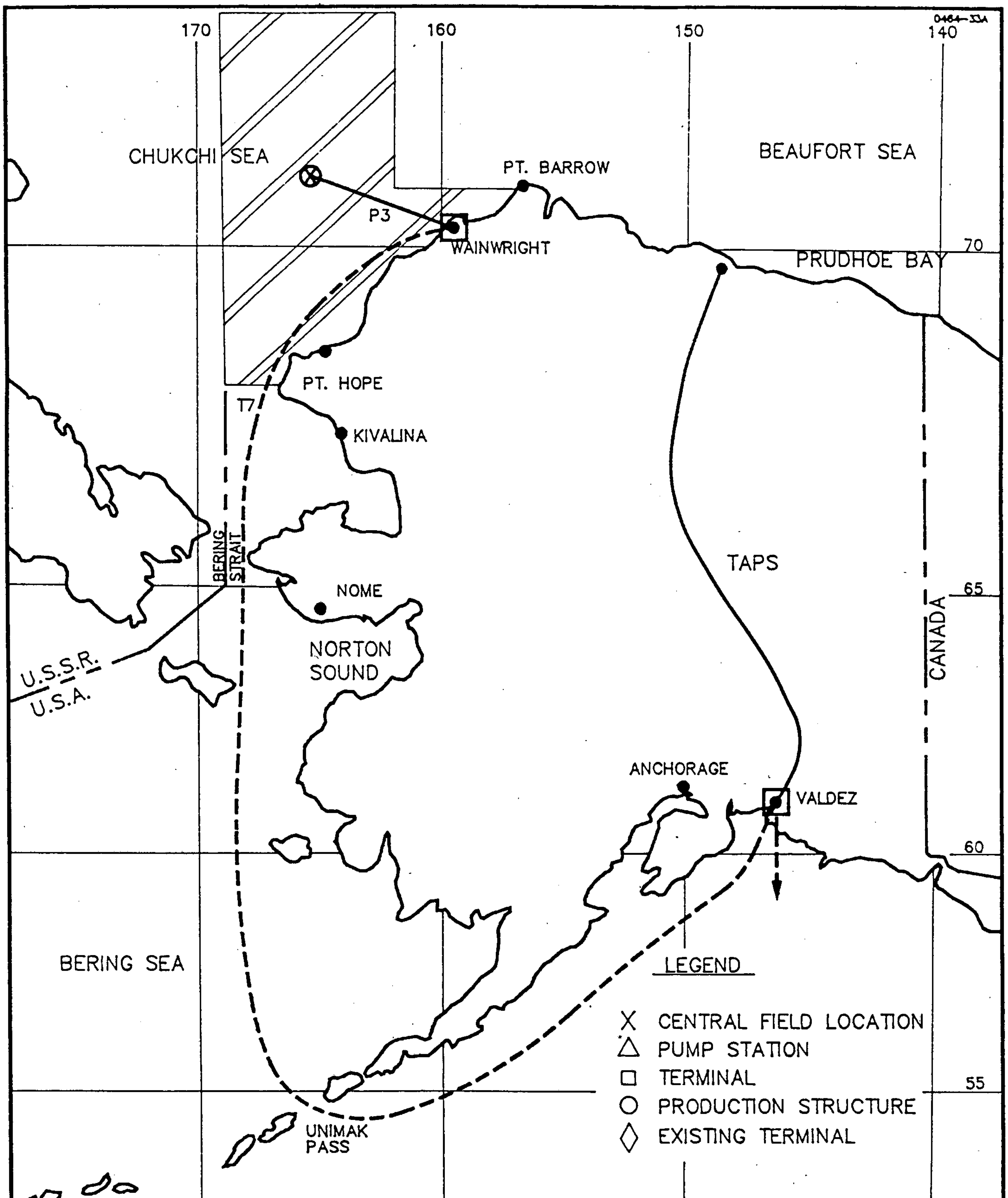
	DATE 12-20-90	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 9

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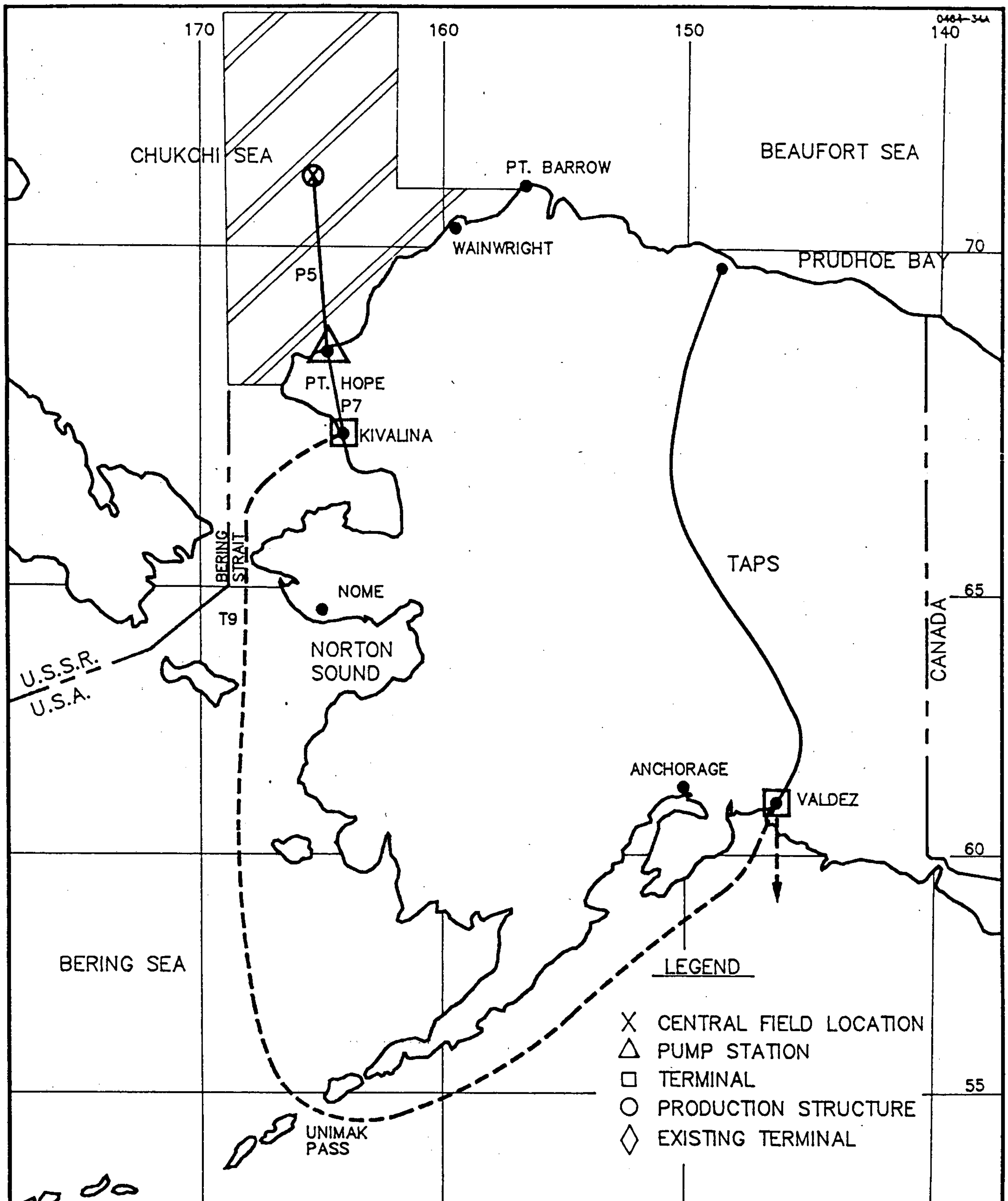
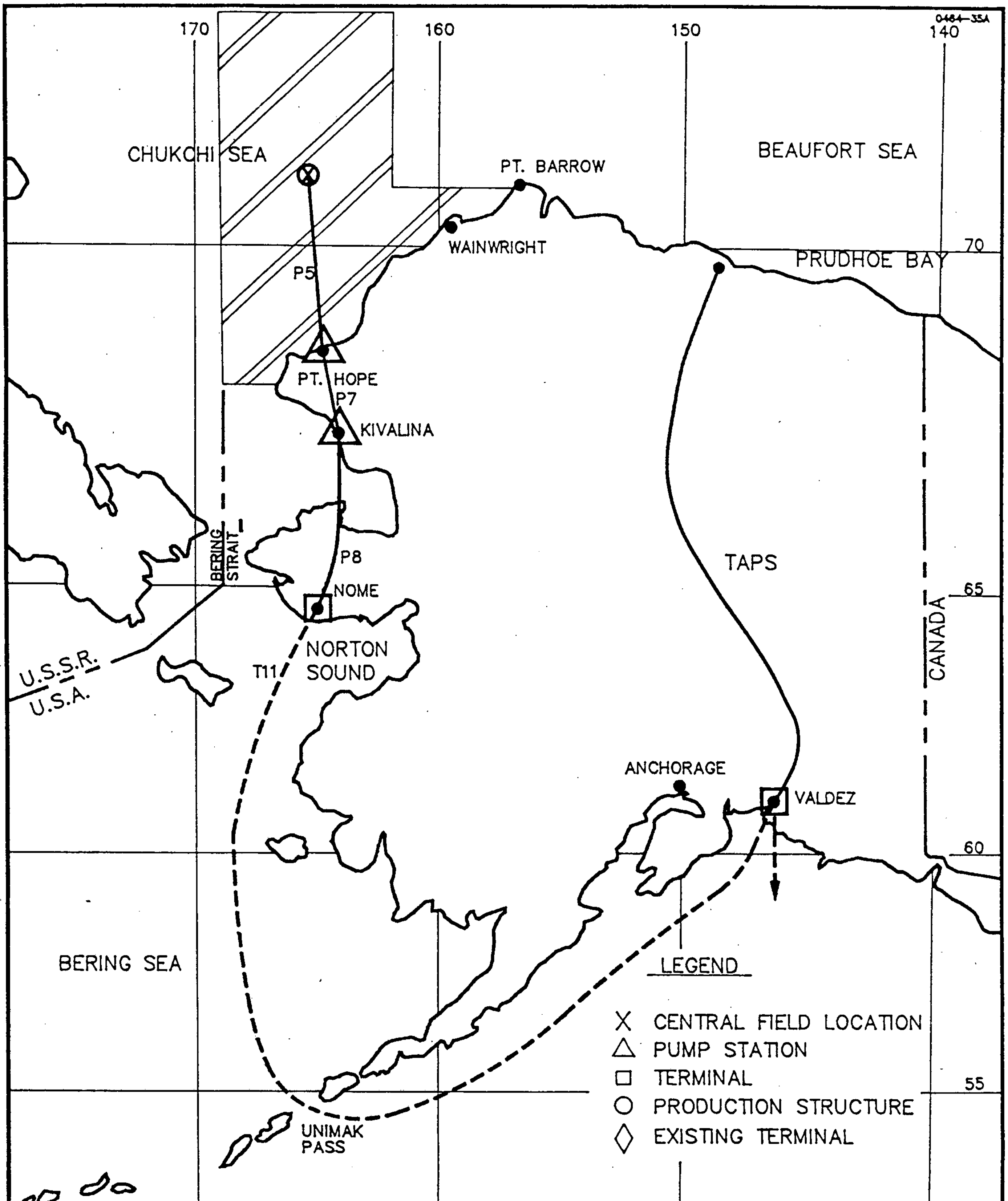


JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

CHUKCHI SEA
TRANSPORTATION SCENARIO 10

INTEC ENGINEERING, INC.

SCALE	DRAWN BY	DRAWING NO.
NONE	KC	810
DATE	JOB NO.	
1-7-91	H-046.4	



JOINT INDUSTRY STUDY
CHUKCHI SEA TRANSPORTATION

CHUKCHI SEA
TRANSPORTATION SCENARIO 11

INTEC ENGINEERING, INC.

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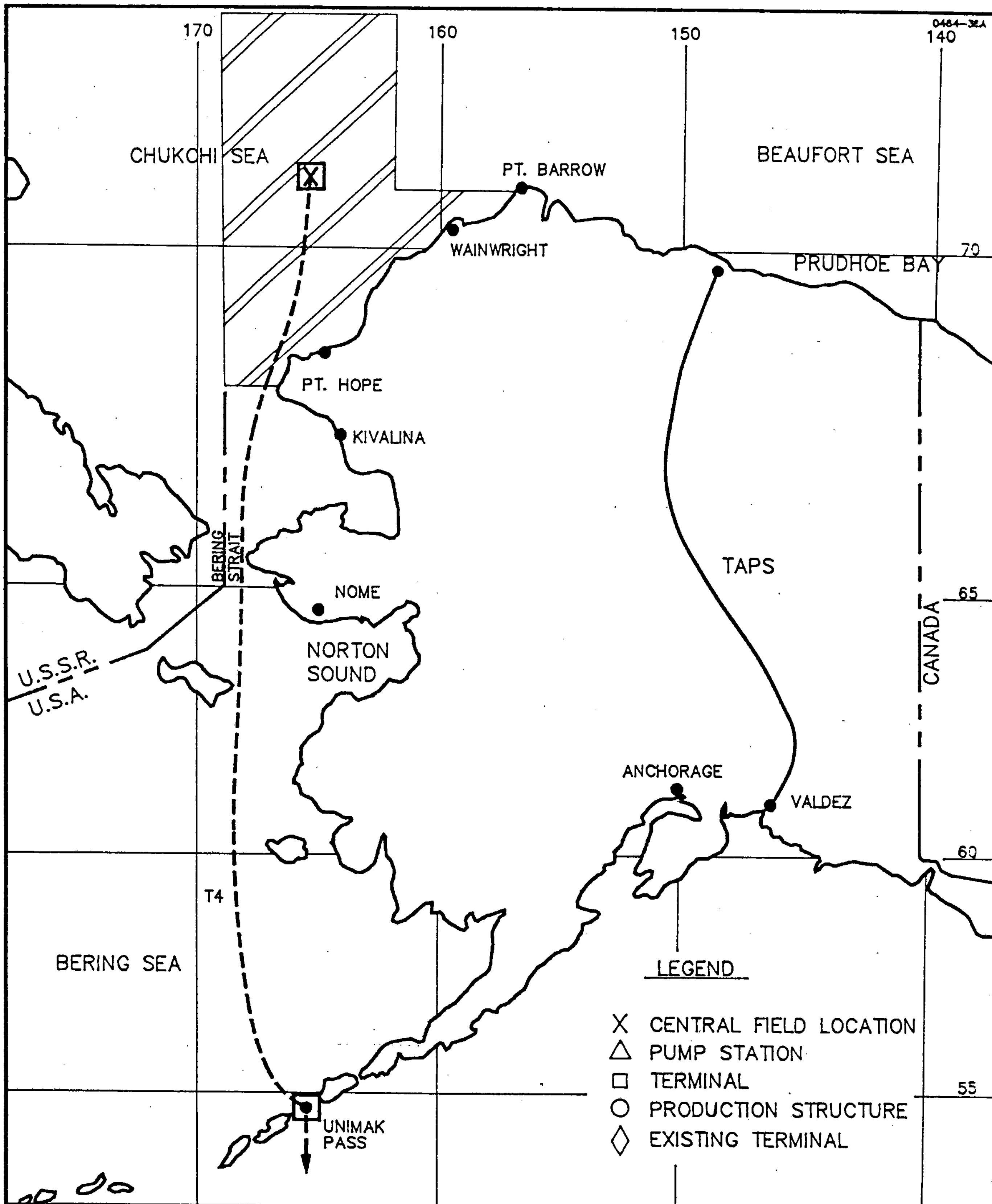
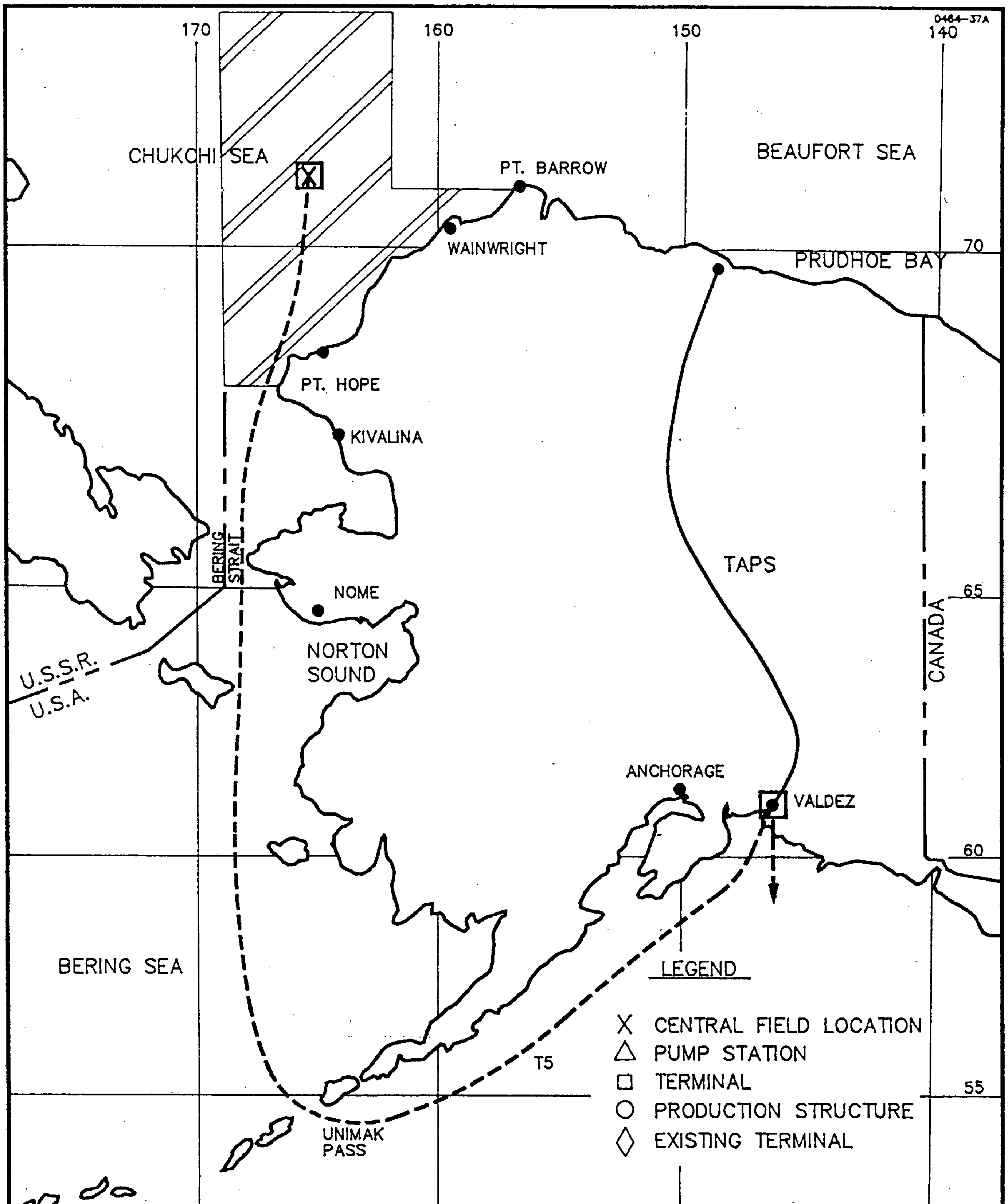
DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 12

INTEC ENGINEERING, INC.

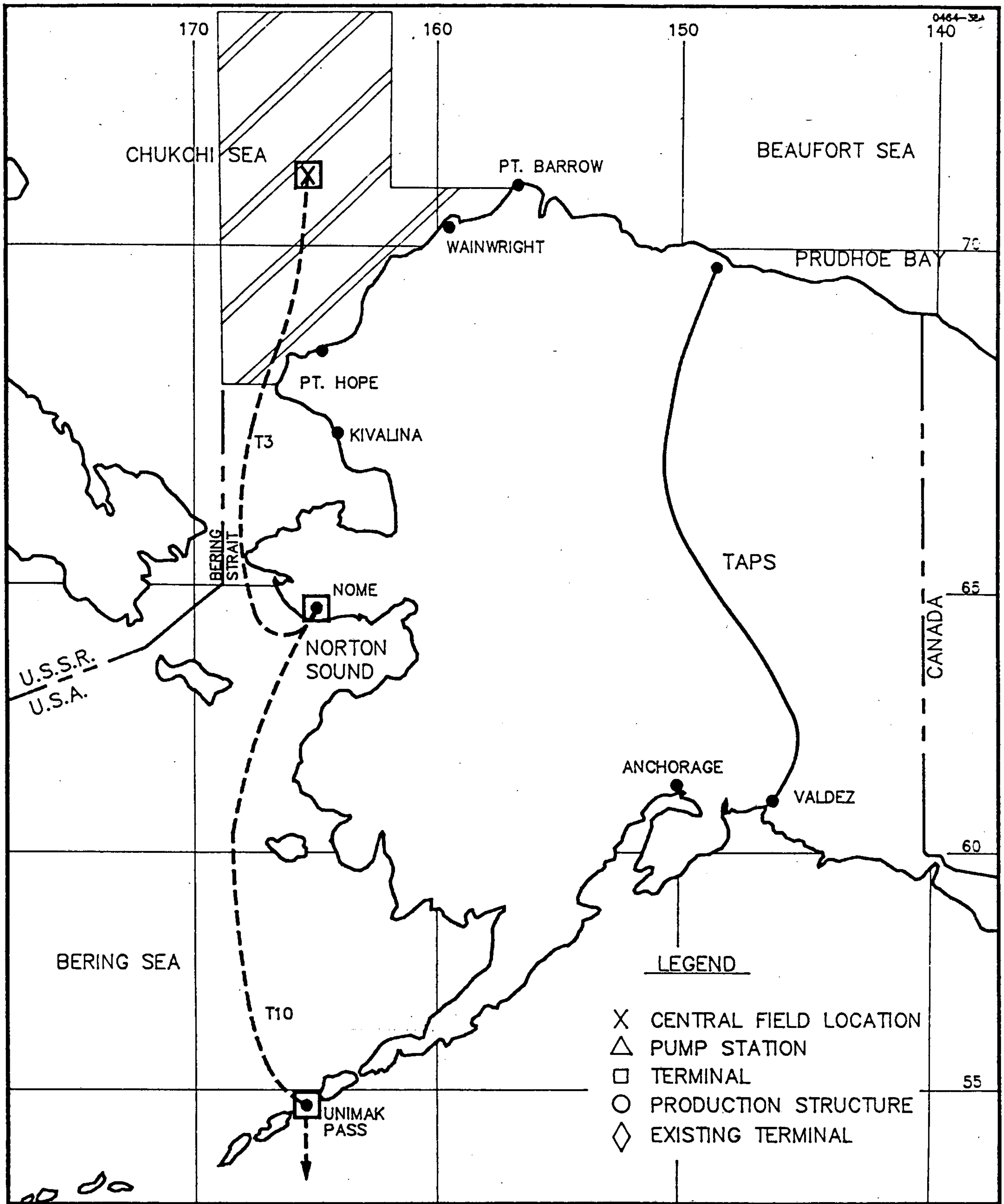
SCALE	DRAWN BY	DRAWING NO.
NONE	KC	812
DATE	JOB NO.	
1-7-91	H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 13

INTEC ENGINEERING, INC.

SCALE	DRAWN BY	DRAWING NO.
NONE	KC	813
DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	CHUKCHI SEA TRANSPORTATION SCENARIO 14		
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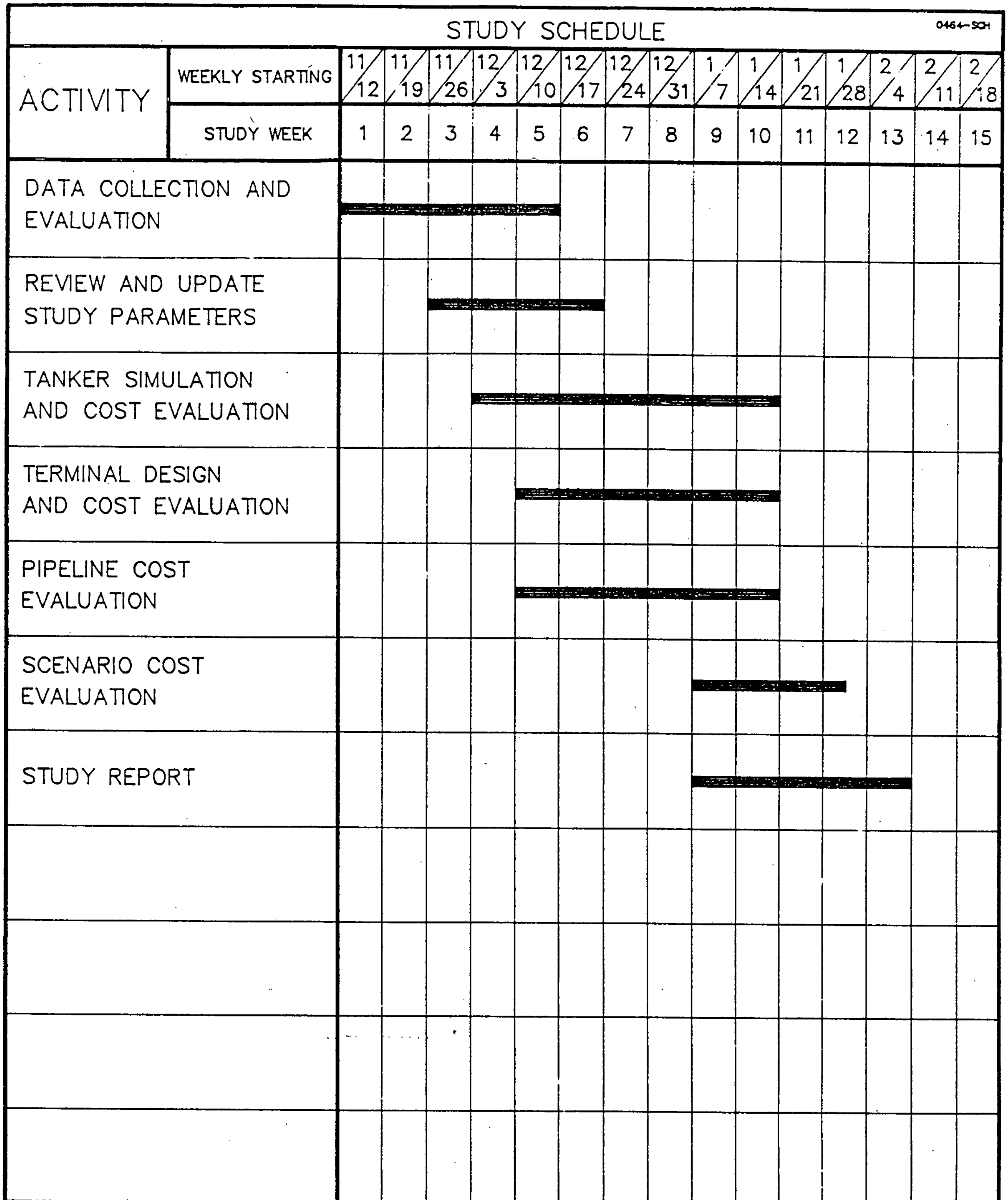
	DATE 1-7-91	JOB NO. H-046.4	



JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION	STUDY SCHEDULE		
INTEC ENGINEERING, INC.	SCALE NONE	DRAWN BY MN	DRAWING NO.
	DATE 11-28-90	JOB NO. H-046.4	

APPENDIX A

CHUKCHI SEA TRANSPORTATION STUDY ICE COMPONENT