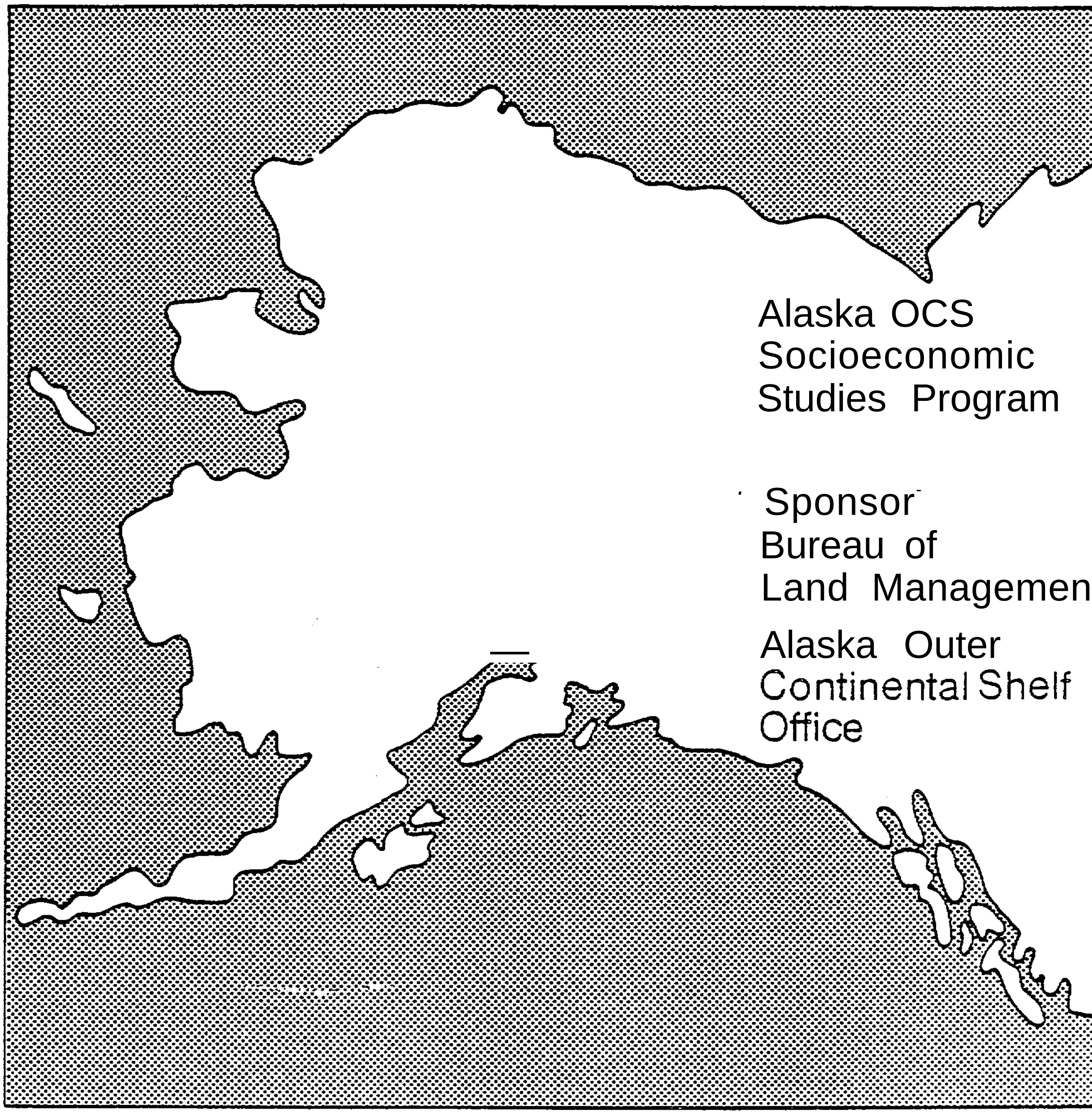
Technical Report

Number 49



Alaska OCS
Socioeconomic
Studies Program

Sponsor
Bureau of
Land Management

Alaska Outer
Continental Shelf
Office

Bering-Norton Petroleum Development Scenarios

The United States Department of the Interior was designated by the Outer Continental Shelf (OCS) Lands Act of 1953 to carry out the majority of the Act's provisions for administering the mineral leasing and development of offshore areas of the United States under federal jurisdiction. Within the Department, the Bureau of Land Management (BLM) has the responsibility to meet requirements of the National Environmental Policy Act of 1969 (lJRPA] as well as other legislation and regulations dealing with the effects of offshore development. In Alaska, unique cultural differences and climatic conditions create a need for developing additional socioeconomic and environmental information to improve OCS decision making at all governmental levels. In fulfillment of its federal responsibilities and with an awareness of these additional information needs, the BLM has initiated several investigative programs, one of which is the Alaska OCS Socioeconomic Studies Program (SESP).

The Alaska OCS Socioeconomic Studies Program is a multi-year research effort which attempts to predict and evaluate the effects of Alaska OCS Petroleum Development upon the physical, social, and economic environments within the state. The overall methodology is divided into three broad research components. The first component identifies an alternative set of assumptions regarding the location, the nature, and the timing of future petroleum events and related activities. In this component, the program takes into account the particular needs of the petroleum industry and projects the human, technological, economic, and environmental offshore and onshore development requirements of the regional petroleum industry.

The second component focuses on data gathering that identifies those quantifiable and qualifiable facts by which OCS-induced changes can be assessed. The critical community and regional components are identified and evaluated. Current endogenous and exogenous sources of change and functional organization among different sectors of community and regional life are analyzed. Susceptible community relationships, values, activities, and processes also are included.

The third research component focuses on an evaluation of the changes that could occur due to the potential oil and gas development. Impact evaluation concentrates on an analysis of the impacts at the statewide, regional, and local level.

In general, program products are sequentially arranged in accordance with BLM's proposed OCS lease sale schedule, so that information is timely to decisionmaking. Reports are available through the National Technical Information Service, and the BLM has a limited number of copies available through the Alaska OCS Office. Inquiries for information should be directed to: Program Coordinator (COAR), Socioeconomic Studies Program, Alaska OCS Office, P. O. Box 1159, Anchorage, Alaska 99510.

Technical Report No. 49

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
NORTON BASIN
OCS LEASE SALE NO. 57
PETROLEUM DEVELOPMENT SCENARIOS

FINAL REPORT

Prepared for

BUREAU OF LAND MANAGEMENT
ALASKA OUTER CONTINENTAL SHELF OFFICE

BY

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January 1980

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NOTICES

1. This document is disseminated under the sponsorship of the U.S. Department of the Interior, Bureau of Land Management, in the interest of information exchange. The U.S. Government assumes no liability for its content or use thereof.

2. This final report is designed to provide preliminary petroleum development data to the groups working on the Alaska OCS Socio-economic Studies Program. The assumptions used to generate off-shore petroleum development scenarios may be subject to revision.

3. The units presented in this report are metric with American equivalents except units used in standard petroleum practice. These include barrels (42 gallons, oil), cubic feet (gas), pipeline diameters {inches), well casing diameters (inches), and well spacing (acres).

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
Norton Basin
OCS Lease Sale No. 57
Petroleum Development Scenarios
Final Report

Technical Report No. 49

Prepared by

DAMES & MOORE

January 1980

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1.0 INTRODUCTION

1.1 Purpose

In order to analyze the-socioeconomic and environmental impacts of Norton Sound petroleum exploration, development, and production, it is necessary to make reasonable and representative predictions on the nature of that development. The petroleum development scenarios in this report serve that purpose; they provide a "project description" for subsequent impact analysis. The socioeconomic impact analysis of Norton Sound petroleum development postulated in this report will be contained in subsequent reports of this study program.

Particularly important to socioeconomic studies are the manpower, equipment and material requirements, and the scheduling of petroleum development. The scenarios have to provide a reasonable range of technological, economic, and geographic options so that both minimum and maximum development impacts can be discerned. The primary purpose of this report is, therefore, to describe in detail a set of petroleum development scenarios that are economically and technically feasible, based upon available estimates of oil and gas resources of Norton Sound.

It should be emphasized that this petroleum scenarios report is specifically designed to provide petroleum development data for the Alaska OCS socioeconomic studies program. The analytical approach is structured to that end and the assumptions used to generate scenarios may be subject to revision as new data become available. Within the study programs that are an integral part of the step-by-step process leading to OCS lease sales, the formulation of petroleum development scenarios is a first step in the study program coming before socioeconomic and environmental impact analyses.

This study, along with other studies conducted by or for the Bureau of Land Management, including the environmental impact statements produced preparatory to the OCS lease sales., are mandated to utilize U.S. Geological Survey estimates of recoverable oil and gas resources in any analysis requiring such resource data.

1.2 Scope

The petroleum development scenarios formulated in this report are for the proposed OCS Bering-Norton Lease Sale No. 57 currently scheduled for November 1982. This is the first lease sale scheduled for the Bering Sea OCS.

The study area considered in this report is that recommended for the lease sale area by the U.S. Geological Survey in Open-File Report 79-720 (Fisher et al., 1979, p. 37-38). This area is bounded in the east by longitude 162° W, in the west by longitude 170° W, in the north by latitude 65° N, and in the south by latitude 63° N (Figure l-l). Along the shoreline of Norton Sound, the Seward Peninsula and northeastern St. Lawrence Island, the lease area boundary lies seaward of the 3-mile limit of state waters. This area covers approximately 40,000 sq. kilometers (15,444 sq. miles). The area of tracts actually leased will, of course, be significantly smaller due to geologic and environmental limitations[1].

Water depths in this potential lease area range from about 7.5 meters (25 feet) in inner Norton Sound to a maximum of about 55 meters (180 feet) in the Bering Sea midway between St. Lawrence Island and the Seward Peninsula; most of Norton Sound east of Nome is characterized by water depths of 18 meters (60 feet) or less. Sea ice covers most of the lease area from six to eight months of the year although multiyear floes do not occur south of the Bering Strait.

The principal components of this study which are an integral part of the scenario development include:

- A review of the petroleum technology that may be required to develop Norton Sound oil and gas reserves, including its costs, and related environmental constraints to petroleum engineering (oceanography, biology, geologic hazards, etc.).

(1) The call for tract nominations for the Norton Basin lease sale was issued in May 1979 and at the time of writing (September 1979) tract selection was underway at the BLM, Alaska OCS Office.

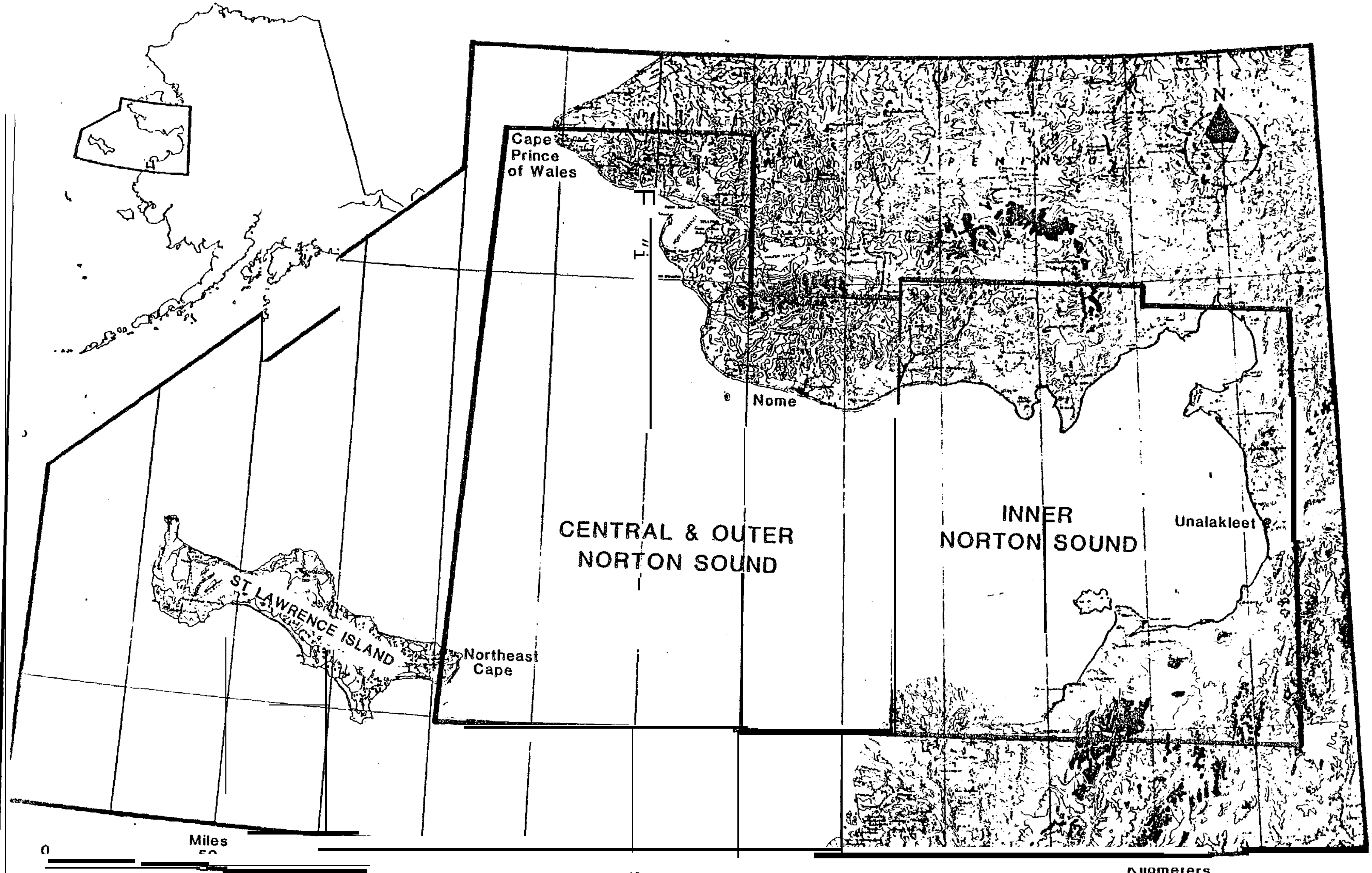


Figure 1-1
LOCATION OF THE STUDY AREA

- A review of the petroleum geology of Norton Basin to formulate reservoir and production assumptions necessary for the economic analysis and, if possible, provide field size distribution data and prospect identification for scenario specification and resource allocation.

- An economic analysis of Norton Basin petroleum resources in the context of projected technology and its costs.

- An analysis of the manpower requirements to explore, develop, and produce Norton Basin petroleum resources in the context of projected technology, and environmental and logistical constraints.

- A facilities siting study to identify suitable sites for major petroleum facilities including crude oil terminals and LNG plants.

The U.S. Geological Survey resources estimates used in this study are as follows (Fisher et al., 1979):

	Minimum	Mean	Maximum
Oil (billions of barrels	0.38	1.4	2.6
Gas (trillions of cubic feet	1.2	2.3	3.2

This study describes scenarios corresponding to the minimum, mean, and maximum resource estimates and for descriptive purposes terms them "low find", "medium find", and "high find", respectively. In addition, a scenario is described which assumes exploration only with no commercial discoveries made.

1.3 Data Gaps and Limitations

In the course of this study, significant data gaps were revealed that imposed limitations on the scenario development and the related analyses listed above. These data gaps and related constraints should be kept in mind when considering the results of this study,

The data gaps to a large extent result from the fact that industry and regulatory agency interest and research is only now beginning to focus on the Bering Sea basins and Norton Sound in particular. To date, research has been principally focused on the North Slope/Beaufort Sea area, Lower Cook Inlet, and Gulf of Alaska.' Norton Sound is much more a frontier area than these areas, and predictions on petroleum technology, its costs, resource economics, manpower and facility requirements, and facility siting are far more speculative. In summary, the principal data gaps include:

- Oceanography - sea ice, wave, and current data required for platform and pipeline design are limited.

- Petroleum facility costs (platforms, pipelines, terminals, etc.) - no petroleum exploration and production has yet taken place in areas with closely similar oceanographic conditions to provide a firm data base for petroleum facility costs in this sub-arctic area.

- Petroleum geology - insufficient geophysical data was available to identify structures and estimate thickness of reservoir rock sections, necessary data to estimate potential field sizes and their location.

1.4 Report Content and Format

This report is structured according to the scenario development process. Thus, the focus of the main body of this report is the methodology and related analytical assumptions in scenario development (Chapters 3.0 and

4.0) and the description of the scenarios themselves -- exploration only (Chapter 5.0), high find (Chapter 6.0), medium find (Chapter 7.0), and low find (Chapter 8.0).

The research findings of this study, upon which the scenarios are con-strutted, are presented in the appendices commencing with the results of the economic analysis (Appendix A). The subsequent appendices detail the cost estimates used in the economic analysis. (Appendix B), petroleum technology (Appendix C), petroleum facilities siting (Appendix D), and employment (Appendix E}. Alternative employment estimates for the Norton Basin scenarios demonstrating the sensitivity of such estimates to certain seasonality, scaling and production' assumptions are given at the end of Appendix E. The results of a marketing study concerning future oil and gas production from the Norton Basin are presented in Appendix F.

This report commences with a summary of findings (Chapter 2.0) under the headings of Petroleum Geology and Resource Estimates, Selected Petroleum Development Scenarios, Employment, Technology, and Resource Economics.

2.0 SUMMARY OF FINDINGS

2.1 Petroleum Geology and Resource Estimates

The resource estimates that form the basis of the petroleum development scenarios in this report are the U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources. These are (Fisher et al., 1979):

	Minimum	Mean	Maximum
Oil (billions of barrels)	0.38	1.4	2.6
Gas (trillions of cubic feet)	1.2	2.3	3.2

These are "unrisked" estimates derived from probabilistic estimates by removing the marginal probabilities that were applied because Norton Basin is a frontier area. For descriptive purposes, the scenarios corresponding to minimum, mean, and maximum resource estimates are termed "low find", "medium find", and "high find", respectively.

A set of reservoir and production assumptions were formulated for the economic analysis based on available geologic/analog data and the need to explore the economic impact of geologic diversity. Nevertheless, the reservoir and production assumptions should bracket expectations indicated by the available geologic data and/or extrapolation from reasonable analogs.

Because detailed geophysical data was unavailable to this study and because there is no drilling history in this basin, formulation of reservoir and production assumptions has had to rely on analog basins. These analogs are producing Pacific Margin tertiary basins such as Cook Inlet in Alaska. In addition non-producing Pacific Margin Tertiary basins such as the Anadyr Basin of northeast Siberia provide analogous geologic data and valuable clues (stratigraphy, structural history and so forth) to extrapolate. or better predict the geologic characteristics of the Norton Basin. The reservoir and production assumptions listed below generally fall within the geologic, reservoir and production characteristics typical of such basins. The assumptions are:

- Average reservoir depths (gas and oil) - 762 meters (2,500 feet), 1,524 meters (5,000 feet), and 2,286 meters (7,500 feet).

- Recoverable reserves per acre - 20,000 bbl and 60,000 bbl.

- Well spacing - variable, consistent with ranges in known producing fields.

- Initial well productivity, oil - 1,000, 2,000, and 5,000 bpd.

- Initial well productivity, gas - 15 and 25 mmcfd.

- Gas resource allocation between associated and non-associated for scenario detailing and analytical simplification, all the gas resources are assumed to be non-associated (i.e. scenarios are detailed which include gas field(s) totaling the U.S.G.S. gas resource estimate);[1] oil fields are implicitly assumed, therefore, to have a low gas-oil ratio (GOR) and that associated gas is uneconomic and is used to fuel platforms with the remainder reinjected.

- A low gas-oil ratio is assumed for analytical simplification (see bullet above).

- No assumption was made on the physical properties of the oil; the range of prices used in the analysis is partly a function of the potential range in crude qualities.

(1) It is recognized, however, that in reality some portion of the gas resource will be associated.

In the absence of sufficient geologic data to make reasonable predictions on a number of prospective structures and field sizes that may be discovered in Norton basin, the field sizes selected for economic screening have, therefore, been selected to be consistent with the following factors:

- Geology (only gross structural geology and stratigraphic data are available).

- Requirement to examine a reasonable range of economic sensitivities.

The field sizes to be evaluated in this study, therefore, range from 100 million barrels to two billion barrels for oil and 500 billion cubic feet to three trillion cubic feet for non-associated gas.

Field location in the scenarios is arbitrary but designed for impact assessment to provide a range of development cases that are shown to be economically and technically realistic options.

2.2 Selected Petroleum Development Scenarios

Four scenarios are detailed describing exploration only (no commercial resources discovered), a high find case assuming significant commercial discoveries, medium find case assuming modest commercial discoveries, and low find case assuming marginal commercial discoveries.

2.2.1 Exploration Only Scenario

The exploration only scenario postulates a low level of exploration with only eight wells drilled overa period of three years (Table 2-1). Exploration is conducted principally in the four month summer openwater season using jack-up rigs augmented by drillships. Two of the wells are drilled from gravel islands constructed in summer. No new onshore facilities are constructed. Nome serves as a forward support base for light supplies and provides aerial support for offshore activities; heavy materials are stored in freighters

TABLE 2-1

EXPLORATION ONLY SCENARIO - LOW INTEREST LEASE SALE

YEAR AFTER LEASE SALE					
1		2		3	
Rigs	Wells	Rigs	Wells	Rigs	Wells
2	2	3C 1G	4	1C 1G	2
TOTAL WELLS = 8					

C = Conventional rigs (jack ups or drillships)
G = Gravel island

Assumptions:

1. An average well completion rate of approximately 4 months.
2. An average total well depth of 3,048 to 3,692 meters (10 ,000 to 13,000 feet).
3. Year after lease sale = 1983.
4. Rigs include jack ups and drillships in summer and some summer-constructed gravel islands in shallow water.

Source: Dames & Moore

and barges moored in Nnd and transshipped to the rigs via supply boats and there is a reacated in the Aleutian Islands.

2.2.2 High Find Sc

The high find scenario significant commercial discoveries of oil and gas. The total reseovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
2,600	3,200

These resources are dd in three "clusters" of fields located respectively in inner ound south of Cape Darby, central Norton Sound south of Nome, aNorton Sound about 64 kilometers (40 miles) southwest of Cape Rodney

All oil and gas produ brought to shore by pipeline to a large crude oil terminal andt located at Cape Nome. Production from the central Norton Sos involves a direct offshore pipeline to Cape Nome while produ the outer and inner Norton Sound fields involves a significant oeline segment.

Oil production from Nnd commences in year 7 (1989) after the lease sale, peaks at 7(in year 13 (1995), and ceases in year 34 (2016). Gas productionmences in year 7 (1989), peaks at 691,200 mmcfd in years 13 thr1995 through 1999), and ceases in year 34 (2016).

The basic characteristis scenario are summarized in Tables 2-2 and 2-3.

2.2.3 Medium Find

The medium find scenarimodest discoveries of oil and non-

TABLE 2-2

HIGH FIND OIL SCENARIO

Field Size Oil (MMBBL)	Location	Reservo Meters	Depth Feet	Production System	Platforms No. /Type*	Number of Production Wells	Initial Well Productivity - - J @ - - -	Peak production Oil (MB/D)	Water Meters	epth Feet	ipeline [o Shore 1 ilometers	tance minal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
500	Inner Sound	2,286	7,500	Gravel island shared pipeline to shore terminal	2 G	80	2,000	153.6	18	60	133	83	20	Cape Nome
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	146	91	20	Cape Nome
200	Inner Sound	2,286	7,500	Gravel Island shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	150	93	20	Cape Nome
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 s	80	2,000	153.6	18	60	34	21	16-18	Cape Nome
200	Central Island	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	21	70	58	36	16-18	Cape Nome
750	Outer Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	3 s	120	2,000	230.4	30	100	129	80	20	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	30	100	140	87	20	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 2-3

HIGH FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Kilometers	Pipeline Distance to Terminal Miles	Trunk Pipeline Diameter [inches) Gas	LNG Plant
1,000	Central Sound	2,286	7,500	Steel platforms with shared pipeline to LNG plant	1 S	16	15	240	20	66	51	32	24-28	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 s	16	1 5	240	18	60	43	27	24-28	Cape Nome
1,200	Central Sound	2,286			1 s	16	15	240	20	66	51	32	20-24	Cape Nome

* S = Ice reinforced steel platform.

' Fields in bracket share same trunk pipeline.

Source: Dames & Moore

associated gas. The basic characteristics of the scenario are summarized in Tables 2-4 and 2-5. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
1,400	2,300

Five oil fields comprise the total reserves. They are located in two groups of fields, one in inner Norton Sound, the second in the central sound south of Nome, plus a single field in the outer sound southwest of Cape Rodney. The gas reserves are contained in two fields located close to each other about 48 kilometers (30 miles) south of Nome.

All crude is brought to a single terminal located at Cape Nome. For the inner sound fields, this involves a 100-kilometer (62-mile) onshore pipeline segment from Cape Darby to Cape Nome; the trunk pipeline from the central and outer sound fields makes landfall close to the terminal site and, therefore, involves minimal onshore pipeline construction.

The non-associated gas fields share a single trunk pipeline to a LNG plant located adjacent to the crude oil terminal at Cape Nome.

Oil production from Norton Sound commences in year 8 (1990) after the lease sale, peaks at 463,000 b/d in year 12 (1994), and ceases in year 29 (2011). Gas production commences in year 7 (1989), peaks at 460.8 mmcfd in years 12 through 18 (1994 through 2000), and ceases in year 28 (2010).

2.2.4 Low Find Scenario

The low find scenario assumes small commercial discoveries of oil and non-associated gas. The basic characteristics of the scenario are summarized in Tables 2-6 and 2-7. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
380	1,200

TABLE 2-4

MEDIUM FIND OIL SCENARIO

Field Size Oil (MMBBL)	Location	Reservoir Depth Meter	Reservoir Depth Feet	Production System	Platforms No. /Type*	Number of Production Wells	Initial Well Productivity (9/D)	Peak Production Oil (hill/D)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	133	83	14	Cape Nome
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	146	91	14	Cape Nome
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 S	80	2,000	153.6	18	60	34	21	18	Cape Nome
250	Central Sound	2,286	7,500	Steel platform with" shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	58	36	18	Cape Nome
250 1	Outer Sound	2,286	7,500	Steel platform with shared pipeline to. shore terminal	1 S	40	2,000	76.8	30	100	9 5	59	18	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 2-5

MEDIUM FIND NON-ASSOCIATED GAS SCENAR10

Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Men Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Gas	LNG Plant
1,300	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	20	66	48	30	20	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	18	60	32	20	20	Cape Nome

● S= Ice reinforced steel platform.

Fields in bracket share same trunk pipeline.

Source: Oames & Moore

TABLE 2-6

LOW FIND OIL SCENARIO

Field Size Oil MMBBL	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
200	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	21	70	34	21	14	Cape Nome
180	Central Sound	2,286	,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	21	70	58	36	14	Cape Nome

* S = Ice reinforced steel platform.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 2-7

LOW FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Gas	LNG Plant
1,200	Central Sound	2,286	7,500	Single steel platform with unshared pipeline to LNG plant	1S	16	15	240	16	54	34	21	14	Cape Nome

* S = Ice reinforced steel platform.

Source: Dames & Moore

These reserves, especially the gas, are barely economic to develop. The oil reserves comprise two fields located between 34 and 58 kilometers (21 and 36 miles) southwest of Nome while the non-associated gas reserves occur in a single field located about 34 kilometers (21 miles) south of Nome. No discoveries are made in the inner or outer sounds.

Two trunk pipelines, both about 34 kilometers (21 miles) long, transport the oil and gas production direct to a crude oil terminal and LNG plant, respectively, located at Cape Nome. Minimal onshore pipeline construction is involved in the development of these fields.

Oil and gas production from Norton Sound both start in year 8 (1990). Oil production peaks at 153,000 b/d in year 11 (1993) and ceases in year 27 (2009). Gas production peaks at 230.4 mmcfd in years 11 through 19 (1993 through 2001), and ceases in year 32 (2014).

2.3 Employment

Estimates of manpower requirements are presented in a series of four tables for each scenario. These are found in Sections 5.0 through 8.0. Definition of terms used to describe manpower requirements are found in Appendix E.

Maximum employment is created in year 9 of the High Find Scenario, when 63,307 man-months of work will be generated (equivalent to an average of 5,276 people per month during the year; peak employment during the year would be higher). Maximum employment is created in year 8 of the Medium Find and Low Find Scenarios, and year 2 of the Exploration Only Scenario, generating 42,649 man-months, 16,506 manmonths, and 3,445 man-months of employment, respectively.

Manpower requirements for onshore activities peak earlier than for offshore activities in the three scenarios that involve field development. Onshore (on site) labor requirements peak in year 5 in the High Find Scenario at 16,498 man-months, and offshore (on site) labor requirements peak in year 9 at 27,328 man-months. In the Medium Find Scenario, onshore [on site) labor requirements peak in year 5 with 9,138 man-months, and offshore (on site) in year 9 with 17,802 man-months. In the Low Find Scenario, onshore (on site) peaks in year 7 with 4,173 man-months, offshore (on site) a year later with 6,978 manmonths. This pattern occurs because construction of the major onshore facilities is begun before most of the platforms are installed, pipeline laid, and production wells drilled, activities that cluster in years 6 through 9.

During the middle of the production phase, onshore labor will average 525 people per month (on site; 810 people total), and offshore labor will average 1,605 people per month (on site; 3,120 people total) in the High Find Scenario. In the Medium Find Scenario and Low Find Scenario, onshore labor will average 327 and 135 people per month respectively (on site; 523 and 222 people total), and offshore labor will average 1,056 and 321 people per month respectively (on site; 1,964 and 624 people total).

Manpower requirements for each scenario are summarized in Tables 2-8 through 2-11.

2.4 Technology and Production Systems

In an oceanographic comparison with Upper Cook Inlet, on the one hand, and the Beaufort Sea, on the other, Norton Sound and adjacent areas of the Bering Sea have certain attributes of both and yet are unique in other aspects. Norton Sound is shallower than Upper Cook Inlet, deeper in general than the Beaufort Sea lease area, and has ice conditions in terms of duration intermediate to both. Water depths range from 7.5 meters (25 feet) off the Yukon Delta (i.e. at the three mile limit) to over 46 meters (150 feet) in the outer sound between St. Lawrence Island and the Seward Peninsula. Pack ice up to 12 meters (40 feet) thick has been reported in the Bering Sea although floe ice within Norton Sound is generally up to 2 meters -(6.5 feet) thick. Shorefast ice extends shoreward of the 10-meter (33-foot) isobath. A maximum wave of about 4.3 meters (14 feet) can be anticipated in Norton Sound.

EXPLORATION ONLY
09/23/79

TABLE 2-8

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	706.	108.	814.	1258.	148.	1406.	105.	13.	118.
2	1812.	246.	2058.	3116.	329.	3445.	260.	28.	288.
3	1106.	13[illegible].	1244.	1858.	181.	2039.	155.	16.	170.

** TOTAL INCLUDES ONSITE AND OFFSITE

HIGH FIND SCENARIO
09/23/79

TABLE 2-9

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	[illegible]	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	211.	324.	[illegible]	3774.	444.	4218.	315.	37.	352.
2	4635.?	[illegible]	[illegible]	8146.?	921.	9064.	679.	77.	756.
3	6754.	1152.	[illegible]	14922.	1532.	16454.	1244.	128.	1372.
4	7660.	6366.	[illegible]	13780.	7347.	21127.	1149.	613.	1761.
5	7520.	16448.?	[illegible]	13286.	16520.	31806.	1106.	1544.	2651.
6	15755.?	12215.	[illegible]	28398.?	13771.	42169.	2367.	1148.	3514.
7	24372.	[illegible]	[illegible]	44591.	12230.	56821.	3716.	1020.	4736.
8	24342.	4632.	[illegible]	46502.	13151.	59653.	3876.	1096.	4971.
9	27324.?	7004.	[illegible]	53013.	10293.	63307.	4418.	858.	5276.
10	26254.?	6644.	[illegible]	50990.	10031.	61020.	4250.	836.	5085.
11	22052.	6440.	[illegible]	43054.	9807.	52861.	3588.	818.	4405.
12	19344.	6474.	[illegible]	37608.	9894.	47502.	3134.	625.	3959.
13	19088.?	6344.?	[illegible]	37056.	9768.	46824.	3088.	814.	3902.
14	18676.?	6336.?	[illegible]	36672.	9756.	46428.	3056.	813.	3869.
15	19980.?	5300.?	[illegible]	37080.	9720.	46800.	3090.	810.	3900.
16	19380.?	6300.	[illegible]	37080.	9720.	46800.	3090.	810.	3900.
17	19260.	6300.	[illegible]	37440.	9720.	47160.	3120.	810.	3930.
18	19260.	6300.	[illegible]	37440.	9720.	47160.	3120.	810.	3930.
19	19260.	6300.	[illegible]	37440.	9720.	47160.	3120.	810.	3930.
20	19260.	6300.	[illegible]	37440.	9720.	47160.	3120.	810.	3930.
21	19260.	6300.	[illegible]	37440.	9720.	47160.	3120.	810.	3930.
22	19260.	6300.	[illegible]	37440.	9720.	47160.	3120.	810.	3930.
23	17976.	[illegible]	[illegible]	34944.?	9408.	44352.	2912.	784.	3696.
24	17976.?	[illegible]	[illegible]	34944.?	9408.	44352.	2912.	784.	3696.
25	17976.?	[illegible]	[illegible]	34944.?	9408.	44352.	2912.	784.	3696.
26	17976.?	[illegible]	[illegible]	34944.?	9408.	44352.	2912.	784.	3696.
27	15160.?	5544.	[illegible]	29952.?	8784.	38736.	2496.	732.	3228.
28	12550.?	5040.	[illegible]	24600.	8160.	32760.	2050.	680.	2730.
29	7524.	4032.	[illegible]	14616.	6912.	21528.	1218.	576.	1794.
30	6240.	3780.?	[illegible]	12120.	6600.	18720.	1010.	550.	1560.

** TOTAL INCLUDES ONSITE [illegible]

MEDIUMFIND SCENAR1O
09/24/79

TABLE 2-10

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	ONSHORE	TOTAL
1	2243.	334.	2577.	3899.	454.	4353.	325.	38.	363.
2	5342.	786.	6128.	9406.	1069.	10475.	784.	90.	873.
3	6448.	924.	7372.	11264.	1251.	12515.	939*	105.	1043.
4	5036.	4044 .	9080.	8748.	4658.	13406.	729.	389.	1118.
5	4090.	9138.	13229.	7095.	10210.	17306.	592.	851.	1443.
6	13194.	453A .	17726.	23843.	5132.	28975.	1987.	428.	2415.
7	11228.	3209.	14437.	20638.	5158.	25796.	1720.	430.	2150.
8	17290.	7962.	25252.	32161.	10489.	42649.	2680.	874.	3555*
9	17802.	4520.	22322.	33782.	6751.	40532.	2816.	563,	3378.
10	16.?24.	4116.	20340.	30672.	6344.	37016.	2556.	529.	3085.
11	13320.	4062.	17382.	24864.	6290.	31154.	2072.	525.	2597.
12	12108.	3960.	16068.	22440.	6188.	28628.	1870.	516.	2386.
13	12132.	3924.	16056.	22488.	6152.	28640.	1874.	513.	2387.
14	12492.	3924.	16416.	23208.	6152.	29360.	9934.	513.	2447.
15	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
16	12672.	3924.	16596.	235613.	6152.	29720.	1964.	513.	2477.
17	12672.	3924.	16596.	23560,	6152.	29720.	1964.	513.	2477.
18	12672.	3924.	16596.	23566.	6152.	29720.	1964.	513..	2477.
19	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513*	2477.
20	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
21	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
22	11388.	3672.	15060.	21072.	5840.	26912.	1756.	487.	2243.
23	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
24	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
25	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
26	10104.	3420.	13524.	18576.	5528.	24104.	1540.	461.	2009.
27	7356.	2916.	10272.	13224.	4904.	18128.	1102.	409.	1511.
28	6072.	1944.	8016.	10728.	3152.	13880.	894.	263.	1157.
29	36'84.	432.	4116.	6096.	512.	6608.	508.	43.	551.
30	2400.	180.	2S60 ,	3600.	200.	3800.	300.	17.	317.

** TOTAL INCLUDES ONSITE AND OFFSITE

LOW FIND SCENARIO
09/24/79

TABLE 2-11

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL (MAN-MONTHS)			TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE)		
	OFFSHORE	ONSHORE	TOTAL	OFFWORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL
1	1412.	216.	1628.	2516.	296.	2812.	210.	25.	235.
2	2518.	354.	2872.	4374.	477.	4851.	365.	40.	405.
3	3624.	492.	4116.	6232.	659.	6891.	520.	55.	575.
4	5036.	708.	5744.	8748.	955.	9703.	729.	80,	809.
5	2212.	1154.	3366.	3716.	1337.	5053.	310.	1126	422.
6	4262.	2454.	6716.	7817.	2774.	10591.	652.	232.	883.
7	6098.	4173.	10272.	11555.	4:34.	16189.	963.	387.	1350.
8	6978.	1820.	8797.	13622.	2884.	16506.	1136.	241.	1376.
9	6384.	1692.	8076.	12552.	2736.	15288.	1046.	228.	1274.
10	4656.	1764.	6420.	9096.	2808.	11904.	758.	234.	992.
11	3480,	1638.	5118.	6744.	2682.	9426.	562.	224.	786.
12	3312.	1620.	4932.	6408.	2664.	9072.	534.	222*	756.
13	3852.	1620.	5472.	7488.	2664.	1015.2.	624.	222*	846.
14	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
15	385.?.	1620.	5472.	7488.	2664 .	10152.	624.	222*	846.
16	3852.	1620.	5472.	7488.	2664.	10152.	424.	222.	846.
17	385.2.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
18	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	046.
19	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
20	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
21	3852.	1620.	5472.	7488.	2664.	10152.	624,	222.	846.
22	3852.	1620.	5472.	7488.	2664.	10152.	624.	222*	846.
23	2748.	1368.	4116.	5352.	2352.	7704.	446.	196,	642.
24	2748.	1368.	4116.	5352.	2352.	7704.	446.	196.	642.
2s	2658.	1368.	4026.	5172.	2352.	7524,	431.	196.	627.
26	2568.	1368.	3936.	"4992.	2352.	7344.	416.	196.	612.
27	2568.	984.	3552.	4992.	1584.	6576.	416.	132.	548.
28	1284.	732.	2016.	249b-	1272.	3768.	208.	106.	314.
2 9	1284.	732.	2016.	2496.	12720	3768.	208.	106.	3140
30	1284.	732.	2016.	2496.	1272.	3768.	208.	106.	314.

** TOTAL INCLUDES ONSITE AND OFFSITE

These preliminary oceanographic findings in conjunction with design criteria for Upper Cook Inlet steel platforms indicate that modified Upper Cook Inlet type platforms may be feasible for operation in Norton Sound. This conclusion is tentative since sufficient oceanographic data to adequately assess platform design requirements does not yet exist. However, such platforms, as opposed to the monotone proposed for Beaufort Sea operations, may be the more likely development strategy. In shal lower waters (less than 18 meters [60 feet]], gravel islands may also be a development alternative especially the caisson-retained design. The economic analysis, therefore, has evaluated the economics of these platform types for the following water depths.

Platform Type	Water Depth meters	feet
Ice reinforced steel platform (modified Upper Cook Inlet Design)	15	50
	30	100
	46	150
Gravel Island	7.6	25
	15	50

Pipeline distances representative of potential discovery situations (in the context of geography) were identified for economic screening as shown on Table 2-12. In addition to development cases assuming pipelines to an onshore crude oil terminal or LNG plant, offshore loading from a production/storage/loading island was considered in the economic analysis for comparative purposes although the costs of such a system are rather speculative.

Given the estimated oil and gas resources of the Norton Basin, all the development options considered in the analysis assumed tankering of crude or LNG to lower 48 markets.

Construction schedules and manpower estimates assumed extensive modularization and integration of onshore and offshore facilities to minimize local construction and speed construction schedules because of the short summer weather window of four to six months.

TABLE 2-12

REPRESENTATIVE PIPELINE DISTANCES TO NEAREST
TERMINAL SITE EVALUATED IN ECONOMIC ANALYSIS

Case	Water Depth of Field meters (feet)	Pipeline Length Offshore kilometers (miles)	Pipeline Length Onshore kilometers (miles)
No. 1	15 (50), 30 (100), 46 (150)	128 (80)	3 (2)
No. 2	15 (50), 30 (100), 46 (150)	64 (40)	3 (2)
No. 3	15 (50)	32 (20)	48 (30)
No. 4	15 (50)	32 (20)	3 (2)
No. 5	15 (50)	16 (10)	3 (2)

Note: Both shared and unshared pipeline cases are screened in the economic analysis.

Source: Dames & Moore

2.5 Resource Economics

The economic characteristics of several likely oil and gas production systems suitable for the harsh and icy conditions of the Norton Sound are analyzed in this report with the model described in Chapter 3.0. The model is a standard discount cash flow algorithm designed to handle uncertainty among the variables and driven by the investment and revenue streams associated with a selected production technology.

The analysis focuses attention on: (1) the engineering technology required to produce reserves in the Norton Sound, and (2) the uncertainty of the interrelated values of the economic and engineering parameters. In view of the uncertainty, it is important to emphasize that there is no single-valued solution for any calculation reported in the analysis. Field development costs associated with the different production systems as well as oil and gas prices have been estimated as a range of values. Sensitivity and Monte Carlo procedures have been used to bracket rather than pin-point the decision criteria calculated with the model.

Two vital pieces of information are estimated in the analysis:

- The minimum economic field size to justify development of a known field with a selected technology in Norton Sound.
- The minimum required price to justify development of a field in Norton Sound.

Both are very sensitive to the location of the discovered field in Norton Sound and the decision to offshore load or pipeline. to a shore terminal as well as the value of money used to discount cash flows. The calculated minimum field sizes for different production technologies are bracketed between 10 percent and 15 percent discount rates. Tables A-2 through A-8 (Appendix A) show the results. The calculated minimum required price for representative oil production systems assuming a 15 percent discount rate is shown on Figure A-3 (Appendix A). Figure A-4 (Appendix A) shows the representative minimum required gas price.

The essential findings of this report are summarized below. The single value calculations discussed are based on the mid-range parameter values. Monte Carlo distributions and sensitivity analyses showing the range of values for the after tax return on investment are discussed in Section II.4 of Appendix A. The technology, financial, reservoir, and production assumptions of the analysis are detailed in Chapter 3.0.

- The magnitude of the investment costs together with high operating costs in the Norton Sound imply that very good reservoir conditions -- regardless of size of field -- will be required to earn in excess of 15 percent return on investment.

- Platform production facilities are so costly in the Norton Sound that shallow reservoirs which allow only eight producing oil wells or four gas wells (assuming standard industry well-spacing) are not economic to develop given the other assumptions of the analysis.

- Intermediate depth reservoir targets that restrict oil platforms to 24 producing wells (assuming standard industry well-spacing) are only marginally economic to develop --'given the other assumptions of the analysis.

- Either faster recovery than 2,000 b/d per well initial production rate or wellhead prices higher than $18.00 are required to justify development of shallow to intermediate reservoir targets in the Norton Sound.

- The minimum field size to justify development of a deep reservoir field depends on the production technology -- offshore loaded or pipeline to shore -- and the length of the pipeline. For a field with an, unshared 32 kilometers (20 miles) pipeline, and a 40 producing well platform, mid-range development costs would be $803.5 million and minimum field size would be 16(I million barrels to earn 10 percent; 240 million barrels to earn 15 percent.

- In the relatively shallow waters of the Norton Sound, minimum field size to earn 15 percent varies between 200 and 240 million barrels as water depth increases from 15 to 45 meters (50 to 150 feet). Platform development costs rise from $704.5 million to $803.5 million as water depth increases from 15 to 45 meters (50 to 150 feet) -- assuming a 40 well platform and 32 kilometers (20 miles) pipeline.

- In the Norton Sound where geologic conditions suggest 1,000 b/d initial production rates might be expected, platforms will need to house more than 40 producing wells to earn 15 percent, or oil will have to be priced in excess of $20.00 a barrel.

- A deep reservoir with 2,000 b/d initial production rate requires a 40 producing well platform with a mid-range investment cost of $759.1 and requires 215 million barrels to earn 15 percent.

- A deep reservoir with 5,000 b/d initial production rate requires only 20 producing wells to drain efficiently and has a mid-range cost of $595.5 million. Minimum field size to earn 15 percent is 190 million barrels. With 5,000 b/d initial production rate a 250 million barrel field is able to earn 20 percent return on investment.

- Unless fields are discovered in the Norton Sound which allow sharing pipelines to shore, investment cost of an unshared pipeline longer than 48 km (30 miles) is so large that no production system is able to earn 15 percent hurdle rate of return.

- Production start-up in the Norton Sound could be delayed by any number of environmental hazards ranging from bad weatherto inability to secure permits in a timely manner. When the delay occurs relative to money invested is critical to the impact on the economics of the project. A one year "worse case" delay can reduce a 15.5 percent project to 13.5 percent. If 15 percent is the hurdle rate, this changes a "go-ahead" to "no development". A two-year "moderate impact" delay reduces the payout to 10 percent.

- There are economics of scale of developing a "giant" reservoir with two or more platforms. The minimum field size that will support two platforms and earn a 15 percent hurdle rate of return is 425 million barrels -- assuming 2,000 b/d wells and a 16 kilometers (10 miles) pipeline.

- If the bottom conditions, water depth, and gravel availability allow, gravel islands are less costly and more economic than steel platforms as a development option. The gravel island in 18-meters (50-feet) water earns 18 percent with maximum recoverable reserves compared to the steel platform -- both with 32 kilometers (20 miles) pipeline to shore.

- For the isolated field too far from shore for a pipeline, offshore loading with storage to allow full production is extremely economic. The minimum field size to earn 15 percent is less than 200 million barrels.

- The economic screening of gas production facilities assumed that gas was sold at the end of the pipeline-to-shore to an LNG processor. The analysis did not include LNG investment costs. These costs and the cost to transport-to-market must be added to assess the marketability of natural gas discovered in the Norton Sound.

- Gas production is sensitive to reservoir target depth and location of the field relative to pipeline costs.

- Shallow gas reservoirs that restrict the number of wells that can be drilled from a platform are not economic unless the wells are highly productive or prices approximate $3.25 mcf.

- Gas reservoirs 16 to 32 kilometers (10 to 20 miles) from shore require gas to be priced at $2.00 to $2.25 mcf to earn a 15 percent hurdle rate of return. A large gas field with a single 16 well platform could support nearly a 100 kilometers (60 miles) pipeline unshared and still earn the 15 percent hurdle rate.

- The standard gas platform with 16 wells initially producing 15 mmcfd/well would require a wellhead price of about $2.35 mcf for a 750 bcf field and $2.00 mcf for 1,350 bcf field to earn 15 percent.

- With initial productivity of 25 mmcfd minimum required price for the 1,350 bcf field is $1.35 mcf instead of $2.00 mcf.

- The minimum required price to develop an oil field that will earn 15 percent in the Norton Sound ranges between $26.00 and $36.00 barrel for 100 million barrel field depending on the development technology; between $15.00 and $18.00 brarel for a 250 million barrel field.

- The Monte Carlo analysis reveals that there is a wide range to the potential payout of either oil or gas development as a result of the range of uncertainty built into the estimates of cost and estimates of resource prices.

3.0 METHODOLOGY AND ANALYTICAL ASSUMPTIONS

3.1 Introduction

This chapter describes and explains the geologic, technical, and economic assumptions of the economic analysis, which forms the central part of this study, and links the various analytic tasks in the scenario development. The study methodology is illustrated in Figure 3-1 and the analytical steps in the economic analysis are further explicated in Figure 3-2. This chapter is organized to reflect the basic data flow of this study as shown in Figure 3-1.

3.2 Petroleum Geology, Reservoir, and Production Assumptions

3.2.1 Introduction

The economic analysis and detailing of scenarios for offshore petroleum development require that some basic assumptions be made about the characteristics and performance of prospective reservoirs. Because the economic analysis considers the total prospective acreage of the lease sale area and not a single site specific prospect, the assumptions that are made have to be generally representative of anticipated conditions. There are very little published data available to guide assumptions for these parameters. Where possible, therefore, a range of values are selected for some parameters.

It should be emphasized that reservoir and production assumptions should not be construed as an attempt to construct a reservoir model for site specific prospects. Rather, they are formulated to evaluate the overall resource economics of a large portion of a sedimentary basin comprising numerous petroleum prospects which may exhibit considerable variation in reservoir characteristics and production potential. The reservoir and production assumptions are designed to evaluate the economic sensitivities of geologic diversity. Nevertheless, the reservoir and production assumptions should bracket expectations' indicated by the available geologic data and/or extrapolation from reasonable analogs.

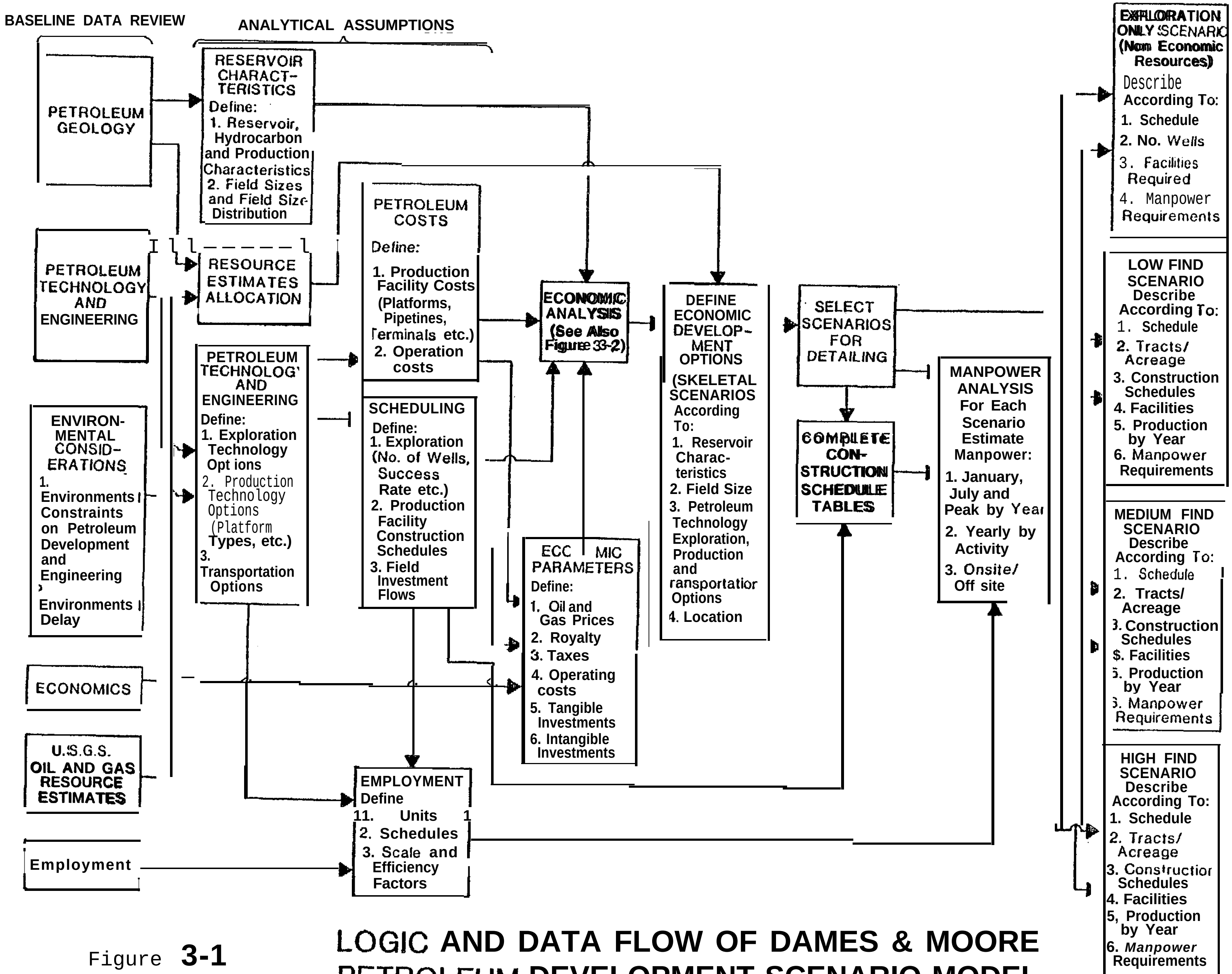
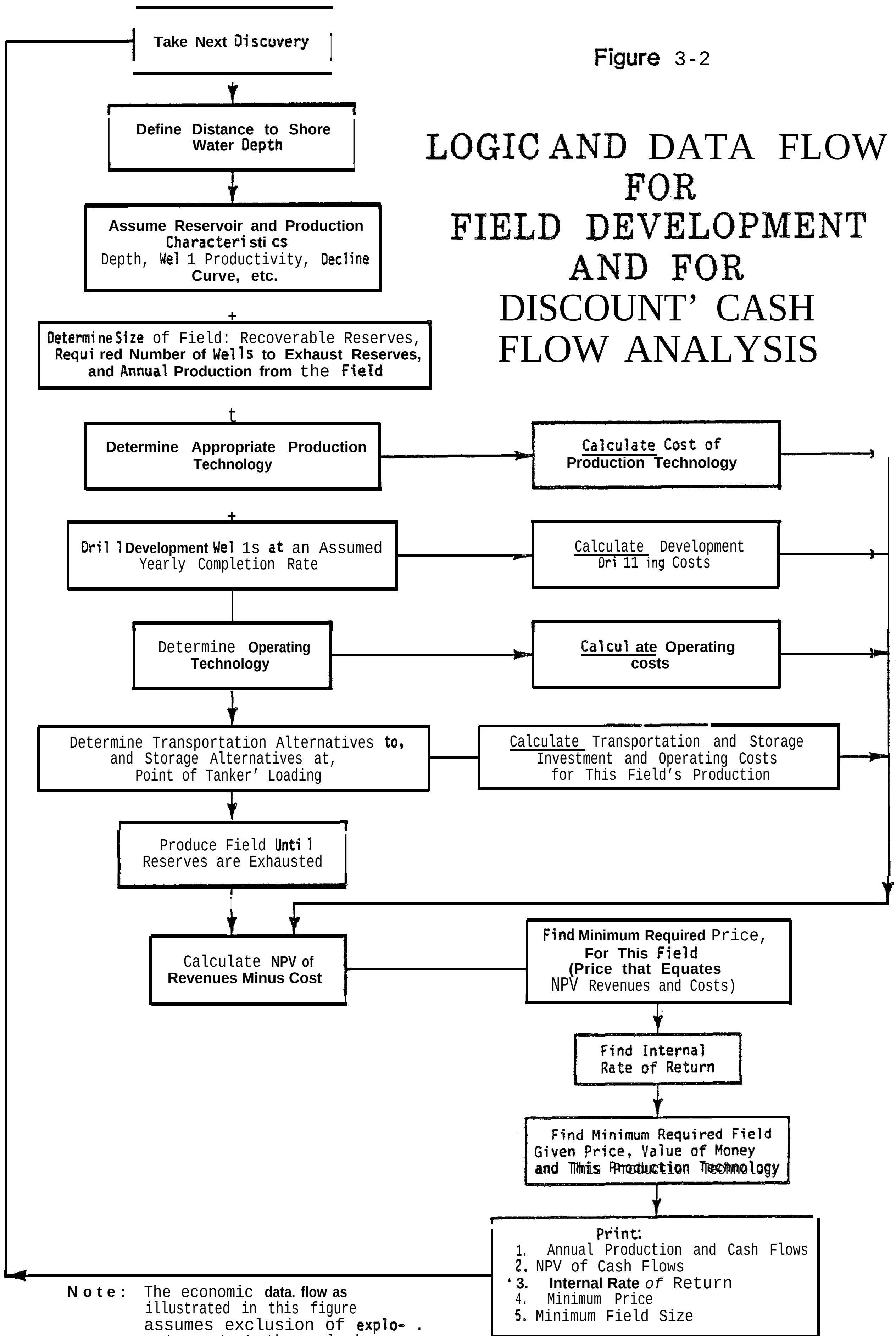


Figure 3-1 LOGIC AND DATA FLOW OF DAMES & MOORE PETROLEUM DEVELOPMENT SCENARIO MODEL

Figure 3-2

LOGIC AND DATA FLOW FOR FIELD DEVELOPMENT AND FOR DISCOUNT' CASH FLOW ANALYSIS



Note: The economic data flow as illustrated in this figure assumes exclusion of exploration costs in the analysis.

There is very little geologic data on the Norton basin to make reasonable petroleum geology reservoir assumptions. The available geologic data on the Norton basin has been summarized in a recent U.S. Geological Survey Open-File Report (Fisher, et al., 1979). Marine seismic data which was shot in Norton Sound was not available for this study because processing of that data was not completed prior to completion of this study.

Critical geologic parameters required by this analysis to conduct a geologic risk evaluation and rating of prospective structures that can be adequately defined by good quality seismic data include:

- Probability of trapping mechanism present.
- Indication of structural growth.
- Probability of presence of adequate thickness of reservoir rock section.

In addition, there are two geologic parameters that only can be accurately ascertained by outcrop and subsurface well information. These are:

- Probability of porosity and permeability present.
- Probability of source rock present.

Outcrop data for the Norton basin is scanty at the present time and no wells have been drilled in the basin. Data with which to determine all five parameters are not now available for the Norton basin. Consequently, reliance has to be placed on use of analog basins to make realistic assumptions on some parameters.

Because detailed geophysical data was unavailable to this study and because there is no drilling history in this basin, formulation of reservoir and production assumptions has had to rely on analog basins. These analogs are producing Pacific Margin Tertiary basins such as Cook Inlet in Alaska. In addition non-producing Pacific Margin Tertiary basins such as the Anadyr

Basin of northeast Siberia provide analogous geologic data and valuable clues (stratigraphy, structural history and so forth) to extrapolate or better predict the geologic characteristics of the Norton Basin.

The economic analysis and scenario formulation require assumptions about:

- Initial production rate.
- Reservoir depth.
- Recoverable reserves.
- Well spacing.
- Production profile.
- Allocation of the U.S. Geological Survey gas resource estimate between associated and non-associated.
- Gas-oil ratio (GOR).
- Oil properties.

This section begins with a summary of Norton basin petroleum geology. The description of the petroleum reservoir and production assumptions follows.

3.2.2 Summary of Norton Basin Petroleum Geology

3.2.2.1 Regional Framework

The Norton basin lies south of Nome and the Seward Peninsula in western Alaska. The major part of the basin is offshore on the shallow water shelf of the Bering Sea.

The basin was formed during the late Cretaceus by crustal extension and subsidence adjacent to a large terrace in northern Alaska that was displaced relatively northeastward by right slip on the major Kaltag fault during the Laramide orogeny.

Marginal outcrops suggest that basin fill may be as old as late Cretaceous; but the major thickness is represented by sediments of Paleogene and Neogene ages. Based on marine seismic data (Fisher, et al., 1979), volcanic flows and sills of Paleogene age are indicated to be present. These volcanic rocks may correlate with Paleogene volcanic rocks on St. Lawrence Island which bounds the basin to the south. An Oligo-Miocene unconformity generally separates non-marine deltaic strata below from marine strata above.

Pre-tertiary rocks on Seward and Chukotsk Peninsulas and St. Lawrence Island consist chiefly of Precambrian, Paleozoic and early Mesozoic non-volcanic sedimentary rocks. The rocks on St. Lawrence Island are nearly identical in lithology and age to the stratigraphic sequence in the northern part of the Brooks Range. A belt of volcanic and sedimentary rocks derived from volcanic terrain underlies the Yukon-Koyukuk Cretaceus province, western St. Lawrence Island and St. Matthew Island in the Bering Sea, and the southern Chukotsk and Anadyr River region in northeast Siberia. Rocks in this belt are mainly of late Mesozoic Age, but locally include some earliest Cenozoic strata. Marine magnetic data (Verba et al.,1976), obtained on the Bering Sea shelf suggest that these volcanic rocks are part of a broad magmatic arc that swings across the shelf from western Alaska to the Gulf of Anadyr.

Based on outcrops in regions surrounding Norton basin, it seems likely that the "basement" floor of Norton basin consists of either or both Paleozoic and Mesozoic sedimentary rocks and Mesozoic volcanic rocks.

The Anadyr basin of northeast Siberia is analogous to the Norton basin in structural style, age, and type of sediment fill and provides important clues as to type of sediment fill in the Norton Basin. In Anadyr, Tertiary and Cretaceus' deposits are superimposed on Cretaceus forearc deposits of the Koryak-Anadyr region. Upper Cretaceus and Paleogene deposits have a total thickness of 1,494 to 1,980 meters (4,900 to 6,500 feet). The upper Cretaceus strata are composed of argillite and fine grained sandstone flysch deposits. These rocks are intruded and overlain by Paleocene to lower Eocene mafic and intermediate volcanic rocks. Upper Eocene to Oligocene terrigenous deposits of sandstone and argillite overlie the volcanics.

Neogene sediments in the Anadyr basin have a total thickness of nearly 3,048 meters (10,000 feet) and comprise the principal fill of the basin. More than 1,980 meters (6,500 feet) of this section is made up of middle and upper Miocene strata which is composed of shallow marine littoral, and coal bearing non-marine sediments. Miocene strata are overlain by 396 to 488 meters (1,300 to 1,600 feet) of Pliocene strata and 61 to 122 meters (200 to 400 feet) of Quarternary deposits.

An interpretation of marine seismic data in Norton basin indicates the sedimentary sequence here to be strikingly similar to that in Anadyr.

Poorly exposed lower tertiary volcanic and non-volcanic coal bearing deposits outcrop on St. Lawrence Island. An older Paleocene unit is composed primarily of volcanic flows and tuffs with thin bands of lignitic coal and tuffaceous sedimentary rocks. A younger Oligocene unit consists of poorly consolidated calcareous sandstone, grit, and conglomerate, carbonaceous mudstone, ashy tuff, and volcanic breccia.

Two small outcrops of poorly consolidated coal-bearing beds of tertiary age are exposed near Unalakleet along the Norton Sound coast. A small isolated patch of conglomerate of Cretaceus or Tertiary age occurs in the Sinuk River valley on the Seward Peninsula, 34 kilometers (21 miles) northwest of Nome. Here sandstone, shale, and coal are also present in minor amounts.

3.2.2.2 Structure

Seismic reflection data in Norton basin indicate the basin is deepest north and west of Yukon delta. The deepest point measured is 7,010 meters

(23,000 feet). West-northwest trending normal faults form grabens, which contain the thickest basin fill. These grabens are separated by horsts over which sediment thickness is generally shallower than 3,048 meters (10,000 feet) and more commonly less than about 1,980 meters (6,500 feet). The deep parts of the basin are formed by progressively deeper step down fault blocks which form a series of horsts, grabens, and half grabens. Deep in the basin, the faults show major displacement (measured in hundreds of meters), but above a horizon, which is generally 1,980 meters to 2,896 meters (6,500 to 9,500 feet) deep, the faults show minor displacement that is less than 91 meters (300 feet). This horizon may be a basin wide unconformity.

The area of horst and graben structure is bounded on the north by an area under which the bottom of the basin forms a platform that slopes gently basinward. The platform is shallow, less than 1,067 meters (3,500 feet) deep, and forms a relatively smooth surface. A normal fault forms the southern limit of the platform in most places. A fault-bounded platform also occurs between St. Lawrence Island and the Yukon delta.

The ages of strata in the basin are not well known. Based on refraction seismic data by Fisher, 1979, and comparison of these data with similar data in the Anadyr basin, the pronounced unconformity within the basin fill probably occurred between the Oligocene and Miocene. The depositional environment of the strata near the unconformity is interpreted from the acoustic signature of the seismic data. Reflections just below the unconformity are mostly irregular and discontinuous, possibly indicating localized sediment units in fluvial or deltaic systems. The sequence of irregular reflections is widespread in the basin and appears to come from the direction of the present Yukon delta; the Yukon, therefore, may have supplied most of the sediment in the sequence. Above the unconformity, reflections are extensive and parallel, suggesting deposition over wide areas by unconfined currents, like those that occur in a marine shelf environment.

Strong, discontinuous reflections from deep within Norton basin are interpreted to be volcanic flows or sills. The volcanic rocks are apparently concentrated deep in the grabens. If the volcanics are coeval with those on St. Lawrence Island, they would have a Paleocene to Oligocene age.

Oil seeps have been reported around Norton Sound for many years; but none of these have been verified during recent surveys by U.S.G.S. geologists.

Gas seeps commonly occur in and around Norton Sound. Two wells at Cape Nome encountered shallow, high pressure gas. Seeps of combustible gas are common on the Yukon delta where gas is often trapped beneath river ice in winter; this gas may be marsh gas (methane) of biogenic origin. Fisher, 1979, reports that craters mark large areas of the seafloor, and acoustic anomalies commonly occur in seismic data, and that gas may cause both the craters and the anomalies. A gas seep, located 64 kilometers (40 miles) south of Nome, contains mostly carbon-dioxide gas, but a small fraction of hydrocarbon gas is also present.

Hydrocarbon source and reservoir characteristics of strata in Norton Basin are inferred by Fisher, et al. (1979) from the characteristics of strata that rim the basin, but which may not be in or beneath the basins and from the acoustic signature of the basin fill.

3.2.2.3 Source Rocks

To determine the source potential of strata around Norton basin, outcrop samples from St. Lawrence Island, from the Sinuk River Valley on the -Seward Peninsula, and from the Yukon-Koyukuk province were analyzed by the U.S.G.S. for thermal maturity and for source richness.

In nine outcrop samples from St. Lawrence Island ranging in age from Devonian to Tertiary, the Paleozoic and Mesozoic rocks showed herbaceous and woody kerogen to predominate, which is indicative of a gas-prone environment. Thermal alteration index values show all samples are thermally immature, except for the sample of Permo-Triassic shale. The low thermal alteration of the samples of Paleozoic rocks implies that these strata have not been deeply buried under St. Lawrence Island. The sample of Permo-Triassic shale is the one thermally mature sample, and the maturity may be attributed to local thermal effects of Cretacreous intrusive.

Non-marine Tertiary strata on St. Lawrence Island are mostly coaly sandstone and siltstone that have high organic-carbon contents. The predominance of woody and coaly kerogen and the low degree of thermal alteration make these strata possible sources for methane gas.

Geochemical analysis of non-marine Tertiary strata in the Sinuk Valley indicate these sediments to be gas prone, as are outcrop shale samples in the middle Cretaceus deltaic strata exposed in the sea cliffs near the town of Unalakleet.

The predominance of woody, herbaceous, and coaly kerogen in the gas-prone Tertiary and Cretaceus strata that rim Norton basin results from the non-marine and deltaic environments of deposition of the strata. If it is inferred that the same type of kerogen predominates in deltaic strata in Norton basin, then gas-prone strata would be yielded here too. The description of strata as "gas-prone" does not mean oil cannot be generated and produced; rather the description means gas is more likely to be produced than oil. The marine strata above the regional unconformity in Norton Basin may contain more amorphous kerogen than the deltaic strata, and may, therefore, be a source for oil if the strata are thermally mature.

In the offshore area, some strata are mature enough to produce hydrocarbons as shown by gas from the seep south of Nome. Though most of the gas is carbon dioxide, gasoline range (C_5-C_7) hydrocarbons that are present in the gas indicate source strata of unknown quality are in the basin.

The magnitude of the thermal gradient in the basin is another unknown. The extensional tectonics that formed the basin may have caused crusts'l attenuation beneath the basin and volcanism; this probably increases the geothermal gradient in the basin over the gradient that exists outside the area of extension. Rifted basins in other areas of the world generally have high geothermal gradients which are preferred in the generation of hydrocarbons.

3.2.2.4 Reservoir Rocks

Although the quality of reservoir rocks in Norton basin is unknown, some assumptions can be made based on regional paleogeography. The quality of reservoir strata older than late Miocene may be dependent on the provenance of the reservoir strata, i.e., the provenance may determine the percentage of quartz in the reservoirs. Since late Miocene time, the Yukon River has had an enormous drainage area that has supplied quartz to Norton basin, as shown by modern Yukon sediments that contain an average of 25 percent quartz. Before the late Miocene, however, the proto-Yukon had a more restricted drainage area, and may have received a-large proportion of sediment from Cretaceus strata in the Yukon-Koyukuk province, and strata in this province contains only 8 percent quartz. Therefore, the reservoir potential of middle Miocene and older strata in the Norton basin may be limited.

Seismic data show a delta of large areal extent in Norton basin that appears to head at or near the present Yukon delta, suggesting a large portion of the pre-late Miocene basin fill came from the Yukon. Sediment may also have been introduced from quartzose sources on the Seward Peninsula. Accordingly, reservoir quality may improve northward from the Yukon delta in strata older than late Miocene. The deepest part of the basin, however, is adjacent to the mouth of the Yukon. Reservoir quality may locally improve because of sorting of the quartz-poor sediment by the proto-Yukon River.

Another local source for basin fill are Paleogene volcanics that may have reduced the reservoir quality of Paleogene strata by introducing chemically reactive material, such as volcanic ash and tuff, that later turn to clay and low grade metamorphic-minerals, impairing both porosity and permeability. Migration of petroleum from Cretaceus or lower Paleogene strata strata contain a large volcaniclastic component.

3.2.2.5 Traps

Traps of economic importance in Norton basin are closures produced by potential sand reservoirs draped over pre-Tertiary "basement" horsts.

A significant criterion to consider in the tectonic evaluation of the Norton basin is the timing of structural growth as it relates to time of deposition of the host reservoir beds. Generally, in the productive Teritary basins which rim the Pacific Margin, early structural growth or development of synchronous "highs", is essential for entrapment of large hydrocarbon accumulations.. It is important to determine seismically if structural growth can be demonstrated over the horst features of the Norton basin.

3.2.3 U.S. Geological Survey Resource Estimates

The petroleum development scenarios described in this report are based upon U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources of Norton Basin. The most recent estimates for Norton Basin are presented in U.S. Geological Survey Open-File Report 79-720 (Fisher et al., 1979). Two estimates are presented in that report.

	95 Percent Probability	5 Percent Probability	Statistical Mean
Oil (billions of barrels)	0	2 . 2	0.54
Gas (trillions of cubic feet)	0	2.8	0.85

These are risked probabilistic estimates to which a marginal probability is assigned to the event that commercial oil and gas might be found since Norton Basin is a frontier area with respect to petroleum exploration. The marginal probabilities applied were 40 percent to oil and 60 percent to gas. Thus the 9.5 percent probability estimate. (above) is zero. For impact assessment purposes, the U.S.G.S. has defined alternate estimates as follows:

	Minimum	Mean	Maximum
Oil (billions of barrels)	0.38	1.4	2.6
Gas (trillions of cubic. feet)	1.2	2.3	3.2

The 'risked' resource estimates presented by the U.S. Geological survey (e.g. the estimates presented in Circular 725 are risked, estimates) are made by applying a marginal probability to unconditional estimates. Risked estimates reflect the possibility of oil or gas not being present and are made for frontier basins for which little geologic data is available and where no drilling may yet have taken place (Gordon Dolton, U.S. Geological Survey Resource Appraisal Group, personal communication). Oil and gas estimates are made independently. (For additional information on U.S. Geological Survey Resource estimates the reader is referred to Circular 725.) The scenarios in this study are based on those unrisked estimates.

The area considered in the U.S.G.S. resource assessment is bounded by latitude 63°00' and 64°45'N and longitude 162°00' and 170°00'W, an area in excess of 40,000 sq. kilometers (15,444 sq. miles). Sediment volume in the assessment area is estimated at about 60,000 cubic kilometers (23,168 cubic miles).

3.2.4 Assumptions

3.2.4.1 Initial Production Rate

Oil

Initial well production rate is a parameter used in the economic analysis and scenario formulation as an index of reservoir performance in the absence of specific data on reservoir characteristics such as pay thickness, porosity, permeability, drive mechanism, etc. initial productivity is a function of such reservoir characteristics as pay thickness, porosity, and permeability. The initial productivity per well influences the numbers of we' 1s which have to be drilled to efficiently drain a given reservoir.

Initial well productivities assumed for this study are 1,000 bpd, 2 000 bpd, and 5,000 bpd. These have been selected, in part, on the basis of limited geologic/analog data and, in part, by the requirement to explore a range of economic senistivities related to this parameter. These values are consistent with the general ranges of reservoir performance for many of the Pacific Margin Tertiary basins including Cook Inlet. As an analog, Upper Cook Inlet initial well productivities have averaged 1,000 to 2,000 bpd although there are some wells which have produced at significantly higher rates, notably in the McArthur River field (Diver, Hart and Graham, 1976). Currently, production from Cook Inlet oil fields is in decline. In 1977, for example, wells were averaging for the individual fields from 159 bpd to 1,530 bpd (State of Alaska, Department of Natural Resources, Division of Oil and Gas, 1977).

Five thousand barrels per day is the maximum sustainable rate realized for the more prolific Pacific Margin Tertiary basins. Available geologic/ analog data imply that initial productivity below 2,000 bpd well is much more likely than initial productivity in the 5,000 bpd well range.

In previous scenario studies for the northern Gulf of Alaska and western Gulf of Alaska (Kodiak Tertiary basins), we assumed an initial well production rate of 2,500 bpd but evaluated limited cases of 7,500 bpd (regarded as unlikely). These are both Pacific Margin Tertiary basins. In Cook Inlet, which is a Tertiary basin but also has Mesozoic prospects in its southern part (Lower Cook Inlet), 1,000, 2,000, and 5,000 bpd initial well productivities were assumed -- the same productivities assumed for this study.

Non-Associated Gas

Initial productivity per well for non-associated gas is assumed to be 15 mmcfd based on the Teritary analog of Upper Cook Inlet. Upper limit productivity is assumed to 25 mmcfd for field size sensitivity testing,

3.2.4.2 Reservoir Depth

Three reservoir depths have been assumed for this study -- 762, 1,524 and 2,286 meters (2,500, 5,000 and 7,500 feet) -- for both oil and gas prospects.

Review of very limited seismic data covering only a portion of the Norton basin indicated sediment thicknesses generally thinner than 3,048 meters (10,000 feet) and more commonly less than about 1,981 meters (6,500 feet over the horsts; the thickest basin fill is located in the intervening grabens. If the sediment thickness indicated in the sample are over the horsts (structurally, the potential Norton basin traps are closures produced by potential sand reservoirs draped over these pre-Tertiary basement horsts) then shallow reservoirs (i.e. <1,524 meters or <5,000 feet) predominate. Reservoir depths selected for analysis in this study are, therefore in the shallow to medium range as follows: 762 meters (2,500 feet), 1,524 meters (5,000 feet) and 2,286 meters (7,500 feet).

Reservoir depth in this analysis is a parameter which defines the number of platforms required to efficiently produce a given field size. All other factors being equal, a shallow field with a thin pay reservoir covering many square kilometers and requiring several platforms to produce is less economic than a field of equal reserves, with a deep, thick pay zone, which can be reached from a single platform. In the economic analysis and scenario detailing, reservoir depth dictates the rate of development well completion which in turn effects the timing of production start-up and peak production (and the schedule of investment return). The well completion rate also affects the development drilling employment.

3.2.4.3 Recoverable Reserves

It can be shown that reservoir characteristics -- porosity, permeability, connate water, driving mechanism; and depth as it relates to pressure, etc. -- together with thickness of payzone define the recoverable reserves per acre. Thus, recoverable reserves per acre is a good proxy in place of more technical functional relationships for determining the number of wells required to produce a field, given its initial production rate. Recoverable reserves are also commonly expressed as barrels per acre foot (of pay). Multiplying the pay thickness by bbl/acre foot gives recoverable reserves per acre. For most Pacific Margin Tertiary basins, including

Cook Inlet, recoverable reserves per acre can generally be bracketed between 20,000 and 60,000 bbl; assuming a recovery factor of 200 bbl/acre foot pay thicknesses would be 30 meters (100 feet) and 91 meters (300 feet) for these recoverable reserves respectively.

Higher recovery factors such as those now found in the Jurassic of the North Sea, the Permo-Triassic of the North Slope of Alaska and Creteceous sand reservoirs of the Middle East cannot be used as a basis for comparison. The reservoirs in these basins are generally mineralogically different than those in pacific Margin Tertiary basins. The Tertiary sand reservoirs are typically arkosic with significant percentages of unstable feldspar minerals which diagenetically alter the clay minerals, thus reducing porosity and permeability. Sand reservoirs in the North Sea and North Slope, however, consist of high percentages of stable minerals such as quartz and have high porosities and permeabilities and correspondingly high productivities.

An assumption on a range of recoverable reserves per acre is required in this study as a general indication of the potential a rein extent of a field for a given (assumed) reserve or field size assuming simple reservoir geometry. This assumption in combination with reservoir depth (see Table 3-1) and well productivity, allows an estimate to be made of the number of platforms required to drain a given field. A "best case" platform spacing is assumed in so far as the reservoir geometry is assumed to be a simple anticline. Obviously, a complex faulted reservoir with the same reserves will necessitate a different platform configuration, more platforms or even the use of subsea wells. Subsea wells may be required in a complex reservoir to drain islolated portions of a reservoir that could not be reached from directionally-drilled wells from a platform if the incremental recovery could not economically justify investment in an additional platform.

Technical Discussion

A brief technical overview of estimating recoverable reserves will demonstrate the complexity of the problem and the requirement for much more

TABLE 3-1

MAXIMUM AREA WHICH CAN BE REACHED WITH
DEVIATED WELLS DRILLED FROM A SINGLE PLATFORM

Depth of Reservoir		Maximum Area Produced		
Meters	Feet	Sq. Miles	Acres	Hectares
762	2,500	1.0	640	259
1,525	5,000	3.0	1,920	777
2,286	7,500	7.0	4,480	1,813
3,050	10,000	12.5	8,000	3,238
3,812	12,500	19.5	12,480	5,051
4,575	15.000	28.0	17,920	7,252

Notes:

1. Maximum angle of deviation assumed to be 50 degrees.

Source: Dames & Moore

detailed reservoir data than is presently available for the Norton Basin.

Recoverable oil from a reservoir is controlled by a combination of the following parameters:

- Oil gravity
- Oil viscosity
- Gas volubility in the oil
- Relative permeability
- Reservoir pressure
- Connate water saturation
- Presence of a gas cap, its size, and method of expansion
- Fluid production rate
- Pressure drop in the reservoir
- Structural configuration of the reservoir

Many studies have been made of the relationship between these parameters, most of which are statistical in nature.

It should be clearly understood that any prediction of recoverable reserves, or recovery factor, is very difficult to evaluate, and usually winds up to be a matter of judgement based on available data and analogy to existing reservoirs of a comparable nature.

In a study for API (Arps, 1967) and a subsequent paper by the same author (Arps, 1968) J.J. Arps presents a "formula" approach for calculating the recovery factor for solution gas drive and water drive reservoirs. The formula also gives tabulated ranges of recovery factors for solution gas with supplemental drive, gas cap, and gravity drainage reservoir drive mechanisms. In order to use the formula, a knowledge or estimate of the following data is needed:

- Porosity
- Water saturation
- Oil information volume factor

- Permeability
- Oil and water viscosities
- Initial and abandonment pressures.

It should be noted that in order to calculate recoverable reserves in barrels an estimate of both reservoir thickness and area? extent is needed.

Probably the most difficult question to answer in estimating recovery factors is what is the effect of production rate. The answer to this is based on the relative permeability effects, and they are very complex. Arps' studies do not take this into account because of the lack of data on relative permeability.

3.2.4.4 Well Spacing

General Considerations and Oil

Well spacings consistent with industry practice and varying as a function of initial well productivity and recoverable reserves per acre are implicit in the scenarios. For shallow reservoirs, industry well spacing practices can restrict the number of wells drilled from a platform and this has economic impact on the field development decision.

The number of wells that can be drilled from a platform depends on:

- Reservoir characteristics of the particular oil or gas field.
- The average depth of the reservoir.

The first item governs how the oil or gas flows. We have fixed initial production rates by assumption (Section 3.2.4.1). Reservoir depth determines the maximum area which can be produced from a platform, assuming that a deviated well can be drilled to an angle of up to 50 degrees from the vertical; Table 3-1 shows that the maximum area that can be produced from a single platform ranges from (640 to 17,920 acres), assuming the depth ranges from 762 to 4,572 meters (2,500 to 15,000 feet). For the assumed reservoir depths of this study, a single platform will be able to reach a maximum area of either one square mile (640 acres) for a 702 meter (2,500 feet) deep reservoir or seven square miles (4,480 acres) for a 2,286 meter (7,500 feet) deep reservoir.

Using industry practices in the Upper Cook inlet as an analog, well spacing for the Norton basin fields should range, therefore, between 80 to 320 acres per well as a function of initial well productivity and re-cover able reserves per acre. The oil wells in McArthur River field in Upper Cook Inlet, for example, are now complete with an 80 acre spacing. Although the original spacing was 160 acres, this subsequently has been reduced by in-filling as field development proceeded. Depending therefore, on reservoir depth, initial productivity, and the number of wells per platform, sufficient platforms will be assumed to house enough wells to:

- Allow spacing between 80 to 320 acres.
- Allow exhaustion of recoverable reserves within 20-25 years.

With a 762 meter (2,500 feet), reservoir depth, 80-acre spacing implies no more than 8 wells may be drilled into a reservoir from a single platform. Forty wells may be drilled into a reservoir at 2,286 meters (7,500 feet). This implies 112 acre spacing.

Non-Associated Gas

As noted in the Lower Cook Inlet scenario study, (Dames & Moore, 1979c) well spacing in Alaska frontier areas is likely to be set by the market demand for gas, rather than by industry desire to maximize recovery. Consistent with reservoir engineering and petroleum geology constraints, well spacing up to 518 hectares (1,200 acres) may allow sufficient gas production to run potential LNG capacity. Final design well spacing in the usual U.S. range of 160 to 320 acres may have little relevance to gas producers in the Norton basin if they have no market for their gas. The onshore Kenai gas field in Upper Cook Inlet, however, which has long-term contracts with both domestic and industrial users in the Cook Inlet area, is currently developed with wells on a 320 acre spacing.

3.2.4.5 Field Sizes and Field Distribution

Traps of economic importance in Norton basin are closures produced by potential sand reservoirs draped over per-Tertiary basement horsts. As indicated in Section 3.2.1, good quality seismic data is required to identify and rate prospective structures in an untested province such as Norton basin.

If the assumption is made that offshore Norton basin traps will be hydrocarbon bearing, and assuming seismic data is available to identify structures and estimate the areas of closure, etc., the all important economic problem is predicting percent fill-up (percent of geological closure or reservoir unit within geological closure that is filled with hydrocarbons). The approach used to predict fill-up is an analogy based on statistical comparisons with known productive Pacific margin basins. It should be emphasized, however, that any analogy based on statistical comparisons with known productive Pacific margin basins. It should be emphasized, however, that any analogical approach to prediction of petroleum resources is extremely hazardous in that each basin is unique. One critical difference in geologic parameters can completely negate the effect of many similarities.

Factors effecting percent fill are the richness of the source rock and quality of reservoir. In addition, trap density is also an important factor. Generally, the greater the trap density, the smaller the fill-up. As examples, the average percent fill-up of productive closures in the Pacific Margin Los Angeles and Ventura basins are 40 percent and 15 percent, respectively.

Unfortunately, there is no reliable way to rationally estimate percent fill-up in Norton basin. Based on data from around the Pacific Margin, we assume that fill-up in excess of 50 percent would be the exception in Norton basin. In estimating potential reserves of this basin, only those areas lying within the 50 percent fill contour should be considered, with 25 percent fill-up considered as average.

In the absence of sufficient geologic data to make reasonable predictions on the number of prospective structures and field sizes that may be discovered in Norton basin, the field sizes selected for economic screening have therefore been selected to be consistent with the following factors:

- U.S. Geological Survey resource estimates (Fisher, et al., 1979).
- Anticipated economic conditions (based on economic studies of other offshore areas).
- Geology (only gross structural geology and stratigraphic data are available).
- Requirement to examine a reasonable range of economic sensitivities.

The field sizes to be evaluated in this study, therefore, range from 100 million barrels to two billion barrels for oil and 500 billion cubic feet to three trillion cubic feet for non-associated gas. ([1]) The maximum field size is determined by the total resource estimate assuming that the total resource is contained in a single field (a most unlikely occurrence).

3.2.4.6' Allocation of the U.S. Geological Survey Gas Resource Estimate Between Associated and Non-Associated and Gas-Oil Ratio (GOR)

Prediction as to hydrocarbon type, (oil versus gas which may be encountered), is extremely difficult to assess in the Norton basin. Based on meager and scattered outcrop data along the onshore perimeter of the basin, Fisher, et al., (1979), believe the offshore Norton province to be gas-prone rather than oil. Our petroleum geologist suggests that this conclusion be viewed with extreme caution, as the Cretaceus and older onshore rocks which were analyzed for source rock potential, probably constitute effective basement in the offshore. There are no known productive Pacific Margin Tertiary basins which also have significant amounts of producible hydrocarbons from pre-Tertiary rocks.

Review of producing Pacific Margin Tertiary basins does not provide meaningful analogs for the Norton basin since these basins present a wide range in the type of natural gas and gas-oil ratio (GOR).

The U.S. Geological Survey estimates do not specify any ratio of associated to non-associated gas resources and no such ratio is implicit in their estimates. If the Norton basin is gas-prone, as the U.S.G.S. contends, then a significant portion of the gas resources cart be assumed to be non-associated.

In the northern Gulf of Alaska petroleum development scenarios study (Dames & Moore, 1979a), the assumption was made that 20 percent of the gas resource was associated and 80 percent was non-associated following an assumption made in a report by Kalter, Tyner and Hughes (1975) based on U.S. historic production data. In the Lower Cook Inlet scenario study (Dames & Moore, 1979c). The assumption was made for scenario detailing and analytical simplification that all the gas resource was non-associated (i.e., scenarios were formulated which included gas field(s) totaling the U.S. Geological Survey gas resource estimate). In reality, however, some portion of the gas resource will be associated; the Lower Cook study implicitly assumed that the oil fields are characterized by a 1 0w gas-oil ratio (GOR) and that the gas was used to fuel the platforms with the remainder reinfected.

The treatment of the associated/non-associated problem in the analysis is critics because in Alaska offshore frontier areas, non-associated gas resources, in many locations, are less economic than the same amount of associated gas. This is because the incremental investment to produce associated gas (with oil the primary product) is less than the total development costs for a non-associated gas field with the same recoverable reserves.

In this study, as with Lower Cook Inlet, we assume that all the gas is non-associated, (i.e., scenarios are formulated which include gas fields totaling the U.S. Geological Survey resource estimate). This assumption is not inconsistent with the possibility expressed by the U.S.G.S. that Norton is gas prone (U.S. historic production data indicates that 80 percent of the U.S. gas resource is non-associated.) With this treatment of the associated gas/non-associated gas problem, the scenarios will assume oil fields with a low GOR and no production to market of associated gas; associated gas is assumed to be used to fuel the platforms and the remainder reinfected. It should be noted that this assumption will increase the number of fields (and hence equipment requirements -- platforms, pipelines, etc.) over a scenario that assumes a significant proportion of the gas reserve is associated and produced incrementally with oil.

There is no available data to provide a firm basis on which an assumption can be made on the gas-oil ratio (GOR) in hypothetical Norton basin reservoirs. GOR can vary considerably from field to field in the same basin and between different reservoirs in the same geologic horizon. Initial GOR in upper Cook Inlet fields, for example, ranges from 65 to 1,110 standard cubic feet (SCF) per barrel (Magoon, et al., 1978).

3.2.4.7 Oil Properties

There is no data to predict the quality of oil that may be found in the Norton basin although many of the producing Pacific Margin Tertiary basin fields produce low sulphur, medium to low gravity (medium to high API numbers) crudes.

The gravity of oil in upper Cook Inlet fields, for example, ranges from 27.7 degrees API (shut in Redoubt Shoal field) to 44 degrees API. Sulphur content is generally low with a maximum of 0.22 percent in the Redoubt Shoal field (shut in).

The uncertainty relating to the characteristics of crude that may be discovered is reflected in the range of prices assumed in the analysis (Section 3.4.3.3).

3.3 Technology and Production System Selection

Having defined the reservoir and production parameters to be evaluated in the economic analysis, the next step in the scenario development process and economic analysis is the selection of production systems to be screened in the economic analysis. This selection, which is central to the study, involves:

- Identifying production systems and transportation options suitable for the oceanographic conditions of Norton Sound and most likely to be adopted by industry for this region.

- Estimating costs for the various components of the systems (platforms, pipelines, terminals, etc.)

- Matching petroleum engineering with representative reservoir conditions (reserves, reservoir depth, recoverable reserves per acre, initial well production rates).

- Scheduling field development investment flows.

- Identifying construction schedules for various production system components for employment estimation.

As indicated in Appendix C, ice reinforced steel platforms of a modified Upper Cook Inlet design will probably be the most favored platform option. Ice conditions may not be sufficiently severe to require more exotic structures such as the monotone or cone. Integrated barged-in deck units may be utilized to reduce offshore construction time due to the short summer weather window.

In the shallower waters of the Norton Sound (<23 meters [75 feet]), depending upon gravel availability and environmental sensitivity, gravel islands and caisson-retained gravel islands may be technically feasible. Modularized barge-mounted process units, ballasted down and surrounded by gravel berms or caissons may be the favored engineering strategy for gravel or caisson-retained production islands.

Economic evaluation of field development not only involves identification of platform types but also transportation requirements including pipeline specifications and shore terminal requirements and some assumption on discovery location.

As discussed in Appendix D, five potential sites have been identified for location of a crude oil terminal and/or LNG plant in Norton Sound and adjacent portions of the Bering Sea: Cape Darby, Cape Nome, Nome, Lost River, and Northeast Cape (St. Lawrence Island). Having established the location of these potential terminal sites, identification of representative discovery locations (in the absence of site-specific data on geologic structures), permits estimation of maximum, minimum, and average potential pipeline distances (offshore and onshore) to the closest suitable terminal site for economic screening; these are summarized in Table 3-2.

3.4 Summary of Field Development Cases for Economic Evaluation

Each field development case evaluated in the economic analysis has the following components (see Figures 3-1 and 3-2):

- Reservoir characteristics.

- Engineering strategy (type of platform, numbers of platforms, pipeline requirements, etc.) which is dependent on the reservoir characteristics, oceanographic conditions, and discovery location relative to shore terminal sites.

- Oceanographic setting (water depth, ice conditions, etc.).

- Geographic location (distance to shore and terminal sites and related logistic constraints).

These components are summarized in Tables 3-2, 3-3, and 3-4. Since there are too many combinations of these parameters to meaningfully evaluate within the time or budgetary constraints of such a study, some selectivity in cases to be analyzed is required. This selectivity involves identification of the key geologic, engineering, and geographic problems affecting the economics of field development in the Norton Sound area. Consideration of the reservoir, engineering, oceanographic, and geographic components summarized in Tables 3-2 through 3-4 led the study team to explore the following field development problems or issues:

- Economic sensitivity of initial well production rates.

- The effects of shallow reservoirs on field development economics.

- Sensitivity of field development economics to pipeline distance.

- Impact of water depth on field development economics.

- Sensitivity of field development economics to delays caused by weather conditions, environmental constraints, or technology problems.

TABLE 3-2

REPRESENTATIVE PIPELINE DISTANCES TO NEAREST TERMINAL SITE EVALUATED IN ECONOMIC ANALYSIS

Case	Water Depth of Field meters (feet)	Pipeline Length Offshore kilometers (miles)	Pipeline Length Onshore kilometers (miles)
No. 1	15 (50), 30 (100), 46 (150)	128 (80)	3 (2)
No. 2	15 (50), 30 (100), 46 (150)	64 (40)	3 (2)
No. 3	15 (50)	32 (20)	48 (30)
No. 4	15 (50)	32 (20)	3 (2)
No. 5	15 (50)	16 (10)	3 (2)

Note: Both shared and unshared pipeline cases are screened in the economic analysis.

Source: Dames & Moore

TABLE 3-3

SUMMARY OF RESERVOIR CHARACTERISTICS
EVALUATED IN THE ECONOMIC ANALYSIS

Field Sizes:	Oil (mmbbl)	- 100, 200, 500, 750, 1,000
	Gas (bcf)	- 1,000, 2,000, 3,000
Recoverable Reserves Per Acre:	Oil (bbl)	- 20,000, 60,000
	Gas (mmcf)	- 120, 300
Initial Well Production Rates:	Oil (bpd)	- 1,000, 2,000, 5,000
	Gas (mmcfd)	- 15, 25
Reservoir Depths:	Meters (feet)	- 762 (2,500), 1,524 (5,000), 2,286 (7,500)

Source; Dames & Moore

TABLE 3-4

PRODUCT ON PLATFORMS AND MATER DEPTHS
EVALU ED IN THE ECONOMIC ANALYSIS

Platform Type	Water Depth	
	meters	feet
Ice reinforced steel platform (modified Upper Cook Inlet Design)	15	50
	30	100
	46	150
Gravel Island	7.6	25
	15	50

Source: Dames & Moore

- Evaluation of "giant" field economics and sensitivity of a number of platforms required to develop a field.

- Evaluation of gravel island economics.

Evaluation of these economic sensitivities requires that some of the field development components remain constant. For example, to test water depth sensitivity, requires that the pipeline distance remain constant. To test reservoir depth sensitivity, for example, requires that other reservoir parameters and pipeline distance be fixed.

The selection of cases for economic analysis also involves sequencing of cases to define the major economic/non-economic boundaries of various field development situations first so that the analysis is meaningfully structured to avoid waste of analytical dollars. For example, reservoirs permitting 1,000 b/d wel 1s are screened prior to those with 2,500 b/d and 5,000 b/d wells since 1,000 b/d wells are an obvious adverse economic condition.

3.5 Economic Analysis

3.5.1 Role of the Economic Analysis in Scenario Formulation

In the scenario formulation process the economic analysis identifies those production systems which are economic and the minimum field sizes required to justify development for various discovery locations and production systems. The results of the economic analysis also indicate the impact of various reservoir characteristics (depth, productivity potential, etc.) upon the economics of field development.

The primary role of the economic analysis in the scenario development process is to:

- Identify a minimum field size for development in relation to various physical characteristics that may be associated with different discovery locations.

- Identify the relationship between water depth and field development for a given field size.

- Identify the most economic production system option for a given field size and discovery location.

- Specify the general reservoir characteristics that would have to be encountered for a given field size in a specified location to justify development.

- Identify the minimum required price for development of a field with specified characteristics.

3.5.2 The Objective of the Economic Analysis

The objective of the economic analysis is to evaluate the relationships among the likely oil and gas production technologies suitable for conditions in Norton Sound and the minimum field sizes required to justify each technology as a function of geologic conditions in different parts of the Sound.

The analysis of this report will focus attention on the engineering technology required to produce reserves under the difficult conditions of the Norton Sound and will emphasize the risk due to the uncertainties in the cost of that technology. Sensitivity and Monte Carlo procedures will be used in the analysis to allow for the uncertainty in the costs of technology and the uncertainty in the price of the oil and gas.

A model has been formulated that will allow determination of either: (a) the Minimum Field Size to justify development under several oil and gas production technologies, or (b) the Minimum Required Price to justify development given a field size and a selected production technology.

The model is a standard discount cash flow algorithm designed to handle uncertainty among key variables and driven by the investment and revenue streams associated with a selected production technology. The essential profitability criteria calculated by the model are: (a) the net present value (NPV) of the net after tax investment and revenue flows given a discount rate, or Value of Money (r) and, (b) the internal rate of return which equates the value of all cash flows when discounted back to the initial time period.

In the following sections, the mode?, its assumptions, and their implications are discussed.

3.5.3 The Model and the Solution Process

3.5.3.1 The Model

The Model calculates the net present value of developing a certain field size with a given technology appropriate for a selected water depth and distance to shore. The following equation shows the relationships among the variables in the solution process of the model.

Equation No. 1:
$$NPV = \Big[[\text{Price} \times \text{Production} \times (1 - \text{Royalty}) - \text{Operation Costs}] (1 - \text{Tax}) + [\text{Tax Credits}] - [\text{Tangible Investments} + \text{Intangible Costs}] \Big] \times PV$$

where:

NPV = net present value of producing a certain field with specified technology over a given time period.

Pv = present value operator to continuously discount all cash flows with value of money, r

Price	= wellhead price
Production	= annual production uniquely associated with a given field size, a selected production technology, and a number of wells
Royalty	royalty rate
Operating Cost	annual operation costs
Tax	tax rate
Tax Credits	= the sum of investment tax credits (ITC) plus depreciation tax credits (DTC) plus intangible drilling costs tax credits (IDC)
Tangible Investments	= development investments depreciated over life of production
Intangible Investments	= development expenditures that can be expensed for tax purposes.

The model does not include exploration costs or an allowance for a bonus payment. The model assumes discovery costs are sunk and answers the question, "What is the minimum field size required to justify development from the time of discovery given a selected production technology?". "Sunk" exploration costs -- seismic and geophysical, dry hold expenditures, and lease bonuses -- must be covered by successful discoveries.

This aumes that these costs which are not small, are covered by theiings from its successful portfolio of exploration investments (

The moct include a term for salvage or equipment at the end of productssumption is made that the cost of removal of all equipment and of the producing area to its pre-development environmental conditit state and federal regulations would be as much as the salvage;he equipment. The model assumes that the cost of removal will bethe value of the salvage.

Solution

Equatiorn be solved deterministically if values for the critical variablern with reasonable certainty. But single values for the independles on the right-hand side of Equation No. 1 are not known. The techat have been developed for the Beaufort Sea and Canadian Arctic, the cost estimates have been made, have not been tested in the Nortand/or cost-estimated in the United States. Thus, upper, lower, age values have been estimated for the critical variables of Equation are used in the solution process.

The modesolved given field size, prices, and a selected technology fie of return that will drive the NPV of production to zero. Sensitiviis can be used to show how the previously calculated rate of returnwith different values for:

-
- ng costs.

(1) Assut "sunk" costs are covered by the successful portfolio of exploratictment implies that. the upstream operations of vertically integrateesmust account for their profit and loss without reliance on downstnings. For non-vertically integrated exploration and production cthere is no alternative.

- Tangible investment costs.

- Intangible drilling costs.

Iterative solutions of Equation No. 1, given prices and a selected technology, can be used to determine the minimum size field to justify. development at various values of money. Sensitivity analysis can be used to show how changes in the values for the four items above change minimum economic field size.

3.5.4 The Assumptions

3.5.4.1 Value of Money

The minimum field size calculation is extremely sensitive to the value of money, r, used to discount the cash flows in Equation No. 1. Dames & Moore has specified that 10-15 percent brackets the "real" rate of return after tax in constant 1979 dollars that winning bidders will be willing to accept to develop a field.

In consultation with BLM economists and major oil company economic analysts, it appears reasonable that 10-15 percent in constant 1979 dollars will bracket most company hurdle rates for development of a given field in the Norton Sound(1). Notice that if inflation is expected to be 8 percent, 10-15 percent in constant dollars is equivalent to 18.8-24.2 percent in current dollars. This assumption follows the precedent of our prior studies.

3.5.4.2 Inflation

The analysis is constructed in 1979 dollars. This constant dollar assumption implies that the existing relationship between prices and costs

(1) In Appendix A we provide solutions based on a range of discount rates between 10 and 15 percent but emphasize 15 percent in discussions because we believe that to be closer to industry practices than 10 percent.

will remain constant, that oil and gas 'prices and the costs of their exploitation will inflate at the same rate between now and the period of exploration and development in the 1980's. From 1974 to mid-to-late 1978, however, the costs of finding and producing oil has risen faster than oil prices as shown by Table 3-5. Alaskan costs (for which we have no index) have risen at a faster rate according to industry sources.

Since the reduction of Iranian production in late 1978, world oil prices have risen faster than costs. This trend may continue for several years or this OPEC price inflation may create a general inflation that will cause costs to rise at a more or less equal rate. We cannot predict which scenario may occur. Thus, we assume prices and costs fixed at their 1979 levels. For economic determinations, the ratio of prices and costs--not their absolute levels--is the important parameter. *

If prices rise faster than costs then the minimum field size will be smaller than estimated. If, on the other hand, costs rise faster, then the minimum field size will be larger.

3.564.3 Oil Prices

World Market

At the Geneva meeting during June, (1979) OPEC benchmark Arabian light crude went up to $18.00/barrel from the $14.54 established in March. The other members of OPEC agreed to a ceiling of $23.50 through the end of 1979. Under this pricing system, Iranian light, which is very similar to Arabian light, is selling at $21.22.

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(1) Our economic analysis was conducted prior to the December 1979 OPEC meeting in Venezuala which failed to reach agreement on oil price and prior to the December pre-OPEC meeting price increases led by Saudia Arabia. Our Norton Basin oil and gas marketing study (Appendix 1), which was conducted after completion of our economic analysis, provides more current information (January, 1980) on OPEC oil pricing.

TABLE 3-5

U.S. AVERAGE OIL AND GAS PRICE AND PRODUCTION COST INFLATION SINCE 1974

	Year	Oil Prices[1]	Gas Prices[2]	IPAA Drilling Cost Per Foot[3]	Oil Field Machinery & Tools[4]
	1974	100	100	100	100
	1975	116	138.9	114.9	124.4
	1976	119.8	188.3	124.6	137.9
	1977	130	266	137.3	149.9
	1978	141.0	310.2	155.0	164.5
Annual Rate of Growth:	1974-78	9.0%	32.7%	11.6%	13.2%

Source: Dames & Moore

[1] BLS, Producer Price Index, 0561
[2] BLS, Producer Price Index, 0531
[3] IPAA, Annual Survey of Costs
[4] BLS, Producer Price Index, 1191

Alaskan crude oil prices are linked to the world market. Essentially, a refiner can choose to take an incremental cargo of either Alaskan crude or OPEC crude depending on the economics at the time of his decision.

California and Hawaiian refiners are running about 875,000 B/D of North Slope crude as their incremental crude above a base load of Californian and Indonesian crudes. California clean air requirements impose very stringent sulfur emission standards which require low sulfur fuel oil in order that they be met. About 400,000 B/D of sweet Indonesian crude is required to meet the state fuel oil demand.

North Slope crude beyond 875,000 B/D currently is shipped either to the Gulf Coast or to the Virgin Islands to Hess's large refinery. According to PIW, companies hope to get upt o 950,000 B/D by the time the pipeline throughput increases to 1.4 million B/D later this year.

Incremental Alaskan crudes from some future discovery say, in the Norton Sound, would exceed West Coast capacity and would move to the Gulf Coast of the United States--unless, of course, its sulfur content was very low and it could replace the Indonesian imports.

In the following analysis the assumption is made that incremental Alaskan crude must compete on the Gulf Coast with either Arabian light, Iranian light, or Mexican crude.

Table 3-6 shows that the landed value of Iranian and Arabian crude on the Gulf Coast is between $20.00 and $23.25/BBL.

The Mexican crude comparable to Arabian and Iranian light is called Isthmus. Price F.O.B. Tampico is $22.60 with the short haul to the Gulf Coast, this will lay-in at about $23.00. One of these crudes is the likely incremental crude for a refiner on the Gulf Coast. A barrel of Alaskan crude must compete with one of these.

The Link to Alaska

Incremental Exxon and Sohio North Slope crude is shipped largely in 100-150M DWT U.S. flag tankers to the Northville Industries terminal in Panama and then transshipped in 40-50 M DWT tankers through the canal to ports on the Gulf Coast. Depending on freight rates and the canal toll, which is currently $1.34 ton or about $0.18 BBL--but going up when U.S. gives up ownership of the canal later in 1979--cost of shipping Alaskan North Slope crude from Valdez to the Gulf Coast is about $3.00 BBL.

Assuming that a barrel of Alaskan crude replaces either a barrel of Isthmus, Iranian light or Arabian light on the Gulf Coast and that the quality differential between the crudes is $0.50, Table 3-7 shows that North Slope crude is worth between $16.50 and $19.75 at Valdez.

North Slope crude destined for Los Angeles is worth about $2.00 a barrel more in Valdez than incremental crude shipped to the Gulf Coast.

If some west-to-east pipeline existed, the oil could get to the Gulf Coast or Midwest for about $0.75 barrel instead of the $2.00 to ship through the canal. In this case, Alaskan North Slope crude would be worth between $19.75 and $21.00 in Valdez.

Norton Basin Crude Well-Head Value (1)

Any discovered crude in the Norton Sound will experience expensive shipping costs to clear the ice bound areas of the northern Alaskan coastal zone, may have vastly different refining properties than Alaska North Slope crude, and may replace imported oil with higher "real" prices than the current upper limit of $19.75 for Iranian light, for instance, low sulfur Sumatran light which would lay into the west coast for about $23.00.

(1) Our economic analysis was conducted prior to the December, 1979, OPEC meeting in Venezuala which failed to reach agreement on oil prices and prior to the December pre-OPEC meeting price increases led by Saudi Arabia. Our Norton Basin oil and gas marketing study (Appendix F), which was conducted after completion of our economic analysis, provides more current information (January 1980) on OPEC oil pricing.

TABLE 3-6

LANDED VALUE OF ARABIAN AND IRANIAN LIGHT CRUDES[1]

	$/BBL
Iranian Light	
Iranian Light, F.O.B. Kharg Island	21.22
Freight: to Bahamas (VLCC) WS 45	1.04
Transship Fee	.20
Freight: Bahamas to U.S. Gulf Coast (60M DWT) WS 75	.33
Loss Allowance (1% of Cost and Freight)	.46
VALUE OF CRUDE LAID-IN	$23.25
Arabian Light	
Arabian Light, F.O.B. Ras Tanura	18.00
Freight and Loss Allowance to U.S. Gulf Coast	2.00
VALUE OF CRUDE LAID-IN	$20.00

Source: PIW (various issues); Platt's Oilgram (various issues).

(1) Our economic analysis was conducted prior to the December, 1979, OPEC meeting in Venezuala which failed to reach agreement on oil prices and prior to the December pre-OPEC meeting price increases led by Saudi Arabia. Our Norton Basin oil and gas marketing study (Appendix F), which was conducted after completion of our economic analysis, provides more current information (January 1980) on OPEC oil pricing.

There is a great deal of uncertainty about how crude from the frozen northwest of Alaska's OCS would be transported to market--or how much it would cost. A 1977 northwest Alaska tanker transportation study conducted for the U.S. Department of Commerce (Global Marine Engineering Co., 1977) indicated that one transportation option was crude shipment in specially designed ice-reinforced shuttle tankers that would take northwest Alaska crude to a terminal in the Aleutians such as Dutch Harbor. There it would be transshipped to conventional tankers for transport to either the West Coast or Gulf Coast. Cost of this is estimated to be between $2.00-$2.50/BBL to the West Coast, or about $1.10-$1.60 more than the $0.90 shipping cost from Valdez to the West Coast. These are very speculative numbers.

Adjusting the value of North Slope crude on the Gulf Coast shown on Table 3-7 by this $1.10-$1.60 differential' indicates that some Norton Sound crude replacing incremental Isthsmus or Iranian crude would be worth between $18.15 to $18.65 at the well head. As a replacement for Arabian Light, some Norton Sound crude would be worth $14.90-$15.40 at the well-head. If it were a low sulfur crude and could replace Sumatran light on the West Coast, it would be worth between $20.50 and $21.00 at the well-head in the Norton Sound.

For this analysis we have pegged the lower, mid, and upper well-head values for the Monte Carlo analysis for Norton basin crude at $14.50, $18.00 and $25.00 a barrel. The upper figure can only be considered a guess representing a conservative bias about future oil "real" price increases. This range is intended to examine the effects of price on the economics of development rather than to claim with any degree of certainty that these upper and lower" limits are the limiting brackets.

3.5.4.4 Gas Prices

Well-head gas prices will be assumed to be the price allowed in mid-1979 by the Natural Gas Act of 1978, i.e., $2.60 MCF. Price increases subsequent to the 1979 price defined by the regulations are designed to move with general inflation plus 3.5 percent to 1981. We believe production costs will inflate faster than general inflation. Thus, assuming prices and costs will move equally from 1979 to whenever the gas is produced,

TABLE 3-7

VALUE OF NORTH SLOPE CRUDE ON GULF COAST REPLACING IRANIAN LIGHT, ARABIAN LIGHT, OR ISTHMUS

	Iranian Light or isthmus	Arabian Light
Crude laid-in to Gulf Coast	$23.25	$20.00
Less quality differential for North Slope	(.50)	(.50)
Equals value of North Slope crude on Gulf Coast	22.75	19.50
Less trans from Valdez to Gulf Coast	(3.00)	(3.00)
Equals value of North Slope crude at Valdez	$19.75	$16.50

Source: PIW (various issues); Platt's Oilgram) (various issues).

(1) Our economic analysis was conducted prior to the December, 1979, OPEC meeting in Venezuala which failed to reach agreement on oil prices and prior to the December pre-OPEC meeting price increases led by Saudi Arabia. Our Norton Basin oil and gas marketing study (Appendix F), which was conducted after completion of our economic analysis, provides more current information (January 1980) on OPEC oil pricing.

the 1979 price together with 1979 costs will allow a valid economic approximation of the requirements to produce gas in the Norton basin. Gs prices and the market ability of Norton Basin gas are discussed in detail in Appendix I. A major ongoing research effort is addressing this thorny question about Alaskan gas.[1] It is not at all clear that gas in Alaska can be transported at a cost of $3.00 to $5.00 MCF to lower 48 markets and compete with Canadian, Mexican, and U.S. natural gas in the late 1980's.

In view of the unresolved economic questions, no solid basis exists to net back to the Alaskan well-head a price based on market conditions. Thus we will adopt the regulated gas price as the mid-range value for the Monte Carlo calculation. Upper and lower values will be $2.30 and $3.25 MCF.

3.5.4.5 Effective Income Tax Rate and Royalty Rate

Federal taxes on corporate income now stand at 46 percent of taxable income. Dames & Moore assumes revenues from Norton Sound development would be incremental and taxable at 46 percent after the usual industry deductions indicated below. Tracts are in federal OCS. No state or local tax applies.

Royalty is assumed to be 16-2/3 percent of the value of production. In consultation with BLM economists (re: the Gulf of Alaska studies), their judgment was adopted that future royalty schemes would change little the outcome of this analysis.

3.5.4.6 Tax Credits Depreciation and Depletion

Investment tax credits of 10 percent apply to tangible investments. Depreciation is calculated by the units-of-production method. No depletion is allowed over the production life of the field.

(1) Tussing, Arlon and Connie Barlow. Three papers on the gas problems, published November 1978 through April 1979, for Legislative Affairs Agency.

3.5.4.7 Fraction of Investment as Intangible Costs

Dames & Moore assumes that expenses will be written off as intangible drilling costs to the maximum extent permissible by law. Fifty percent of investment totals are considered to be intangible expenses. Expenses incurred before production are carried forward until production begins and then expensed against revenue. The 50 percent fraction is consistent with an industry rule-of-thumb.

3.5.4.8 Investment Schedules

Continuous discounting of cash flow is assumed to begin when the first development investment is made. This assumes that time lags and costs for permits, etc., from the time of field discovery to initial development investment is expensed against corporate overhead. This is a critical assumption which has the effect of removing 12 to 24 months of discounting from the ultimate cash flow and making minimum field size calculated smaller than if the lags were included.

Typical investment schedules for the various production technologies identified in Section 3.4 are a function of the selected technological assumptions. These assumptions are discussed in Appendix B.

Both tangible and intangible investment costs will be entered into the model as lower, mid-range, and upper limits. The lower limit is derived from calculations and is estimated to be 75 percent of mid-range. The upper limit, also derived from calculations, is estimated to be 150 percent of the mid-range. The model yields a base case solution on the mid-range investment level along with the sensitivity tests at the upper and lower limits. In some cases, Monte Carlo analysis will also be used over these ranges of values.

3.5.4.9 Operating Costs

Annual operating costs are entered as follows:

	$ Millions 1979 Mid-Range Value
One Platform Field	40
Two Platform Field	80
Three Platform Field	115

A fixed annual operating cost based on the number of platforms required was determined by the study team to be a reasonable model of these costs given the uncertainties of the data base. In reality, operating costs will fluctuate during the life of the field. There are several other approaches to estimating or modeling operating costs such as costing by throughput or number of wells; for a discussion of these and problems related to modeling operating costs the reader is referred to a report by Gruy Federal, Inc., 1977.

4.0 SCENARIO DEVELOPMENT

4,1 Identification of Skeletal Scenarios and Selection of Detailed Scenarios

The cases that were screened in the economic analysis were selected as reasonably representative of':

(a) Probable production technologies n shallow water ice-infested environments.

(b) Field sizes likely to justify development within the resource levels defined by the U.S. Geological Survey.

(c) Probable reservoir characteristics (well productivity, depth, etc.).

(d) Anticipated ranges of water depths and distances to shore of possible oil and gas discoveries in Norton Sound.

The economic analysis, as discussed in Section 3.5, defines those field sizes, discovery locations, production systems, and reservoir conditions that are economically viable under the assumptions of the analysis.

Since there is still a considerable number of permutations of field size, production technologies and discovery situations (water depth, distance to shore, geographic location) which have been demonstrated to be economically viable, it is necessary to limit the number of possible developmental options at each level of resource discovery (high find, medium find, low find, no commercial resources) through application of some basic assumptions and determination of the key parameters governing potential impacts on the Alaskan economy and environment.

A three phased approach in the scenario development is conducted at this point in the study:

- A number of skeletal petroleum development scenarios are defined with various combinations of discovery location (water depth, distance to shore, etc.), production systems, field sizes and reservoir characteristics (depth, initial well productivity) which have been shown to be economic.

- The staff of the Bureau of Land Management, Alaska OCS Office selected from among the suggested skeletal scenarios one scenario to be detailed for each resource level.

- The equipment, materials, facilities, manpower and siting requirements, and scheduling of each selected scenario (high find, medium find, low find, no commercial resources found) were detailed to show the magnitude of impacts.

Tables 4-1 through 4-11 provide skeletal scenario options (cases) considered for selection by 5LM.

It is important to point out that the location, production and reservoir characteristics, field size, and infrastructure sharing arrangements associated with each of the scenarios are essential combinations to generate a rate of return sufficiently large to induce development. In other words, we recognize that the conditional probability of all of the characteristics that define the skeletal scenarios is somewhat low - lower, without doubt, than the U.S.G.S. estimates of "economically recoverable resources". However, if any of the characteristics are much changed from those described in the skeletal scenarios, the reserves quickly become uneconomic and undevelopable.

Since there is insufficient geologic data to identify the location, number, and reserve potential of prospects or structures, three geographically representative discovery locations in the Norton Sound area have been defined for scenario formulation:

- Inner Norton Sound (longitudes 162° W to 164° W).

- Central Norton Sound (longitudes 164° W to 166° W).

- Outer Norton Sound (west of longitude 166° W).

TABLE 4-1

HIGH FIND OIL MAXIMUM ONSHORE IMPACT

ield ize Oil MBBL	Locatior	Reservi Meter	Depth Feet	Product ion System	Pl atforms No. /Type*	Number of Production Wells	Initial Well Product ivity (B/D)	Peak' Product ion Oil (MB/D)	Water Meter	epth eet	ipeline [o Shore 1 ilometers	stance rminal m	Trunk ipel ine iameter inches) Oil	Shore Terminal Location
500	Inner Sound	2,286	7,500	Gravel island shared pipeline to shore terminal	2 G	80	2, 000	153.6	18	60	19	12	20	Cape Darby
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	40	25	20	Cape Darby
200	Inner Sound,	2,286	7,500	Gravel Island shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	40	25	20	Cape Darby
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 s	80	2,000	153.6	18	60	30	19	16-18	Cape Nome
200	Central Island	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	56	35	16-18	Cape Nome
750	Outer Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	3 S	120	2,000	230.4	30	100	129	80	20	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	30	100	140	87	20	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-2

HIGH FIND OIL MINIMUM ONSHORE IMPACT

Field Size Oil W	Location	Reservoir Meters	Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (We)	Peak Production Oil (MB/D)	Water Meters	Depth Feet	Pipeline to Shore Kilometers	Distance to Terminal lTill%-	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 s	80	2,000	153.6	18	60	30	19	20	Cape Nome
200	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	21	70	56	35	20	Cape Nome
200	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	16.8	24	80	56	35	20	Cape Nome
750	Outer Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	3 s	120	2,000	230.4	30	100	129	80	20-24	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	30	100	140	87	20-24	Cape Name
200	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	34	110	145	90	20-24	Cape Nome
500	Central Sound	2,286	7,500	Steel platforms with unshared pipeline to shore terminal	2 s	80	2,000	153.6	18	60	69	43	16	Cape Nome

* S = Ice reinforced steel platform.

Fields in same bracket share trunk pipeline.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-3

MEDIUM FIND OIL MAXIMUM ONSHORE IMPACT

Field Size Oil (MMBBL)	Location	Reservoir Depth Meter	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MBB/D)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	19	12	16	Cape Darby
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	40	25	16	Cape Darby
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 S	80	2,000	153.6	18	60	30	19	20	Cape Nome
250	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	56	35	20	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	30	100	93	58	20	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-4

MEDIUM FIND OIL MINIMUM ONSHORE IMPACT

Field Size Oil (MMBL)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No. / Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 S	80	2,000	153.6	18	60	30	19	24-30	Cape Nome
250	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	56	35	24-30	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	30	100	93	58	24-30	Cape Nome
200	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	24	80	56	35	24-30	Cape Nome
200	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	34	110	96	60	24-30	Cape Nome

* S = Ice reinforced steel platform.

Fields in same bracket share trunk pipeline.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-5

LOWFIND OIL SCENARIO MAXIMUM ONSHORE IMPACT

Field Size Oil (MMBBL	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No. /Type*	Number of Production Wells	Initial Well Productivity (B/D	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth Feet	Pipeline to Shore Kilometer	stance rminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
200	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8,	21	70	49	30	16	Cape Nome
180	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	72	45	16	Cape Nome

* S = Ice reinforced steel platform.

Fields in same bracket share trunk pipeline.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-6

LOW FIND OIL SCENARIO MINIMUM ONSHORE IMPACT

Field Size Oil (MMBBL)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
200	Central Sound	2,286	7,500	Gravel island with offshore processing, storage and loading	1 G	40	2,000	76.8	15	48	N/A	N/A	N/A	N/A
180	Central Sound	2,286	7,500	Gravel island with offshore processing, storage and loading	1 G	40	2,000	76.8	12	40	N/A	N/A	N/A	N/A

* G = Caisson retained gravel island.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specifie

Source: Dames & Moore

TABLE 4-7

HIGH FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Gas	LNG Plant
		Meters	Feet						Meters	Feet	Kilometers	Miles		
1,000	Central Sound	2,286	7,500	Steel platforms with shared pipeline to LNG plant	1 S	16	15	240	20	66	51	32	24-28	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	18	60	43	27	24-28	Cape Nome
1,200	Central Sound	2,286	7,500	Steel platform with unshared pipeline to LNG plant	1 S	16	15	240	20	66	54	33	20-24	Cape Nome

* S = Ice reinforced steel platform.

Fields in bracket share same trunk pipeline.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-8

MEDIUM FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Gas	LNG Plant
1,300	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1S	16	15	240	20	66	64	40	20-24	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1S	16	15	240	18	60	47	29	20-24	Cape Nome

* S = Ice reinforced steel platform.

Fields in bracket share same trunk pipeline.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-9

LOW FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Gas	LNG Plant
1,200	Central Sound	2,286	7,500	Single steel platform with unshared pipeline to LNG plant	1 S	16	15	240	16	54	34	21	16-18	Cape Nome

* S = Ice reinforced steel platform.

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 4-10

HIGH INTEREST LEASE SALE

YEAR AFTER LEASE SALE		
1	2	3
No. of Wells	No. of Wells	No. of Wells
4	6	4
TOTAL WELLS = 14		

Assumptions:

1. An average well completion rate of approximately 4 months.
2. An average total well depth of3,048 to 3,692 meters (10,000 to 13,000 feet).
3. Year after lease sale = 1983.
4. Rigs include jack ups and drill ships in summer and some gravel islands in shallow water.

Source: Dames & Moore

TABLE 4-11

LOW INTEREST LEASE SALE

YEAR AFTER LEASE SALE"		
1	2	3
No. of Wells	No. of Wells	No. of Wells
2	4	2
TOTAL WELLS = 8		

Assumptions:

1. An average well completion rate of approximately 4 months.
2. An average total well depth of 3,048 to 3.692 meters (10,000 to 13,000 feet).
3. Year after lease sale = 1983.
4. Ri js nclude jack ups and dri 1 ships in summer and some grave" is ands in sha ow water.

Source: Dames & Moore

The facility siting evaluation presented in Appendix D has identified five technically feasible sites for the location of a crude oil terminal and/or LNG plant:

- Cape Darby (Inner Sound).
- Cape Nome (Central Sound).
- Nome (Central Sound).
- Lost River (Outer Sound/Bering Sea).
- Northeast Cape, St. Lawrence Island (Outer Sound/Bering Sea.

Given the economics of pipelining and other factors, production from discoveries made east of longitude 167° W would probably be taken to onshore facilities located at one of the first three sites. Cape Nome appears to be the most suitable of these three sites.

The skeletal scenarios are based on the "unrisked" resource estimates presented in U.S. Geological Survey Open-File Report 79-720 (Fisher et al., 1979, p. 36). These are:

	Minimum	Mean	Maximum
Oil (millions of barrels)	360	1,400	2,600
Gas (billions of cubic feet)	1,200	2,300	3,200

For descriptive purposes, the scenarios corresponding to minimum, mean, and maximum resource estimates are termed "low find", "medium find", and "high find" respectively.

The skeletal scenario options are essentially based upon differences in discovery locations that would affect the amount of onshore construction and related impacts, in particular, the number and location of onshore terminals.

Some of the important conclusions of the economic analysis (see Appendix A) that have affected the specifications of the skeletal scenarios are:

- Shallow reservoirs (762 meters or 2,500 feet) would (under most assumptions of the analysis) be uneconomic to develop.

- Field development economics are relatively insensitive to water depth in Norton Sound.

- Reservoirs only capable of sustaining 1,000 b/d initial production rates per well would (undermost assumptions of the analysis) be uneconomic to develop.

- Fields that would have to support the total investment of a pipeline to shore (i.e. unshared) greater than 48 kilometers (30 miles) long would not earn a 15 percent hurdle rate; offshore loading may be a development strategy in these cases.

- Assuming a medium - deep oil reservoir (2286 meters) permitting 2000 b/d wells and a pipeline distance of 48 kilometers (30 miles) or less to a shore terminal, the minimum economic field size (assuming a 15 percent hurdle rate) in Norton Sound generally ranges between 200 and 250 million barrels.

- In shallow water (18 meters or less) gravel islands may be economically competitive with steel platforms assuming adjacent borrow materials and assuming that they are environmentally acceptable.

In all cases, the oil scenarios assume a medium to deep reservoir (2,286 meters or 7,500 feet), 2,000 b/d wells, and 60,000 bbl/acre recovery. Although 5,000 b/d wells were evaluated in the economic analysis and are more economic than 2,000 b/d or 1,000 b/d wells, 2,000 b/d wells were selected for the scenario since 1,000 b/d wells proved uneconomic and 2,000 b/d initial well productivity is geologically more realistic than 5,000 b/d.

For those oil fields with relatively short, shared pipelines (<48 kilometers or 30 miles), shallower reservoirs (1,525 meters or 5,000 feet) are generally economic although the number of platforms to drain a given field size would be double assuming the same recoverable reserves per acre. This substitution or variation is possible in the scenario specifications. Doing such has important socioeconomic implications in terms of employment generation.

A further variation can also be postulated in the skeletal scenarios as illustrated in the low find oil options. Some of the Norton reserves could be discovered in small, isolated fields, distant from suitable shore terminal sites; there are two areas where long offshore pipelines would be required -- the shallow waters west of the Yukon Delta and the western portion of the area of call midway between Cape York (Seward Peninsula) and St. Lawrence Island. In these locations, the development strategy of offshore loading may be the development option for isolated fields. It could also be postulated that certain portion of the high or medium find oil resources would be offshore loaded obviating the need for lengthy offshore pipelines and onshore terminals.

The skeletal scenario tables are introduced in the following paragraphs. Possible variations in scenario specifications are noted where applicable.

4.1.1 Oil Scenarios

High Find Maximum Onshore Impact (Table 4-1)

This skeletal scenario postulates that discoveries are made in three widely separated locations necessitating two crude oil terminals, one at Cape Darby and the other at Cape Nome. Three major trunk pipelines would be constructed. Gravel islands are assumed to be the development strategy for the fields near Cape Darby. Depending upon the order of discovery, production characteristics, hydrocarbon characteristics, unitization agreements, etc., a single crude oil terminal in the central and inner portion of Norton Sound is, however, more likely given possible pipeline distances and hydrographic conditions (there would be tanker size restrictions at Cape Darby).

In keeping with the concept of "maximum impact", this scenario could be modified so that the total resource is discovered in a larger number of fields that are more widely dispersed.

High Find Minimum Onshore Impact (Table 4-2)

This skeletal scenario assumes that only one crude oil terminal (at Cape Nome) is constructed to serve two "clusters" of fields, one located south of Nome and the other approximately 64 kilometers (40 miles) southwest of Cape Rodney. This scenario could be modified by assuming fewer fields closer together.

Medium Find Maximum Onshore Impact (Table 4-3)

As postulated in the high find scenario, maximum development would occur assuming widely scattered fields requiring two terminals. This option assumes two crude terminals - one at Cape Darby and the other at Cape Nome.

Medium Find Minimum Onshore Impact (Table 4-4)

This option, as with the high find minimum impact case, postulates construction of only one terminal at Cape Nome to serve two clusters of fields, one south of Nome - the other southwest of Cape Rodney, sharing a single trunk pipeline.

Low Find Maximum Onshore Impact (Table 4-5)

This scenario postulates two fields south of Nome sharing a single pipeline to a crude terminal at Cape Nome.

Low Find Minimum Onshore Impact (Table 4-6)

For some small fields isolated from other discoveries, and distant from suitable terminal sites, offshore loading of crude may be the more economic option obviating the need for a long offshore pipeline and shore terminal. This skeletal scenario postulates discovery of two small fields about. 120 kilometers (75 miles) south of Nome; caissonretained gravel islands are used as production platforms with one of the islands providing the storage and loading facilities.

4.1.2 Non-Associated Gas Scenarios (Tables 4-7, 4-8, and 4-9)

To be economically developable the postulated gas resources of Norton Sound would have to be found in a few large fields, generally one tcf reserves or greater. Furthermore, it is unlikely, given the gas resources estimated, that more than one LNG plant would be constructed. This restricts the developmental options that can be formulated. No skeletal scenario options were, therefore, proposed for gas. However, some variation in impact potential" is possible by assuming different discovery locations (the scenarios presented in Tables 4-7, 4-8, and 4-9 assume discoveries about 32 to 64 kilometers [20 to 40 miles] south of Nome). To be economic the fields should share pipelines if greater than 48 kilometers (30 miles) from shore.

4.1.3 Exploration Only

Two exploration scenario options are provided reflecting high industry interest (Table 4-10) and low industry interest (Table 4-11) in Sale 57.

4.1.4 Scenarios Selected for Detailing

The following skeletal scenarios were selected by BLM staff for detailing:

Oil

Table 4-1 High Find Oil -- Maximum Onshore Impact -- at the request of BLM staff, this scenario was modified by assuming that the Cape Darby fields would also produce to a Cape Nome crude terminal which is also an economic option under the assumptions of the analysis. In terms of impact assessment this modification restricts onshore development to a single crude oil terminal although increasing onshore pipeline construction through the requirement to build a 100-kilometer (62-mile) oil line between Cape Darby and Cape Nome.

Table 4-3 Medium Find Oil - Maximum Onshore Impact - as with the high find oil scenario, this scenario was selected with the same modification, i.e., Cape Darby fields producing through an onshore pipeline to a Cape Nome crude oil terminal.

Table 4-5 Low Find Oil - Maximum Onshore Impact - (selected without modification).

Non-associated Gas

Tables 4-7, 4-8 & 4-9 Non-associated gas scenarios, for which alternate development cases were not provided, were approved by BLM staff without modification.

Exploration Only

Table 4-11 Low interest lease sale.

4.2 Detailing of Scenarios

4.2.1 Introduction

The basic characteristics of the selected scenarios have already been defined in the skeletal scenarios (platform, pipeline and shore facility requirements, and general location). Detailing of the scenarios involves the following basic steps:

- Location of fields.
- Identification of an exploration and field discovery schedule.

- Specification of major facilities requirements and their siting.

- Formulation of field development (construction) and operation schedules.

- Translation of field development and operation schedules into employment estimates.

4.2.2 The Location of Fields

The first step in scenario detailing is the location of fields identified in the selection of the skeletal scenario (the general location of the field has already been defined by distance to terminal site, water depth, etc.). If possible, the field should be located on a known geologic structure of sufficient (apparent) size to accommodate the reserves within the range of recoverable reserves per acre assumed in the analysis. Further, the size and number of fields specified should be made to be consistent with estimated resources and the results of field size distribution analysis.

In this study, the geologic data is insufficient to locate structures, estimate percent fill-up, and conduct a field size distribution analysis. Therefore, the location of fields is arbitrary but designed to provide three geographically representative discovery locations for impact assessment. As noted above, these are:

- Inner Norton Sound (longitudes 162° W to 164° W).

- Central Norton Sound (longitudes 164° W to 166° W).

- Outer Norton Sound (west of longitude 166° W).

4.2.3 Exploration and Field Discovery Schedules

The exploration and field discovery schedules forming the basis of the scenario descriptions were formulated to be consistent with the following considerations:

- An exploratory effort consistent with the postulated resources at an assumed rate of discovery which has been sustained historically in some other offshore areas (a high discovery ratio is assumed for the high find scenario and more modest success ratio for the medium and low find scenarios).

- An exploration pattern that builds up to a peak and then declines as prospects become fewer and more difficult to find and as petroleum company resources shift from exploration to field development investment.

- The larger fields are in general discovered and developed first.

- Most of the discoveries are made within five years of the lease sale (i.e. the initial tenure of the leases).

- Although availability of exploration rigs at the time of the lease sale cannot be predicted, the number of drill rigs and exploration well scheduling has been tailored to discover most, if not all, of the postulated resources within the five year tenure of the leases.

As explained in Appendix B, once a discovery has been made two or three delineation wells are assumed to be drilled and the decision to develop is assumed to be made 18 to 24 months after discovery. Significant investment in field development is assumed to commence the year following the decision to develop. Implicit in this schedule is some delay related environmental regulation. The first year of significant investment in field development is the year in which contracts are placed for platforms, process equipment,. etc.; this is year 1 of the investment schedule as used in the economic analysis (see Appendix B).

4.2.4 Major Facilities and Their Siting

The major shore facility requirements of Norton Sound petroleum development to a large degree will depend upon the production options discussed in Section 3.4 and the assumed location and distribution of fields. In this study, a facilities siting analysis (see Appendix D) is conducted concurrently with the petroleum technology review (Appendix C) to assess the field development and transportation options for economic analysis and scenario specification. For each representative discovery location, technically and economically feasible crude oil terminal and LNG plant sites are identified.

4.2.5 Field Development and Operation Scheduling

Once discovery and decision-to-develop dates have been established, field development schedules are defined for each scenario based on the assumptions explained in Appendix B; these are consistent with schedules in other offshore areas modified for the environmental constraints peculiar to Norton Sound. Schedules for each scenario are shown on a series of tables showing the timing of platform installation and commissioning, development well drilling, major facilities construction, pipelaying, etc. For each field, a production schedule is identified based on the production timing and production decline rates defined in Appendix A. These provide information on production start-up and field life necessary to determine the timing of facilities construction (marine terminals, pipelines, etc.) and the operational life of the field. Each of the construction and production schedule tables presented in Chapters 6.0, 7.0, and 8.0 for the high, medium, and low find scenarios is compiled in sequence; the tables are interrelated such that a change in one assumption or specification affects the others.

4.2.6 Translation of Field Development and Operation Schedules Into Employment Estimates

The field development and operation tables developed for scenario detailing, supplemented by information on the size of facilities (e.g. marine terminal capacity in barrels per day) or location of construction work (e.g. water depth of pipelaying), form the basis for estimating scenario employment.

The components of the construction and operation schedule are broken down into a number of employment tasks (development drilling, platform installation and commissioning, terminal and pipeline operations, etc.) of specified durations. Using a computer program specifically developed for this series of scenario studies, the scenario employment calculations 'are made. The methodology and assumptions of this OCS manpower model are explained in Appendix E. The reader is also referred to a worked example of these computations in a companion report of the Alaska OCS Socioeconomic Studies Program (Northern Gulf of Alaska Petroelum Development Scenarios, Appendix D, Dames & Moore, 1979a),

5.0 EXPLORATION ONLY SCENARIO

5.1 General Description

The exploration only scenario assumes that no commercial oil and/or gas resources are discovered. Industry interest is low and principally centered in central Norton Sound. A low level of exploration with only eight wells drilled over a period of three years characterizes the exploration program (Table 5-1).

Exploration is conducted principally in the four month summer open-water season using jack ups augmented by drillships in the deeper water of the outer sound (the waters of most of Norton Sound are too shallow to use semi-submersible rigs). Two of the wells located in the shallow water (less than 18 meters [60 feet]) are drilled with conventional rigs from summer-constructed gravel islands.

5.2 Tracts and Location

No tracts are specified in this scenario. The total of wells drilled (eight) indicates that eight of the leased tracts are drilled (the assumption has been made that no more than one well is drilled per tract). Several of the larger structures are explored with more than one. well, thus the total number of prospects examined is somewhat less than the total number of wells drilled.

5.3 Exploration Schedule

The exploration schedule, presented in Table 5-1, shows that exploration commences in the first year after the lease sale, peaks in the second year, and terminates in the third year after discouraging results.

5.4 Facility Requirements and Locations

Exploration in Norton Sound will be conducted by a combination of jack up rigs, drillships, and a few gravel islands in shallower water (if environ-

TABLE 5-1

EXPLORATION ONLY SCENARIO - LOW INTEREST LEASE SALE

YEAR AFTER LEASE SALE					
1		2		3	
Rigs	Wells	Rigs	Wells	Rigs	Wells
2	2	3C 1G	4	1C 1G	2
TOTAL WELLS = 8					

C = Conventional rigs (jack ups or drillships)
G = Gravel island

Assumptions:

1. An average well completion rate of approximately 4 months.
2. An average total well depth of 3,048" to 3,692 meters (10,000 to 13,000 feet).
3. Year after lease sale = 1983.
4. Rigs include jack ups and drillships in summer and some summer-constructed gravel islands in shallow water.

Source: Dames & Moore

mentally acceptable and if adjacent borrow materials are available). Exploration support will be a problem in Norton Sound due to geographic isolation, the lack of local infrastructure, including ports, and potential port sites. Significant investments would be required to provide port facilities even for supply boats. Because of these problems, this scenario postulates that Nome would be a forward support base for air-shipped light supplies and personnel shipment. Heavy supplies (mud, cement casing, etc.) are assumed to be stored on location in freighters or barges moored in Norton Sound with transshipment to rigs provided by supply boats. In addition, a rear support base providing storage and shipment for heavy supplies is assumed to be located in the Aleutian Islands.

5.5 Manpower Requirements

The manpower requirements associated with the exploration program are presented in Tables 5-2 through 5-5.

5.6 Environmental Considerations

With the low drilling activities anticipated in this scenario, vessel and aircraft traffic will be the principal source of environmental impact. Two areas are particularly susceptible to traffic disturbance. On the western margin of Norton Sound exploratory activities are likely to disturb aggregations of seals and walrus, especially in early spring (April) when reproductive activity occurs and navigable routes will be limited. Precautions to avoid areas frequented by pregnant or nursing females should be taken. Sledge Island, a federal marine resource withdrawal area and site of established seabird colonies, should also be avoided in routing of vessels and aircraft. The inner islands of Norton Sound (Besboro, Stuart, and Egg Islands) are also 'sensitive seabird areas.

Construction of shallow-water gravel islands may potentially harm fishery resources in the Nome area. Hydrographic surveys of the well site should precede island construction to determine the extent and direction of turbidity increases.

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TABLE 5-2

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	498.	52.	0.	0.	208.	511.	11.	766.	108.	814.
2	598.	104.	400.	30.	416.	112.	0.	1812.	246.	2058.
3	498.	52.	400.	30.	208.	56.	0.	11060	138.	1244.

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TABLE 5-3

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0.	0.	164.	138.	26.	10.	338.	6	365.
2	0.	0.	0.	0.	0.	389.	238.	43.	12.	682.	6	682.
3	0.	0.	0.	0.	0.	364.	238.	41.	12.	655.	6	682.

EXPLORATION ONLY
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TABLE 5-4

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
	ONSITE	[illegible]	40.	0.	0.	0.	0.	0.	0.	0.	0.	50.	448.	0.	0.	0.	208.
	OFFSITE	[illegible]	40.	0.	0.	0.	0.	0.	0.	0.	0.	0.	448.	0.	0.	0.	104.
2	ONSITE	1[illegible].	80.	0.	0.	0.	0.	0.	0.	0.	0.	100.	896.	0.	400.	0"	416.
	OFFSITE	3.	[illegible]	0.	0.	0.	0.	0.	0.	0.	0.	0.	896.	0.	200.		208.
3	ONSITE	9[illegible].	40.	0.	0.	0.	0.	0.	0.	0.	0.	50.	448.	0.	400.	0. 0.	208.
	OFFSITE	3.	40.	0.	0.	0.	0.	0.	0.	0.	0.	0.	448.	0.	200.	0.	104.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 5-4 (Attachment)

LIST OF TASKS BY ACTIVITY

ONSHORE

Activity

1 Service Bases (Onshore Employment - which would include all onshore administration, service base operations, rig and platform service
- Task 1 - Exploration Well Drilling
- Task 2 - Geophysical Exploration
- Task 5 - Supply/Anchor Boats for Rigs
- Task 6 - Development Drilling
- Task 7 - Steel Jacket Installations and Commissioning
- Task 8 - Concrete Installations and Commissioning
- Task 11 - Single-Leg Mooring System
- Task 12- Pipeline-Offshore, Gathering, Oil and Gas
- Task 13 - Pipeline-Offshore, Trunk, Oil and Gas
- Task 20- Gravel Island Construction
- Task 23- Supply/Anchor Boats for Platform
- Task 24- Supply/Anchor Boats for Lay Barge
- Task 27 - Longshoring for Platform
- Task 28- Longshoring for Lay Barge
- Task 31 - Platform Operation
- Task 33- Maintenance and Repairs for Platform and Supply Boats
- Task 37 - Longshoring for Platform (Production)
- Task 301 - Gravel Island Construction

2 Helicopter Service
- Task 4 - Helicopter for Rigs
- Task 21 - Helicopter Support for Platform
- Task 22 - Helicopter Support for Lay Barge
- Task 34- Helicopter for Platform

Construction

3 Service Base
- Task 3 - Shore Base Construction
- Task 10- Shore Base Construction

4 Pipe Coating
- Task 15 - Pipe Coating

5 Onshore Pipelines
- Task 14 - Pipeline, .Onshore, Trunk, Oil and Gas

6 Terminal
- Task 16 - Marine Terminal (assumed to be oil terminal)
- Task 18 - Crude Oil Pump Station Onshore

7 LNG Plant
- Task 17 - LNG Plant

8 Concrete Platform Construction
- Task 19 - Concrete Platform Site Preparation
- Task 20 - Concrete Platform Construction

9 Oil Terminal Operations
- Task 36 - Terminal and Pipeline Operations

10 LNG Plant Operations
- Task 38 - LNG Operations

OFFSHORE

Activity

11 Survey
- Task 2 - Geophysical and Geological Survey

12 Rigs
- Task 1 - Exploration Well

13 Platforms
- Task 6 - Development Drilling
- Task 31 - Operations
- Task 32 - Workover and Well Stimulation

14 Platform Installation
- Task 7 - Steel Jacket Installation and Commissioning
- Task 8 - Concrete Installation and Commissioning
- Task 11 - Single-Leg Mooring System
- Task 20 - Gravel Island construction
- Task 301 - Gravel Island Construction

15 Offshore Pipeline Construction
- Task 12 - Pipeline Offshore, Gathering, Oil and Gas
- Task 13 - Pipeline Offshore, Trunk, Oil and Gas

16 Supply/Anchor/Tug Boat
- Task 5 - Supply/Anchor Boats for Rigs
- Task 23 - Supply/Anchor Boats for platform
- Task 24 Supply/Anchor Boats for Lay Barge
- Task 25 - Tugboats for Installation and Towout
- Task 26 - Tugboats for Lay Barge Spread
- Task 29 - Tugboats for SLMS
- Task 30 - Supply Boat for SLMS
- Task 35 - Supply Boat for SLMS

EXPLORATION ONLY
09/23/79

TABLE 5-5

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	ONSHORE	TOTAL
1	706.	108.	814.	1258.	148.	1406.	105.	13.	118.
2	1812.	246.	2058.	3116.	329.	3445.	260.	28.	288.
3	1106.	138.	1244.	1858.	181.	2039.	155.	16.	.70

** TOTAL INCLUDES ONSITE AND OFFS TE

6.0 HIGH FIND SCENARIO

6.1 General Description

The high find scenario assumes significant commercial discoveries of oil and gas. The basic characteristics of the scenario are summarized in Tables 6-1 and 6-2. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
2,600	.3,200

These resources are distributed in three "clusters" of fields located respectively in inner Norton Sound south of Cape Darby, central Norton Sound south of Nome, and outer Norton Sound about 64 kilometers (40 miles) southwest of Cape Rodney (Figures 6-1 and 6-2).

All oil and gas production is brought to shore by pipeline to a large crude oil terminal and LNG plant located at Cape Nome. Production from the central Norton Sound fields involves a direct offshore pipeline to Cape Nome while production from the outer and inner Norton Sound fields involves a significant onshore pipeline segment.

6.2 Tracts and Location

The discovery tracts and their locations (designated by OCS protraction diagram numbers) are given in Table 6-3. The productive acreage cited relates to the optimal recoverable reserves per acre assumed for the scenario analysis.

6.3 Exploration, Development, and Production Schedules

Exploration, development, and production schedules are shown on Tables 6-4 through 6-14. The assumptions on which these schedules are based are given in Appendix B and E.

TABLE 6-1

HIGH FIND OIL SCENARIO

Field Size Oil MMBBL	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No. /Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meter	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
500	Inner Sound	2,286	7,500	Gravel island shared pipeline to shore terminal	2 G	80	2,000	153.6	18	60	133	83	20	Cape Nome
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	146	91	20	Cape Nome
200	Inner Sound	2,286	7,500	Gravel Island shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	150	93	20	Cape Nome
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 S	80	2,000	153.6	18	60	34	21	16-18	Cape Nome
200	Central Island	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	58	36	16-18	Cape Nome
750	Outer Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	3 S	120	2,000	230.4	30	100	129	80	20	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	30	100	140	87	20	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 6-2

HIGH FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Gas	LNG Plant
1,000	Central Sound	2,286	7,500	Steel platforms with shared pipeline to LNG plant	1 S	16	15	240	20	66	51	32	24-28	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	18	60	43	2?	24-28	Cape Nome
1,200	Central Sound	2,286	7,500	Steel platform with unshared pipeline to LNG plant	1 S	16	15	240	20	66	51	32	20-24	Cape Nome

* S = Ice reinforced steel platform.

Fields in bracket share same trunk pipeline.

Source: Dames & Moore

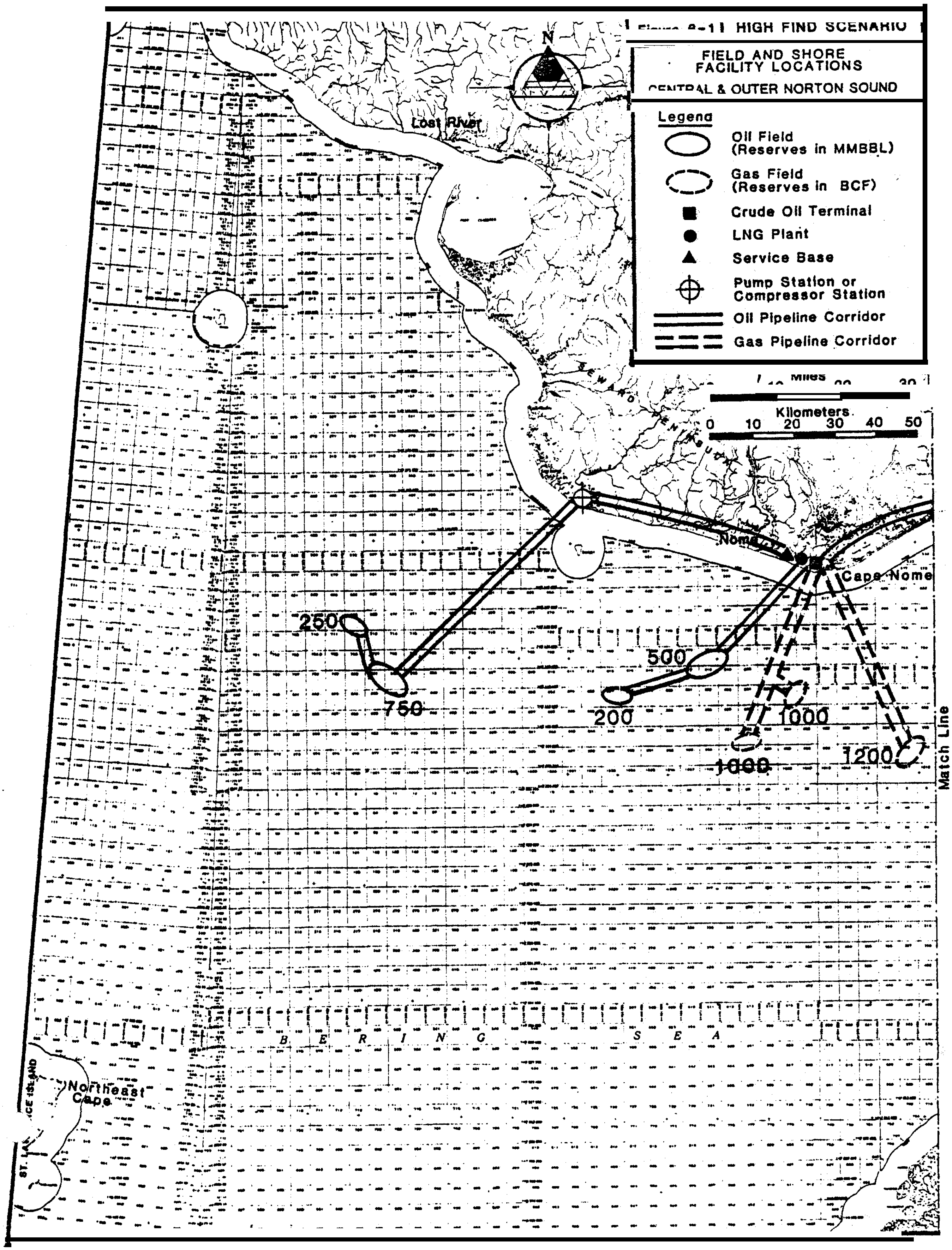

Figure 8-11 HIGH FIND SCENARIO
FIELD AND SHORE FACILITY LOCATIONS
CENTRAL & OUTER NORTON SOUND
Legend
Oil Field (Reserves in MMBBL)
Gas Field (Reserves in BCF)
Crude Oil Terminal
LNG Plant
Service Base
Pump Station or Compressor Station
Oil Pipeline Corridor
Gas Pipeline Corridor
Miles
Kilometers
0 10 20 30 40 50
N
Lost River
SEWARD PENINSULA
Nome
Cape Nome
250
750
500
200
1000
1000
1200
B E R I N G S E A
Northeast Cape
ST. LAWRENCE ISLAND
Match Line

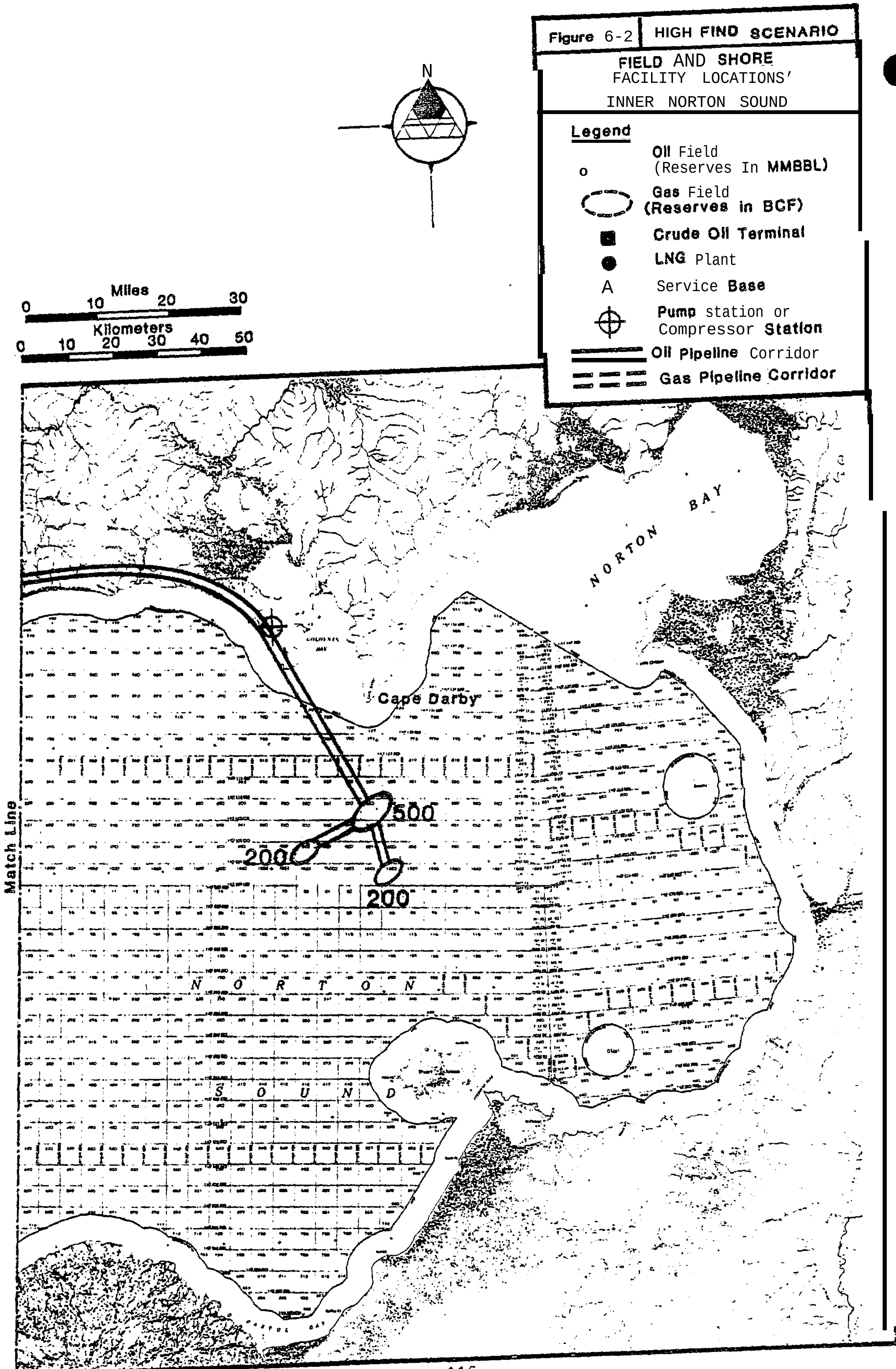

Figure 6-2 HIGH FIND SCENARIO
FIELD AND SHORE FACILITY LOCATIONS'
INNER NORTON SOUND

TABLE 6-3

HIGH FIND SCENARIO - FIELDS AND TRACTS

Location	Field Size		Acres[1]	Hectares	No. of Tracts[2]	OCS Tract Numbers[3]
	Oil (mmbbl)	Gas (bcf)				
Inner Sound	500	--	8,333	3,373	1.5	902, 903, 904, 946, 947
Inner Sound	200	--	3,333	1,349	0.6	967, 968
Inner Sound	200	--	3,333	1,349	0.6	1035, 1036
Central Sound	500	--	8,333	3,373	1.5	773, 774, 775, 817, 818
Central Sound	200	--	3,333	1,349	0.6	857, 858
Outer Sound	750	--	12,500	5,059	2.2	756, 757, 800, 801, 802, 845, 816
Outer Sound	250	--	4,167	1,686	0.7	667, 668, 712, 713
Central Sound	--	1,000	4,000	1,618	0.7	951, 952, 953, 995, 996
Central Sound	--	1,200	3,333	1,349	0.6	823, 866, 867
Central Sound	--	1,000	4,000	1,618	0.7	973, 974

[1] Recoverable reserves in the scenario are assumed to be 60,000 barrels per acre for oil and 300 mmcf for non-associated gas.

[2] A tract is 2,304 hectares (5,693 acres).

[3] Tracts listed include all tracts that are involved in the surface expression of an oil or gas field. In some cases only portions (a corner, etc.) of a tract are involved. However, the entire tract is listed above. (See Figures 6-1 and 6-2 for exact tract location and portion involved in surface expression of fields.)

Source: Dames & Moore

TABLE 6-4

EXPLORATION SCHEDULE FOR EXPLORATION AND DELINEATION WELLS - HIGH FIND SCENARIO

Well Type	Year After Lease Sale																				Well Totals
	1		2		3		4		5				7		8		9		10		
	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	
Exp.[1]		6		9		12		12		12		10		6							67
	3		6		9		10		7		6		4								
Del.[2]			2	3	2	7	2	8	2	2	2	2	2	2							24
TOTAL		6		12		19		20		14		12		8							91

[1] In this high find scenario a success rate of one significant discovery for approximately every seven expiration wells is assumed. This is somewhat higher than the average of 10 percent success rate in U.S. offshore areas in the past 10 years and significantly higher than the average of the past five years (Tucker, 1978).

[2] The number of delineation wells assumed per discovery is two field sizes of less than 500 mmbbl oil or 2,000 bcf gas, and three for fields of 500 mmbbl oil and 2,000 bcf gas and larger.

[3] An average completion time of four months per exploration/delineation well is assumed. The drilling season is assumed to be extended to a maximum of eight months by ice breaker support. In addition, the limited use of summer-constructed gravel islands to extend drilling into the winter is also postulated.

Source: Dames & Moore

TABLE 6-5

TIMING OF DISCOVERIES - HIGH FIND SCENARIO

Year After Lease Sale	Type	Reserve Size		Location	Water pth	
		Oil (mmbbl)[1]	Gas (bcf)		Meters	Feet
1	Oil	500	--	Central Sound	18	60
2	Oil	750	--	Outer Sound	30	100
2	Gas	--	1,000	Central Sound	20	66
2	Oil	200	--	Central Sound	21	70
3	Oil	250	--	Outer Sound	30	100
3	Gas	--	1,000	Central Sound	18	60
3	Oil	500	--	Inner Sound	18	60
4	Oil	200	--	Inner Sound	18	60
5	Gas	--	1,200	Central Sound	20	66
6	Oil	200	--	Inner Sound	18	60

[1] Assumes field has low GOR and associated gas is used to power-platform and reinfected.

Source: Dames & Moore

TABLE 6-6

PLATFORM CONSTRUCTION ANO INSTALLATION SCHEDULE - **HIGH** FIND SCENARIO

Location	Field		Year After Lease Sale											
	011 (MMBBL)	Gas (BCF)	1	2	3	4					9	10	11	12
Inner Sound	500	--			*		D	ΔG	ΔG					
Inner Sound	200	. .				*		D	ΔG					
Inner Sound	200	--						*		D	ΔG			
Central Sound	500	--	*		D		ΔS	ΔS						
Central Sound	200	--		*		D		ΔS						
Outer Sound	750	--		*		D		ΔS	As	ΔS				
Outer Sound	250	_-			*		D		ΔS					
Central Sound	--	1,000		*		D		ΔS						
Central Sound	--	1,000			*		C1		ΔS					
Central Sound	--	1 ,200					*		D		ΔS			

*= Discovery; D = Decision to Develop; ΔS = Steel Platform; ΔG = Gravel Island

Notes:

1. Steel platform installation is assumed to begin in June in each case; gravel island construction starts the year after decision to develop and takes two summer seasons.
2. Platform "installation" includes module lifting, hook-up, and commissioning.

Source: Dames & Moore

TABLE 6-7

DEVELOPMENT HELL DRILLING SCHEDULE - HIGH FIND SCENARIO

Location	Field Oil MMBBL	Field Gas (BCF)	Platforms Nos.	Platforms Type[1]	No.[2] of Drill Rigs Per Platform	Total No. of Production Wells	Other Wells[4]	Start of Drilling[3] Month	Year After Lease Sale - No. of Wells: 1	2	3	4		5	7	11	9	10	11	12	13		15	16	17
Inner Sound	500	--	2	G	2	40	8	April 1						ΔG		12	16P	16	4						
				G	2	40	8	April 1							ΔG		12	16P	16	4			W		
Inner Sound	200	--	1	G	2	40	8	April							ΔG		12	16P	16	4			W		
Inner Sound	200	--	1	G	2	40	8	April 1									G		12	16P	16				W
Central Sound	500	--	2	S	2	40	8	April 1					ΔS	12	16P	16	4			W					
				S	2	40	8	April 1						ΔS	12	16P	16	4			W				
Central Sound	200	--	1	S	2	40	8	April 1						ΔS	12	16P	16	4			W				
Outer Sound	750	--	3	S	2	40	8	April 1						ΔS	12	16P	16	4			W				
				S	2	40	8	April 1							ΔS	12	16P	16	4						
				S	2	40	8	April 1								ΔS	12	16P	16	4			W		
Outer Sound	250	--	1	S	2	40	8	April 1							S	12	16P	16	4						
Central Sound	--	1,000	1	S	1	16		April 1						ΔS	6P	6	2								
Central Sound	--	1,000	1	S	1	16		April 1							ΔS	6P	8	2							
Central Sound	--	1,200	1	S	1	16		April 1									ΔS	6P	8	2					
TOTALS														12	58	120	154	118	G -	30	16				

[1] S = Steel; G = Gravel

[2] Platforms sized for 40 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 40 well slots are assumed to have one drill rig operating during development drilling.

[3] Drilling progress is assumed to be 45 days per well.

[4] Gas or water injection wells etc., well allowances assumed to one well for every five oil production wells.

ΔS = Platform arrives on site -- assumed to be June; platform installation and commissioning assumed to take 10 months.

ΔG = Gravel island construction starts June 1 the year after decision to develop and take two summer seasons.

W = Work over commences -- assumed to be five years after beginning of production from platform.

P = Production starts; assumed to occur when first 10 oil wells are completed or first four 9as wells.

Source: Dames & Moore

TABLE 6-8

EXPLORATION AND PRODUCTION GRAVEL ISLANDS -
HIGH FIND SCENARIO

Year After Lease Sale	Exploration 7.5 m (25 ft)	m (50 ft)	Production	Total	Number of Construction Spreads
1					
2	1			1	1
3	1			1	1
4		1		1	2
5		1		1	2
6		1	1	2	2
7		1	2	3	3
8					
9			1	1	1
10					
TOTALS	2	4	4	10	N/A

Note: Arrows show exploration islands expanded and modified for production.

TABLE 6-9

PIPELINE CONSTRUCTION SCHEDULE - HIGH FIND SCENARIO - KilometerS (MILES) CONSTRUCTED BY YEAR

	Pipeline Diameter (inches)		Water Depth		Year After Lease Sale										
	Oil	Gas	Meters	Feet	1	2	3	4	5	6	7	8	9	10	11
Offshore	18		0-18	0-60								34 (21)			
	12		18	60									13 (8)		
	12		0-18	0-60											16 (10)
	16		18	0-60						30 (19)					
	12		18	60							24 (15)				
	18		0-30	0-100							64 (40)				
	12		30	100								11 (7)			
		24	0-30	0-60						48 (30)					
		16	18	60							10 (6)				
		24	0-30	0-60									48 (30)		
	Subtotal									78 (49)	98 (61)	44 (28)	61 (38)		16 (10)
Onshore	18											100 (62)			
	16									3 (2)					
	18										64 (40)				
		24								3 (2)					
		24											3 (2)		
	Subtotal									6 (4)	64 (40)	100 (62)	3 (2)		
Total										84 (53)	162 (101)	144 (90)	64 (40)		16 (10)

Source: Dames & Moore

TABLE 6-10

MAJOR FACILITIES CONSTRUCTION SCHEDULE - HIGH FIND SCENARIO

Facility [a]/Location	Peak Throughput Oil (MBD)	Peak Throughput Gas (MMCFD)	Year After Lease Sale 1	2	3	4	5	6	7	8	9	10	11	12
Cape Nome Oil Terminal	765	--				←	—	—						
Cape Nome LNG Plant	--	691				←	—	→						
Cape Nome Support Base (permanent)	(large)					←	→							

[a] Assume construction starts in spring of year indicated.

Source: Dames & Moore

TABLE 6-11

FIELD PRODUCTION SCHEDULE - HIGH FINO SCENARIO

Location	Field Oil (MMBBL)	Field Gas (BCF)	Peak Production Oil (MBD)	Peak Production Gas (MMCFD)	Years After Lease Sale: Production Start Up	Years After Lease Sale: Production Shut Down	Years After Lease Sale: Peak Production	Years of Production[1]
Inner Sound	500	--	153.6	--	9	28	12-13	20
Inner Sound	200	--	76.8	--	10	29	13	20
Inner Sound	200	--	76.8	--	12	31	15	20
Central Sound	500	--	153.6	--	7	26	10-11	20
Central Sound	200	--	76.8	--	8	27	11	20
Outer Sound	750	--	230.4	--	8	34	12-13	27
Outer Sound	250		16.8	--	9	22	11-13	14
Central Sound	--	1,000	--	230.4	7	26	10-16	20
Central Sound	--	1,000	--	230.4	8	26	11-17	20
Central Sound	--	1,200	--	230.4	10	34	13-21	25

[1] Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms.

Source: Dames & Moore

TABLE 6-12

HIGH FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL) Inner Sound 500	Inner Sound 200	Inner Sound 200	Central Sound 500	Central Sound 200	Outer Sound 750	Outer Sound 250	Totals
1983	1								
1984	2								
1985	3								
1986	4								
1987	5								
1988	6								
1989	7				7.008				7.008
1990	8				24.528	7.008	7.008		38.544
1991	9	7.008			45.552	14.016	24.528	7.008	98.088
1992	10	24.528	7.008		56.064	21.024	52.560	17.520	178.704
1993	11	45.552	14.016		56.064	28.032	73.584	28 .032	245.280
1994	12	56.064	21.024	7.008	54.005	27.050	84.096	28.032	277.279
1995	13	56.064	28.032	14.016	46.354	22.401	84.096	28.032	278.995
1996	14	54.005	27.050	21.024	38.598	17.432	76.708	W .982	262.799
1997	15	46.354	22.401	28.032	32.168	13.897	62.453	24.906	230.211
1998	16	38.598	17.432	27.050	26.840	11.000	51.293	20.647	192.860
1999	17	32.168	13.897	22.401	22.420	8.886	40.869	17.116	157.757
2000	18	26.840	11.000	17.432	18.757	6.835	33.885	14.187	128.936
2001	19	22.420	8.886	13.897	15.221	5.250	28.094	11.763	105.531
2002	20	18.757	6.835	11.000	12.703	4.154	23.293	9.751	86.493
2003	21	15.221	5.250	8.886	10.616	3.286	19.312	8.084	70.655
2004	22	12.703	4.154	6.835	8.886	2.600	16.012	6.701	57.891
2005	23	10.616	3.286	5.260	7.452	2.057	13.274		41.935
2006	24	8.886	2.600	4.154	6.263	1.628	11.007		34.538
2007	25	7.452	2.057	3.286	5.328	1.288	9.126		28.537
2008	26	6.263	1.628	2.600	4.417	1.019	7.566		23.493
2009	27	5.328	1.288	2.057		0.837	7.088		16.598
2010	28	4.417	1.019	1.628			5.876		12.940
2011	29		0.837	1.288			4.872		6.997
2012	30			1.019			4.040		5.059
2013	31			0.837			3.349 "		4.186
2014	32						2.776		2.776
2015	33						2.302		2.302
2016	34						1.909		1.909

Peak 0{ 1 Product ion = 764,400 b/d.

Source: Dames & Moore

TABLE 6-13

HIGH FIND SCENAR [0 PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - NON-ASSOCIATED GAS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound 1000	000	1200	Totals
1983	1				
1984	2				
1985	3				
1986	4				
1987	5				
1988	6				
1989	7	21.024			21.024
1990	8	42.048	21.024		63.072
1991	9	63.072	42.048		105.120
1992	10	84.096	63.072	21.024	168.192
1993	11	84,096	84.096	42.048	210.240
1994	12	84.096	84.096	63.072	231.264
1995	13	84.096	84.096	84.096	252.288
1996	14	84.096	84.096	84.096	252.288
1997	15	84.096	84.096	84.096	252.288
1998	16	84.096	84.096	84.096	252.288
1999	17	72.423	84.096	84.096	240.615
2000	18	54.122	72.423	84.096	210.641
2001	19	40.521	54.122	84.096	178.739
2002	20	30.310	40.521	84.096	154.927
2003	21	22.672	30.310	84.096	137.078
2004	22	16.958	22.672	69.600	109.23
2005	23	12.685	16.958	54.680	84.323
2006	24	9.788	12.685	42.933	65.106
2007	25	7.097	9.488	33.710	50.295
2008	26	5.309	7.097	26.468	38.874
2009	27		5.309	20.782	26.091
2010	28			16.317	16.317
2011	29			12.812	12.812
2012	30			10.059	10.059
2013	31			7.888	7.888
2014	32			6.193	6.193
2015	33			4.862	4.862
2016	34			3.817	3.817
2017	35				

Peak Gas Production =691,200 mmcfd.

Source: Dames & Moore

TABLE 6-14

MAJOR SHORE FACILITIES START UP AND SHUT DOWN DATES - HIGH FIND SCENARIO

Facility	Year After Lease Sale	
	Start Up Date[1]	Shut Down Date[2]
Cape Nome Oil Terminal	7	34
Cape Nome LNG Plant	7	34

[1] For the purposes of manpower estimat· on start up is assumed to be January 1.
[2] For the purposes of manpower estimat· on shut down is to be December 31.

Source: Dames & Moore

Exploration commences in the first year after the lease sale (1983), peaks in year4 with 20 wells drilled, and terminates in the seventh year with a total of 90 wells drilled (Table 6-4). Ten commercial discoveries are made (seven oil, three non-associated gas) over a six-year period (Table 6-5). The exploration program involves jack-up rigs and drillships (in the outer sound) and limited use of summer-constructed gravel islands in shallow water (15 meters [50 feet] or less) where suitable borrow materials are either adjacent to the well site or within economic haul distance. Economics dictate extension of the drilling season from the four to six month open-water season to a maximum of eight months; this is accomplished by the use of ice-breaker support.

Field construction commences in year 4 after the decision to develop the first discovery (a 500 mmbbl oil field in central Norton Sound) and the first platform is installed in the summer of year 5 (Table 6-6). Development drilling commences the following year and the first oil production is brought to shore in year 7 (1989). The last platforms (a gravel island in inner Norton Sound and a steel gas platform in central Norton Sound) are installed in year 9.

Oil production from Norton Sound commences in year 7 (1989) after the lease sale, peaks at 764,000 b/d in year 13 (1995), and ceases in year 34 (2016) (Tables 6-11 and 6-12). Gas production also commences in year 7 (1989), peaks at 691,200 mmcfd in years 13 through 16 (1995 through 1998), and ceases in year 34 (2016) (Tables 6-10 and 6-13).

6.4 Facility Requirements and Locations

Facility requirements (platforms, pipelines, terminals, etc.) and related construction scheduling are summarized in Tables 6-6 through 6-10. This scenario assumes that all oil and gas production is brought to shore to a single crude oil terminal and LNG plant, respectively, both located at Cape Nome.

The major facility constructed is a crude oil terminal located at Cape Nome. The terminal is designed to handle the estimated peak production of about

750,000 bpd from the three "clusters" of fields. The terminal completes crude stabilization, recovers LPG, treats tanker ballast water, and provides storage for about 10 million barrels of crude (approximately 14 days production). Terminal configuration includes buried pipelines to a two-berth loading platform located approximately four kilometers (2.5 miles) offshore. These berths are designed to handle 70,000 to 120,000 DWT tankers that transport crude to the U.S. west coast. The tankers are conventional tankers reinforced for Bering Sea ice; ice-breaker support for these tankers is required.

The other major facility, also located at Cape Nome, is a LNG plant designed to handle the estimated peak gas production of nearly 700 million cubic feet per day. The LNG plant is a modularized barged-in facility and has a single berth loading platform designed to handle 130,000m^3 LNG tankers. A fleet of three tankers transports the LNG to the U.S. west coast. With a loading frequency of six to seven days, storage capacity for about ten days of LNG production is provided at the plant.

A forward service base supporting construction and operation of the Norton Sound fields is constructed adjacent to the Cape Nome facilities. Field construction is also supported by storage and accommodation barges and freighters, moored in Norton Sound, and a rear support base located in the Aleutian Islands.

The exploration phase of petroleum development in Norton Sound involves aerial support and light supply transshipment provided by Nome, storage barges and freighters moored in Norton Sound, and an Aleutian Island storage and transshipment facility,

6.5 Manpower Requirements

Manpower requirements associated with this scenario are shown in Tables 6-15 through 6-18.

HIGH FIND SCENARIO
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TABLE 6-15

OCS I - MANPOWER REQUIREMENTS BY INDUSTRY
(ON SITE MAN-MONTHS)

YEAR AFTER LEASE SALE	PETROLEUM OFFSHORE	PETROLEUM ONSHORE	CONSTRUCTION OFFSHORE	CONSTRUCTION ONSHORE	TRANSPORTATION OFFSHORE	TRANSPORTATION ONSHORE	MFG ONSHORE	ALL INDUSTRIES OFFSHORE	ALL INDUSTRIES ONSHORE	ALL INDUSTRIES TOTAL
1	1494.	156.	0.	0.	624.	168.	0.	2118.	324.	2442.
2	2908.	312.	480.	30.	1248.	336.	0.	4636.	678.	5314.
3	4482.	468.	2400.	180.	1872.	504.	0.	8754.	1152.	9906.
4	4940.	520.	840.	5286.	2080.	560.	0.	7860.	6366.	14226.
5	3485.	364.	[illegible]	15525.	2109.	609.	0.	7520.	16498.	24018.
6	3996.	420.	7725.	10374.	4037.	1421.	0.	15758.	12215.	27973.
7	8592.	826.	11075.	3625.	4705.	3155.	1200.	24372.	8806.	33178.
8	15120.	1416.	6458.	4258.	2764.	2758.	1200.	24342.	9632.	33974.
9	21576.	1925.	3267.	1136.	2485.	2803.	1200.	27328.	7064.	34333.
10	22608.	1764.	1397.	755.	2253.	2925.	1200.	26258.	6644.	32902.
11	18816.	1392.	1135.	984.	2101	2863.	1200.	22052.	6440.	28492.
12	15840.	990.	1344.	1344.	2160.	2940.	1200.	19344.	6474.	25818.
13	15564.	864.	1344.	1344.	2160.	2940.	1200.	19068.	6348.	25416.
14	15276.	756.	1440.	1440.	2160.	2940.	1200.	18876.	6336.	25212.
15	15480.	720.	1440.	1440.	2160.	2940.	1200.	19080.	6300.	25380.
16	15480.	720.	1440.	1440.	2160.	2940.	1200.	19080.	6300.	25380.
17	15660.	720.	1440.	1440.	2160.	2940.	1200.	19260.	6300.	25560.
18	15660.	720.	1440.	1440.	2160.	2940.	1200.	19260.	6300.	25560.
19	15660.	720.	1440.	1440.	2160.	2940.	1200.	19260.	6300.	25560.
20	15660.	720.	1440.	1440.	2160.	2940.	1200.	19260.	6300.	25560.
21	15660.	720.	1440.	1440.	2160.	2940.	1200.	19260.	6300.	25560.
22	15660.	720.	1440.	1440.	2160.	2940.	1200.	19260.	6300.	25560.
23	14616.	672.	1344.	1344.	2016.	2832.	1200.	17976.	6048.	24024.
24	14616.	672.	1344.	1344.	2016.	2832.	1200.	17976.	6048.	24024.
25	14616.	672.	1344.	1344.	2015.	2832.	1200.	17976.	6048.	24024.
26	14616.	672.	1344.	1344.	2016.	2832.	1200.	17976.	6048.	24024.
27	12526.	576.	1152.	1152.	1728.	2616.	1200.	15406.	5544.	20952.
28	10260.	480.	960.	960.	1440.	2400.	1200.	12660.	5040.	17700.
29	6564.	288.	576.	576.	384.	1968.	1200.	7524.	4032.	11556.
30	5040.	240.	480.	480.	720.	1860.	1200.	6240.	3780.	10020.

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TABLE 6-16

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0.	0.	271.	207.	41.	15.	534.	5	561.
2	0.	0.	0.	0.	0.	742.	514.	97.	32.	1385.	6	1412.
3	0.	0.	[illegible]	0.	0.	838.	621.	125.	45.	1629.	3	3800.
4	0.	0.	67.	7.	74.	1120.	790.	622.	103.	2635.	9	2784.
5	1.	0.	571.	95.	967.	1103.	798.	1607.	203.	3710.	8	3724.
6	254.	215.	523.	157.	2150.	2330.	1802.	1056.	144.	5331.	6	5657.
7	1296.	1126.	442.	246.	3112.	3126.	2412.	1168.	338.	7044.	6	7044.
8	2106.	1968.	547.	273.	4833.	2454.	2130.	1050.	319.	5953.	6	5953.
9	2062.	1953.	596.	310.	5231.	2690.	2448.	595.	276.	6009.	6	6009.
10	2606.	2483.	617.	287.	5992.	2160.	1976.	541.	282.	4959.	1	5992.
11	1986.	1900.	550.	280.	4714.	1760.	1676.	526.	280.	4242.	6	4783.
12	1465.	1516.	571.	255.	4576.	1514.	1424.	529.	285.	3752.	1	4578.
13	1559.	1444.	524.	285.	3902.	1589.	1499.	529.	285.	3902.	1	3902.
14	1557.	1567.	537.	285.	4046.	1545.	1455.	525.	285.	3810.	1	4046.
15	1557.	1516.	523.	285.	3900.	1590.	1500.	525.	285.	3900.	1	3900.
16	1540.	1510.	525.	285.	3900.	1590.	1500.	525.	285.	3900.	1	3900.
17	1605.	1515.	525.	285.	3930.	1605.	1515.	525.	285.	3930.	1	3930.
18	1605.	1515.	525.	285.	3930.	1605.	1515.	525.	285.	3930.	1	3930.
19	1605.	1515.	525.	285.	3930.	1605.	1515.	525.	285.	3930.	1	3930.
20	1605.	1515.	525.	285.	3930.	1605.	1515.	525.	285.	3930.	1	3930.
21	1605.	1515.	525.	285.	3930.	1605.	1515.	525.	285.	3930.	1	3930.
22	1605.	1515.	525.	285.	3930.	1605.	1515.	525.	285.	3930.	1	3930.
23	1498.	1414.	504.	280.	3696.	1498.	1414.	504.	280.	3696.	1	3696.
24	1498.	1414.	504.	280.	3696.	1498.	1414.	504.	280.	3696.	1	3696.
25	1498.	1414.	504.	280.	3696.	1498.	1414.	504.	280.	3696.	1	3696.
26	1498.	1414.	504.	280.	3696.	1498.	1414.	504.	280.	3696.	1	3696.
27	1284.	1212.	462.	270.	3228.	1284.	1212.	462.	270.	3228.	1	3228.
28	1055.	995.	420.	260.	2730.	1055.	995.	420.	260.	2730.	1	2730.
29	627.	591.	336.	240.	1794.	627.	591.	336.	240.	1794.	1	1794.
30	520.	490.	315.	235.	1560.	520.	490.	315.	235.	1560.	1	1560.

HIGH FLOW SCE
[illegible]

TABLE 6-17

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	[illegible]	120.	0.	0.	0.	0.	0.	0.	0.	0.	150.	1344.	0.	0.	0.	624.
	OFFSITE	[illegible]	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1344.	0.	0.	0.	312.
2	ONSITE	[illegible]	240.	0.	[illegible]	0.	0.	0.	0.	0.	0.	300.	2688.	0.	400.	0.	1248.
	OFFSITE	3.	240.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2688.	0.	200.	0.	624.
3	ONSITE	792.	360.	0.	0.	0.	0.	0.	0.	0.	0.	450.	4032.	0.	2400.	0.	1872.
	OFFSITE	20.	360.	0.	0.	0.	0.	0.	0.	0.	0.	0.	4032.	0.	1200.	0.	936.
4	ONSITE	740.	460.	0.	0.	0.	5226.	0.	0.	0.	0.	500.	4480.	0.	800.	0.	2080.
	OFFSITE	7.	400.	0.	0.	0.	575.	0.	0.	0.	0.	0.	4480.	0.	400.	0.	1040.
5	ONSITE	840.	315.	600.	0.	0.	12462.	1020.	0.	0.	0.	350.	3136.	0.	2025.	0.	2009.
	OFFSITE	20.	315.	194.	0.	0.	1371.	114.	0.	0.	0.	0.	3136.	0.	1625.	0.	1005.
6	ONSITE	[illegible]	415.	1600.	[illegible]	0.	5226.	2220.	0.	0.	0.	300.	2688.	1008.	7025.	700.	4037.
	OFFSITE	[illegible]	415.	194.	[illegible]	0.	575.	244.	0.	0.	0.	0.	2688.	1008.	6225.	700.	2019.
7	ONSITE	3215.	505.	0.	612.	1350.	0.	0.	0.	1320.	1200.	200.	1792.	6600.	10200.	875.	4705.
	OFFSITE	117.	505.	0.	57.	215.	0.	0.	0.	1320.	1200.	0.	1792.	6600.	8600.	875.	2353.
8	ONSITE	[illegible]	530.	0.	612.	[illegible]	0.	0.	0.	1320.	1200.	0.	0.	16128.	4925.	525.	2764.
	OFFSITE	[illegible]	530.	0.	67.	343.	0.	0.	0.	1320.	1200.	0.	0.	16128.	4125.	525.	1382.
9	ONSITE	[illegible]	665.	0.	[illegible]	350.	0.	0.	0.	1320.	1200.	0.	0.	21576.	2550.	525.	2485.
	OFFSITE	34.	665.	0.	27.	43.	0.	0.	0.	1320.	1200.	0.	0.	21576.	2150.	525.	1243.
10	ONSITE	[illegible]	[illegible]	[illegible]	[illegible]	0.	0.	0.	0.	1320.	1200.	0.	0.	22008.	1325.	0.	2253.
	OFFSITE	12.	[illegible]	[illegible]	[illegible]	0.	0.	0.	0.	1320.	1200.	0.	0.	22008.	925.	0.	1127.
11	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	18816.	0.	175.	2101.
	OFFSITE	3.	645.	0.	[illegible]	0.	0.	0.	0.	1320.	1200.	0.	0.	18816.	0.	175.	1051.
12	ONSITE	[illegible]	[illegible]	0.	[illegible]	[illegible]	0.	0.	0.	1320.	1200.	0.	0.	15840.	0.	0.	2160.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15840.	0.	0.	1080.
13	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15564.	0.	0.	2160.
	OFFSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15564.	0.	0.	1080.
14	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15276.	0.	0.	2160.
	OFFSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15276.	0.	0.	1080.
15	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15480.	0.	0.	2160.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15480.	0.	0.	1080.

** SEE ATTACHED KEY FOR ACTIVITIES

TABLE 6-17 (Cont.)

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/AC			2	3	4	5	6		8	9	0		2	3	4	5	6 *a
16	ONSITE	2880.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15480.	0.	0.	2160.
	OFFSITE	0.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15480.	0.	0.	1080.
17	ONSITE	2880.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	2160.
	OFFSITE	0.	900.	0.	[illegible]	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	1080.
18	ONSITE	2880.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	2160.
	OFFSITE	0.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	1080.
19	ONSITE	2880.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	2160.
	OFFSITE	0.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	1080.
20	ONSITE	2880.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	2160.
	OFFSITE	0.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	1080.
21	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	2160.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	1080.
22	ONSITE	2880.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	2160.
	OFFSITE	0.	900.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15660.	0.	0.	1080.
23	ONSITE	[illegible]	840.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14616.	0.	0.	2016.
	OFFSITE	0.	840.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14616.	0.	0.	1008.
24	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	146 6.	0.	0.	2016.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	46 6.	0.	0.	1008.
25	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14616.	0.	0.	2016.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14616.	0.	0.	1008.
26	ONSITE	[illegible]	840.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14616.	0.	0.	2016.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14616.	0.	0.	1008.
27	ONSITE	[illegible]	720.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	12528.	0.	0.	728.
	OFFSITE	0.	720.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	12528.	0.	0.	864.
28	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	10260.	0.	0.	440.
	OFFSITE		[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	10260.	0.	0.	720.
29	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	6084.	0.	0.	864.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	6084.	0.	0.	432.
30	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	5040.	0.	0.	720.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	5040.	0.	0.	360.

*a [illegible]

TABLE 6-17 (Attachment)

LIST OF TASKS BY ACTIVITY

ONSHORE

Activity

1 Service Bases (Onshore Employment - which would include all onshore administration, service base operations, rig and platform service
- Task 1 - Exploration Well Drilling
- Task 2 - Geophysical Exploration
- Task 5 - Supply/Anchor Boats for Rigs
- Task 6 - Development Drilling
- Task 7 - Steel Jacket Installations and Commissioning
- Task 8 - Concrete Installations and Commissioning
- Task 11 - Single-Leg Mooring System
- Task 12 - Pipeline-Offshore, Gathering, Oil and Gas
- Task 13 - Pipeline-Offshore, Trunk, Oil and Gas
- Task 20- Gravel Island Construction
- Task 23- Supply/Anchor Boats for Platform
- Task 24 - Supply/Anchor Boats for Lay Barge
- Task 27 - Longshoring for Platform
- Task 28- Longshoring for Lay Barge
- Task 31 - Platform Operation
- Task 33 - Maintenance and Repairs for Platform and Supply Boats
- Task 37 - Longshoring for Platform (Production)
- Task 301 - Gravel Island Construction

2 Helicopter Service
- Task 4 - Helicopter for Rigs
- Task 21 - Helicopter Support for Platform
- Task 22 - Helicopter Support for Lay Barge
- Task 34 - Helicopter for Platform

Construction

3 Service Base
- Task 3 - Shore Base Construction
- Task 10 - Shore Base Construction

4 Pipe Coating
- Task 15 - Pipe Coating

5 Onshore Pipelines
- Task 14 - Pipeline, Onshore, Trunk, Oil and Gas

6 Terminal
- Task 16 - Marine Terminal (assumed to be oil terminal)
- Task 18 - Crude Oil Pump Station Onshore

7 LNG Plant
- Task 17 - LNG Plant

8 Concrete Platform Construction
- Task 19 - Concrete Platform Site Preparation
- Task 20 - Concrete Platform Construction

9 Oil Terminal Operations
- Task 36 - Terminal and Pipeline Operations

10 LNG Plant Operations
- Task 38 - LNG Operations

OFFSHORE

Activity

11 Survey
- Task 2 Geophysical and Geological Survey

12 Rigs
- Task 1 - Exploration Well

13 Platforms
- Task 6 - Development Drilling
- Task 31 - Operations
- Task 32 - Workover and Well Stimulation

14 Platform Installation
- Task 7 - Steel Jacket Installation and Commissioning
- Task 8 - Concrete Installation and Commissioning
- Task 11 - Single-Leg Mooring System
- Task 20 - Gravel Island construction
- Task 301 - Gravel Island Construction

15 Offshore Pipeline Construction
- Task 12 - Pipeline Offshore, Gathering, Oil and Gas
- Task 13 - Pipeline Offshore, Trunk, Oil and Gas

16 Supply/Anchor/Tug Boat
- Task 5 - Supply/Anchor Boats for Rigs
- Task 23 - Supply/Anchor Boats for Platform
- Task 24 - Supply/Anchor Boats for Lay Barge
- Task 25 - Tugboats for Installation and Towout
- Task 26 - Tugboats for Lay Barge Spread
- Task 29 - Tugboats for SLMS
- Task 30- Supply Boat for SLMS
- Task 35 - Supply Boat for SLMS

HIGH FIND SCENARIO
04/23/79

TABLE 6- 8

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL MAN-MONTHS OFFSHORE	TOTAL MAN-MONTHS ONSHORE	TOTAL MAN-MONTHS TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	2118.	324.	2442.	3774.	444.	4218.	315.	37.	352.
2	4636.	678.	5314.	8148.	921.	9069.	679.	77.	756.
3	8754.	1152.	9906.	14922.	1532.	16454.	1244.	128.	1372.
4	7860.	6366.	14226.	13780.	7347.	21127.	1149.	613.	1761.
5	7520.	16498.	24018.	13286.	18520.	31806.	1108.	1544.	2651.
6	15758.	12215.	27973.	28398.	13771.	42169.	2367.	1148.	3514.
7	24372.	8806.	33178.	44591.	12230.	56821.	3716.	1020.	4736.
8	24342.	9632.	33974.	46502.	13151.	59653.	3876.	1096.	4971.
9	27329.	7004.	34333.	53013.	10293.	63307.	4418.	858.	5276.
10	26258.	6644.	32902.	50990.	10031.	61020.	4250.	836.	5085.
11	22052.	6440.	28492.	43054.	9807.	52861.	3588.	818.	4405.
12	19344.	6474.	25818.	37608.	9894.	47502.	3134.	825.	3959.
13	19068.	6348.	25416.	37056.	9768.	46824.	3088.	814.	3902.
14	18876.	6336.	25212.	36672.	9756.	46428.	3056.	813.	3869.
15	19080.	6300.	25380.	37080.	9720.	46800.	3090.	810.	3900.
16	19080.	6300.	25380.	37080.	9720.	46800.	3090.	810.	3900.
17	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
18	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
19	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
20	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
21	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
22	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
23	17976.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
24	17975.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
25	17976.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
26	17976.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
27	15408.	5544.	20952.	29952.	8784.	38736.	2496.	732.	3228.
28	12660.	5040.	17700.	24600.	8160.	32760.	2050.	680.	2730.
29	7524.	4032.	11556.	14616.	6912.	21528.	1218.	576.	1794.
30	6240.	3780.	10020.	12120.	6600.	18720.	1010.	550.	1560.

** TOTAL INCLUDES ONSITE AND OFFSITE

6.6 Environmental Considerations

The potential impacts of petroleum exploration discussed in Section 5.6 apply as well to the high find scenario. Here, however, the anticipated construction of onshore and offshore pipelines introduces the potential for strong, negative impact on salmon populations and shore nesting seabirds and waterfowl. The pipelines paralleling the coast between Rocky Point and Cape Rodney, to Cape Nome intersect eight important salmon streams. Between Nome and Cape Rodney is found extensive migrating waterfowl habitat. The bluffs between Nome and Rocky Point are the established nesting grounds (with associated offshore feeding areas) of common murres, black-legged kittiwakes, horned puffins, thick-billed murres, and other seabirds. Strong environmental regulations and stipulations may heavily constrain pipeline construction in this area.

Construction of extensive facilities at Cape Nome may demand greater gravel resources than the area can supply. Removal of gravel from salmon streams should be carefully regulated.

The routing of offshore pipelines to Cape Nome should minimize the loss of navigable area in fishing zones, and potential for fishery resource loss in the event of oil spill.

Drilling south of Cape Nome will likely occur near areas of high benthic productivity and diversity, which may have negative impact on the subsistence king crab fishery. Efforts should be made to avoid localized points of high density or diversity when drilling sites are chosen.

During the production phase, ice leads artificially maintained along vessel routes and around well sites may attract seals and walruses, leading to unnatural opportunities for impact. The Canadian petroleum development experience in the Beaufort Sea may provide some guage of the potential for this situation.

7.0 MEDIUM FIND SCENARIO

7.1 General Description

The medium find scenario assumes modest discoveries of oil and non-associated gas. The basic characteristics of the scenario are summarized in Tables 7-1 and 7-2. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
1,200	2,300

Five oil fields comprise the total reserves. They are located in two groups of fields, one in inner Norton Sound, the second in the central sound south of Nome, plus a single field in the outer sound southwest of Cape Rodney (Figures 7-1 and 7-2). The gas reserves are contained in two fields located close to each other about 48 kilometers (30 miles) south of Nome.

All crude is brought to a single terminal located at Cape Nome. For the inner sound fields, this involves a 100-kilometer (62-mile) onshore pipeline segment from Cape Darby to Cape Nome; the trunk pipeline from the central and outer sound fields makes landfall close to the terminal site and therefore, involves minimal onshore pipeline construction.

The non-associated gas fields share a single trunk pipeline to a LNG plant located adjacent to the crude oil terminal at Cape Nome.

7.2 Tracts and Location

The discovery tracts and field locations (designated by OCS protraction diagram numbers) are given in Table 7-3. The productive acreage cited relates to the optima? recoverable reserves per acre assumed for the scenario analysis.

TABLE 7-1

MEDIUM FIND OIL SCENARIO

Field Size Oil (MMBBL)	Location	Reservoir Depth- Meters	Reservoir Depth- Feet	Production System	Platform No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	"Peak Production oil (MB/D)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
200	inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	133	83	14	Cape Nome
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	146	91	14	Cape Nome
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 s	80	2,000	153.6	18	60	34	21	18	Cape Nome
250	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1s	40	2,000	76.8	21	70	58	36	18	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 s	40	2,000	76.8	30	100	95	59	18	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 7-2

MEDIUM FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Gas	LNG Plant
1,300	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	20	66	48	30	20	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	18	60	32	20	20	Cape Nome

* S = Ice reinforced steel platform.

Fields in bracket share same trunk pipeline.

Source: Dames & Moore

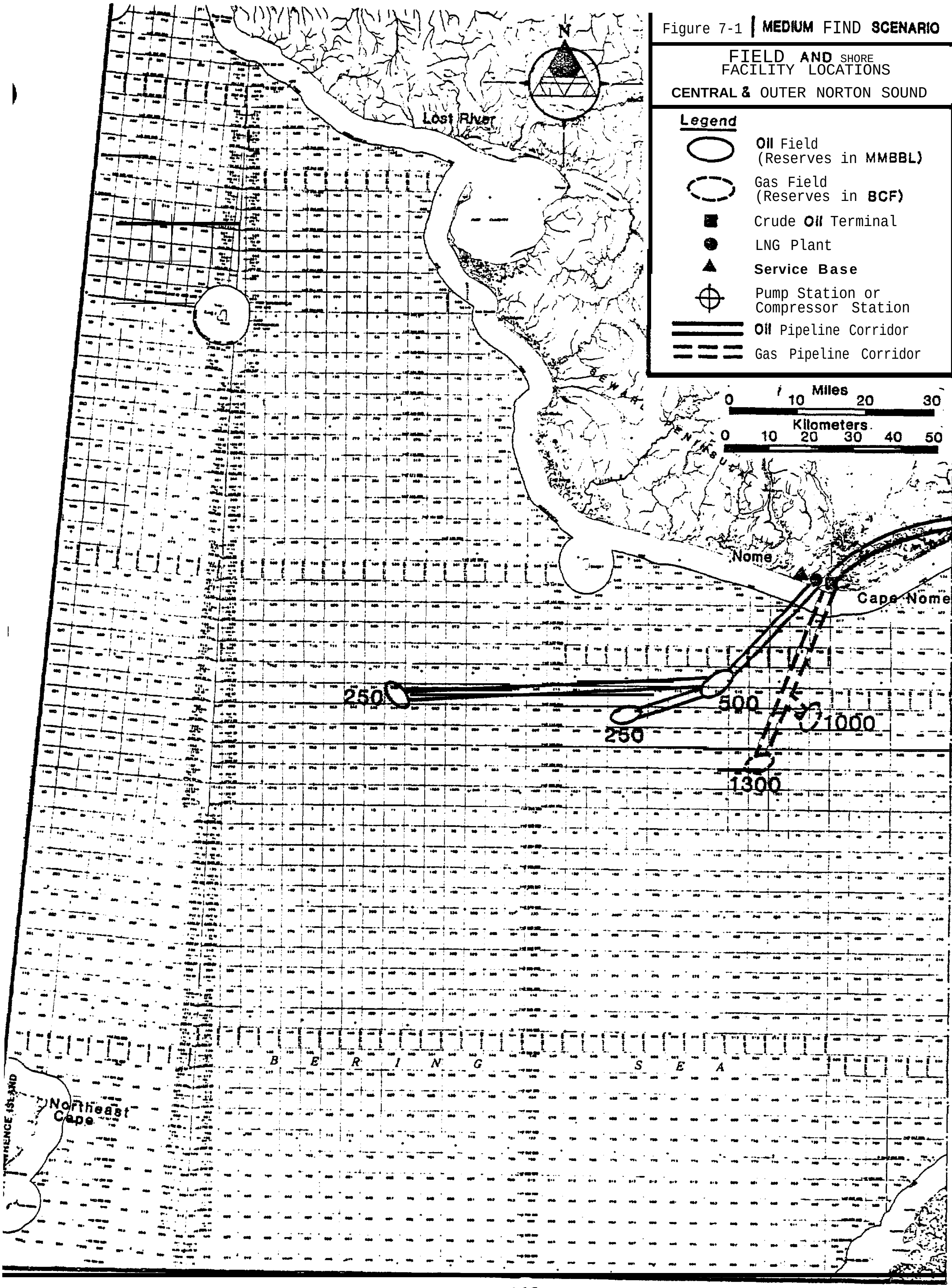

Figure 7-1 MEDIUM FIND SCENARIO
FIELD AND SHORE FACILITY LOCATIONS
CENTRAL & OUTER NORTON SOUND
Legend
Oil Field (Reserves in MMBBL)
Gas Field (Reserves in BCF)
Crude Oil Terminal
LNG Plant
Service Base
Pump Station or Compressor Station
Oil Pipeline Corridor
Gas Pipeline Corridor
Miles
0 10 20 30
Kilometers
0 10 20 30 40 50
N
Lost River
Nome
Cape Nome
250
500
250
1000
1300
Match Line
B E R I N G S E A
Northeast Cape

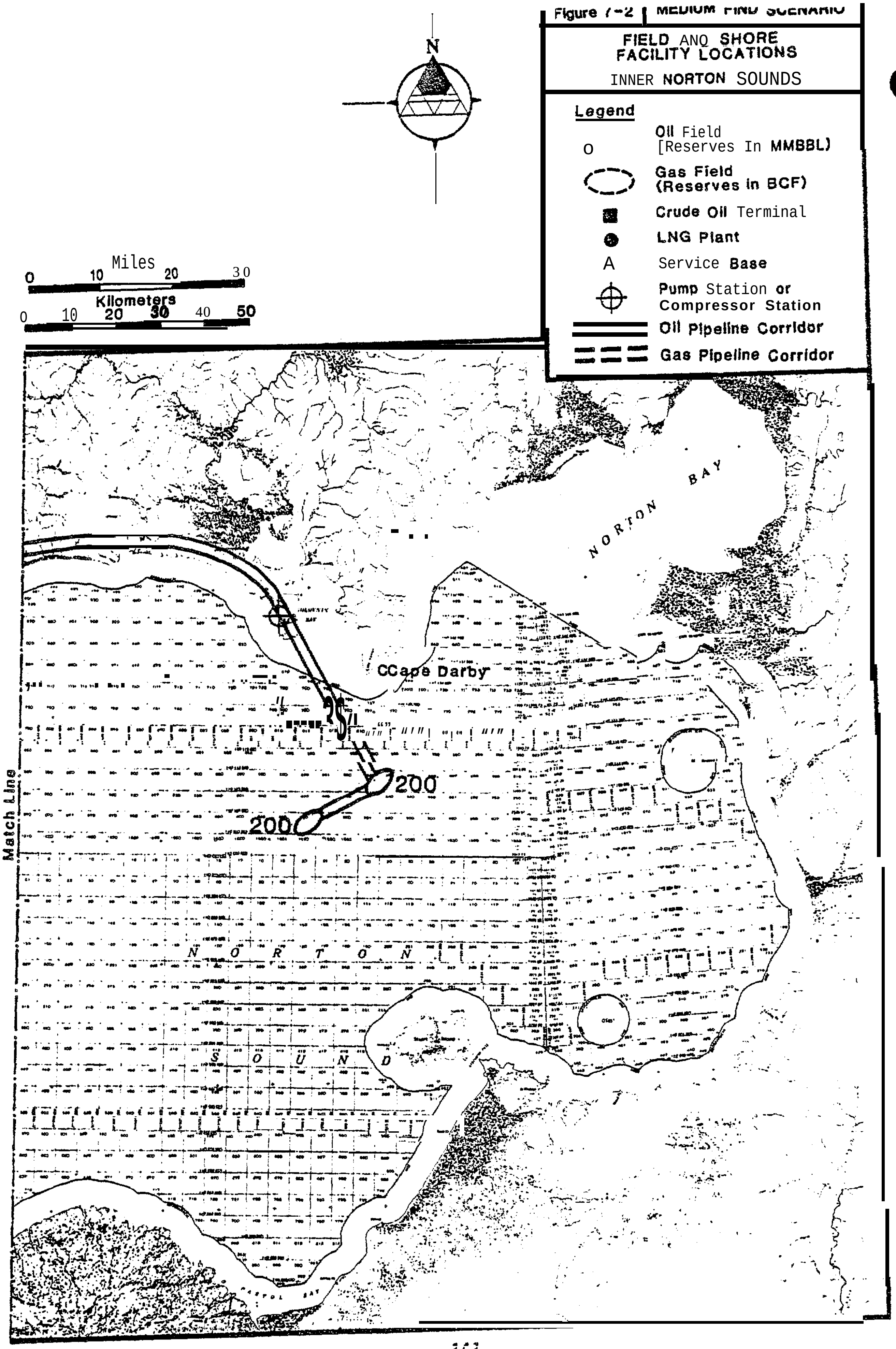

Figure 7-2 MEDIUM FIND SCENARIO

FIELD AND SHORE FACILITY LOCATIONS

INNER NORTON SOUNDS

TABLE 7-3

MEDIUM FIND SCENARIO - FIELDS AND TRACTS

Location	Field Size		Acres[1]	Hectares	No. of Tracts[2]	OCS Tract Numbers[3]
	Oil (mmbbl)	Gas (bcf)				
Inner Sound	200	--	3,333	1,349	0.6	903, 904
Inner Sound	200	--	3,333	1,349	0.6	967, 968
Central Sound	500	--	8,333	3,373	1.5	773, 774, 775, 817, 818
Central Sound	250	--	4,167	1,686	0.7	857, 858
Outer Sound	250	--	4,167	1,686	0.7	802, 803, 846
Central Sound	--	1,300	4,333	1,754	0.8	952, 953, 996
Central Sound	--	1,000	3,333	1,349	0.6	823, 866, 867

[1] Recoverable reserves in the scenario are assumed to be 60,000 barrels per acre for oil and 300 mmcf for non-associated gas.
[2] A tract is 2,304 hectares (5,693 acres).
[3] Tracts listed include all tracts that are involved in the surface expression of an oil or gas field. In some cases only portions (a corner, etc.) of a tract are involved. However, the entire tract is listed above. (See Figure 7-1 and 7-2 for exact tract location and portion involved in surface expression of fields.)

Source: Dames & Moore

7.3 Exploration, Development, and Production Schedules

Exploration, development, and production schedules are shown on Tables 7-4 through 7-14. The assumptions on which these schedules are based are given in Appendix B and E.

Exploration commences in the first year after the lease sale (1983), peaks in year 3 with 16 wells drilled, and terminates in the seventh year with a total of 64 wells drilled (Table 7-4). Seven commercial discoveries are made (five oil, two non-associated gas) over a five year period (Table 7-5). The exploration involves jack-up rigs and drillships (in the outer sound) and limited use of summer-constructed gravel islands in shallow water (15 meters [50 feet] or less) where suitable borrow materials are either adjacent to the well site or within economic haul distance.. Economics dictate extension of the drilling season from the four to six month open-water season to a maximum of eight months; this is accomplished by the use of ice-breaker support.

Field construction commences in year 4 after the decision to develop the first discovery (a 500 mmbbl reserve oil field in central Norton' Sound) and the first platform is installed in year 5 (Table 7-6). Development drilling commences the following year and the first oil production is brought to shore in year 7 (1989) (Table 7-7). Offshore construction activity peaks in year 6 when four platforms are installed, The favored development strategy is ice-reinforced steel platforms; two caisson-retained grave? production islands are, however, constructed in the inner sound to develop the two 200 mmbbl oil fields. The last platform is installed in year 8.

Oil production from Norton Sound commences in year 8 (1990) after the lease sale, peaks at 463,000 b/d in year 12 (1994), and ceases in year 29 (2011) (Tables 7-11 and 7-12). Gas production commences in year 7 (1989), peaks at 460.8 mmcfd in years 12 through 18 (1994 through 2000), and ceases in year 28 (2010) (Tables 7-11 and 7-13).

TABLE 7-4

EXPLORATION SCHEDULE FOR EXPLORATION AND DELINEATION WELLS - MEDIUM FIND SCENARIO

Well Type	Year After Lease Sale																				Well Totals
	1						4		5		6		7		8		9				
	Rigs	Wells[3]	Rigs	Wells	Rigs	ells	Rigs	Wells	Rigs	Wells	Rigs	'ens	Rigs	Wells	" 9	'e'"	Rigs	Wells	Rigs	ells	
Exp.[1]		6		11		12		8		6		4		4							52
	3		7		8		6		4		2		2								
Del.2				3		4		4		2											13
TOTAL		6		14		16		12		8		4		4							64

[1] In this high find scenario a success rate of one significant discovey for approximately every eight exploration wells is assumed. This is slightly higher than the average 10 percent success rate in U.S. offshore areas in the past 10 years and significantly higher than the average of the past five years (Tucker, 1978).

[2] The number of delineation wells assumed per discovery is two field sizes of less than 500 mmbbl oil or 2,000 bcf gas, and three for fields of 500 mmbbl oil and 2,000 bcf gas and larger.

[3] An average completion time of four months pre exploration/delineation well 's assumed. The drilling season is assumed to be extended to a maximum of eight months by ice breaker support. In addition, the limited use of summer-constructed gravel islands to extend drilling into the winter is also postulated.

Source: Dames & Moore

TABLE 7-5

TIMING OF DISCOVERIES - MEDIUM FIND SCENARIO

Year After Lease Sale	Type	Reserve Size Oil (mmbbl)[1]	Reserve Size Gas (bcf)	Location	Water Meters	!?fM&-
1	Oil	500	--	Central Sound	18	60
2	Oil	250	--	Central Sound	21	70
2	Gas	..-	1,300	Central Sound	20	66
3	Oil	200	--	Inner Sound	18	60
3	Oil	250	--	Outer Sound	30	100
4	Gas	. .	1,000	Central Sound	18	60
5	Oil	200	--	Inner Sound	18	60

Assumes field has low GOR and associated gas is used to power platform and reinfected.

Source: Dames & Moore

TABLE 7-6

PLATFORM CONSTRUCTION AND INSTALLATION SCHEDULE - MEDIUM FIND SCENARIO

Location	Field		Year After Lease Sale											
	Oil (MMBBL)	Gas (BCF)	1	2	3	4	5	6			9	10	11	12
Inner Sound	2D0	--			*		D	ΔG						
Inner Sound	200	--				*		D	ΔG					
Central Sound	500	--	*		D		ΔS	ΔS						
Central Sound	250	.-		*		D		ΔS						
Outer Sound	250	.-			*		D		ΔS					
Central Sound	--	1,300		*		D		ΔS						
Central Sound	--	1,000				*		D		ΔS				
OTALS							l(s)	l(G) 3(s)	1(G) 1(S)	l(s)				

* = Discovery; D = Decision to Develop; ΔS = Steel Platform; ΔG = Gravel Island

Notes:

1. Steel platform installation is assumed to begin in June in each case; gravel island construction starts the year after decision to develop and takes two summer seasons.
2. Platform "installation" includes module lifting, hook-up, and commissioning.

Source: Dames & Moore

TABLE 7-7

DEVELOPMENT WELL DRILLING SCHEDULE - MEDIUM FIND SCENARIO

Location	Field Oil (MMBBL)	Field Gas (BCF)	Platforms Nos.	Platforms Type 1	No.[2] of Drill Rigs Per Platform	Total No. of Production Wells	Other Wells[4]	Start of Drilling Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
nner Sound	200	--	1	G	2	40	8	April						ΔG		12	16P	16	4			w			
nner Sound	200	--	1	G	. 2	40	8	April							ΔG		12	16P	16	4			w		
entral Sound	500	--	2	s	2	40	8	Apt-i l					ΔS	12	16P	16	4			W					
				s	2	40	8	Apri l						ΔS	12	16P	16	4			W				
entral Sound	250	--	1	S	2	40	8	Apri l						ΔS	12	16P	16	4			W				
uter Sound	250	--	1	S	2	40	8	April							As	12	16P	16	4			w			
entral Sound	--	1,300	1	s	1			Apri 1						ΔS	6P	8	2								
entral Sound	--	1,000	1	s	1			Apri l								As	6P	8	2						
OTALS														12	46	80	88	64	26	4					

Year After Lease Sale - No. of Wells Drilled[3]

[1] S = Steel; G = Gravel

[2] Platforms sized for 40 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 40 well slots are assumed to have one drill rig operating during development drilling.

[3] Drilling progress is assumed to be 45 days per well.

[4] Gas or water-injection wells etc. , well allowances assumed to one well for every five oil production wells.

ΔS = Platform arrives on site -- assumed to be June; platform installation and commissioning assumed to take 10 months.

ΔG = Gravel island construction starts June 1 the year after decision to develop and takes two summer seasons.

W = Work over commences -- assumed to be five years after beginning of production from platform.

P = Production starts; assumed to occur when first 10 oil wells are completed or first four gas wells.

Source: Dames & Moore

O

TABLE 7-8

EXPLORATION AND PRODUCTION GRAVEL ISLANDS - MEDIUM FIND SCENARIO

Year After Lease Sale	Exploration 7.5 Ill (25 ft)	Exploration 15 m (50 ft)	Production	Total	Number of Construction Spreads
1					
2	1			1	1
3		1		1	1
4		1		1	2
5		1		1	2
6		1	1	2	2
7			1	1	1
8					
9					
10					
TOTALS	1	4	2	7	N/A

Note: Arrows show exploration islands expanded and modified for production.

TABLE 7-9

PIPELINE CONSTRUCTION SCHEDULE - MEDIUM FIND SCENARIO - KILOMETERS (MILES) CONSTRUCTED BY YEAR

	(inches)		Water Depth												
	Oil	Gas	Meters	Feet	1	2	3	4	5	6	7	8	9		1
Offshore	14		0-18	0-60								34 (21)			
	12		18	60								13 (8)			
	18		0-18	0-60						31 (19)					
	12		18	60						24 (15)					
	12		18-30	60-100								61 38			
		20	0-18	0-60						48 (30)					
		16	18	60								10 6			
Onshore															
Total										109 (68)		218 (135)			

Source: Dames &

TABLE 7-10

MAJOR FACILITIES CONSTRUCTION SCHEDULE - MEDIUM FIND SCENARIO

Facility[1]/Location	Peak Throughput Oil (MBD)	Gas (MMCFD)	Year After Lease Sale 1	2	3	4		6		8	9	10	11	12
Cape Nome Oil Terminal	436	--												
Cape Nome LNG Plant	--	461				4								
Cape Nome Support Base (permanent)	(medium)					-4-s								

[1] Assume construction starts in spring of year indicated.

Source: Dames & Moore

TABLE 7-11

FIELD PRODUCTION SCHEDULE - MEDIUM FIND SCENARIO

Location	Fi[illegible]		Peak Production		Year After Lease Sale			Years of Production[1]
	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	
Inner Sound	200	--	76.8	--	9	28	12	20
Inner Sound	200	--	76.8	--	10	29	13	20
Central Sound	500	--	153.6	--	7	26	10-11	20
"Central Sound	250	--	76.8	--	8	21	10-12	14
Outer Sound	250	--	76.8	--	9	22	11-13	14
Central Sound	--	1,300	--	230.4	7	27	9-18	21
Central Sound	--	1,000	--	230.4	9	28	12-18	20

[1] Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms.

Source: Dames & Moore

TABLE 7-12

MEDIUM FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL) Inner Sound		Central Sound		Outer Sound	Totals
		zoo	200	500	250	250	
1983	1						
1984	2						
1985	3						
1986	4						
1987	5						
1988	6						
1989	7			7.008			7.008
1990	8			24.528	7.008	7.008	31.536
1991	9	7.008		45.552	17.520	7.008”	77.088
1992	10	14.016	7.008	56.064	28.032	17.520	122.640
1993	11	21.024	14.016	56.064	28.032	28.032	147.168
1994	12	28.024	21.024	54.005	28.032	28.032	159.125
1995	13	27.050	28.032	46.354	27.982	28.032	157.450
1996	14	22.401	27.050	38.598	24.906	27.982	140.937
1997	15	17.432	22.401	32.168	20.647	24.906	117.554
1998	16	13.897	17.432	26.840	17.116	20.647	95.932
1999	17	11.000	13.897	21.420	14.187	17.116	77.620
2000	18	8.886	11.000	18.757	11.763	14.187	64.593
2001	19	6.835	8.886	15.221	9.751	11.763	52.456
2002	20	5.250	6.835	12.703	8.084	9.751	42.623
2003	21	4.154	5.250	10.616	6.701	8.084	34.805
2004	22	3.286	4.154	8.886		6.701	23.027
2005	23	2.600	3.286	7.452			13.338
2006	24	2.057	2.600	6.263			10.920
2007	25	1.628	2.057	5.328			9.013
2008	26	1.288	1.628	4.417			7.333
2009	27	1.019	1.288				2.307
2010	28	0.837	1.019				1.856
2011	29		0.837				0.837
2012	30						
2013	31						
2014	32						
2015	33						
2016	34						

Peak 011 Product ion * 436,000 b/d.

Source: Dames & Moore

TABLE 7-13

MEDIUM FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL NON-ASSOCIATED GAS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound 1300	1000	Totals
1983	1			
1984	2			
1985	3			
1986	4			
1987	5			
1988	6			
1989	7	26.280		26.280
1990	8	63.072		63.072
1991	9	84.096	21.024	105.120
1992	10	84.096	42.048	126.144
1993	11	84.096	63.072	147.168
1994	12	84.096	84.096	168.192
1995	13	84.096	84.096	168.192
1996	14	84.096	84.096	168.192
1997	15	84.096	84.096	168.192
1998	16	84.096	84.096	168.192
1999	17	84.096	84.096	168.192
2000	18	84.096	84.096	168.192
2001	19	76.846	72.423	149.269
2002	20	61.980	54. 122	116.102
2003	21	49.936	40.521	90.477
2004	22	40.265	30.710	70.575
2005	23	32.454	22.672	55.126
2006	24	26.157	16.958	43.115
2007	25	21.002	12.685	33.772
2008	26	16.992	9.488	26.480
20D9	27	13.696	7.097	20.793
201D	28		5.309	5.309
2011	29			
2012	30			
2013	31			
2014	32			
2015	33			
2016	34			

Peak Gas Production = 460.8 MMCFD.

Source: Dames & Moore

TABLE 7-14

MAJOR SHORE FACILITIES START UP AND SHUT DOWN DATES - MEDIUM FIND SCENARIO

Facility	Year After Lease Sale	
	Start Up Date[1]	Shut Down Date[2]
Cape Nome Oil Terminal	6	29
Cape Nome LNG Plant	7	38

[1] For the purposes of manpower estimation start up is assumed to be January 1.
[2] For-the purposes of manpower estimation shut down is to be December 31.

Source: Dames & Moore

7.4 Facility Requirements and Locations

Facility requirements (platforms, pipelines, terminals, etc.) and related construction scheduling are summarized in Tables 7-6 through 7-10. This scenario assumes that all oil and gas production is brought to shore to a single crude oil terminal and LNG plant, respectively, both located at Cape Nome, for processing and transport to the lower 48 by tanker.

The major facility constructed is a medium-sized crude oil terminal, located at Cape Nome, designed to handle the estimate peak production of about 460,000 b/d. (Original ly, after discovery the 500 mmbbl field, a smaller terminal is planned but with further significant discoveries in the following two years, plans for a larger facility are made). The terminal completes crude stabilization, recovers LPG, treats tanker ballast water, and provides storage for about 6 million barrels of crude (approximately 14 days production). Terminal configuration includes buried pipelines to a two-berth loading platform located approximately four kilometers (2.5 miles) offshore. These berths are designed to handle 70,000 to 120,000 DWT tankers that transport crude to the U.S. west coast. The tankers are conventional tankers reinforced for Bering Sea ice; ice-breaker support for these tankers and docking facilities is required.

The other major facility, also located at Cape Nome, is a LNG plant designed to handle the estimated peak gas production of about 460 million cubic feet per day. The LNG plant is a modularized barged-in facility and has a single berth loading platform designed to handle 130,000m^3 LNG tankers. A fleet of three tankers transports the LNG to the U.S. west coast. With a loading frequency of approximately once a week, storage capacity for about ten days of LNG production (4.5 BCF) is provided at the plant.

A forward service base supporting construction and operation of the Norton Sound fields is-constructed adjacent to the Cape Nome facilities. Field construction is also supported by storage and accommodation barges and freig ters, moored in Norton Sound, and a rear support base located in the Aleut an Islands.

The exploration phase of petroleum development in Norton Sound involves aerial support and light supply transshipment provided by Nome, storage barges and freighters moored in Norton Sound, and an Aleutian Island storage and transshipment facility.

The exploration phase of petroleum development in Norton Sound involves aerial support and light supply transshipment provided by Nome, storage barges and freighters moored in Norton Sound, and an Aleutian Island storage and transshipment facility.

7.5 Manpower Requirements

Manpower requirements associated with this scenario are shown in Tables 7-15 through 7-18.

7.6 Environmental Considerations

Discussion of the impacts associated with the medium find scenario may be drawn from the high find case, where applicable. Thus, the onshore pipeline from Cape Nome to Rocky Point will traverse established seabird colonies at Bluff and five major salmon streams. Precautions against disturbance of these resources will be required. Though comparatively reduced, the requirements for gravel in the Nome area will likely strain local resources and further destruction from gravel mining may result. Other impacts, resulting from exploration, drilling, and construction of gravel islands, are as discussed in Sections 5.6 and 6.6.

MEDIUM FIND SCENARIO
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TABLE 7-15

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	1619.	166.	0.	0.	624.	168.	0.	2243.	334.	2577.
2	3466.	364.	400.	30.	1456.	392.	0.	5342.	786.	6126.
3	3984.	416.	800.	60.	1664.	448.	0.	6448.	924.	7372.
4	2988.	312.	800.	3396.	1248.	336.	0.	5036.	4044.	9080.
5	1096.	112.	2025.	8697.	969.	329.	0.	4090.	9138.	13229.
6	2004.	212.	7900.	3091.	3290.	1228.	0.	13194.	4531.	17726.
7	5692.	518.	4300.	375.	1236.	1596.	720.	11228.	3209.	14437.
8	10176.	912.	5475.	4487.	1639.	1843.	720.	17290.	7962.	25252.
9	13440.	1128.	3117.	814.	1245.	1857.	720.	17802.	4520.	22322.
10	12288.	960.	2784.	564.	1152.	1872.	720.	16224.	4116.	20340.
11	9096.	618.	3072.	852.	1152.	1872.	720.	13320.	4062.	17382.
12	7788.	420.	3168.	948.	1152.	1872.	720.	12108.	3960.	16068.
13	7812.	384.	3168.	948.	1152.	1872.	720.	12132.	3924.	16056.
14	8172.	384.	3168.	948.	1152.	1872.	720.	12492.	3924.	16416.
15	8352.	384.	3168.	948.	1152.	1872.	720.	12672.	3924.	16596.
16	8352.	384.	3168.	948.	1152.	1872.	720.	12672.	3924.	16596.
17	8352.	394.	3168.	948.	1152.	1872.	720.	12672.	3924.	16596.
18	8352.	384.	3168.	948.	1152.	1872.	720.	12672.	3924.	16596.
19	8352.	384.	3168.	948.	1152.	1872.	720.	12672.	3924.	16596.
20	8352.	384.	3168.	948.	1152.	1872.	720.	12672.	3924.	16596.
21	8352.	384.	3168.	948.	1152.	1872.	720.	12672.	3924.	16596.
22	7308.	336.	3072.	852.	1008.	1764.	720.	11388.	3672.	15060.
23	6264.	288.	2976.	756.	864.	1656.	720.	10104.	3420.	13524.
24	6264.	288.	2976.	756.	864.	1656.	720.	10104.	3420.	13524.
25	6264.	288.	2976.	756.	864.	1656.	720.	10104.	3420.	13524.
26	6264.	288.	2976.	756.	864.	1656.	720.	10104.	3420.	13524.
27	3996.	192.	2784.	564.	576.	1440.	720.	7356.	2916.	10272.
28	2952.	144.	2688.	468.	432.	1332.	0.	6072.	1944.	8016.
29	1044.	48.	2496.	276.	144.	108.	0.	3684.	432.	4116.
30	0.	0.	2400.	180.	0.	0.	0.	2400.	180.	2580.

MEDIUMFIND SCENARIO
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TABLE 7-16

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
{NUMBER OF PEOPLE)

	JANUARY					JULY					PEAK	
YEAR AFTER LEASE SALE	OFFSHORE ONSITE	OFFSHORE OFFSITE	ONSHORE ONSITE	ONSHORE OFFSITE	JANUARY TOTAL	OFFSHORE ONSITE	OFFSHORE OFFSITE	ONSHORE ONSITE	ONSHORE OFFSITE	JULY TOTAL	MONTH	TOTAL
1	0.	0.	0.	0.	0.	296.	207.	43.	15.	561.	5	588.
2	o.	0.	0.	0.	0.	849.	583.	112.	37.	1581.	6	1581,
3	0.	0.	0.	0.	0.	931.	652.	125.	42.	1750.	6	1750.
4	0.	o*	0.	o*	0.	742.	514.	371.	62.	1689.	9	1937,
5	0.	0.	696.	77.	773.	668.	453.	859.	103.	2083.	6	2121.
b	254.	215.	584.	66.	1118.	977.	1526.	376.	55.	3933*	6	4100.
7	1296.	1126.	376.	182.	2980 .	985.	748.	244 .	157.	2134.	1	2980.
8	928.	804.	253-	166.	2151.	866.	1560.	908.	238.	4573.	6	4573.
9	1674.	1493.	.770.	230.	4167.	420.	1278.	332.	181.	3211.	1	4167.
10	1520.	1372.	361.	1(36.	3439 .	296.	1148.	337.	186.	2967.	1	3439.
11	1320.	1172.	361.	186.	3039.	040.	892.	331.	186.	2449.	1	3039.
12	1093*	945.	339.	186.	2563.	981.	833.	327.	186.	2327.	1	2563.
13	1011.	863.	327.	186.	2387.	1011.	863.	327.	186.	2387.	1	2307,
14	1041.	893.	327.	1860	244 7.	1041.	893.	327.	186.	2447.	1	2447,
15	1056.	908.	327,	186.	2477.	1056.	908.	327.	186.	2477.	1	2477.
16	1056.	908.	327.	186.	2477.	1056.	908.	327.	186.	2477.	1	2477.
17	1056.	908.	327.	186.	2477.	1056.	908.	327,	186*	2477.	1	2477.
18	1056.	908.	327-	186.	2477.	1056.	908.	327.	186.	2477.	1	2477.
19	1056.	908.	327,	186.	2477.	1056.	908.	327.	186.	2477.	1	2477,
20	1056.	908.	327.	186.	2477.	1056.	908.	327,	186.	2477.	1	2477.
21	1056.	908.	327.	186.	2477.	1056.	908.	327.	186.	2477.	1	2477,
22	949.	807.	306.	181.	2243.	949.	8070	3060	181.	2243.	1	2243.
23	842.	706.	285.	176.	2009-	842.	706.	205,	176.	2009.	1	2009.
24	842.	706.	285.	176.	2009.	842.	706.	285.	176.	2009.	1	2009.
25	842.	706.	285.	176.	2009.	842.	706.	285.	176.	2009.	1	2009.
26	842.	706.	285.	176.	2009.	842,	706.	285.	176.	2009-	1	2009.
27	613.	489.	243.	166.	1511.	613.	489.	243.	166.	1511.	1	1511.
28	506a	388.	162.	101.	1157.	506.	388.	162.	101.	1157.	1	1157.
29	307.	201.	36.	7.	551.	307.	"201.	36.	7.	551.	1	551.
30	200.	100.	15.	2.	317.	200.	100.	15.	2.	317.	1	317.

MEDIUM FIND SCENARIO
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TABLE 7-17

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
{MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	b	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	214.	120.	0.	o*	0.	0*	0.	0.	0.	0.	275.	1344.	0.	0.	o*	624.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0*	0.	0.	0.	1344.	0.	o*	o.	312.
2	ONSITE	506.	260.	0.	0.	08	0.	0.	0.	0.	0.	350 *	3136.	0.	400.	0.	1456.
	OFFSITE	3.	280.	0.	o*	0.	0.	0.	0.	0.	0.	0.	3136.	0.	200.	0.	728.
3	ONSITE	604.	320.	0.	0.	0.	0.	o*	0*	0.	o*	400.	3584.	08	800.	0.	1664.
	OFFSITE	7.	320.	o*	0.	0.	0.	0.	0.	0.	0.	00	3584.	0.	400.	0.	832.
4	ONSITE	468.	240.	1600.	0.	0.	1736.	0.	0.	0.	0.	300.	2688.	0.	800.	0.	1248.
	OFFSITE	7.	240.	176.	0.	0.	191.	0.	0.	0.	0.	0.	2688.	0.	400.	0.	624.
5	ONSITE	508.	115.	500.	0.	0.	7006.	1009.	0.	0.	0.	200.	896.	0.	2025.	0.	969.
	OFFSITE	20.	115.	55.	o*	0.	771.	111.	0.	0.	0.	0.	896.	0.	1625.	0.	485.
6	ONSITE	1965.	260.	0.	368.	0.	930.	1009.	0.	0.	0.	100.	896.	1008.	7025.	875.	3290.
	OFFSITE	86.	260.	0.	40.	0.	102.	111.	0.	0.	0.	0.	896.	1008.	6225.	875.	1645.
7	ONSITE	1301.	180.	00	04	o*	0.	0*	0.	1008.	720.	100.	0,	5592.	4300.	0.	1236.
	oFFSITE	41.	180.	0.	00	0.	0.	0.	0*	1008.	720.	0.	0.	5592.	3200.	0.	618.
8	ONSITE	1951.	305.	0.	857.	3120.	o*	0.	0.	1008.	720.	o*	0.	10176.	4425.	1050.	1639.
	OFFSITE	56.	305.	0.	94.	343.	0.	0*	0.	1008.	720.	0.	0.	10176.	2825.	1050.	820.
9	ONSITE	1967.	435.	00	0.	390.	0.	0.	0.	1008.	72o.	0.	o*	13440.	2925.	0.	1245.
	OFFSITE	26.	43s.	0.	o*	43.	0.	0.	o.	1008.	720.	0.	0.	13440.	1725.	0.	623.
10	ONSITE	1908.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	12288.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	0.	0.	0.	0*	0.	1008.	720.	0.	0.	12288.	1200.	0.	576,
11	ONSITE	1854.	480.	0.	o*	0.	0.	0.	o*	1008.	72o.	0.	0.	9096.	2400.	0.	1152.
	OFFSITE	20.	480.	o*	0.	o*	0.	0.	0.	1008.	720.	0.	0.	9096.	1200.	0.	576,
12	ONSITE	1752.	480.	0.	09	0.	0.	0.	0.	10080	720.	0.	0.	7788.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	o*	00	0.	0.	0.	1008.	720.	0.	o*	7788.	1200.	0.	576.
13	ONSITE	1716.	480.	00	0.	0.	0.	0.	0.	1008.	720.	0.	o*	7812.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	7812.	1200.	0.	576.
14	ONSITE	1716.	480.	0.	0.	0.	0.	0.	o*	1008.	720.	0.	0.	8172.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	0.	o*	0.	0.	0.	1008.	7.20.	0.	0.	8172.	1200.	0.	576*
15	ONSITE	1716.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	2400.	0.	1152.
	OFFSITE	20.	480,	0.	0.	0.	0.	00	0.	1008.	720.	0.	0.	8352.	1200.	0.	576.

** SEE ATTACHED KEY OF ACTIVITIES

P

MEDIUM FIND SCENARIO
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TABLE 7-17 (Cont.)

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	1716.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	1200.	0.	576.
17	ONSITE	1716.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	2400.	0.	1152.
	OFFSITE	209	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	1200.	0.	576.
18	ONSITE	1716.	480.	0.	0.	0.	0.	0.	0.	1008.	7.20.	0.	0.	8352.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	0.	0.	09	0.	0.	1008.	720.	0.	0.	8352.	1200.	0.	576.
19	ONSITE	1716.	480.	0.	0.	00	09	0.	0.	1008.	720.	0.	0.	8352.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	09	0.	0.	0.	0.	1008.	720.	0.	0.	8352,	1200.	0.	576.
20	ONSITE	1716.	480,	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	00	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	1200.	0.	576.
21	ONSITE	1716.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	2400.	0.	1152.
	OFFSITE	20.	480.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8352.	1200.	0.	576.
22	ONSITE	1524.	420.	0.	0.	09	0.	0.	0.	1008.	720.	0.	0.	7308.	2400.	0,	1008.
	OFFSITE	20.	420.	0.	0.	0.	0.	0.	0.	1008.	720.	00	0.	7308.	1200.	0.	504.
23	ONSITE	1332.	360.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6264.	2400.	0.	864.
	OFFSITE	20.	360.	0.	0.	0.	0.	0.	00	10080	720.	0.	0.	6264,	12004	0.	432,
24	ONSITE	1332.	360.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6264,	2400.	0.	864.
	OFFSITE	20.	360.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6264.	1200.	0.	432.
25	ONSITE	1332.	360.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6264.	2400.	0.	864.
	OFFSITE	20.	360.	0.	0.	0.	0.	0.	0.	10080	720.	0.	0.	6264.	1200.	0.	432.
26	ONSITE	1332.	360.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6264,	2400.	0.	864.
	OFFSITE	20.	360.	0.	00	0.	0.	0.	0.	1008.	720.	0.	0.	6264,	1200.	0.	432.
27	ONSITE	948.	240.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	3996.	2400,	0.	576.
	OFFSITE	20.	240.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	3996.	1200.	0.	288.
28	ONSITE	756.	180.	0.	0.	0.	0.	0.	00	1008.	0.	0.	0.	2952.	2400.	0.	432.
	OFFSITE	20.	180.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0,	2952.	1200.	0.	216.
29	ONSITE	372.	60.	0.	0.	0.	08	0.	0.	0.	0.	0.	0.	1044.	2400.	0.	144.
	OFFSITE	20.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1044,	1200.	0.	72.
30	ONSITE	180.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2400.	0.	0.
	OFFSITE	.20.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1200.	0.	0.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 7-17 (Attachment)
LIST OF TASKS BY ACTIVITY"

ONSHORE

Activity	
1	Service Bases (Onshore Employment - which would include all onshore administration, service base operations, rig and platform service
	Task 1 - Exploration Well Drilling
	Task 2 - Geophysical Exploration
	Task 5 - Supply/Anchor Boats for Rigs
	Task 6 - Development Drilling
	Task 7 - Steel Jacket Installations and Commissioning
	Task 8 - Concrete Installations and Commissioning
	Task 11 - Single-Leg Mooring System
	Task 12 - Pipeline-Offshore, Gathering, Oil and Gas
	Task 13 - Pipeline-Offshore, Trunk, Oil and Gas
	Task 20 - Gravel Island Construction
	Task 23 - Supply/Anchor Boats for Platform
	Task 24 - Supply/Anchor Boats for Lay Barge
	Task 27 - Longshoring for Platform
	Task 28 - Longshoring for Lay Barge
	Task 31 - Platform Operation
	Task 33 - Maintenance and Repairs for Platform and Supply Boats
	Task 31 - Longshoring for Platform (Production)
	Task 301 - Gravel Island Construction
2	Helicopter Service
	Task 4 - Helicopter for Rigs
	Task 21 - Helicopter Support for Platform
	Task 22 - Helicopter Support for Lay Barge
	Task 34 - Helicopter for Platform
	Construction
3	Service Base
	Task 3 - Shore Base Construction
	Task 10 - Shore Base Construction
4	Pipe Coating
	Task 15 - Pipe Coating
5	Onshore Pipelines
	Task 14 - Pipeline, Onshore, Trunk, Oil and Gas
6	Terminal
	Task 16 - Marine Terminal (assumed to be oil terminal)
	Task 18 - Crude Oil Pump Station Onshore
7	LNG Plant
	Task 17 - LNG Plant
8	Concrete Platform Construction
	Task 19 - Concrete Platform Side Preparation
	Task 20 - Concrete Platform Construction
9	Oil Terminal Operations
	Task 36 - Terminal and Pipeline Operations
10	LNG Plant Operations
	Task 38 - LNG Operations

OFFSHORE

Activity	
11	Survey
	Task 2 - Geophysical and Geological Survey
12	Rigs
	Task 1 - Exploration Well
13	Platforms
	Task 6 - Development Drilling
	Task 31 - Operations
	Task 32 - Workover and Well Stimulation
14	Platform Installation
	Task 7 - Steel Jacket Installation and Commissioning
	Task 8 - Concrete Installation and Commissioning
	Task 11 - Single-Leg Mooring System
	Task 20 - Gravel Island construction
	Task 301 - Gravel Island Construction
15	Offshore Pipeline Construction
	Task 12 - Pipeline Offshore, Gathering, Oil and Gas
	Task 13 - Pipeline Offshore, Trunk, Oil and Gas
16	Supply/Anchor/Tug Boat
	Task 5 - Supply/Anchor Boats for Rigs
	Task 23 - Supply/Anchor Boats for Platform
	Task 24 - Supply/Anchor Boats for Lay Barge
	Task 25 - Tugboats for Installation and Towout
	Task 26 - Tugboats for Lay Barge Spread
	Task 29 - Tugboats for SLMS
	Task 30 - Supply Boat for SLMS
	Task 35 - Supply Boat for SLMS

MEDIUM FIND SCENARIO
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TABLE 7-18

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	ONSHORE	TOTAL
1	2243.	334.	2577.	3899.	454.	4353.	325.	38.	363.
2	5342.	786.	6128.	9406.	1069.	10475*	784.	90.	873.
3	6448.	924.	7372.	11264.	1251.	12515.	939.	105.	1043.
4	5036.	4044.	9080.	8748.	4656.	13406.	729.	389.	11180
5	4050.	9138.	13229.	7(195*	AO21O.	17306.	592.	851.	1443.
6	13194.	4531.	17726.	23843.	5132.	28975.	1987.	428.	2415.
7	11228.	3209.	14437.	20638.	5158.	.?5796.	1720.	430.	2150.
8	17290.	7562.	25252.	32161.	10489.	42649.	2680.	874.	3555.
9	17802.	4520.	22322.	33782.	6751.	40532.	2816.	563.	3378.
10	16224.	4116.	20340.	30672.	6344.	37016.	2556.	529.	3085.
11	13320.	4062.	17382.	24864.	6290.	31154.	2072.	525.	2597.
12	12108.	3960.	16068.	22440.	6188.	28628.	1870.	516.	2386.
13	12132.	3924.	16056.	22488.	6152.	28640.	1874.	513.	2387.
14	12492.	3924.	16416.	23208.	6152.	29360.	1934.	513.	2447 .
15	12672.	3924.	165'26.	23566.	6152.	29720.	1964.	513.	2477.
16	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
17	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
18	12672.	3924.	16596.	23566.	6152.	29720.	1964.	513.	2477.
19	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
20	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
21	12672.	39.24*	16596.	23568.	6152.	29720.	1964.	513.	2477.
22	11388.	3672.	15060.	21072.	5840.	26912.	1756.	407.	2243.
23	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
24	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
25	10104.	3420.	13524.	18S76.	5528.	24104.	1548.	461.	2009.
26	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
27	7356.	2916.	10272.	13224.	4904.	18128.	1102.	409.	1511.
28	6072.	1944.	8016.	10728.	3152.	13680.	694 .	263.	1157.
29	3684.	432.	4116.	6096.	512.	6608.	508.	43.	551.
30	2400.	180.	2580.	3600.	200.	3800.	300.	17.	317.

** TOTAL INCLUDES ONSITE AND OFFSITE

8.0 LOW FIND SCENARIO

8.1 General Description

The low find scenario assumes small commercial discoveries of oil and non-associated gas. The basic characteristics of the scenario are summarized in Tables 8-1 and 8-2. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
380	1,200

These reserves, especially the gas, are barely economic to develop. The oil reserves comprise two fields located between 34 and 58 kilometers (21 and 36 miles) southwest of Nome while the non-associated gas reserves occur in a single field located about 34 kilometers (21 miles) south of Nome (Figure 8-1). No discoveries are made in the inner or outer sounds (Figures 8-1 and 8-2).

Two trunk pipelines, both about 34 kilometers (21 miles) long, transport the oil and gas production direct to a crude oil terminal and LNG plant, respectively, located at Cape Nome. Minimal onshore pipeline construction is involved in the development of these fields.

8.2 Tracts and Location

The discovery tracts and their locations (designated by OCS protraction diagram numbers) are given in Table 8-3. The productive acreage cited relates to the optimal recoverable reserves per acre assumed for the scenario analysis.

8.3 Exploration, Development, and Production Schedules

Exploration, development, and production schedules are shown on Tables 8-4 through 8-14. The assumptions on which these schedules are based are given in Appendix B and E.

TABLE 8-1

LOW FIND OIL SCENARIO

Field Size Oil (MMBBL)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production oil (MB/D)	Water Depth Meters	Water Depth Feet	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal Miles	Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
200	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	10	34	21	14	Cape Nome
1 BO	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	58	36	14	Cape Nome

* S = Ice reinforced steel platform.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 8-2

LOW FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Gas	LNG Plant
		Meters	Feet						Meters	Feet	Kilometers	Miles		
1,200	Central Sound	2,286	7,500	Single steel platform with unshared pipeline to LNG plant	1 S	16	15	240	16	54	34	21	14	Cape Nome

* S = Ice reinforced steel platform.

Source: Dames & Moore

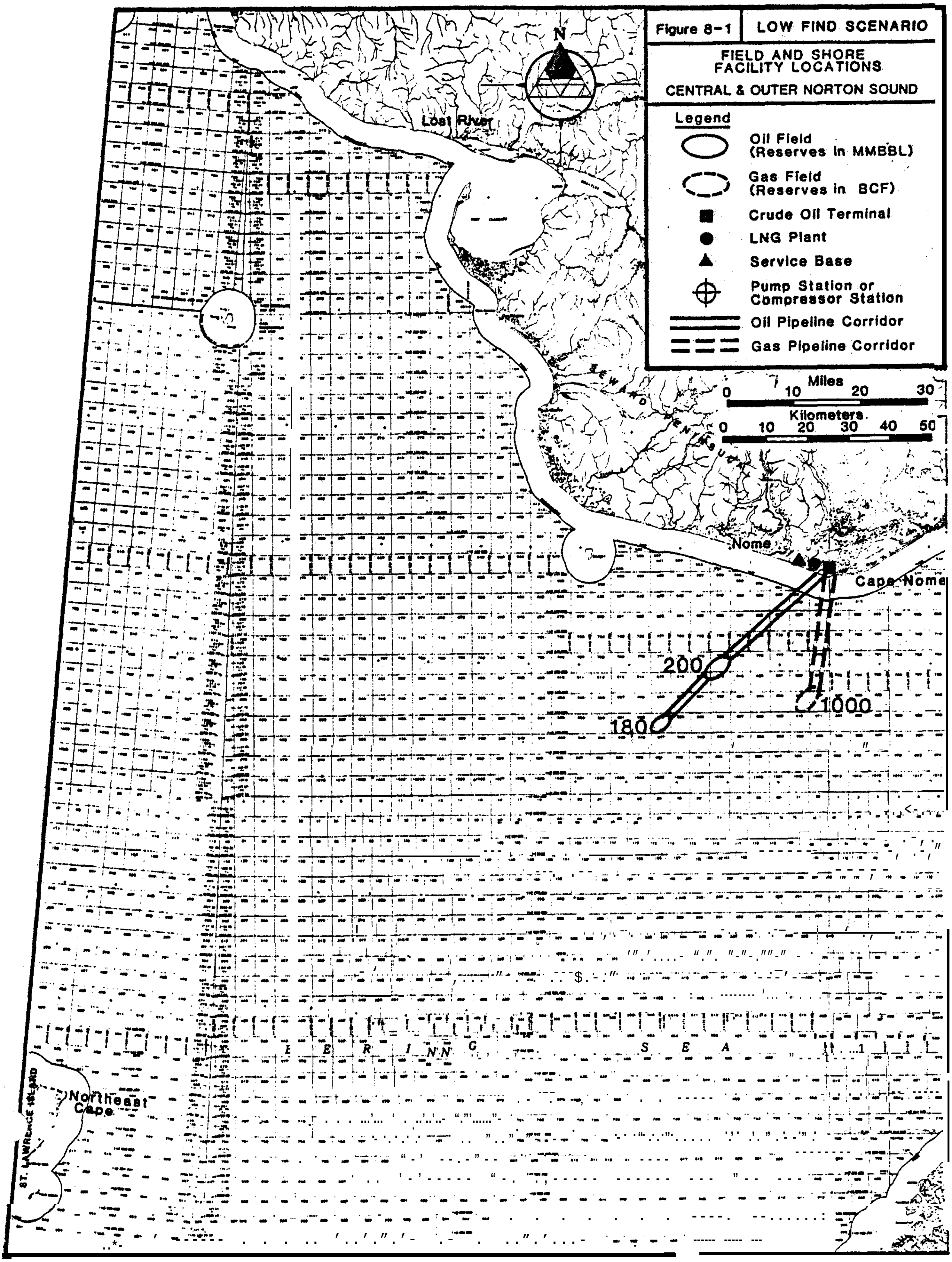
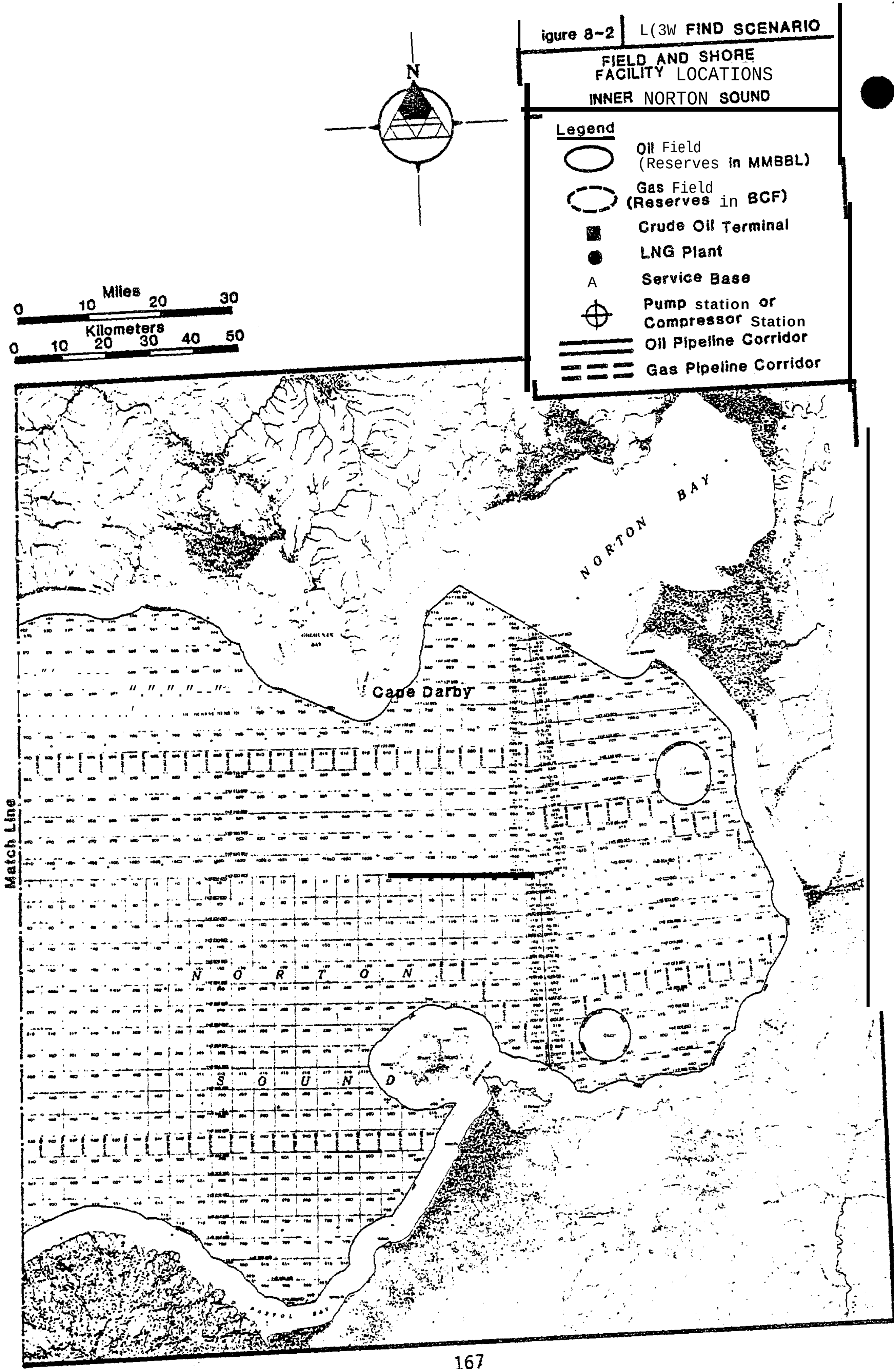


Figure 8-1
LOW FIND SCENARIO
FIELD AND SHORE FACILITY LOCATIONS
CENTRAL & OUTER NORTON SOUND
Legend
Oil Field (Reserves in MMBBL)
Gas Field (Reserves in BCF)
Crude Oil Terminal
LNG Plant
Service Base
Pump Station or Compressor Station
Oil Pipeline Corridor
Gas Pipeline Corridor
Miles
0 10 20 30
Kilometers
0 10 20 30 40 50
N
Lost River
SEWARD PENINSULA
Nome
Cape Nome
200
180
1000
BERING SEA
Northeast Cape
ST. LAWRENCE ISLAND



igure 8-2
LOW FIND SCENARIO
FIELD AND SHORE FACILITY LOCATIONS
INNER NORTON SOUND
Legend
Oil Field (Reserves in MMBBL)
Gas Field (Reserves in BCF)
Crude Oil Terminal
LNG Plant
Service Base
Pump station or Compressor Station
Oil Pipeline Corridor
Gas Pipeline Corridor
N
Miles
0 10 20 30
Kilometers
0 10 20 30 40 50
NORTON BAY
Cape Darby
Match Line
N O R T O N
S O U N D

TABLE 8-3

LOW FIND SCENARIO - FIELDS AND TRACTS

Location	Field Size		Acres [1]	Hectares	No. of Tracts [2]	OCS Tract Numbers [3]
	Oil (mmbbl)	Gas (bcf)				
Central Sound	200	--	3,333	1,349	0.6	773, 774, 817, 818
Central Sound	180	--	3,000	1,214	0.5	903
Central Sound	--	1,200	4,000	1,618	0.7	866, 867

[1] Recoverable reserves in the scenario are assumed to be 60,000 barrels per acre for oil and 300 mmcf for non-associated gas.
[2]. A tract is 2,304 hectares (5,693 acres).
[3] Tracts listed include all tracts that are involved in the surface expression of an oil or gas field. In some cases only portions (a corner, etc.) of a tract are involved. However, the entire tract is listed above. (See Figures 8-1 and 8-2 for exact tract location and portion involved in surface expression of fields.)

Source: Dames & Moore

TABLE 8-4

EXPLORATION SCHEDULE FOR EXPLORATION AND DELINEATION WELLS - LOW FIND SCENARIO

Well Type	Year After Lease Sale																				Well Totals
	1		2		3		4		5		6		7		8		9		10		
	Rigs	Wells[3]	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	
Exp.[1]	2	4	4	6.	5	5	6	9	3	5	1	2									30
Del.[2]						4		2													6
TOTAL		4		6		9		11		5		2									36

[1] In this high find scenario a success rate of one significant discovey for approximately every 10 exploration wells is assumed. This is consistent with a 10 percent success rate in U.S. offshore areas in the past 10 years although higher than the average of the past five years (Tucker, 1978).
[2] The number of delineation wells assumed per discovery is two field sizes of less than 500 mmbbl oil or 2,000 bcf gas, and three for fields of 500 mmbbl oil and 2,000 bcf gas and larger.
[3] An average completion time of four months pre exploration/delineation well is assumed. The drilling season is assumed to be extended to a maximum of eight months by ice breaker support. In addition, the limited use of summer-constructed gravel islands to extend drilling into the winter is also postulated.

Source: Dames & Moore

TABLE 8-5

TIMING OF DISCOVERIES - LOW FIND SCENARIO

Year After Lease Sale	Type	Reserve Size		Location	Water Depth	
		Oil (mmbbl)[1]	Gas (bcf)		Meters	Feet
2	Oil	200	--	Central Sound	21	70
2	Oil	180	--	Central Sound	16	54
3	Gas	--	1,200	Central Sound	21	70

[1] Assumes field has low GOR and associated gas is used to power platform and reinfected.

Source: Dames & Moore

TABLE 8-6

PLATFORM CONSTRUCTION ANO INSTALLATION SCHEDULE - LOW FIND SCENARIO

Location	Field		Year After Lease Sale											
	Oil (MMBBL)	Gas (BCF)	1	2	3	4					9	10	11	12
Central Sound	200	--		*		D		ΔS						
Central Sound	180	--		*		D		ΔS						
Central Sound	--	1,200			*		D		As					
OTALS								2(s)	1(s)	1(S)				

* = Discovery; D = Decision to Develop; AS = Steel Platform

Notes:

1. Steel platform installation is assumed to begin in June in each case; gravel island construction starts the year after decision to develop and takes two summer seasons.
2. Platform "installation" includes module lifting, hook-up, and commissioning.

Source: Darnes & Moore

TABLE 8-7

DEVELOPMENT WELL DRILLING SCHEOULE - LOW FIND SCENARIO

Location	Field		Platforms		No. of Drill Rigs Per Platform	Total No. of Production Wells	Other Wells'	Start of Drilling	Year After Lease Sale - No. of Wells Drilled[3]																
	Oil (MMBBL)	Gas (BCF)	Nos.	Type[1]				Month	1	2	3	4	5					1 0	11	12	13		15	16	17
Central Sound	200	--	1	S	2	40	8	Apri 1						4s	12	16P	16	4			W				
Central Sound	180	--	1	S	2	40	8	April						ΔS	12	16P	16	4			W				
Central Sound	--	1,200	1	s	1			Apri 1							ΔS	6P	8	2							
TOTALS															24	38	40	10							

[1] S = Steel
[2] Platforms sized for 40 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 40 well slots are assumed to have one drill rig operating during development drilling. .
[3] Drilling progress is assumed to be 45 days per well.
[4] Gas or water injection wells etc., well allowances assumed to one well for every five oil production wells.
AS = Platform arrives on Site -- assumed to be June; platform installation and commissioning assumed to take 10 months.
W = Work over commences -- assumed to be five years after beginning of production from platform.
P = Production starts; assumed to occur when first 10 oil wells are completed or first four gas wells.

Source: Dames & Moore

TABLE 8-8

EXPLORATION AND PRODUCTION GRAVEL ISLANDS -.
LOW FIND SCENARIO

Year After Lease Sale	Exploration 7.5 m (25 ft)	Exploration 15 m (50 ft)	Production	Total	Number of Construction Spreads
1					
2	1			1	1
3		1		1	1
4		1		1	1
5		1		1	1
6					
7					
8					
9					
10					
TOTALS	1	3	0	10	N/A

TABLE 8-9

PIPELINE CONSTRUCTION SCHEDULE - LOW FINO SCENARIO - KILOMETERS (MILES) CONSTRUCTED BY YEAR

	Pipeline Diameter (inches)		Water Depth		Year After Lease Sale										
	Oil	Gas	Meters	Feet	1	2	3	4	5	6	7	8	9	10	11
Offshore	14		0-18	0-60							31 (19)				
	12		18	60							24 (15)				
		14	0-18	0-60							31 (19)				
	Subtotal										86 (53)				
Onshore	14										3 (2)				
		14									3 (2)				
	Subtotal										6 (4)				
Total											92 (57)				

Source: Dames & Moore

TABLE 8-10

MAJOR FACILITIES CONSTRUCTION SCHEDULE - LOW FIND SCENARIO

Facility[1]/Location	Peak Throughput Oil (MBD)	Peak Throughput Gas (MMCFD)	Year After Lease Sale 1	2	3	4	5	6	7	8	9	10	11	12
Cape Nome Oil Terminal	153.6	--												
Cape Nome LNG Plant	--	230.4												
Cape Nome Support Base (permanent)	(small)													

[1] Assume construction starts in spring of year indicated.

Source: Dames & Moore

TABLE 8-11

FIELD PRODUCTION SCHEDULE - LOW FIND SCENARIO

Location	Field		Peak Production		Year After Lease Sale			Years of Production[1]
	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	
Central Sound	zoo	--	76.8	--	8	27	11	20
Central Sound	180	--	76.8	--	8	22	11	15
Central Sound	--	1,200	--	230.4	8	32	11-19	25

[1] Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms.

Source: Dames & Moore

TABLE 8-12

LOW FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL) Central Sound 200	180	Totals
1983	1			
1984	2			
1985	3			
1986	4			
1987	5			
1988	6			
1989	7			
1990	8	7.008	7.008	14.016
1991	9	14.016	14.016	28.032
1992	10	21.024	21.024	42.048
1993	11	28.032	28.032	56.064
1994	12	27.050	26.962	54.012
1995	13	22.401	20.788	43.189
1996	14	17.432	16.028	33.460
1997	15	13.897	12.357	26.254
1998	16	11.000	9.527	20.527
1999	17	8.886	7.346	16.232
2000	18	6.835	5.66.3	12.498
2001	19	5.250	4.366	9.616
2002	20	4.154	3.366	7.520
2003	21	3.286	2.595	6.881
2004	22	2.600	0.922	3.522
2005	23	2.057		2.057
2006	24	1.628		1.628
2007	25	1.288		1.288
2008	26	1.019		1.019
2009	27	0.837		0.837
2010	28			
2011	29			
2012	30			
2013	31			
2014	32			
2015	33			
2016	34			

Peak Oil Production = 153,600 b/d

Source: Dames & Moore

TABLE 8-13

LOW FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL NON-ASSOCIATED GAS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound	Totals
1983	1		
1984	2		
1985	3		
1986	4		
1987	5		
1988	6		
1989	7		
1990	8	21.024	21.024
1991	9	42.048	42.048
1992	10	63.072	63.072
1993	11	84.096	84.096
1994	12	84.096	84.096
1995	13	84.096	84.096
1996	14	84.096	84.096
1997	15	84.096	84.096
1998	16	84.096	84.096
1999	17	84.096	84.096
2000	18	84.096	84.096
2001	19	84.096	84.096
2002	20	69.600	69.600
2003	21	54.680	54.680
2004	22	42.933	42.933
2005	23	33.710	33.710
2006	24	26.468	26.468
2007	25	20.782	20.782
2008	26	16.317	16.317
2009	27	12.812	12.812
2010	28	10.059	10.059
2011	29	7.888	7.888
2012	30	6.193	6.193
2013	31	4.862	4.862
2014	32	3.817	3.817
2015	33		
2016	34		

Peak Gas Production = 230.4 MMCFD.

Source: Dames & Moore

TABLE 8-14

MAJOR SHORE FACILITIES START UP AND SHUT DOWN DATES - LOW FIND SCENARIO

Facility	Year After Lease Sale	
	Start Up Date[1]	Shut Down Date[2]
Cape Nome Oil Terminal	8	27
Cape Nome LNG Plant	8	32

[1] For the purposes of manpower estimation start up is assumed to be January 1.
[2] For the purposes of manpower estimation shut down is to be December 31.

Source: Dames & Moore

Exploration commences in the first year after the lease sale (1983), peaks in year 4 with 12 wells drilled, and terminates in year 6 with a total of 36 wells drilled (Table 8-4). No discoveries are made until the second year of exploration when two small oil fields southwest of Nome are discovered (Table 8-5) . The only commercial gas discovery is made in year 3 (1985) after which no further commercial hydrocarbon finds are made. The exploration program involves jack-up rigs and drillships (in the outer sound) and limited use of summer-constructed gravel islands in shallow water (15 meters [50 feet] or less) where suitable borrow materials are either adjacent to the well site or within economic haul distance. Economics dictate extension of the drilling season from the four to six month open-water season to a maximum of eight months; this is accomplished by the use of ice-breaker support.

The decision to develop the two small oil fields is made concurrently in year 4. Single ice-reinforced steel platforms for each field are installed 24 months later (Table 8-6). Development drilling commences in year 7 and crude production is brought on line in year 8 (1990). Field construction to develop the gas field starts with the installation of a single steel platform in year 7 (1989) and gas production commences the following year (1990).

Oil and gas production from Norton Sound both start in year 8 (19'30). Oil production peaks at 153,000 b/d in year 11 (1993) and ceases in year 27 (2009) (Tables 8-11 through 8-12). Gas producti on peaks at 230.4 mmcfd in years 11 through 19 (1993 through 2001), and ceases n year 32 (2014) ("Tab"es 8-11 and 8-13).

8.4 Facility Requirements and Locations

Facility requirements (platforms, pipelines, terminals, etc.) and related construction scheduling are summarized in Tables 8-6 through 8-10, As with the high and medium find scenarios, this scenario also assumes that all oil and gas production is brought to shore to a single crude oil terminal and LNG plant, respectively, both located at Cape Nome.

The major facility constructed is a small crude oil terminal located at Cape Nome. The terminal, which is designed to handle the estimated peak production of about 150,000 bpd, completes crude stabilization, recovers LPG, treats tanker ballast water, and provides storage for about two million barrels of crude (approximately 14 days production). Terminal configuration includes a buried pipeline to a single-berth loading platform located approximately four kilometers (2.5 miles) offshore. This berth is designed to handle 70,000 DWT tankers that transport crude to the U.S. west coast. The tankers are conventional tankers reinforced for Bering Sea ice; ice-breaker support for these tankers is required.

The other major facility, also located at Cape Nome, is a small LNG plant designed to handle the estimated peak gas production of about 230 million cubic feet per day. The LNG plant is a modularized barged-in facility and has a single berth loading platform designed to handle 130,000m^3 LNG tankers. A fleet of two tankers transports the LNG to the U.S. west coast. With a loading frequency of once every ten days, storage capacity for about 15 days of LNG production is provided at the plant.

A forward service base supporting construction and operation of the Norton Sound fields is constructed adjacent to the Cape Nome facilities. Field construction is also supported by storage and accommodation barges and freighters, moored in Norton Sound, and a rear support base located in the Aleutian Islands.

The exploration phase of petroleum development in Norton Sound involves aerial support and light supply transshipment provided by Nome, storage barges and freighters moored in Norton Sound, and an Aleutian island storage and transshipment facility,

8.5 Manpower Requirements

Manpower requirements associated with this scenario are shown in Tables 8-15 through 8-18.

LOW FIND SCENARIO
09/24/79

TABLE 8-15

ONSITE MANPOWER REQUIREMENTS BY 1NDUSTR%
{ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	996.	104.	0*	0.	416.	112.	0.	1412.	216.	1628.
2	1494.	156.	400.	30.	624.	168.	0.	2518.	354.	2872.
3	1992.	208.	800.	60.	832.	224.	0.	3624.	492.	4116.
4	2988.	312,	800.	60.	1248.	336.	0.	5036.	708.	5744.
5	996.	104.	800.	938.	416.	112.	0.	2212.	1154.	3366.
6	498.	52.	2450 .	1912.	1314.	490.	0.	4262.	2454.	6716.
7	2016.	216.	2800.	3461.	1282.	496.	0.	6098.	4173.	10272.
8	5'784.	486.	525.	53*	669.	801.	460.	6978.	1820.	8797.
9	5952.	504.	0*	0.	432.	708.	480.	6384.	1692.	8076.
10	3936.	288.	268.	288.	432.	708.	480.	4656.	1764.	6420.
11	2760.	162.	288.	288.	432.	708.	480.	3480.	1638.	5118.
12	2592.	144.	288.	288.	432.	708.	480.	3312.	1620.	4932.
13	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472.
14	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472.
15	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472.
16	3132.	144.	288.	288,	432.	708.	480.	3852.	1620.	5472.
17	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472.
18	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472.
19	3132.	144.	288.	288,	432.	708.	480.	3852.	1620.	5472.
20	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472.
21	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472,
22	3132.	144.	288.	288.	432.	708.	480.	3852.	1620.	5472.
23	2268.	96.	192.	192,	288.	600.	480.	2748.	1368.	4116.
24	2268.	96.	192.	192.	288.	600.	480.	2748.	1368.	4116.
25	2178.	96.	192.	192.	288.	600.	400.	2658.	1368.	4026.
26	2068.	96.	192.	192.	288.	600.	480.	2568.	1368.	3936.
27	2088.	96.	192.	192.	288.	216.	480.	2568.	984.	3552.
28	1044.	48.	96.	96.	144.	106.	480.	1284.	732.	2016.
29	1044.	48.	96,	96,	144.	108.	480.	1284.	732.	2016.
30	1044.	48.	96.	96.	144.	108.	480.	1284.	732.	2016.

LOW FIND SCENARIO
09/??24/79

TABLE 8-16

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0*	0.	189.	138.	28.	10.	365.	5	365.
2	0.	0.	0.	09	0.	471.	307.	56,	17.	851.	6	851.
3	0.	0.	0.	09	o*	570.	376.	71*	22*	1047.	6	1047.
4	0*	0.	0.	08	0.	742.	514.	97.	32.	1385.	6	1412.
5	0.	0.	0.	0.	o*	389.	238.	175.	26.	828.	8	876.
6	o*	0*	0.	0.	0.	590.	498.	238.	33.	1359,	10	1572.
7	508.	429.	534.	62.	1533.	738.	656.	446.	50.	1889.	6	1932.
8	730.	673.	184.	94*	1680.	532.	514*	141.	87.	1274.	1	1680.
9	532*	514.	141.	87.	1274.	532.	514.	141.	87.	1274.	1	1274.
10	556.	538 .	165.	87.	1346.	332.	314.	141.	87.	874.	1	1346.
11	332.	314.	141.	87.	874.	276.	258.	135.	87.	756.	1	874.
12	276.	258.	135.	87.	756.	276.	258 .	135.	87.	756.	1	756.
13	321.	303.	135.	87.	846.	321.	303.	135.	87.	846.	1	846.
14	321.	303.	135*	87.	846.	321.	303.	135.	87.	846.	1	846.
15	321.	303.	135.	87.	846.	321.	303.	135.	87.	846.	1	846.
16	321.	303.	1354	87.	846.	321.	303.	135.	87.	846.	1	846.
17	321.	303.	135.	87.	846.	321.	303.	135.	87.	846.	1	846.
18	321.	3030	135.	87.	846.	321.	303.	135.	87.	846.	1	846.
19	321.	303.	135.	87.	846,	321.	303.	135.	87.	846.	1	846.
20	321.	303.	35*	87.	846.	321.	303.	135*	87.	846,	1	846.
21	321.	303.	359	87*	846.	321.	303.	135.	87,	846.	1	846.
22	321.	303.	35*	87.	846.	321.	303.	135.	87.	846.	1	846.
23	229.	217.	14.	82.	.@~-	229.	217.	114.	82.	642.	1	642.
24	229.	217.	14.	82.	642.	229.	217.	114.	82.	642.	1	642.
25	229.	217.	14.	-432.	642.	214.	2020	114.	82,	612.	1	642.
26	214.	202.	14.	82.	612.	214.	2029	114.	82.	612.	1	612.
27	214.	202.	82.	50.	548.	214.	202.	82.	50.	548.	1	548.
28	107.	101.	61.	45.	314.	107.	101.	61.	45.	314.	1	314.
29	107.	101.	61.	45*	314.	107.	101.	61.	45.	314.	1	314.
30	107.	101.	61.	45.	314.	107.	101.	61.	45.	314.	1	314.

LOWFIND SCENARIO
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TABLE 8-17

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	136.	80.	0*	0.	0.	0*	0.	0.	0.	0.	100.	896.	0*	0.	0.	416.
	OFFSITE	0.	80.	0*	0.	0*	0.	0.	0.	0.	0.	0*	896.	0.	0*	0.	208.
2	ONSITE	234.	120.	0.	0.	0.	0.	0.	0.	0.	0.	150.	1344.	0.	400.	0.	624.
	OFFSITE	3*	120.	0.	0*	0.	0.	0.	0.	0.	0.	0.	1344.	0.	200.	0.	312.
3	ONSITE	332.	160.	0*	0.	0.	0.	0*	0.	0.	0.	200.	1792.	0.	800.	0.	832.
	OFFSITE	7.	160.	0.	0*	0.	0.	0*	0.	0*	0.	0.	1792.	0.	400.	0.	416.
4	ONSITE	468.	240.	0.	0*	0.	0*	0.	0.	0.	0.	300.	2688.	00	8000	0.	1248.
	OFFSITE	7*	240.	0.	0.	0.	0.	0.	0.	0.	0.	0*	2688.	0*	400.	0.	624.
5	ONSITE	196.	80.	878.	-0.	0*	0.	0.	0.	0.	0.	100.	896.	0.	800,	0.	416.
	OFFSITE	7.	80.	97.	0.	0.	0.	0.	0.	0.	0.	0.	896,	0.	400.	0.	208,
6	ONSITE	677.	110.	0.	0*	0.	1092.	575.	0*	0.	0*	50.	448,	0.	2450-	0,	1314.
	OFFSITE	27.	110.	0*	0.	0.	120.	63.	0.	0.	0.	0.	448.	0.	2450.	0.	657.
7	ONSITE	933.	80.	0*	368.	0.	2418.	375*	0.	0*	0.	0.	0*	2016.	2275,	5.25.	1282.
	OFFSITE	33.	80.	0*	40.	0.	266.	41.	0.	0.	0.	0.	0.	2016.	2275.	525.	641.
8	ONSITE	760.	195.	0.	0.	0.	00	0.	0*	384*	480.	0.	0.	5784.	525.	0.	669.
	OFFSITE	6.	195.	0.	0.	0.	0.	0.	0*	384.	480.	0*	0.	5784.	525.	0.	335.
9	ONSITE"	648.	180.	0.	0*	0.	0.	0.	0.	384.	480.	0.	0.	5952 .	0.	0.	432.
	OFFSITE	0.	180.	0*	0.	0.	0*	0.	0.	364.	480.	0.	0.	5952.	0*	0.	216,
" 10	ONSITE	720.	180.	0.	0*	0.	0.	0*	0.	384.	480.	0.	0.	3936.	0*	0.	43.2.
	OFFSITE	0*	180.	0.	0*	0.	00	00	0.	384.	480.	0.	0*	3936.	0.	o*	216.
11	ONSITE	594.	180.	0*	0.	0.	0.	0.	0.	384.	480.	0.	0.	2760.	0*	o.	432.
	OFFSITE	0.	180.	0*	0*	0.	0.	0.	0.	3a4.	480.	0.	0.	2760.	0.	0.	.216.
12	ONSITE	576.	180.	0.	0.	0.	0.	0*	0.	384.	480.	0.	0.	2592.	0.	0.	43.?.
	OFFSITE	0.	180.	0.	0.	0*	0.	0.	0.	384.	480.	0.	0.	2592.	0.	0.	216.
13	ONSITE	576.	180.	0.	0.	0*	0*	0.	0.	384.	480,	0.	0.	3132.	0.	0.	432.
	OFFSITE	0.	180.	0*	0.	0.	0*	0.	0.	384.	480,	0.	0*	3132.	0*	0.	216.
14	ONSITE	576.	180.	0.	0.	0.	0*	0.	0*	384.	480.	0.	0.	3132.	0*	0.	432.
	OFFSITE	0.	180.	0*	0.	0.	u.	0.	0.	384.	480.	0.	0.	3132.	0.	0.	216.
15	ONSITE	576.	180.	0.	0.	0*	o.	0.	0.	384.	480.	0.	0.	3132.	0.	0.	43.?.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3132.	0.	0.	216.

** SEE ATTACHED KEY OF ACTIVITIES

LOW FIND SCENARIO
09/24/79

TABLE 8-17 (Cont.)

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	576.	180.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3132.	0.	0.	432.
	OFFSITE	0*	180.	0*	0.	0.	0.	0.	0.	384.	480.	0.	0*	3132.	0.	0.	216.
17	ONSITE	576.	180.	00	00	0.	0*	0.	0*	384.	480.	0.	0.	3132.	0*	0.	432.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3132.	0*	0.	216.
18	ONSITE	576.	180.	0.	0.	0.	0.	0.	0*	384.	480.	0.	0.	31320	0.	0.	432.
	OFFSITE	00	180.	0.	0.	0.	0.	0.	0.	304.	480.	0.	0.	3132.	0.	0.	216.
19	ONSITE	576..	180.	0.	0.	0.	0.	0.	0.	384.	460.	0*	0.	3132.	0.	0.	432.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3132.	0.	0.	216.
20	ONSITE	576.	180.	0*	0.	0.	0*	0.	0.	384.	480.	0.	0.	3132.	0.	0.	432.
	OFFSITE	0*	180.	0.	0.	0.	0.	0.	0*	384.	480.	0.	0.	3132.	0.	0.	216.
21	ONSITE	576.	180.	0*	0.	0?.	0.	0.	0.	384.	480.	0.	0.	3132.	0*	0.	432.
	OFFSITE	0.	180.	0.	0.	0*	0*	0.	0.	384 .	480.	0.	0.	3132.	0.	0.	216.
22	ONSITE	576.	180.	0*	0.	0.	0.	0.	0*	384.	480.	0.	00	3132.	0.	0.	432.
	OFFSITE	0.	180.	0*	0.	0.	0.	0.	0.	384.	480.	0.	0.	3132.	0.	0.	216.
23	ONSITE	384.	120.	0*	0*	0.	0.	00	0*	384.	480.	0.	0*	2268.	0,	0.	288.
	OFFSITE	0.	120.	0.	0*	0.	0.	0.	0.	384.	480.	0*	0.	226a*	0.	0*	144*
24	ONSITE	384.	120.	09	0.	0..	0.	0*	0.	384.	480.	0.	0.	2268.	0.	0*	288.
	OFFSITE	0.	120.	0.	0*	0.	0.	0.	0.	384.	480.	0*	0.	2268.	0.	0.	144.
25	ONSITE	384.	120.	0*	0.	0.	0.	0.	0.	384.	480.	0*	0*	2178.	0*	0.	288.
	OFFSITE	0*	120.	0.	0.	0*	0.	0.	0.	384.	480.	0.	0.	2178.	00	0.	144.
26	ONSITE	384.	120.	0*	0*	0.	0.	0.	0*	384.	480.	0.	0.	2088.	0.	0*	288.
	OFFSITE	0.	120.	0.	0.	0.	0*	0.	0.	384.	480.	0.	0.	2088.	0.	0.	144.
27	ONSITE	384.	120.	0.	0*	0.	0.	0.	0.	0.	480.	0.	0.	2088.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	2088.	0.	0*	144.
28	ONSITE	192.	60.	0.	0.	0.	0.	0.	0.	0.	4$0.	0.	0.	1044.	0.	0.	144.
	OFFSITE	0*	60.	0.	0*	0.	0.	0.	0.	0.	480.	0*	0.	1044.	0.	0*	7.2.
29	ONSITE	192.	60.	0.	0.	0.	00	0*	0.	0.	480.	0.	0*	1044.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1044.	0.	0.	72.
30	ONSITE	192.	600	0.	0.	0.	0.	0*	0.	0.	480.	0.	0.	1044.	0.	0*	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0*	480.	0.	0*	1044.	0*	00	72.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 8-17 (Attachment)
LIST OF TASKS BY ACTIVITY

ONSHORE

Activity	
1	**Service Bases** (Onshore Employment - which would include all onshore administration, service base operations, rig and platform service Task 1 - Exploration Well Drilling Task 2 - Geophysical Exploration Task 5 - Supply/Anchor Boats for Rigs Task 6 - Development Drilling Task 7 - Steel Jacket Installations and Commissioning Task 8 - Concrete Installations and Commissioning Task 11 - Single-Leg Mooring System Task 12 - Pipeline-Offshore, Gathering, Oil and Gas Task 13 - Pipeline-Offshore, Trunk, Oil and Gas Task 20 - Gravel Island Construction Task 23 - Supply/Anchor Boats for Platform Task 24 - Supply/Anchor Boats for Lay Barge Task 27 - Longshoring for Platform Task 28 - Longshoring for Lay Barge Task 31 - Platform Operation Task 33 - Maintenance and Repairs for Platform and Supply Boats Task 37 - Longshoring for Platform (Production) Task 301 - Gravel Island Construction
2	Helicopter Service Task 4 - Helicopter for Rigs Task 21 - Helicopter Support for Platform Task 22 - Helicopter Support for Lay Barge Task 34 - Helicopter for Platform
3	Construction Service Base Task 3 - Shore Base Construction Task 10 - Shore Base Construction
4	Pipe Coating Task 15 - Pipe Coating
5	Onshore Pipelines Task 14 - Pipeline, Onshore, Trunk, Oil and Gas
6	Terminal Task 16 - Marine Terminal (assumed to be oil terminal) Task 18 - Crude Oil Pump Station Onshore
7	LNG Plant Task 17 - LNG Plant
8	Concrete Platform Construction Task 19 - Concrete Platform Site Preparation Task 20 - Concrete Platform Construction
9	Oil Terminal Operations Task 36 - Terminal and Pipeline Operations
10	LNG Plant Operations Task 38 - LNG Operations

OFFSHORE

Activity	
11	Survey Task 2 Geophysical and Geological Survey
12	Rigs Task 1 - Exploration Well
13	Platforms Task 6 - Development Drilling Task 31 - Operations Task 32 - Workover and Well Stimulation
14	Platform Installation Task 7 - Steel Jacket Installation and Commissioning Task 8 - Concrete Installation and Commissioning Task 11 - Single-Leg Mooring System Task 20 - Gravel Island Construction Task 301 - Gravel Island Construction
15	Offshore Pipeline Construction Task 12 - Pipeline Offshore, Gathering, Oil and Gas Task 13 - Pipeline Offshore, Trunk, Oil and Gas
16	Supply/Anchor/Tug Boat Task 5 - Supply/Anchor Boats for Rigs Task 23 - Supply/Anchor Boats for Platform Task 24 - Supply/Anchor Boats for Lay Barge Task 25 - Tugboats for Installation and Towout Task 26 - Tugboats for Lay Barge Spread Task 29 - Tugboats for SLMS Task 30 - Supply Boat for SLMS Task 35 - Supply Boat for SLMS

LOW FIND SCENARIO
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TABLE 8-18

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL (MAN-MONTHS)			TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE)		
	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL
1	1412.	216.	1628.	2516.	296.	2812.	210.	25.	235.
2	2518.	354.	2872.	4374.	477.	4851.	365.	40.	405.
3	3624.	492.	4116.	6232.	659.	6891.	520.	55.	575.
4	5036.	708.	5744.	874a.	95S.	9703.	729.	80.	809.
5	2212.	1154.	3366.	3716.	1337.	5053.	310.	112.	422.
6	4262.	2454.	6716.	7817.	2774.	10591.	652.	232.	aa3.
7	6098.	4173.	10272.	11555.	4:34.	16189.	963.	387.	1350.
&	6978.	1820.	8797.	13622.	2884.	16506.	1136.	241.	1376.
9	4384,	1692.	8076.	12552.	2736.	15288.	1046.	228.	1274.
10	4656.	1764.	6420.	9096.	2808.	11904.	758.	234.	992.
11	3480.	1638.	5118.	6744.	2682.	9426.	562.	224.	786.
12	3312.	1620.	4932.	640a.	2664.	9072.	534.	222.	756.
13	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
14	3852.	1620.	5472.	7488.	2664.	10152.	624.	222*	a46.
15	3852.	1620.	5472.	7488.	2664.	10152.	624.	222*	846.
16	3852.	1620.	5472.	7488.	2664.	10A52.	624.	222.	846.
17	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
18	3852.	1620.	5472.	7488.	2664.	10152.	624.	222*	846.
19	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
20	3852.	1620.	5472.	7.488.	2664.	10152.	624.	2.22.	846.
21	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
22	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
23	2748.	1368.	4116.	5352.	2352.	7704.	446.	196.	642.
24	2748.	1368.	4116.	5352.	2352.	7704.	446.	196.	642.
25	2658.	1368.	4026.	5172.	235.2.	7524.	431.	196.	627.
26	2568.	1368.	3936.	4992.	2352.	7344.	416.	196.	612.
27	2568.	984.	3552.	4992.	1584.	6576.	416.	132.	54a,
28	1284.	732.	2016.	2496.	1272.	3768.	208.	106.	314.
29	1284.	732.	2016.	2496.	1272.	3768.	208.	106.	314.
30	1284.	732.	2016.	2496.	1272.	3768.	208.	106.	314.

** TOTAL INCLUDES ONSITE AND OFFSITE

8.6 Environmental Considerations

The low find case will presumably bear all of the impacts discussed under exploration only scenario but impacts arising from development will be reduced to those associated with offshore pipelines, drilling and construction of gravel islands, and terminal facilities at Nome.

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APPENDIX A

APPENDIX A

THE ECONOMICS OF FIELD DEVELOPMENT IN THE NORTON BASIN

I. Introduction

The economic analysis of the development of oil and gas resources in the Norton Sound evaluated three basic production systems and a variety of physical parameters that effect the economic results.

1. Ice reinforced steel platform with a pipeline to a new shore terminal;
2. Gravel Island in shallow water with a pipeline to a new shore terminal;
3. Ice reinforced steel platform with offshore loading.

The steel reinforced platforms with a pipeline to a new shore terminal were evaluated under the following physical parameters.

I.1 Oil

1. Initial Production rates: 1000, 2000, 5C00 B/D/well;
2. Reservoir Target Depth: 762 meters (2500 feet), 1525 meters (5000 feet), 2286 meters (7500 feet);
3. Water Depth: 15 meters, 30 meters, 45 meters;
4. Pipeline distance to shore: 16 to 160 kilometers (10 miles to 100 miles).

Cases were screened in 1979 dollar values with the mid-range well-head price assumed to be $18.00. This well-head price is tied to the world price of OPEC "marker" crudes laid-into the Gulf Coast of the United States as explained in Chapter 3[1]. All cases were price sensitivity tested with upper and lower oil prices equal to $25.00 and $14.50. So, too, all cases were sensitivity tested with upper and lower limit costs equal to 150% and 75% of the mid-range values shown. Oil production was assumed to begin with

(1) The economic analysis was conducted prior to the December, 1979, OPEC price increases.

partial capacity in the fifth year and step up to peak production in the seventh year(1). A case to examine the effect of a delay on the project after construction has begun evaluated a one-year and two-year delay.

1.2 Gas

1. Initial Production Rates: 15 or 25 MMCFD/well.
2. Reservoir Target Depth: 762 meters (2500 feet) and 2286 meters (7500 feet).
3. Pipeline distance to shore: 16 kilometers to 100 kilometers (10 miles to 100 miles).

Cases were screened in 1979 dollar values with the mid-range well-head prices assumed to be $2.60. This is based on the Natural Gas Policy Act of 1978. Upper and lower limit prices were assumed to be $2.25 and $3.25 for sensitivity testing. Upper and lower limit costs equal to 150% and 75%.of mid-range values were sensitivity tested.

Gas discovered in the Norton Basin will have to be converted into LNG for transport to major markets. No investment in LNG processing equipment has been included in this analysis. The gas is assumed to be sold to the LNG processor at the end of the pipeline. This economic screening is thus an evaluation of offshore gas production technology under the assumption that another $4-5 per MCF to process and ship LNG could be added to either the mid-range well-head price or the estimated price to earn a 15% hurdle rate of return. Further study would be required to pin-down with greater accuracy the cost of processing and shipping LNG and marketing LNG in domestic west coast or foreign markets at total costs in the range of $5-7 MCF. The results of this study do not imply that gas could be marketed at an economic price. Rather this study only considers whether gas is economical developable given allowable well-head prices. This marketability question is a larger issue, which is addressed in Appensix F.

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(2) From decision to develop; about two years from assumed discovery date.

II. Analytical Results

11.1 Minimum Field Size to Justify Development

11.1.1 Oil

11.1.1.1 Effect of Reservoir Target Depth on Oil Field Development Economics

The amount of oil that can be recovered from a single platform over the lifetime of a field is related to the depth of the reservoir, the angle of deviation that the wells can achieve and the recoverable reserves per acre or acre-foot. Recoverable reserves per acre-foot is dependent on a host of reservoir conditions including porosity, permeability, drive mechanism, connate water percentage, etc.

Assuming 50° angle of deviation a single platform can reach the areas shown on Table A-1 as a function of target depth under ideal conditions. If the oil field is irregularly shaped the platform could reach fewer acres.

Recoverable reserves per acre-foot in the range of 200-600 barrels is not unreasonable. One thousand barrels per acre-foot is possible under extremely ideal conditions, but unlikely in Norton Basin. An acre-foot filled only with oil would contain approximately 7640 barrels. One thousand barrel recovery would imply 13% recovery. But oil does not occur with nothing else in the same space. Oil occurs between sandstone particles and among other mineral deposits and usually with some water mixed in. If half of the space were filled with oil -- 3,820 barrels -- 1000 barrel recovery would imply 26% recovery. In reality, less than half the space is filled with oil under most conditions and primary recovery ranges from 25-35% of reserves.

The assumption that recoverable reserves per acre range from 20,000 to 60,000 barrels implies an assumption about reservoir thickness given our 200-600 barrel per acre-foot assumption. At the extreme values, 32 meter (100 foot) thickness is implied. Although highly prolific fields with reservoirs much thicker than 32 meters (100 feet) exist, the greater number of fields have, in fact, reservoir sections less than 100 feet thick. Table A-1 shows

TABLE A-1

MAXIMUM ULTIMATE RECOVERABLE RESERVES FROM A SINGLE PLATFORM

Reservoir target depth		Area of coverage from a single platform with 50" well deviation	Maximum recoverables reserves at 200000 BBLS/Acre	Maximum recoverables reserves at 600000 BBLS/Acre	Maximum number of wells that can be drilled from a platform with well-spacing of 80 Acres/well	Maximum number of wells that can be drilled from a platform with well-spacing of 160 Acres/well
Meters	(Feet)	Acres	MB			
762	(2,500)	60	12.8	38.4	8	4
1525	(5,000)	1920	38.4	115.2	24	12
2286	(7,500)	4466	89.3	268.0	56	28

Source: Dames & Mooe Calculation

maximum recoverable reserves that can be reached from a single platform associated with the reservoir target depths that fit the geology of the Norton Basin. The geology of the basin suggests that shallow targets may be encountered. Interpretation of Table A-1 shows that for shallow reservoirs:

1. Platforms can only house 8 wells given standard industry spat ng of 80 acres;
2. A single platform can recover only 38.4 million barrels over ·ts lifetime.

Large reservoirs at shallow depths would thus require multiple platforms.

Table A-2 shows the results of the economic analysis of reservoir target depths. The shallow reservoir case -- 762 meters (2500 feet) -- is configured assuming the most optimistic values for water depth - 15 meters (50 feet); initial production rate -- 5000 B/D; and pipeline distance to shore -- 16 kilometers (10 miles).

Constructing this case with three platforms sharing a pipeline to a shore terminal allows for economies in the pipeline cost and thus, improves the economics over a single platform field development. Three platforms can recover a 115.2 $\bar{M}$ barrel field. Column 9 shows that even under these optimistic conditions the shallow reservoir is able to eawrn a return on investment of only 4.8%. Column 10 shows that the well-head value for a barrel of oil would have to be $26.25 to earn 15%.

The production systems for the 1,525 (5,000 feet) and 2,286 (7,500 feet) meter reservoir are exactly comparable. Twenty-four producing wells are the maximum that can be drillied from the platform with a 1,525 meter (5,000 feet) reservoir depth. Forty is the upper limit assumed for the 2,286 meter (7,500 feet) reservoir.

Costs rapidly increase as platform size increases to house more wells to reach deeper targets. Wells to the deeper target are more costly. The

TABLE A-2

EFFECT OF RESERVOIR TARGET DEPTH ON OIL FIELD DEVELOPMENT ECONOMICS

1	2	3	4	5	6	7	8		9		10
Reservoir target depth	Water depth	Pipeline distance to shore terminal (offshore/ on-shore)	Number of platforms	Number of producing wells per platform	Initial production rate per well	Mid-range investment	Minimum field size to earn		Return on Investment for maximum recoverable reserves (1)		Minimum required price (2)
							10Z	15%			
(Meters)	(Meters)	(Km)			(MBD)	($M)	(MB)		(MB)	(%)	($)
762	15	16 - 3	3	a	5,000	$890.6	NE	NE	115.2	4.8	26.2S
1525	45	3 2 - 3	1	2 4	2,000	$443.2	75	NE	115.2	12.8	21.00
2286	45	32-3	1	40	2,000	$803.5	160	240	268	15.1	17.90

NE - Not Economic

Source: Dames & Moore Calculation

(1) Maximum recoverable reserves over the life of the project are defined by the number of producing wells that can reach a reservoir target and the initial production rate of the reservoir. Standard reservoir engineering practices to achieve MER are implied.

(2) The minimum required price Co earn 15% after tax over the production life of maximum recoverable reserves.

platform to house 40 wells is larger and has more equipment to handle the 80,000 B/D peak rate compared to 48000 for 24 wells. The larger peak throughput entails a larger share of shore terminal capacity and a proportionately larger share of terminal cost. In total, Table A-2 shows that the production system for the 2286 meter reservoir is over 80% more costly than the 1525 meter reservoir. However, the rate of return associated with the maximum recoverable reserves on the more costly system is 15.1% compared to 12.8% for the 24 well system. The ability to produce more oil (total reserves) more quickly (peak production rate) through the larger platform overshadows the increased cost. Over the lifetime of the field the deeper target allows maxiumum ultimate recovery of 6.7 $\bar{M}$ barrels per well compared to 4.8M barrels per well for the 1525 meter target.

11.1.1.2 Effects of Water Depth on Oil Field Development' Economics

Table A-3 shows the results of the analysis to examine the sensitivity of water depth on the economics of field development. In this case, the production profile is the same for each water depth. The maximum ultimate recovery is 6.7 $\bar{M}$ barrels per well over the 18-year production life of the field. Thus, changes in rate of return are wholly associated with changes in platform investment cost due to increased water depth.

Clearly, in the Norton Basin, water depth is not critical. Minimum field size to earn 15% varies between 200-400 M barrels as water depth increases from 15 to 45 meters (50 to 150 feet). The rate of return earned from producing 268 $\bar{M}$ barrels, the maximum single platform recoverable reserves, declines from 17.2% to 15.1% as water depth increases. The minimum' price required to earn 15% increases from $16.25 to $17.90 as water depth increases.

II.1.1.3. The Effect of Initial Well Production Rates on Oil Field Development Economics

Table A-4 shows the effect of initial well productivity on field development economics. Initial well production rates affects the selection of platform

TABLE A-3

EFFECT O? WATER DEPTH ON OIL FIELD DEVELOPMENT ECONOMICS

1		3	4	5	6	7	8		9		10
Water depth	Reservoir target depth	Pipeline distance to shore terminal (offshore/ on-shore)	Number of platforms	Number of producing wells per platform	Initial production rate per well	Mid-range investment	Minimum field size to earn 10%	5 %	Return on investment for maximum recoverable reserves (1)		Minimum required price (2)
(Meters)	(Meters)	(Km)			(MBD)	($M)	(MB)		(MB)	(%)	($)
15	2286	32-3	1	40	2,000	$704.5	130	200	268	17.2	16.25
30	2286	32 - 3	1	40	2,000	$770.6	150	225	268	15.8	17.2S
45	2286	32-3	1	40	2,000	$803.5	160	240	268	15.1	17.90

Source: Dames & Moore Calculation

(1) See Table A-2

(2) See Table A-2

TABLE A-4

EFFECT OF INTIAL WELL PRODUCTIVITY ON FIELD DEVELOPMENT ECONOMICS

1	2	3	4	5	6	7	8		9		10
Initial production rate per well	Water depth	Reservoir target depth	Pipeline distance to shore terminal (offshore/on-shore) (1)	Number of platforms	Number of producing wells per platform	Mid-range investment	Minimum field size to earn		Return on investment for maximum recoverable reserves (2)		Minimum required price (3)
							10%	15%			
(MBD)	(Meters)	(Meters)	(Km)			($M)	(MB)		(MB)	(%)	($)
1000	15	1,525	16 -3	1	24	$330.0	NE	NE	115.2	9.2	25.00
1000	15	2,286	16 -3	1	40	$505.0	150	NE	268	13.2	20.30
2000	15	2,286	16 -3	1	40	$759.1	140	215	268	15.2	16.75
5000	15	2,286	16 -3	1	20	$595.5	<100	~190	268	20.0	14.40

1 Pipeline to shore is assumed to be half shared with another producing field.

2 See Table A-2 (1)

3 See Table A-2 (2)

Source: Dames & Moore Calculations

equipment, the number of wells to produce a field, the size of pipeline, and share of shore terminal costs. These affect costs.

The first case shows that with a reservoir target of 1525 (5,000 feet), 24 wells producing at 1000 B/D cannot recover the oil quickly enough to earn a minimum 10% hurdle rate of return. Twenty-five dollars a barrel of oil would be required to earn 15%.

The next two cases compare the effects of 1000 B/D and 2000 B/D initial production rates on the economics of producing a deep reservoir. At 1000 B/D, 40 wells are unable to recover the oil fast enough to earn 15%. Thus, in the Norton Sound where geological conditions suggest 1000 B/D initial production rates might be reasonably expected, platforms will need to house more than 40 producing wells to earn minimum hurdle rates, or oil will have to be priced above $20.00 a barrel.

Investment costs increase 50% when initial production rates double to 2000 B/D. Platform deck load and the platform's assumed share of terminal throughput and cost increase as initial well productivities increase. The increase in revenue is due to faster oil recovery which more than offsets the increase in cost for the maximum recoverable resources.

The rate of return earned from producing maximum recoverable reserves with the larger investment associated with 2000 B/D initial production is 16.2% compared to 13.2% for the 1000 B/D production system. The minimum field size to earn 15% is 215 million barrels.

If initial production rates were 5000 B/D, fewer wells would be required to produce the reservoir. Thus, the platform would be smaller. Investment is 20% lower than the 2000 B/D case. The rate of return for maximum recoverable reserves is 20.0%. Oil priced at $14.40 per barrel would earn 15%.

No other case screened in the entire analysis earned 20% on investment. The magnitude of the investment costs together with high operating costs in the Norton Sound suggest that ideal reservoir conditions will be required to earn 15-20% hurdle rates.

11.1.1.4 The Effect of Pipeline Distance to Shore on Oil Field Development Economics

Table A-5 shows the effect of pipeline costs on oil field development economics. The production profile is identical in each case. Only the investment flows change as pipeline distances increase. The investment costs of these cases assume all pipeline costs are supported by a single platform. In reality there may be opportunities to share a trunkline among several producing fields.

Column 8 shows that the minimum field size to earn 15% increases from 215 M to 250M barrels as pipeline distance to shore increases from 8 to 48 kilometers (5 to 30 miles). Beyond 48 kilometers (30 miles), the investment cost of an unshared pieline is so large that this production system is unable to earn 15%.

Figure A-1 shows the relationship between offshore pipeline distances to shore and the ratge of return. At 160 kilometers (100 miles), the maximum recoverable reserves for a single platform will earn 12%.

If pipeline costs were one-half to one-third shared with other field operators, pipeline distances from shore that will carp a 15% hurdle rate approximately double and triple to 96 to 145 kilometers (60 to 90 miles).

The 40-kilometer (30-mile) limit to earn a 15% hurdle rate for a pipeline whose cost can not be shared with other field operators implies that for fields discovered beyond this limit offshore loading will be required.

11. 1.1.5 Effect of Delay on Oil Field Development Economics

Table A-6 shows the impact of a potential delay in production start up on oil field development economics. One year and two year delays are analyzed. The basic production system is taken from Table A-3: a deep reservoir field with 24 kilometers (15 miles) of offshore pipeline to a shore terminal. This

TABLE A-5

EFFECT OF PIPELINE DISTANCE TO SHORE ON FIELD DEVELOPMENT ECONOMICS

1	2	3	4	5	6	7	8		9		10
Pipeline distance to shore terminal (offshore/on-shore) (1)	Water depth	Reservoir target depth	Number of platforms	Number of producing wells per platform	Initial production rate per well	Mid-range Investment	Minimum field size to earn 10%	15%	Return on investment for maximum recoverable reserves (2)		Minimum required price (3)
(Km)	(Meters)	(Meters)			(MBD)	($M)	(MB)		(MB)	(%)	($)
8 (5)	45	2266	1	40	2,000	$759.1	140	215	268	16.5	16.75
26 (15)	45	2286	1	40	2,000	$788.4	150	230	268	15.5	17.40
32 (20)	45	2286	1	40	2,000	$803.5	160	240	268	15.1	17.80
48 (30)	45	2286	1	40	2,000	$827.2	165	250	268	15.0	17.90
161 (100)	45	2286	1	40	2,000	$1,022.6	~200	NE	268	12.0	21.60

1 All pipeline investment is assumed to be unshared.

2 See Table A-2 (1)

3 See Table A-2 (2)

Source: Damee & Moore Calculations

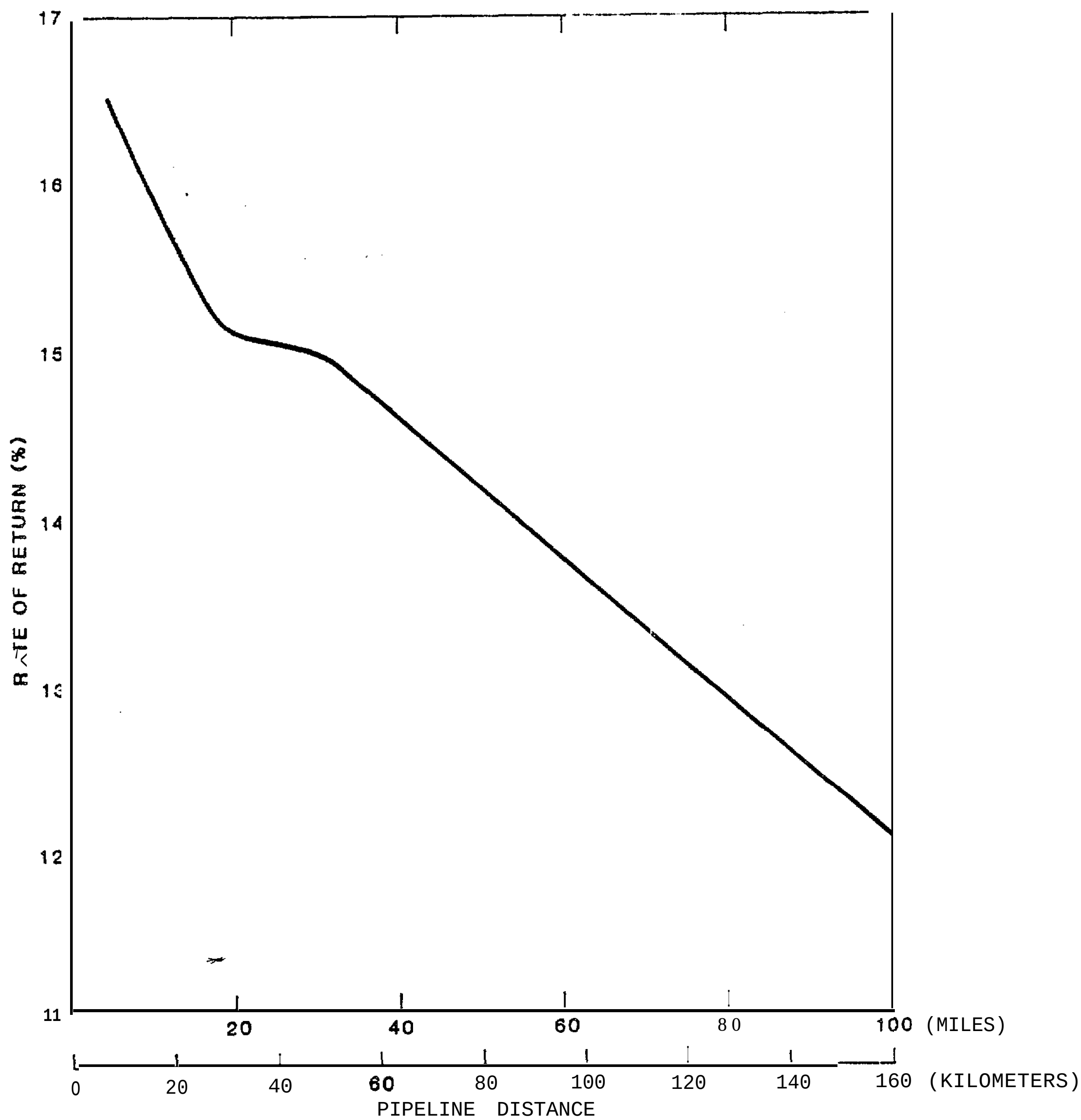


Figure A-1

EFFECT OF OFFSHORE PIPELINE DISTANCE ON RATE OF RETURN
(Oilfield: 268 mB Reserves, 2,000 B/D Wells,
2,286 m Reservoir, 45 m Water Depth)

TABLE A-6

EFFECT OF DELAY ON OIL FIELD DEVELOPMENT ECONOMICS

1	2	3	4	5	6	7	8	9		10
Reservoir target depth	Water depth	Pipeline distance to shore terminal (offshore/on-shore)	Number of platforms	Number of producing wells per platform	Initial production rate per well	Mid-range investment	Net present value of cash flows at 15% discount rate	Return on investment for maximum recoverable reserves (1)		Minimum required price (2)
(Meters)	(Meters)	(Km)			(MBD)	($M)	($M)	(MB)	(%)	($)
BASECASE :										
2286	'45	16-3	1	40	2,000	$788.2	10.8	268	15.5	17.40
ONE-YEAR DELAY										
No change							(53.3)	268	13.5	20.50
TWO-YEAR DELAY										
No change							(167.7)	268	10.0	~27.00

Source: Dames & Moore Calculation

(1) See Table A-2

(2) See Table A-2

production system cost $788.4 M and required a 230 M barrel field to earn 15%. Investment flows occured over a six year period. Oil production started in the fifth year and stepped up to peak in the seventh year.

Delays may occur at any time and for a variety of reasons. Missing the very narrow annual "weather window" during which the platform may be towed up and put on target is one potential source of delay. Permit delay is another potential source. When the delay occurs relative to how much investment has been made is critical to the impact of delay on the economics. The one-year delay is a "worst" case. The investment flow are identical to the base case, but production starts one year later, in the sixth year instead of the fifth. The two-year delay represents a two-year "stretch out" of the project beginning in the third year. 'Investment flows occur for eight years. Production begins in the seventh year and peaks in the ninth. The stretch out of the investment flows moderates the impact of the two-year delay on the field development economics.

Columns 8, 9 and 10 of Table A-6 show how much a delay can harm the outcome of a development project in the Norton Sound. A one year "worst case" delay can turn a $20.8 million winner into a $53.3 million loser. (The new present value of revenue and cost cash flows are exactly equal when a project just earns its hurdle discount rate, 15% in this case. A positive net present value implies the project is able to earn more than the hurdle rate. The base case has a 10.8 million positive net present value and earns 15.5%.)

A two year delay in a project would severely reduce the profitability of the project. The second year of delay, even with investment flows stretched out, makes the net present value of cash flows more than $100 M worse than the one year delay. The best this project could earn would be 10.0%. To earn 15%, oil would have to be priced in the range of $27.00.

11.1.1.6 The Effects of Other Production Systems on Oil Field Development Economics

Two Platforms

Table A-7 shows the analysis of two-platform development, gravel island development and offshore loading. The two platform case compares to the

TABLE A-7

EFFECT OF OTHER PRODUCTION SYSTEMS ON OIL FIELD DEVELOPMENT ECONOMICS

1		3	4	5	6	7	8		9		10
Reservoir target depth (Meters)	Water depth (Meters)	Pipeline distance to shore terminal (offshore/ on-shore) (Km)	Number of platforms	Number of producing wells per platform	Initial production rate per well (MBD)	Hid-range investment ($M)	Minimum field size to earn 10% (MB)	15%	Return on investment for maximum recoverable reserves (1) (iiD).	(%)	Minimum required price (2) ($)"
TWO PLATFORMS											
2286	30	32-3	2	40	2,000	$1,392.8	250	425	536	16.0	$17.25
GRAVEL ISLAND											
2286	30	32-3	1	40	2,000	$ 687.5	125	200	68	18.0	$15.25
OFFSHORE LOADING											
2286	15		1	40	2,000	$ 687.9	125	190	68	18.0	$15.25

Source: Dames & Moore Calculations

(1) See Table A-2

(2) See Table A-2

$770.6 M single platform development case in 32 meter (100 feet) water depth shown on Table A-3. If a reservoir is large enough to support the second platform, the incremental investment is $622.2 $\bar{M}$. There are some economies related to pipeline and terminal costs associated with two platform field development for very large reservoirs.

The minimum field that will support two platforms and earn 15% is 425 $\bar{M}$ barrels. The maximum recoverable reserves for two platforms -- 536 M barrels -- will earn 16%.

Gravel Islands

Gravel islands appear to be less costly and consequently more economic than the steel platform development option. The gravel island case compares to the same $770.6 $\bar{M}$ steel platform alternative on Table A-3. The higher rate of return for the gravel island -- 18.0% compared to 15.8% -- suggests that gravel islands may be preferred technology in shallow water.

Offshore Loading

For the isolated platform too far from shore for a pipeline, offshore loading with storage to allow full-protection is extremely economic. The minimum field size is less than 200 $\bar{M}$ barrels. Such a system would involve the caisson-retained production/storage/loading island concept proposed by Dome Petroleum for the Beaufort Sea. The estimated costs for such a system are, however, highly speculative. Offshore loading without storage and limited to 65% production has been shown in our analysis of the Gulf of Alaska to be mostly uneconomic.

11.1.2 Non-Associated Gas

Table A-8 shows the results of the economic analysis of the development of non-associated gas. Three cases were analyzed to consider the effects of various reservoir characteristics on the development of natural gas:

TABLE A-8

EFFECT OF RESERVOIR CONDITIONS ON GAS FIELD DEVELOPMENT ECONOMICS

	1	2	3	4	5	6	7	8		9		10
	Hid-range investment	Water depth	Reservoir target depth	Number of platforms	Number of producing veils per platform	Initial production rate per well	Pipeline distance to shore terminal (offshore/ on-shore)	Minimum field sire to earn 10%	15%	Return on investment for maximum recoverable reserves (1)		Minimum required price (2)
	($M)	(Meters)	(Meters)			(MMCFD)	(Km)	(BCF)		(BCF)	(%)	($)
GAs CASE I												
Reservoir Target Depth												
(A) Shallow Reservoir	$121.0	15	760	1	4	15	16-3	NE	NE"	192	0	3.25
(B) Deep Reservoir	$269.9	30	2286	1	16	15	16-3	750	750	1344	20	2.00
GAS CASE II												
Initial Production Rates												
(C) Fast Recovery	$252.3	30	2286	1	12	25	16-3	<750	<750	1344	24.3	1.35
Moderate Recovery (See B)												
GAS CASE 111												
Pipeline Distances												
16 Kilometers (see B)												
(D) 32 Kilometers	$315.3	30	2286	1	16	15	32-3	<750	~1000	1344	18.0	$2.15
(E) 29 Kilometers	$471.6	30	2286	1	16	15	129-3	.-"1000	NE	1344	13.2	$2.90

Source: Dames & Moore Calculations

(1) See Table A-2

(2) See Table A-2

Case I : Reservoir Target Depth

Case II: Initial Production Rates

Case III: Pipeline Distances to Shore

Water depth effects were not examined because the oil reservoir analysis showed that in the shallow waters of Norton Sound water depth is not a factor.

11.1.2.1 Effects of Reservoir Target Depth on Gas Field Development Economics

Case I shows that shallow reservoir gas fields with standard industry well spacing of 160 acres/well allow a maximum ultimate recovery of only 192 BCF of reserves (assuming recoverable reserves per acre of 300,000 MCF). This is insufficient to earn 10% return on investment. Over the lifetime of the field each of the four wells on the shallow reservoir is able to recover a maximum of only 48 BCF. The deeper target allows 16 wells with spacing of 280 acres to recover 84 BCF each over the production life of the field. A shallow reservoir field would need to be priced above $3.25 MCF to earn 15% return on investment.

Case I shows that the much "larger ultimate recovery makes a large difference. The deep reservoir gas field would earn 20% with a maximum ultimate recoverable reserves of 1.344TCF.

11.1.2.2. Effect of Initial Production Rates on Gas Field Development Economics

Faster recovery improves the economics of development. Gas Case II shows that the minimum required price to earn 15% producing the deep reservoir with the maximum recoverable reserves of 1.334 TCF drops from $2.00 MCF with 15 MMCFD/well initial production rate to $1.35 with 25 MMCFD/well. Return on investment with $2.60 well-head price rises from 20.0% to 24.3%. Standard reservoir engineering would allow fewer wells at the faster recovery rate.

11.1.2.3 Effect of Offshore Pipeline Distance to Shore on Gas Field Development Economics

Gas Case III shows that return on investment for producing the deep reservoir of 1.344 TCF declines as pipeline distance and pipeline investment increase. Figure A-2 shows that a field located to require a pipeline longer than 96 kilometers (60 miles) shared with another field is unable to earn 15%. At 129 kilometers (80 miles) gas would have to be priced at $2.90 MCF to earn 15%.

11.2 Minimum Required Price to Justify Field Development

Given the estimated costs of various oil and gas production systems identified in this report, the minimum price to justify development (the minimum price to earn 15% return on investment) has been calculated using the model for various field sizes.(1) Tables A-2 through A-8 showed the minimum price to earn 15 percent for the maximum reservoir size that could be reached and recovered by the production system on each table. Different production systems with different investment costs yield different minimum prices for development. Furthermore, the minimum required price is sensitive to water depth, reservoir target depth and initial well production rate as well as the assumed value of money.

In the following sections the minimum required price as a function of field size is identified with selected reservoir characteristics.

(1) In this analysis we have provided solutions based upon a 10 to 15% range but emphasize 15% in discussions because we believe that is closer to industry practice than 10%.

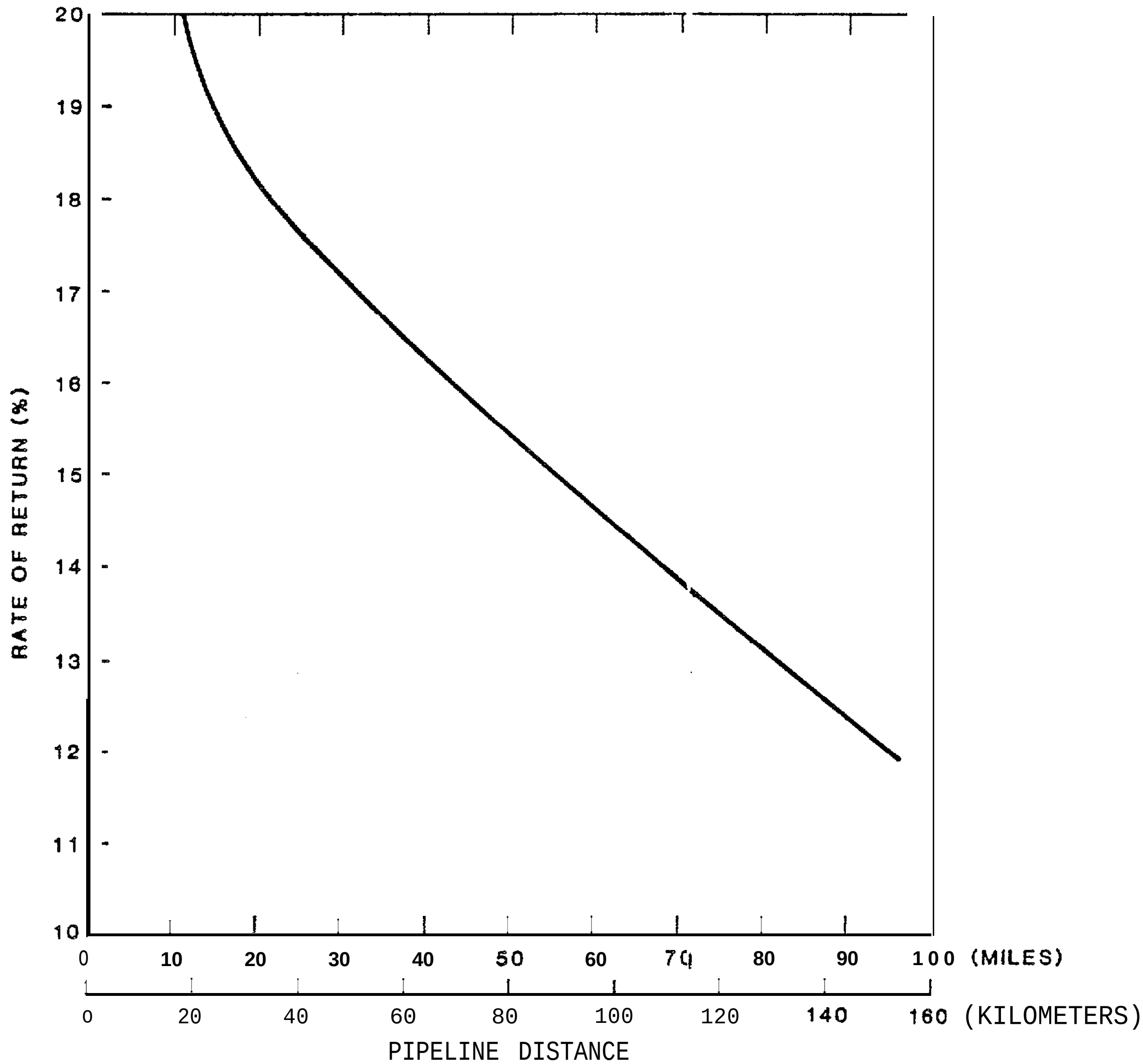


Figure A-2

EFFECT OF OFFSHORE PIPELINE DISTANCE ON RATE OF' RETURN
(Gas Field: 1,344 TCF Reserves, 15 MMCFD Wells,
2,286 m Reservoir, 16 Well Platform)

II.2.1 Oil

Figure A-3 shows the minimum required price to develop a known oil field with a single platform with a 2286 meter reservoir target and 2000 B/D initial well production rate. Two production systems are shown: (1) off-shore loading with storage capability, and (2) pipelining to shore, a distance of 32 kilometers (20 miles). The offshore loading system is less costly ($688 million versus $803.5 mid-range investment cost) than the pieline system. While the offshore loaded platform is in 15 meters (50 feet) of water and the pipeline platform in 45 meters (150 feet) of water, most of the cost difference is in the difference in pipeline and terminal investment compared with offshore loading technology. For a field within 32 kilometers (20 miles) of shore, these two production technologies at the different water depths can be said to bound the upper and lower limit minimum required price. Fields further from shore with a pipeline to a shore terminal would require higher prices.

Figure A-3 shows that the minimum required price to earn 15% is relatively high. For a 100 million barrel field the price is above $26.00 with offshore loading; above $36.00 with the pipeline to shore. The minimum required price drops below $20.00 with the offshore loading system at 150 million barrels; with the pipeline system more than 200 million barrels before the minimum price is under $20.00. At 250 million barrels, the minimum price is $15.25 and $18.00 for the two systems.

The minimum required price declines little for field larger than 250 million barrels. Barrels recovered beyond 20 years in the future add little to the economic payoff and have little impact on minimum price calculations.

11.2.2 Non-Associated Gas

Figure A-4 shows the minimum required price for developing a known gas field with a signle steel platform housing 16 wells. Initial productivity is assumed to be 15 MMCFD. The platform is assumed to be 16 kilometers (10

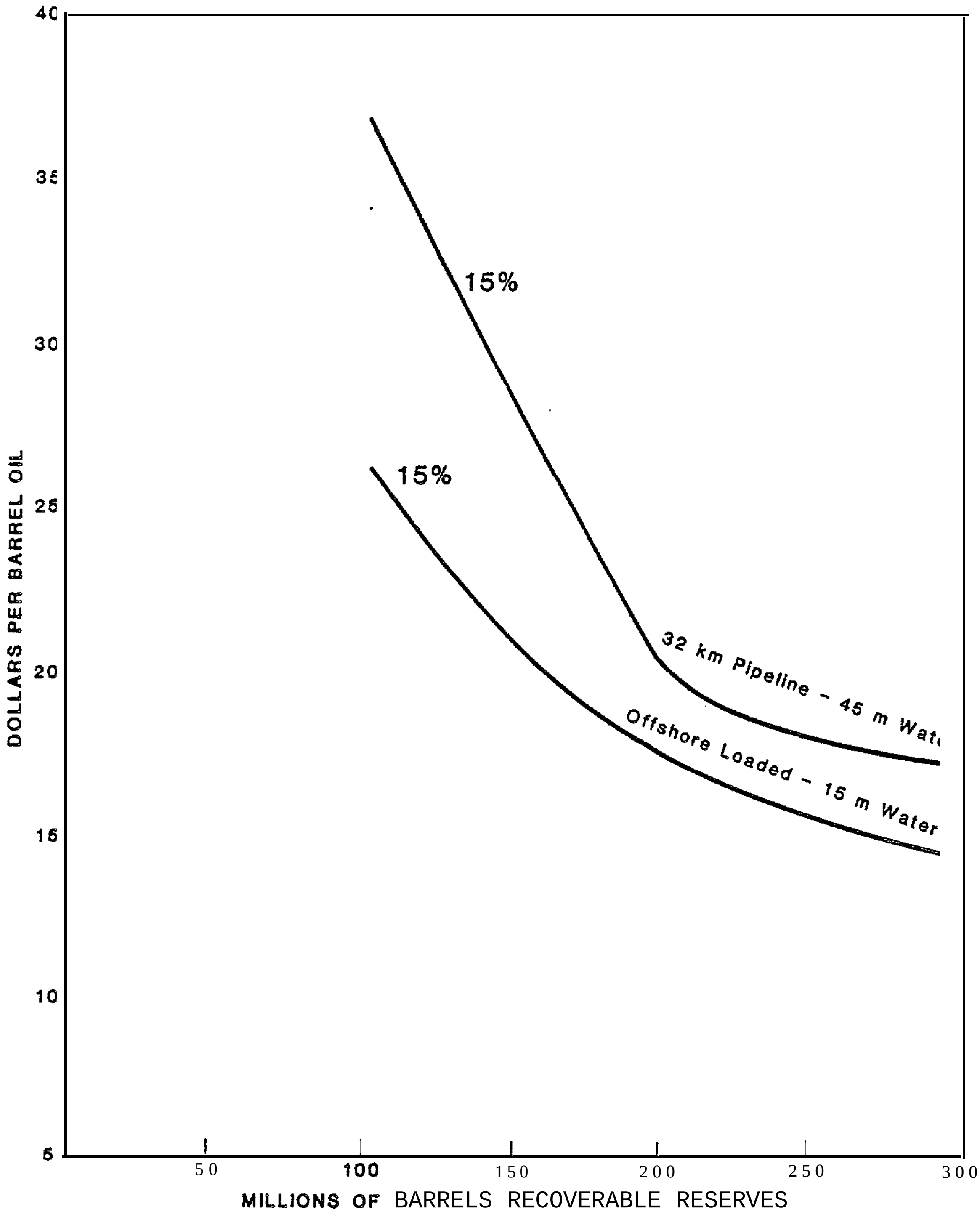


Figure A-3

MINIMUM PRICE TO JUSTIFY DEVELOPMENT' OF AN OIL FIELD:
Offshore Loading Compared with Pipeline to Shore
(2,286m Reservoir, 2,000 B/D Wells, Single Platform)

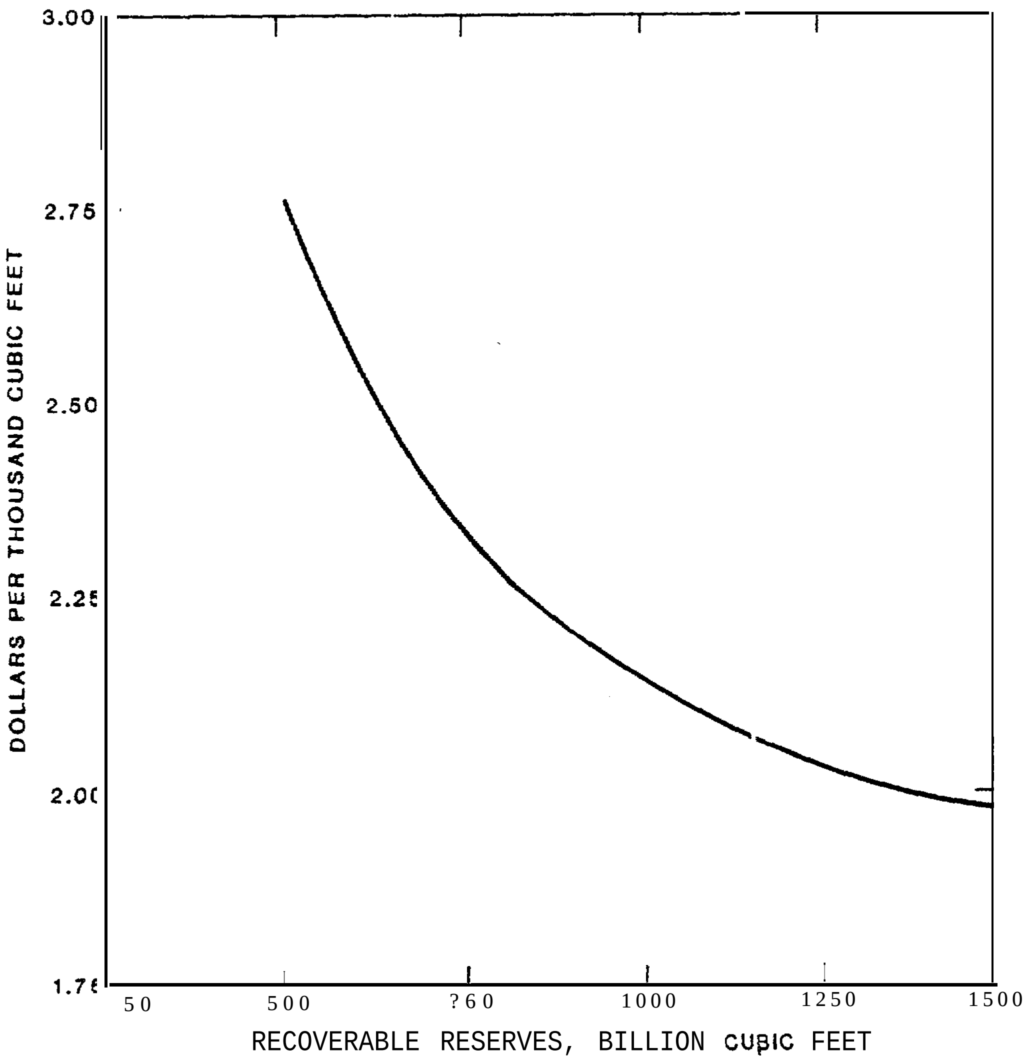


Figure A-4

MINIMUM PRICE TO JUSTIFY DEVELOPMENT OF A GAS FIELD
(Single Steel Platform with 16 km Pipeline to Shore,
2,286 m Reservoir, 15 MMCFD/Wells)

miles) from shore. The minimum price is sensitive to pipe" ine distance to shore as previously shown with as Case III on Table A-8.

The minimum price to justify development at 15% drops from $2.75 MCF for a 500 BCF field to $1.95 MCF for 1500 BCF of recoverable reserves.

11.3 Distribution of Oil Development Costs between Offshore Production, Pipeline Transport and Shore Terminal

Offshore pipelines will be extremely expensive in the Norton Sound. Initial mobilization with the narrow "weather window" and installation under harsh environmental conditions will be difficult at best.

Table A-9 shows that the share of costs arising from the offshore platform decreases from 70% with a 16 kilometer (10 mile) pipeline to 49% with a 161 kilometer (100 mile) pipeline.

Figure A-1 previously showed that a pipeline longer. 48 kilometers (30 miles) that could not be shared with another field operator added such an investment burden that the investment could not earn a minimum 15% hurdle rate -- given the assumptions of the analysis.

II.4 The Effect of the Uncertainty of Estimated Costs and Prices on Field Development Economics

II.4.1 Sensitivity Analysis for Single Steel Platform Oil Field Development

Table A-3 previously identified a 240 million barrel field as sufficient to earn a 15% hurdle rate of return for a single steel platform with a 32 kilometer (20 mile) pipeline to shore and deep reservoir to allow 40 producing wells. Table A-10 estimates the range of uncertainty of the after tax rate of return implicit in the range of costs employed in the analysis.

TABLE A-9

DISTRIBUTION OF OIL DEVELOPMENT COSTS BETWEEN OFFSHORE PRODUCTION, PIPELINE TRANSPORT AND TERMINAL (1)

($Million)

	Pipeline Distance to Shore		
	16 Km	48 Km	161 Km
Platform Fabrication & Installation	160.0	160.0	160.0
Platform Equipment & Miscellaneous	210.0	210.0	210.0
Wells (45)	180.0	180.0	180.0
Sub Total: Platform	550.0	550.0	550.0
Share of Shore Terminal (26%)	153.6	153.6	153.6
Pipeline			
- Onshore (3Km)	6.0	6.0	6.0
- Offshore	53.2	106.5	355.0
Miscellaneous Design Engineering	21.3	26.6	51.5
Total Mid-range Investment	$784.2	$842.7	$1116.1
Percentage Distribution:			
% Platform	70.0	65.0	49.0
% Terminal & Pipeline	30.0	35.0	51.0

Source: Dames & Moore Calculations

{1) Single steel platform with 40 producing wells, in 45 meters water depth with 2286 meter reservoir target. Initial well production rate - 2000 B/D. The shore terminal is assumed to transship 300 MBD. Cost is shared in proportion to peak production rate.

TABLE A-10

SENSITIVITY ANALYSIS FOR AFTER TAX RATE OF RETURN
AS A FUNCTION OF UPPER & LOWER LIMIT OIL DEVELOPMENT COSTS (1)

	Lower Cost	Mid-range cost	Upper cost	Range
Tangible Investment	17.3	15.0	11.6	5.7
Intangible Investment	16.5	15.0	12.4	4.1
Operating Costs	15.5	15.0	13.9	1.6
General & Administrative costs	15.3	15.0	14.5	008

Source: Dames & Moore Calculation

(1) Single steel platform with 40 producing wells in 45 meter water depth, with 2286 meter reservoir target. 2000 E/D initial production rate. 32 Km pipeline. Recoverable reserves - 240 million barrels. Mid-range investment: $803.5 million

Fifteen percent rate of return is the expected rate of return for the mid-range cost estimates. Upper and lower limit tangible and intangible costs were estimated at 75% and 150% of mid-range costs.

Mid-range operating costs were estimated at $32 million annually with upper and lower limit of $24 and $48 million. Mid-range administrative costs were estimated at $8 million with upper and lower limits of $6 and $12 million. Administrative costs start when development begins; operating costs start when production begins.

The upper and lower limit rate of returns for each variable on Table A-10 assumes all the other variables at their mid-range values. The variables are listed in the order of their effect on the range of variability of the rate of return. Clearly, if tangible or intangible investment are closer to high cost estimate than to mid-range, development of this 240 million barrel field could earn substantially less than 15%. The range of uncertainty in operating and administrative costs has much less impact on the success of the development project. At their mid-range values, the sum of operating and administrative costs is equal to $1.42 per barrel at peak production rate and $2.37 per average barrel over the life of the field. Per barrel operating costs increase as field production declines.

11.4.2 Monte Carlo Results for Selected Production Scenarios

11.4.2.1 Range of Values for After Tax Return on Investment

Previous sections have reported results based on the mid-range values for prices and costs. Repeatedly, however, this report has emphasized that costs for production technology that will be employed in the mid-1980's can only be estimated in 1979 dollars within a range of values. In this section, Monte Carlo distributions for the after-tax return on investment for selected production scenarios are reported to emphasize the uncertainty built into this economic analysis of field development in the Norton Sound.

Just as there is a range of values estimated for prices and costs, there is a range of values for the profitability criteria calculated by the model. A Monte Carlo solution to the model is a way to estimate the range of outcomes by repeatedly solving the model with values selected at random in each solution pass for each of the variables whose values are entered as a range. With a few hundred solution passes, the Monte Carlo distribution reveals a probabilistic estimation of the worst outcome, best outcome and intermediate results.

11.4.2.2 Oil Platforms

Table A-n and Figure A-5 show the Monte Carlo results for the distribution of return on investment for an oil development scenario that would be plausible in most places of the world except Norton Sound. The field is assumed to be a 125 million barrel reservoir. A single 40 producing well oil platform with an unshared 32 kilometer (20 mile) pipeline to shore has an expected rate of return of only 5.8% with this large-by-any conventional standards reservoir. Table A-2 previously showed that a 240 million barrel reservoir was required, after-tax return on investment could range from 7% to 14.2%. There is a 93.5% change of earning less than 9.9%. There is, therefore, little change of earning even a 10% hurdle rate.

Figure A-5 shows the cumulative distribution that graphically displays these results.

11.4.2.3 Gas Platforms

Table A-12 shows the Monte Carlo distribution for the rate of return for a gas platform also connected to shore by a 32 kilometer (20 mile) pipeline. Recoverable reserves are assumed to be 1.3 TCF. Table A-12 and Figure A-6 show:

- There is 2.5 percent chance of earning less than 13.5 percent;

TABLE A-11

SINGLE OIL PLATFORM WITH 32Km PIPELINE TO SHORE
125MILLION BARREL FIELD, 45M. WATER DEPTH, 2286 M. RESERVOIR TARGET
INITIAL PRODUCTION RATE: 2000 B/D

MID-RANGE INVESTMENT: $803.5 MILLION

MONTE CARLO RESULTS FOR
AFTER-TAX DCF RATE OF RETURN

RESULT VALUE	PROB. OF BEING LESS THAN RESULT
.7088	.025000
1.4176	.035000
2.1264	.080000
2.8352	.150000
3.5441	.195000
4.2529	.295000
4.9617	.415000
5.6705	.530000
6.3793	.630000
7.0881	.700000
7.7969	.755000
8.5057	.820000
9.2145	.910000
9.9233	.935000
10.6322	.960000
11.3410	.965000
12.0498	.980000
12.7586	.990000
13.4674	.995000
14.1762	1.000000

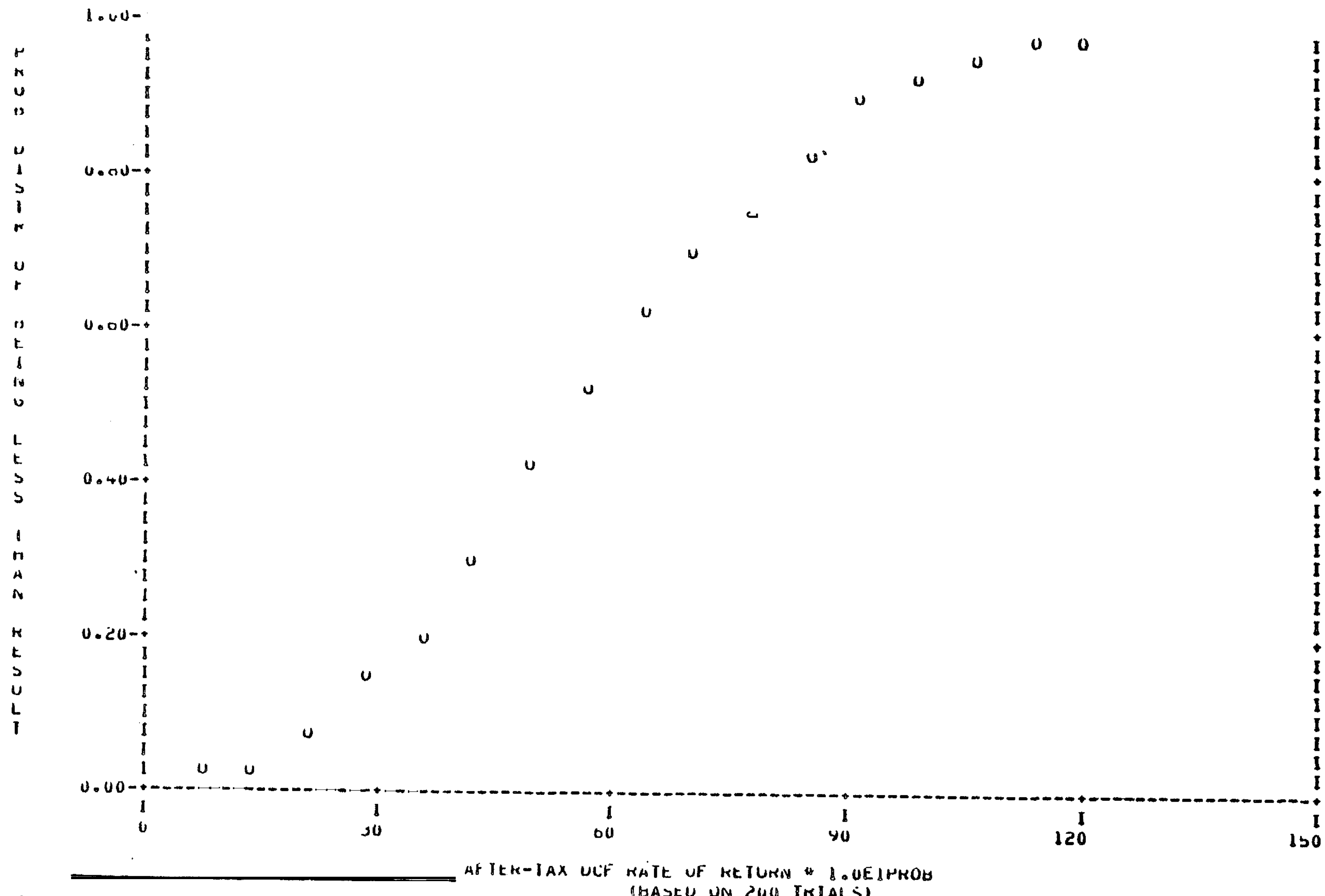
EXPECTED VALUE = 5.7674
STANDARD DEVIATION = 2.7386

Source: Dames & Moore Calculation

FIGURE A-5

MONTE CARLO RESULTS FOR AFTER TAX RATE OF RETURN SINGLE OIL PLATFORM WITH 32 Km. PIPELINE TO SHORE 125 MILLION BARREL RESERVOIR

MID-RANGE INVESTMENT: $803.5 MILLION



Source: Dames & Moore Calculation

TABLE A-12

SINGLE GAS PLATFORM WITH 32 Km PIPELINE TO SHORE
30 M. WATER DEPTH, 2286 M. RESERVOIR TARGET
INITIAL PRODUCTION RATE : 15 MMCFD

1.3 TCF FIELD MID-RANGE INVESTMENT: $315.3 MILLION

MONTE CARLO RESULTS FOR
AFTER-TAX DCF RATE OF RETURN

RESULT VALUE	PROB. OF BEING LESS THAN RESULT
13.4984	.025000
13.9963	.055000
14.4943	.085000
14.9922	.145000
15.4901	.195000
15.9881	.330000
16.4860	.465000
16.9840	.530000
17.4819	.625000
17.9798	.685000
18.4778	.765000
18.9757	.835000
19.4737	.865000
19.9716	.935000
20.4695	.955000
20.9675	.965000
21.4654	.975000
21.9633	.985000
22.4613	.990000
22.9592	1.000000

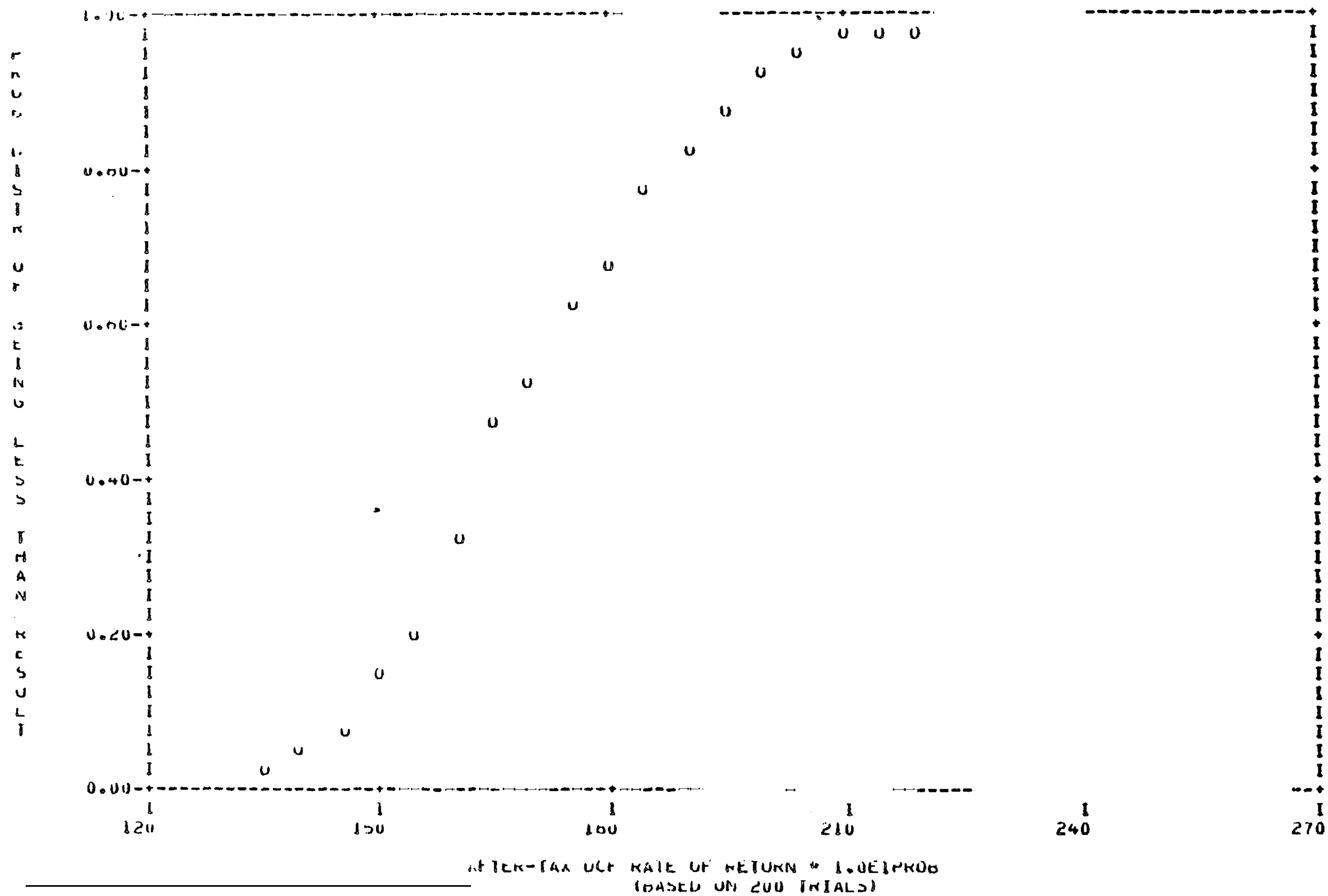
EXPECTED VALUE = 17.0198
STANDARD DEVIATION = 1.9766

Source: Dames & Moore Calculations

FIGURE A-6

MONTE CARLO RESULTS FOR AFTER TAX RATE OF RETURN
SINGLE GAS PLATFORM WITH 32Km PIPELINE TO SHORE

MID-RANGE INVESTMENT: $315.3 MILLION



Source: Dames & Moore Calculations

- There is 14.5 percent chance of earning less than 15.0 percent;
- There is 100 percent chance of earning less than 23.0 percent;
- The expected value for rate of return is 17.0 percent.

While these are very favorable economic results, the 23 percent upper limit implies that a much larger gas field than 1.3 TCF -- which is very large -- must be discovered to produce a bonanza payoff.

APPENDIX B

APPENDIX B

PETROLEUM DEVELOPMENT COSTS AND FIELD DEVELOPMENT SCHEDULES

1. Data Base

This appendix presents the field development and operating cost estimates used in the economic analysis. Exploration costs are not included in the economic analysis and are, therefore, not discussed here (see discussion in Chapter 3.0)."

Predictions on the costs of petroleum development in frontier areas such as Norton Basin (where no exploration has yet occurred) can be risky or even spurious. Such predictions rely on extrapolation of costs from known producing areas suitably modified for local geographic, economic, and environmental conditions. Further, cost predictions require identification of probable technologies to develop, produce, and transport OCS oil and gas. For the Norton Basin, there is very little or no cost experience from comparable operating environments where petroleum development has taken place to provide a firm data base for economic analysis.

In the course of studies on the Gulf of Alaska (Dames & Moore, 1979a and b) and Lower Cook Inlet (Dames & Moore, 1979c), a considerable data base on petroleum facility costs for offshore areas was obtained which provided the starting point for this study. That data was based on published literature, interviews with oil companies, construction companies, and government agencies involved in OCS related research. Petroleum development cost data is either direct cost experience of projects in current producing areas such as the Gulf of Mexico and North Sea, or projections based upon experience elsewhere modified for the technical and environmental constraints of the frontier area. For sub-arctic and arctic areas, facility cost projections may involve estimates for new technologies, construction techniques, etc. that have no base of previous experience.

In addition to reviewing estimated costs from current producing areas, and projections for Cook Inlet, data was obtained on exploration cost experience in the Canadian Beaufort Sea and projections of development costs for that areas, and the Alaskan Beaufort Sea related to the upcoming joint state-federal lease sale. Consultations were made directly with Alaskan and Canadian operators with interests in these areas, and Alaskan operators interested in the Bering Sea OCS. It should be emphasized that in-depth research on production technologies and related costs for the Bering Sea basins and Norton Sound in particular has only begun in recent years.

II. Published Data Base

It is appropriate to briefly describe the published data base that is available on petroleum development costs for frontier areas in general.

The North Sea cost data base includes the "North Sea Service" of blood, Mackenzie & Co. which monitors North Sea petroleum development and conducts economic and financial appraisals of North Sea fields. The Wood, Mackenzie & Co. reports provide a breakdown and scheduling of capital cost investments for each North Sea field. All. Little, Inc. (1976) have estimated petroleum development costs for the various U.S. OCS areas, including Alaskan frontier areas, and have identified the costs of different technologies and the various components (platforms, pipelines, etc.) of field development. The results of the A.D. Little study have also been produced in a text by Mansvelt Beck and Wiig (1977).

Gulf of Mexico data has provided the basis for several economic studies of offshore petroleum development (National Petroleum Council, 1975; Kalter, Tyner and Hughes, 1975). Gulf of Mexico cost data has been extrapolated to provide cost estimates in more severe operating regions through the application of a cost factor multiplier. For example, Bering Sea (ice laden area) cost estimates for exploration and development have been developed using cost factor multipliers of 2.3 (exploration) and 3.7 (development) as defined by Kalter, Tyler and Hughes (1975). This approach has been used in this report to provide a comparison among estimates.

Other important cost data sources include occasional economic reports and project descriptions in the Oil and Gas Journal, Offshore and various industry and trade journals, and American Petroleum Institute (API) statistics on drilling costs. A problem with some of the cost data, especially estimates contained in technology references, is that they do not precisely specify the component costed. Thus, a reference to a platform quoted to cost $100 million may not specify whether the estimate refers to fabrication of the substructure, fabrication and installation of the substructure, or the completed structure including topside modules. Another problem is that the year's dollars (1975, 1976, etc.) to which the cost estimate is related is often not specified.

III. Cost and Field Development Schedule Uncertainties

As stated elsewhere in this report, the purpose of the economic analysis is not to evaluate a site specific prospect with relatively well known reservoir and hydrocarbon characteristics but to bracket the resource economics of the lease basin which comprises a number of prospects that will have a range of reservoir and hydrocarbon characteristics. To accomplish this requires a set of standardizing assumptions on reservoir and hydrocarbon characteristics and technology (see Chapter 3.0). The facilities cost data, presented in Tables B-1 through 13-7, have been structured to accommodate this necessary simplification.

It should be emphasized that in reality field development costs will vary considerably even for fields with similar recoverable reserves, production systems, and environmental setting. Some of the important factors in this variability are reservoir characteristics, quality of the hydrocarbon stream, distance to shore, proximity of other fields, and lead time (from discovery to first production). For example, platform process facility costs can vary significantly with reservoir characteristics including drive mechanism, hydrocarbon properties, and anticipated production performance. Analytical simplification, however, requires that costs vary with throughput while the other parameters are fixed by assumption: The available cost data is insufficient to provide all these economic sensitivities. Other factors also play a role in field development costs

TABLE B-1

PLATFORM COST ESTIMATES INSTALLED[3]

Platform Type[2]	Water Depth		cost $ Millions 1979 Midrange Value[1]
	meters	feet	
Modified Upper Cook Inlet Steel Jacket	15	50	70
Modified Upper Cook Inlet Steel Jacket	30	100	130
Modified Upper Cook Inlet Steel Jacket	46	150	160

[1] A midrange value is given here. In the economic analysis, a low estimate of 25 percent less than this value and a high estimate of 50 percent greater than this value were investigated. Explanation of this range is presented in the text.

[2] Sensitivity for numbers of well slots or production throughput is accommodated by taking the low range value for platforms with 24 slots or less, and midrange value for 25 slots or more.

[3] In addition to fabrication in a lower 48 yard, these estimates include the cost of platform installation which involves site preparation, tow out, setdown, pile driving, module lifting, facilities hook up, etc.

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1976; Bendiks, 1975; Peat, Marwick, Mitchell & Co., 1975; Offshore, November, 1978; Department of Energy, 1979 (see text).

TABLE B-2

ARTIFICIAL ISLAND COST ESTIMATES

Platform Type[1]	Water Depth meters	Water Depth feet	cost $ Millions 1979 Midrange Value[2]
Gravel Island	7.6	25	24
Gravel Island	15	50	60
Caisson Retained[3] Process/Storage/ Loading Island	21	70	150

[1] Island specifications include 213 meter (700 feet) working surface diameter, 7.6 meter (25 feet) freeboard, and 4:1 side slopes.

[2] Gravel island costs can be anticipated to be extremely variable since costs are principally dependent on gravel availability, haul distance, and construction technique.

[3] Offshore terminal includes 244 meter (800 feet) diameter island, three million barrel crude storage, ship loading facilities, and crew quarters (Dome Petroleum, Ltd., 1977a and b).

Sources: Dames & Moore estimates compiled from various sources including deJong and Bruce, 1979a and b; Dome Petroleum, Ltd., 1977 and 1978 (see text).

TABLE B-3K

PLATFORM EQUIPMENT AND FACILITIES
COST ESTIMATES OIL PRODUCTION

Platform Type[2,3]	Peak Capacity Oil (MBD)	cost $ Millions 1979 Midrange Value[1]
Modified Upper Cook Inlet Steel Jacket and Gravel Island[4]	25	80
	25-50	100
	50-100	160

[1] See No. 3, Table B-l.

[2] It is assumed that associated gas is not produced to market and is used to fuel platforms with the remainder reinfected.

[3] It is also assumed that a reservoir pressure maintenance program involving water injection will be required.

[4] Process equipment to be placed on gravel island nay have difficult configuration and installation techniques, but there is insufficient data to indicate differences in costs from modular topside facilities installed on steel platforms.

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1975; Department of Energy, 1979 (see text).

TABLE B-3B

PLATFORM EQUIPMENT AND FACILITIES COST ESTIMATES
NON-ASSOCIATED GAS PRODUCTION

Platform Type	Peak Capacity Gas (MMCFD)	cost $ Millions 1979 Midrange Value[1]
Modified Upper Cook Inlet Steel Jacket	200-300	40
	300-400	55

[1] See No. 3, Table B-1.

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1976; Department of Energy, 1979 (see text).

TABLE B-4

DEVELOPMENT WELL COST ESTIMATES

Well Type	Well Depth		Cost $ Millions 1979 Midrange Value[1]
	meters	feet	
Development Well[2] (Each)	762	2,500	2.0
	1,524	5,000	3.0
	2,286	7,500	4.0

[1] See No. 3, Table B-1.

[2] It is assumed that the well is deviated and a single completion.

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; API, 1978; Gruy Federal, Inc., 1977; Bendiks, 1975 (see text).

TABLE B-5A

MARINE PIPELINE COST ESTIMATES

Diameter	Average Cost Per Mile[1] $ Millions 1979		
	Low	Midrange	High
20-29	3.5	4,7	7.0
10-19	2.6	3.3	5.0
<lo	1.7	2.0	3.0

[1] High estimate used for short pipelines less than 16 kilometers (10 miles). Midrange estimate used for medium length pipelines 16 to 32 kilometers (10 to 20 miles). Low estimate used for long pipelines greater than 32 kilometers (20 miles).

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; API, 1978; O'Donnell, 1976; Eaton, 1977; Oil and Gas Journal, August 14, 1978; Oil and Gas Journal, August 13, 1979; Offshore, July, 1977; Offshore, July, 1979 (see text).

TABLE B-5B

ONSHORE PIPELINE COST ESTIMATES

Diameter	Average Cost Per Mile $ Millions 1979 Midrange Value[1]
20-29	4.0
10-19	3.0
<10	1.9

[1] See No. 1, Table B-1.

Sources: Dames & Moore estimates compiled from various sources including Oil and Gas Journal, August 13, 1979 (see text).

TABLE B-6

OIL TERMINAL[1] COST ESTIMATES

Peak Throughput (MBD)[2]	Total Cost Per Mile $ Millions 1979 Midrange Value[3]
<100	260
100-200	340
200-300	600
300-500	750

[1] The shore terminals costed here are assumed to perform the following functions; pipeline terminal (for offshore lines), crude stabilization, LPG recovery, tanker ballast treatment, crude storage (sufficient for about 10 days' production), and tanker loading for crude transshipment to the lower 48.

[2] There is a cost index which equates facility cost with daily bbl capacity - the terminal costs cited here range- from about $1,800 to $3,000 per daily bbl capacity.

[3] See No. 1, Table B-1.

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; Duggan, 1978; Cook Inlet Pipeline Co., 1978; Shell Oil Co., 1978; Global Marine Engineering Co., 1977; Engineering Computer Opteconomics, Inc., 1977 (see text).

TABLE B-7

ANNUAL FIELD OPERATING COST ESTIMATES

	$ Millions 1979 Midrange Value
1 Platform Field, Pipeline-Terminal	40
2 Platform Field, Pipeline-Terminal	80
3 Platform Field, Pipeline-Terminal	115

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1975; Gruy Federal, Inc., 1977 (see text).

such as market conditions. The price an operator pays for a steel platform, for example, will be influenced by national or international demand for steel platforms at the time he places his order, whether he is in a buyers or sellers market. Similarly, offshore construction costs will be influenced by lease rates for construction and support equipment (lay barges, derrick barges, tugs, etc.) which will vary according to the level of offshore activity nationally or internationally.

The cost estimates presented in Tables B-1 through B-7 are essentially an amalgam of estimates from various sources in some cases made by rationalizing several pieces of sometimes conflicting evidence. It should further be emphasized that there is considerable variation in both published and industry data; this is understandable given the unknowns of operating in the harsh environment of the northern Bering Sea. Because of these significant variations, low, medium, and high values for the various petroleum facilities and equipment were defined. A low estimate of 25 percent less than the mid-range (medium) value and a high estimate of 50 percent greater than this value were selected and used for economic screening.

In general terms, field development costs in similar water depth ranges can be anticipated to be somewhat greater than Cook Inlet but less than the Beaufort Sea. Norton Sound does not have as severe ice conditions as the Beaufort Sea, "length of ice season, or such a remote location in terms of logistics.

All the cost figures cited in Tables B-1 through B-7 are given in 1979 dollars. Cost figures from the various sources have been inflated to 1979 dollars using United States petroleum industry indices.

Briefly discussed below are the principal uncertainties relating to the cost estimates' for the various facility components.

111.1 Platform Fabrication and Installation (Tables B-1 and B-2)

In addition to Upper Cook Inlet type steel platforms, we have evaluated the economics of artificial gravel/sand islands based on cost experience of exploration islands in the southern Canadian Beaufort Sea and projections for permanent production islands in both the Canadian and Alaskan Beaufort. The cost of such islands is very sensitive to the cost of gravel/sand which is related to the haul distance of the fill. Our estimates have taken gravel costs at the upper end of costs for dredged borrow in the Canadian Beaufort which involves haulage by dump barge.

In addition to the cost sensitivity of water depth for steel platforms, factors such as design deck load and number of well slots also affect cost. To provide, more cost sensitivity than just water depth, we have taken the low range investment value for smaller platforms (24 well slots or less) and the mid-range value for platforms with 25 or more well slots. With a fixed initial productivity per well and with the maximum number of wells per platform related to reservoir depth, this assumption also provides for some sensitivity related design deck load as related to throughput capacity of process equipment.

III.2 Platform Process Equipment (Tables B-3A and B-3B)

As noted above, our platform process facility costs (Tables B-3A and B-3B) vary with throughput and assume that other parameters are fixed as noted on the tables.

111.3 Marine Pipeline Cost Estimates (Table B-5A)

Particularly uncertainty exists on marine pipeline costs that may be incurred on northern Bering Sea projects as suggested by the range of projections for Arctic and sub-Arctic areas.

Pipelaying costs in the Norton Basin are uncertain or may vary considerably because:

- The lack of support base sites are a particular problem in Norton Sound; resupply and support of Norton Basin pipelaying operations may have to be provided by an Aleutian Island base considerably extending resupply turnaround schedules.

- While most projects could be completed in one summer season in the northern Bering Sea given the distances to shore and typical laying rates, extensive burial of pipelines or extended resupply lines could extend a project into a second season especially for the discovery sites more distant from shore (100 kilometers [60 miles] plus).

- The geologic and oceanographic hazards of Norton Sound may require special engineering or re-routing especially close to shore and at landfalls where ice is a problem. This will increase pipeline costs compared with open water areas to the south.

- The short summer weather window, fall storms, and possible extended supply lines contribute to project risk and hence uncertainty of project costs especially for longer lines.

Other factors being equal, the per unit costs (i.e. per meter or kilometer' of pipelaying will decrease with the length of the line except where a line is too long to lay in one season. Shore approaches and landfalls are particularly expensive and mobilization/demobilization costs comprise a greater portion of project costs the shorter the line. Because of these factors, we have assumed the high range cost for short lines ('less than 16 kilometers [10 miles]), mid-range value for intermediate lengths (16 to 32 kilometers [10 to 20 miles]) and low estimate for long lines (over 32 kilometers [20 miles]).

III.4 Onshore Pipelines (Table B-5B)

Onshore pipeline costs in the Norton Sound area can be anticipated to be significantly greater than projects in the Cook Inlet area because of the special engineering requirements of construction in permafrost terrain, remote location, possibily greater environmental sensitivity, and other factors related to construction in a harsh environment. cost estimation relies on the experience of Alyeska and Cook Inlet development, and projections related to the Alcan, Polar Gas, Pacific Alaska

LNG (Cook Inlet), Kuparuk field development, and Beaufort Sea lease sale projects. In comparison with lower 48 costs, Norton Sound onshore pipelines can be anticipated to cost four to six times as much.

111.5 Oil Terminal Costs (Table B-6)

Oil terminal costs will vary as a function of throughput, quality of crude, upgrading requirements of crude for tanker transport, terrain and hydrographic characteristics of the site, type, size and frequency of tankers, and many other factors. Permafrost terrain, sea ice, and remote location will impose significantly greater costs on terminal construction than a similar project in the Cook Inlet area or lower 48. There is little cost experience to project terminal costs in Alaska except Cook Inlet and Alyeska. Further afield, there is the North Sea experience of the relatively remote Flotta and Sullom Voe terminals located in the Orkney and Shetland Islands, respectively.

Two studies have addressed the economics of terminal siting and marine transportation options in the Bering Sea (Global Marine Engineering, 1977; and Engineering Computer Optecnomics, 1977). A third study addressing these problems was conducted for the Alaska Oil and Gas Association (AOGA) and is currently proprietary.

As indicated on Table B-6, it is assumed that the marine terminal combines the functions of a partial processing facility (to upgrade crude for tanker transport) and a storage and loading terminal.

IV. Methodology

The cost tables presented in this appendix were the basic inputs in the economic analysis. Each case analyzed was essentially defined by reserve size, production technology, and water depth. To cost a particular case, the economist took the required cost components (field facility and equipment components) from Tables B-1 through B-7 using a building block approach; in some cases a facility or equipment item was deleted or substituted. The construction of cases for economic evaluation is explained in Chapter 3.0, Section 3.4.

The cost components of each case are then scheduled as indicated in the examples presented in Table B-8. The schedules of capital cost expenditures are based upon typical development schedules in other offshore areas modified for the environmental conditions of Norton Sound assuming certain assumptions on field construction schedules (see discussion below).

V. <u>Exploration and Field Development Schedules</u>

This appendix discusses the assumptions made in defining the exploration and field development schedules contained in the scenario descriptions in Chapters 5.0, 6.0, 7.0, and 8.0. These schedules are basic inputs into the economic analysis (scheduling of investments) and manpower calculations (facility construction schedules) as described in Chapter 3.0. As with facility costs, exploration field construction schedules are somewhat speculative due to unknowns about technology, environmental conditions (oceanography, etc.), and logistics. Nevertheless, the economic and manpower analyses require a number of scheduling assumptions based upon the available data and experience in other offshore areas.

Figure 6-1 illustrates the field development schedule for a medium-sized oil field involving a single steel platform, pipeline to shore, and shore terminal in a non-ice-infested but harsh oceanographic environment such a Lower Cook Inlet, the Gulf of Alaska, or North Sea.

The sequence of events in field development from time of discovery to start-up of production involves a number of steps commencing with field appraisal, development planning, and construction. The appraisal process involves evaluation of the geologic data obtained (see Figure B-2) from the discovery well, followed by a decision to drill delineation (appraisal) wells to obtain additional geologic/reservoir information for reservoir engineering. There is a trade-off between additional delineation wells to obtain more reservoir data (to more closely predict reservoir behavior and production profiles) and the cost of the drilling investment. Using the results of the geological and reservoir engineering studies, a set of development proposals are formulated. These would also take into account

TABLE B-8

EXAMPLE OF TABLES USED IN ECONOMIC ANALYSIS CASE - SINGLE STEEL PLATFORM, PIPELINE TO SHORE TERMINAL, WATER DEPTHS 15 to 46 METERS, 2,286 METER OIL RESERVOIR

A. SCHEDULE OF CAPITAL EXPENDITURES FOR FIELD DEVELOPMENT - PLATFORM COMPONENT

Facility/Activity	Year After Decision to Develop - Percent of Expenditure					
		2	3			
Platform Fabrication	40	50	10			
Platform Equipment	40	50	10			
Platform Installation			100			
Development Wells[1] - 48[2]			30 (12)	40 (16)	30 (12)	
Miscellaneous		33	33	34		

[1] Example presented is for 48 wells based on assumption of two rigs working at a completion rate of 45 days per rig; for different numbers of wells the expenditures are prorated approximately at the assumed completion rate.
[2] Figure in parentheses is the number of wells drilled per year.

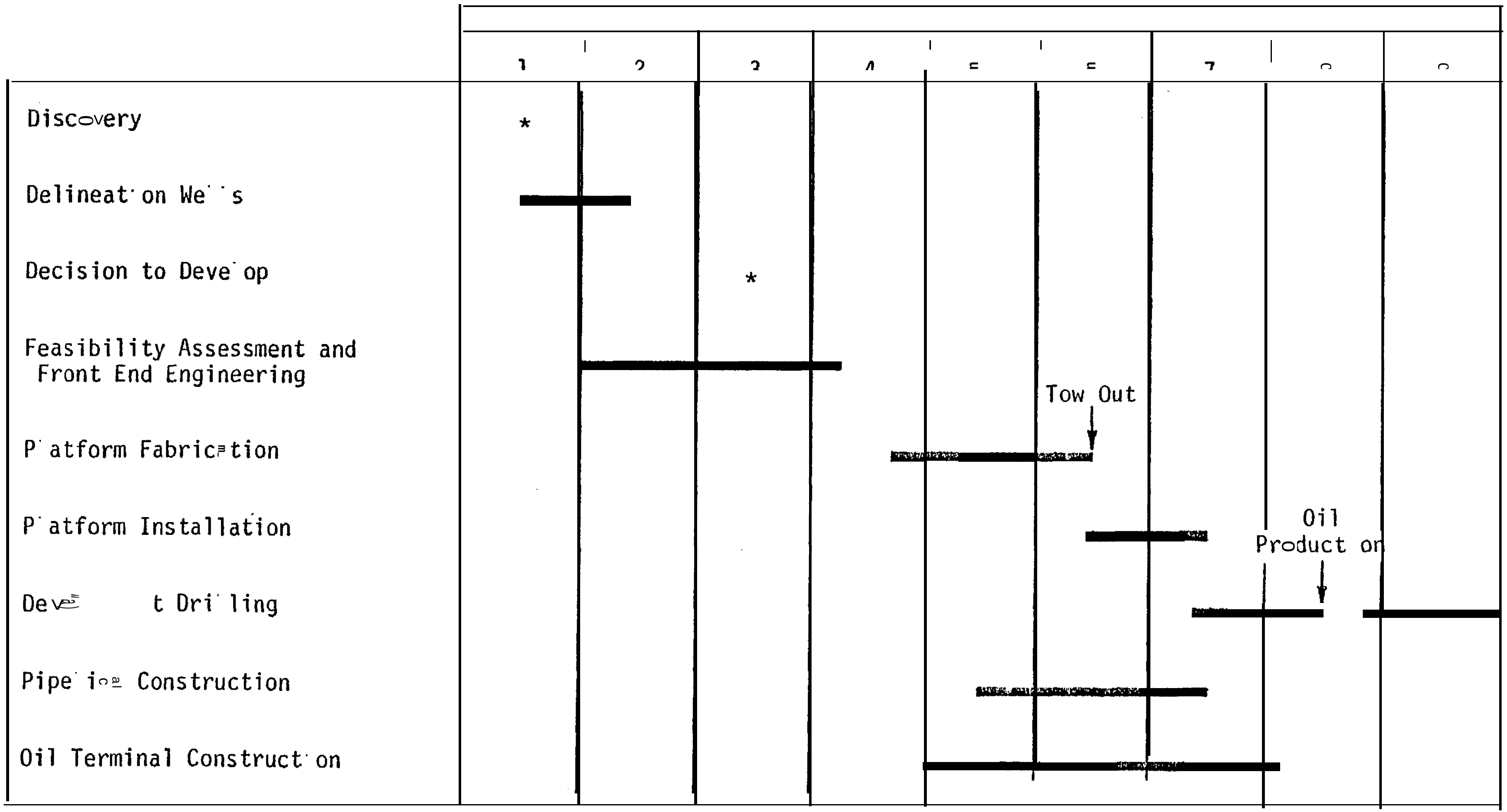
B. SCHEDULE OF CAPITAL COST EXPENDITURES - PIPELINE AND TERMINAL COMPONENTS

Facility/Activity	Year After Decision to Develop - Percent of Expenditure					
Oil Pipeline (10 to 20 inch) 32 km (20 miles)	30	70				
Terminal (100-300 MBO)	5	40	40	15		

Source: Dames & Moore

FIGURE B-1

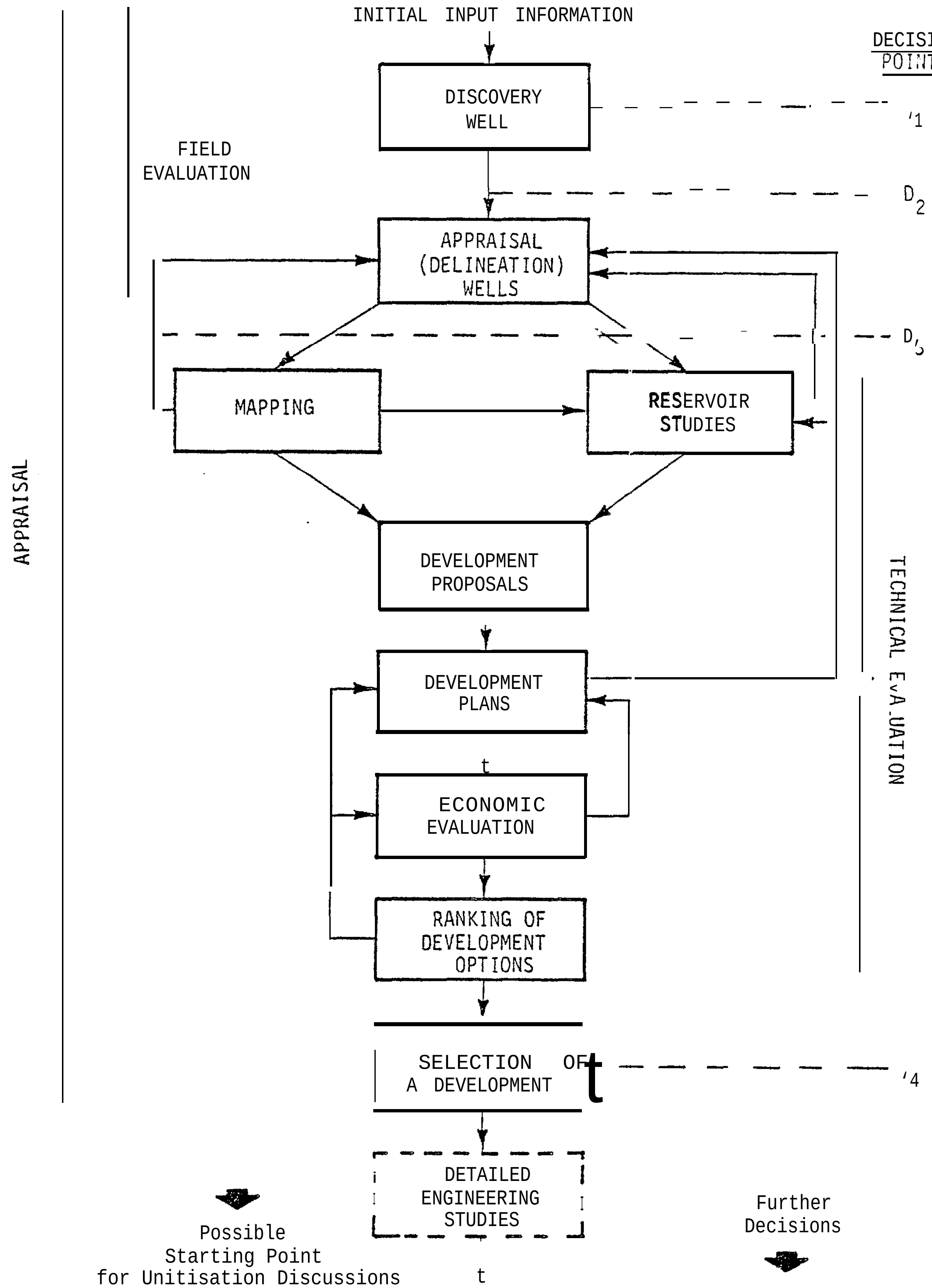
EXAMPLE OF MEDIUM-SIZED FIELD COMPLETION SCHEDULE
SINGLE STEEL PLATFORM, OIL PIPELINE TO SHORE, SHORE TERMINAL[2]
IN NON-ICE-INFESTED ENVIRONMENT



Source: Dames & Moore

[1]For illustrative purposes, discovery is assumed to occur in year following lease sale which is assumed to be first year of exploration.
[2]Seasonality of the level of some activities is not reflected in this figure.

FIGURE B-2



THE APPRAISAL PROCESS

Source: Birks (1978)

locational and environmental factors such as meteorologic and oceanographic conditions; The development proposals involve preliminary engineering feasibility with consideration of the number and type of platforms, pipeline vs. offshore loading, processing requirements, etc.

As illustrated in Figure B-2, the development proposals are screened for technical feasibility and other sensitivities, reducing them to a small number to be examined as development plans. These are further screened for technical, environmental, and political feasibility. An economic analysis of these plans is conducted similar to that conducted in this study , In the economic evaluation, facilities, equipment, and operating expenditures are costed, and expenditures and income scheduled. A ranking of development plans according to economic merit is then possible and weighed accordingly with technical, environmental, and political factors to select a development plan for subsequent engineering design. The feasibility appraisal process is complete. At this time, the operator will make a preliminary go, no-go decision.

If the decision is made to proceed, the operator will conduct preliminary design studies which involve marine surveys, compilation of detailed design criteria, evaluation of major component alternatives, and detailed economic and budget evaluation. Trade offs between technical feasibility and economic considerations will be an integral part of the design process. The preliminary design stage will be concluded when the operator selects the prefered alternatives for detailed "design. The decision to develop will then be made.

The field development and production plan will then have to pass regulatory agency scrutiny and approval. In the United States, the operator will have to submit an environmental report, together with the proposed development and production plan, to the U.S. Geological Survey in accordance with U.S. Geological Survey Regulation S250.34-3, Environmental Reports presented in the Federal Register, Vol. 43, No. 19, Friday, January 27, 1978.

In terms of the effect upon the development schedule, delays due to regulatory agency review, environmental requirements, etc. can not be predicted with accuracy for possible Norton Sound discoveries. The time that may elapse from discovery to decision to develop is field specific and also difficult to predict as in the number of delineation wells required to assess the reservoir. However, these factors are accommodated in this report by the schedule assumptions cited below.

With the decision to develop final design of fat-" ities and equipment commences and contracts placed with manufacturers, suppliers, and construction companies. Significant investment expenditures commence at this time. Front-end engineering and design would take from one to two years following decision to develop, depending upon the facility/equipment. Design and fabrication of the major field component -- the drilling and production platform would take about three years for a large steel jacket such as Chevron's North Sea Ninian Southern Platform (Hancock, White and Hay, 1978). Onshore fabrication of a steel jacket platform will vary from about 12 to 24 months depending upon size and complexity of the structure (Antonakis, 1975). An additional seven months of offshore construction will be required for pile driving, module placement and commissioning.

A critical part of offshore field development is scheduling as much offshore work in the summer "weather window" and timing of onshore construction to meet deadlines imposed by the weather window. In the Gulf of Alaska or North Sea, platform tow-out and installation would occur in early summer, May or June, to permit maximum use of the weather window. If the weather window was missed or the platform was installed in late summer, costly delays up to 12 months in length could result.

Construction of offshore pipelines and shore terminal facilities are scheduled to meet production start-ups which is related to platform installation and commissioning and development well drilling schedules. If shore terminal and pipeline hookups are not planned to occur until after production can feasibly commence, offshore loading facilities may be provided as an interim production system (and long-term backup). The operator has to weigh the investment costs of such facilities against the potential loss of production revenue from delayed production.

Development well drilling will commence as soon as is feasible after platform installation. If regulations permit, the operator may elect to commence drilling while offshore construction is still underway even though interruptions to construction activities on the platform occur during "yellow alerts" in the drilling process (Allcock, personal communication, 1978). The operator has to weigh the economic advantages of early production vs. delays and inefficiencies in platform commissioning. Development drilling will generally commence from six to 12 months after tow-out on steel jacket platforms. Development wells may be drilled using the "batch" approach whereby a group of wells are drilled in sequence to the surface casing depths, then drilled to the 13-3/8-inch setting depth, etc. (Kennedy, 1976). The batch approach not only improves drilling efficiency but also improves material-supply scheduling. On large platforms, two drill rigs may be used for development well drilling, thus accelerating the production schedule. One rig may be removed after completion of all the development wells, leaving the other rig for drilling injection wells and workover.

V.1 Potential Problems with Norton Basin Exploration and Field Construction Schedules

The weather window in the northern Bering Sea varies from four to six months. Although it is possible to install a steel platform and add the deck and modules (or utilize a completely integrated deck) in one open water season, the schedule is nevertheless very tight. 'In the case of Upper Cook Inlet, platform installation, deck installation, and module lifting was generally accomplished in about four months and development drilling was able to commence sometime between October and January. With ice breaker support to tow the platform around Point Barrow in early summer, Dome Petroleum believes that it is possible to install and commission a monotone production platform (with integrated barge-mounted deck units) in one season in the southern Canadian Beaufort Sea and commence development drilling the following winter. Gravity structures would require less installation time than piled structures.

A particular problem in Norton Sound be the provision of the necessary logistical support required during the season of ice cover to assist facilities hook up, platform commissioning, and development drilling activities. There is insufficient deck space to accommodate drilling and other supplies necessary to support these activities unassisted during the winter months. If this problem can be surmounted, development driling could commence within 12 months of platform installation.

The construction schedule for an artificial grave-. production island is less certain since none have been built. In deeper water (about 18 meters [60 feet]), Canadian experience indicates that a production island would probably take two seasons to construct. For soil stabilization purposes, it may also be advisable to leave the island undisturbed for one season. In the scenarios, we have assumed that gravel island construction would commence the year following decision to develop and take two summer seasons. Barge-mounted integrated process units would arrive on site in the second open water season; these units could be either floated into a basin left open in the island which would then be closed and drained, or the units could be skidded on to the island. In comparison, the steel platform development schedule assumes that the platform is installed in the second year after the decision to develop. During the first year, the platform is being fabricated in a lower 48 ship yard. (Construction of a gravel island can commence a year earlier since it is built of local materials and only requires mobilization of a dredge spread; a caisson design may require longer because of the need to fabricate the caissons.)

Because of the uncertainties in construction schedules and the risk of - missing the summer weather window, economic cases are evaluated which assume one or two years delay in the field development schedule.

Another schedule, problem concerns the weather window restriction on exploratory drilling. With the potential resources as indicated by the U.S.G.S. estimates and, assuming U.S. historic find rates (number of exploration wells per significant discovery), it is apparent that either a significant number of rigs would be on location in Norton Sound each summer or the exploration program would extend beyond the initial five

- Significant capital expenditures commence the year following "decision to develop"; that year is year 1 in the schedule of expenditures in the economic analysis.

- Steel platforms in all water depths are fabricated and installed within 24 months of construction start-up. Platform installation and commissioning is assumed to take ten months. Development well drilling is thus assumed to start about ten months after platform tow-out.

- Steel platform tow-out and emplacement is assumed to take place in June.

- Artificial island construction commences the year after decision to develop in June and takes two summer seasons. Process equipment is installed in the second summer and development drilling commences ten months later.

- Platforms sized for 36 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 36 well slots are assumed to have one drill rig operating during development well drilling.

- Drilling progress is assumed to be 20 days per oil development well per drilling rig, i.e. 12 wells per year for 762 meters (2,500 feet) reservoirs, 30 days per well (12 per rig per year) for 1,524 meter (5,000 feet) reservoirs and 45 days (8 per rig per year) for 2,286 meters (7,500 feet) reservoirs.

- Production is assumed to commence when about ten of the oil development wells have been drilled and when about 6 gas wells have been completed.

- Well workover is assumed to commence five years after production start-up.

- Oil terminal and LNG plant construction takes between 24 and 36 months depending on design throughput.

year tenure of OCS leases. Only one well per rig could be reasonably anticipated to be drilled assuming a four month season unless targets were particularly shallow. An extension of the drilling season through ice breaker support and use of ice-reinforced rigs could extend the season and increase the number of wells accomplished per rig. (Dome Petroleum has extended the drilling season beyond that feasible for conventional rigs using ice-resistant drillships dnd ice breaker support.) In the shallower waters of Norton Sound, the use of gravel islands could also extend the drilling season. The key problems relating to extension of the drilling season by these methods are not technical but rather economic and environmental. Extension of the season into spring and fall occurs at critical biological seasons in the migration and/or other aspects of life history of some species, the impact upon which would depend on the location of drilling activities.

VI. Scheduling Assumptions

Based upon a review of technology data, industry experience, and environmental conditions in the northern Bering Sea, the following assumptions have been made on exploration and field development scheduling (see field development schedules in Chapters 6.0, 7.0, and 8.0 and economic assumptions in Chapter 3.0, Section 3.6).

- Exploration commences the year' following the lease sale (i.e. 1983); all schedules relate to 1983 as year 1.

- An average completion rate of four per exploration/delineation well is assumed with an average total well depth of 3,048 to 3,692 meters (10,000 to 13,000 feet).

- The number of delineation wells assumed per discovery is two for field sizes of less than 500 mmbbl oil or 2,000 bcf gas, and three for fields of 500 mmbbl oil and 2,000 bcf gas and larger.

- The "decision to develop" is made 24 months after discovery.

APPENDIX C

APPENDIX C

PETROLEUM TECHNOLOGY AND PRODUCTION

This appendix reviews offshore petroleum technology that may be applicable to Norton Sound petroleum development, in particular Arctic and sub-Arctic engineering. Data for this review comes from published sources including:

(1) Professional and trade journals such as Journal of Petroleum Technology, Offshore, World Oil, Proceedings of the Offshore Technology Conference (various years), Oil and Gas Journal, and Petroleum Engineer.

(2) Dames & Moore data files.

(3) Discussions with engineering and exploration departments of oil companies operating in Alaska and in the Canadian Arctic.

(4) Interviews with petroleum industry construction companies.

Data on petroleum facility costs was obtained concurrently with data gathering in petroleum technology.

Throughout this discussion, it should be borne in mind that Norton Sound is a frontier area yet to experience the drill bit (offshore). In fact, only one offshore well has been drilled in the whole Bering Sea - a C.O.S.T. well drilled in St. George's Basin in 1976 by Atlantic Richfield and partners. Furthermore, only recently has research focus turned to Norton Sound as regulatory agencies and industry have concentrated on areas further up on the lease schedule list such as the Beaufort Sea and Gulf of Alaska. A C.O.S.T. well is scheduled to be drilled in Norton sound in the summer of 1980 using a jack-up rig.

This appendix commences with a brief review of offshore Arctic petroleum experience that will enable petroleum development in Norton Sound to be placed in the context current state-of-the-art engineering. A description of the environmental constraints to petroleum development in Norton Sound then follows. The remainder of the appendix describes the various production systems, particularly platforms, that may be suitable to develop Norton Basin petroleum resources.

I. Offshore Arctic Petroleum Experience

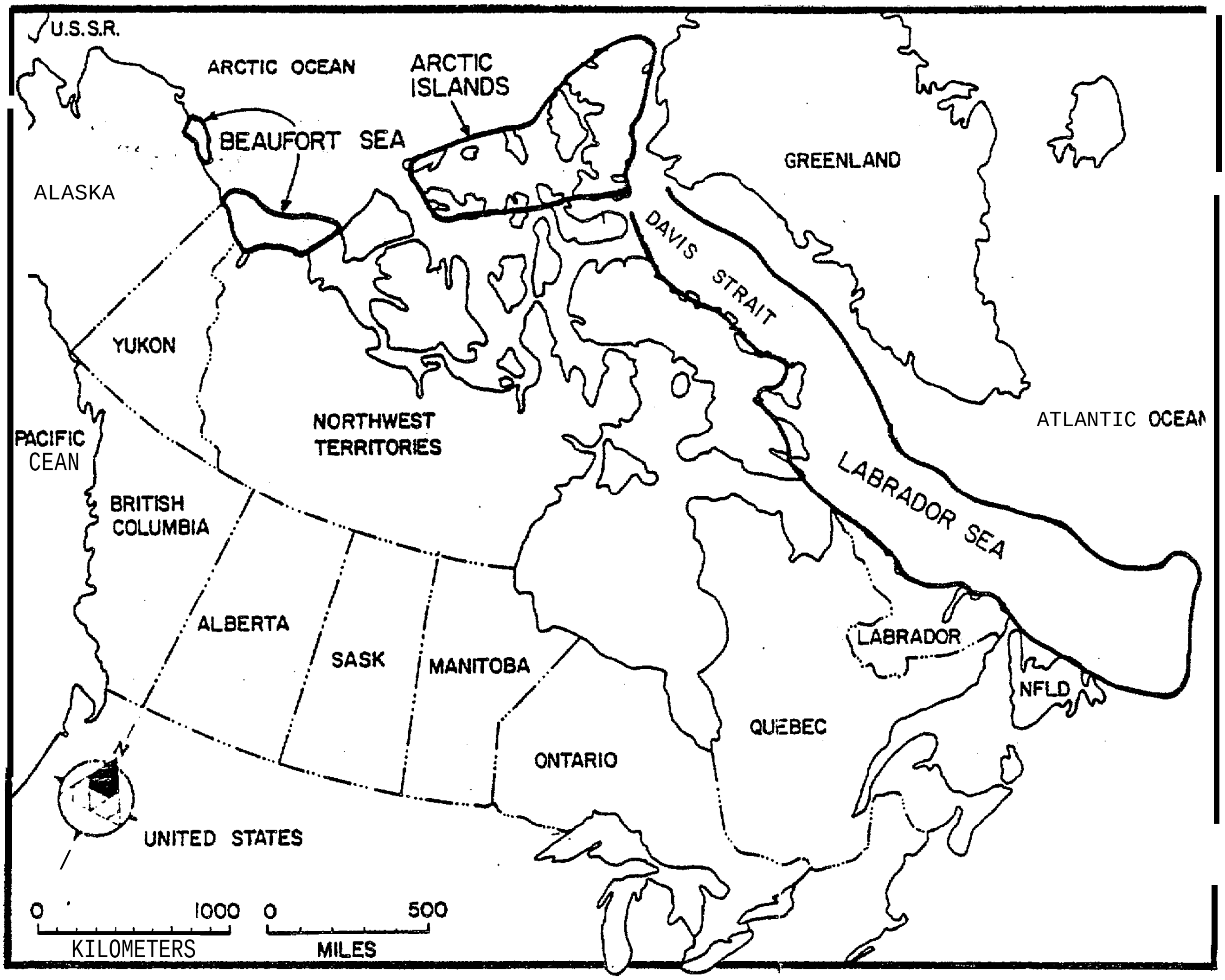
I.1 Canadian Beaufort Sea

Exploration drilling in the Canadian Arctic started in the Mackenzie Delta in the mid-1960's. After several years of extensive onshore exploration, which resulted in the discovery of commercial gas reserves, exploration extended offshore into the Beaufort Sea (Figure C-l). The first well was drilled in the winter of 1973-74 frcm the artificial island, Immerk B-48, in 3 meters (10 feet) of water. To date, artificial islands have been constructed in the Beaufort Sea to a maximum water depth of 20 meters (65 feet). The most recent artificial island is "Issungnak" located in 20 meters (65 feet) of water, 25 kilometers (15.5 miles) from shore; the island is of sacrificial beach design requiring 3.5 million cubic meters (4.6 million cubic yards} of fill and two summer seasons (1978 and 1979) to construct.

Exploration drilling with ice-strengthened drillships started in deeper waters (over 30 meters [100 feet] in 1976). Three drillships were operating in the Canadian Beaufort Sea in the summers of 1977 and 1978. A fourth ship was scheduled to join the fleet late in the 1979 season. At the end of the 1977 drilling season, three gas discoveries and one oil discovery had been made by the Dome ships. Four wells were spudded and drilled to varying depths in 1978 and the 1979 drilling program called for re-entry of four wells and spudding of four new wells. The recent announcement of a major oil discovery at the M-13 Koponoar well indicates significant promise for hydrocarbon production in this area.

1.2 Alaskan Beaufort Sea

In contrast to the Canadian Beaufort, Alaskan Beaufort Sea exp"loration has been limited to ice islands near the Colville delta (Union Oil) and



SO URCE: CROA SDALE , 1977.

Figure **C-1**

ARCTIC PETROLEUM FRONTIERS

several wells drilled from gravel pads in shallow water in Prudhoe Bay on existing state leases. The joint State-Federal lease sale scheduled for December 1979 will, of course, change the picture.

1.3 Canadian Arctic Islands

The other major arctic frontier is the Canadian Arctic Islands. Exploration drilling started in 1961 and off-ice drilling began in 1974 on the landfast ice that covers the sea between the islands for up to 11 months of the year. The first offshore well, Panarctic's Helca N-52, was successfully drilled from a reinforced ice platform in 130 meters (429 feet) of water, 13 kilometers (9 miles) from shore. Six gas fields have been discovered to date in the Sverdrup basin of the Arctic islands. Polar Gas has proposed a 48-inch, 5,330-kilometer-long (3,200-mile) pipeline, which would involve crossing several deep inter-island channels, to transport the gas to southern Canadian and eastern United States markets. Proven arctic island gas reserves could now exceed the threshold of 20 trillion cubic feet required to support this pipeline with the announcement made in early 1979 of the Whitefish H-63 discovery.

A LNG system, the Arctic Pilot Project, has been proposed as an interim transportation system to take arctic gas to market by Petro-Canada. That system would involve construction of a gas pipeline across Melville Island, a LNG plant and marine loading terminal, and a LNG shipping system employing ice-breaking tankers (World Oil, November, 1977). A pilot project involving the first arctic subsea production system and submarine pipeline was completed in 1978. An 18-inch, 1.3-kilometer-long (0.8-mile) pipeline was constructed to take gas from Panarctic's Drake F-76 gas well, situated in 58 meters (185 feet) of water to shore.

1.4 Eastern Canadian Arctic

Exploration drilling has begun off the east coast of Labrador in Canada and in the Davis Strait between Greenland and Canada. Ice-free periods vary from 365 days per year in the south to about 100 days in the Davis Strait. These icc-free periods permit the use of conventional drilling platforms such as semi-submersibles and drillships. The main contrast with other ice-infested waters is the threat of icebergs. An average of 15,000 icebergs a year calve from west Greenland; some weigh over 3 million tons and have drafts over 260 meters (858 feet). Techniques for iceberg avoidance and handling have been developed which involve radar tracking and towing systems using support vessels. Because of the threat . of iceberg collision and the need for rapid move-off, dynamically positioned drillships or semi-submersibles are better suited to this area than systems using mooring lines. Drilling on the Canadian portion of the Labrador Sea and Davis Strait south of 60°N started in 1971; exploration began on the Greenland (Danish) side in 1976. Because of the iceberg threat, only dynamically-positioned vessels are permitted to work in Greenlandic waters. By the end of 1978, five wells had been completed on the Greenland side of the Davis Strait, while drilling was scheduled to commence on the Canadian side north of 60°N in the summer of 1979.

II. Environmental Constraints to Petroleum Development

II.1 Oceanography

11.1.1 Introduction

The oceanographic setting of the proposed sale area is primarily within the Chirikov and Norton Basins, north and west of St. Lawrence Island.. Climatically, this region is in a transition zone. During the summer, winds are from the south and west and a maritime climate prevails; in the winter, wind direction changes to the north and east and a continental climate is more in evidence.

This area is ice free less than half the year. Little is known of the oceanographic conditions under the ice. There is some evidence to indicate that oceanographically, summer and winter may differ markedly. For instance, except for smaller eddies due to islands and irregular coastlines, the flow everywhere appears to be toward the north during the summer. On the other hand, a general cyclonic (counterclockwise) motion may be established in the Bering Sea during the winter.

Also the proposed sale area is strongly influenced by the Yukon River which discharges 5,660 cubic meters per second (200,000 cfs) annually into the southeast portion of this region. The Yukon is responsible for the creation of a large delta on the southern side of Norton Sound and most of the recent sedimentation in this region is probably due to the introduction of material by this giant river.

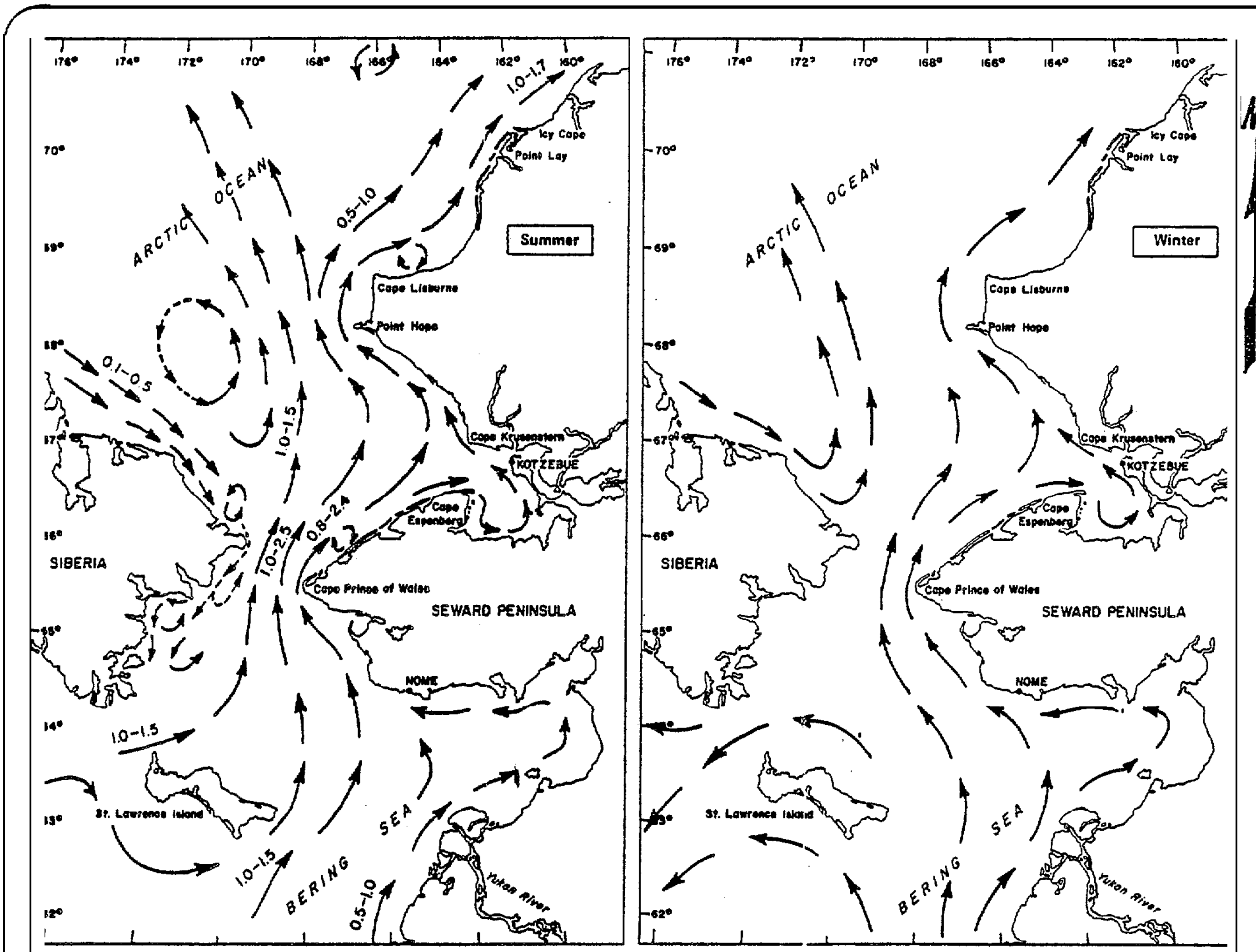
11.1.2 Bathymetry

Shallow water conditions characterize the entire sale area. The deepest portion, in the northwest corner, is just over 49 meters (160 feet). A channel 46 meters (150 feet) deep lies just off the eastern edge of St. Lawrence Island. A deltaic fan created by the Yukon River forms a large shoal generally less than 15 meters (50 feet) deep in the southwest portion of Norton Sound. The Sound has an average depth of 18 meters (60 feet) (Cacchione and Drake, 1978), and is relatively uniform except for an anomalous channel located just south of the shoreline of Nome. The bottom of the Sound slopes gently from east to west.

As a result of the growth of the polar ice caps and increased continental glaciation, the Bering Sea has become a subaerial feature several times in the last million years. The last time only about 11,000 years ago.

11.1.3 Circulation

The general flow through the Bering Sea is northward. Water is transported from the North Pacific through the Bering Strait into the Chukchi Sea. Superimposed on this flow are several medium-sized eddies which result from the presence of St. Lawrence Island and from irregularities in the Siberian and Alaskan coastline. In addition to these fluctuations, there are other topographically induced variations in the northward transport as the flow is funneled past St. Lawrence Island and through the Bering Strait, the flow is slowed when passing certain large embayments such as Norton Sound and the Gulf of Anadyr. A minor southward flow is indicated in the western Bering Strait during the summer (U.S. Weather Bureau and U.S. Navy Hydrographic Office, 1961). Also during the winter a cyclonic circulation pattern may tend to become established under the ice (Figure C-2).



Current direction well established

--- Hypothetical current direction or sporadic flow

0.8-2.4 Mean current velocity range in knots (1 Knot= 0.51 m/sec)

Note: Under-ice current velocities have been poorly documented.

Adapted from D. C. Burbank, 1974. Suspended Sediment Transport and Deposition in Alaskan Coastal Waters with Special Emphasis on Remote Sensing by the ERTS-1 Satellite. and U.S. Weather Bureau and U.S. Navy Hydrographic Office, 1961. Climatological and Oceanographic Atlas for Mariners. Volume II. North Pacific Ocean; and G.J. Potocsky, 1975. Alaskan Area 15- and 30-day Ice Forecasting Guide.

Source: Selkregg, 1974, Fig. 41

Figure C-2.

SURFACE WATER CIRCULATION PATTERN
IN SUMMER AND WINTER

Actual current measurements within the Bering Sea are quite limited. In 1967, measurements were made both north and south of the eastern side of the Bering Strait. The southern station was approximately 96 kilometers (60 miles) from the Strait in a water depth of 48 meters (157 feet). The mean flow was 31 cm/sec (0.6 knots) at 13 meters (43 feet) and 21 cm/sec (0.4 knots) at 35 meters (115 feet). During the monitoring period, several reversals of relatively short duration were noted; being more common in the lower meter. The reason for these reversals is not known. Apparently they are not associated with tides nor with local wind patterns (Coachman et al., 1975).

Coachman et al., (1975), report that in 1968 three current meters were deployed in the Bering Sea -- one just off Northwest Cape on St. Lawrence Island. Thirty hours of continuous data showed a mean current of 36 to 41 cm/sec (0.7 to 0.8 knots) with a semidiurnal variation of from 10 to 26 cm/sec (0.2 to 0.5 knots). During the same cruise, 30 hours of data were also obtained from Anadyr Strait, west of St. Lawrence Island. The mean current was approximately 51 cm/sec (1 knot) with semidiurnal variations equal to that average current.

The third station was well north of St. Lawrence Island, approximately 56 km (35 miles) southeast of Cape Krigugan on the Russian mainland. This station was occupied for approximately 25 hours. The mean flow was much less -- on the order of 21 cm/sec (0.4 knots) and there were no apparent semidiurnal variations in the flow.

According to Coachman et al. (1978), several current meters were deployed during the winter of 1976 and 1977 in the Bering Sea. Of the 13 recovered, data from three have been processed. Two were in the strait between St. Lawrence Island and the mainland to the east; the other was in the Bering Strait. These current meters were placed a distance of 9 meters (30 feet) from the bottom and remained in place over the entire ice season producing long-term records in excess of seven months. The meters in the vicinity of St. Lawrence Island showed a long-term mean of 51 cm/sec (1 knot), generally to the north or slightly east of north. There were large north-south variations in excess of 51 cm/sec (1 knot) at both diurnal and semidiurnal periods. The current meter deployed in the Bering Strait showed a long-term average of 10 cm/sec (0.2 knots) with variations also in excess of 51 cm/sec (1 knot). However, these variations could not be tied directly to tidal periods witn the possible exception of a trace of semidiurnal signal. Additional data remain to be analyzed from this program and should shed light on many questions about the general circulation of the Bering Sea.

In addition to the area just north and east of the eastern tip of St. Lawrence Island, Norton Sound makes up the eastern half of the proposed sale area. Its physical oceanography, like that of the Bering Sea, is only beginning to be investigated. It has already become evident, however, that the dynamics of Norton Sound are very complex. Norton Sound can be divided into two distinct regions -- the western part, which has good communication with the general circulation of the Bering Sea; and the more isolated eastern portion which apparently has only limited communication with the main portion of the Norton Sound. The latter apparently represents an anomalous feature in that it has bottom water that is colder and more saline than the water at the same depth in the western part of the Sound. Muench et al. (1977), speculated that this is a remnant feature created during the formation of ice in which more saline cold water is formed as surface water freezes. The more dense water then sinks and owing to the limited mixing in this part of the Sound, remains after the ice melts. It then probably becomes mixed and replaced by water during the next freeze-up.

The U.S. Weather Bureau, U.S. Navy Hydrographic Office (1961), and Meunch et al. (1977), have indicated that the western portion of Norton Sound is characterized by a counterclockwise gyre. Cacchione and Drake (1978) measured currents over an 80-day ice-free period at a location 59 km (37 miles) south of Nome. They obtained an average value of about 5 cm/sec (0.1 knot) at a distance 1.4 meters (4.5 feet) off the bottom in 17 meters (57 feet) of water. This current was directed slightly east of north and had associated with it semidiurnal tidal fluctuations up to 36 cm/sec (0.7 knots). These tidal variations tended to be in the east-west direction. They also found that on at least one occasion the northerly current was so intensified by southern winds as to essentially mask the tidal variations in the flow. The data that were taken by Cacchione and Drake south of Nome would tend not to support the cyclonic gyre theory proposed by Muench et al. (1977). Additional measurements were taken by Muench et al. (1977) southwest of Cape Darby which showed tidal variations of about 36 cm/sec (0.7 knots). However, the mean flow was essentially zero.

Cacchione and Drake (1978) compiled data collected by C. H. Nelson and divided the Norton Sound area into three distinct current regimes. The area east of a line from Cape Darby to Stewart Island has been assigned a mean current of 7.5 cm/sec (0.15 knots). Between that line and a line between Sedge Island south to a point approximately 24 km (15 miles) west of Kawanak Pass has been assigned a value of 15.3 cm/sec (0.30 knots). The area west of that line to a line approximately 50 km (31 miles) west of Point Clarence south-southeast to a latitude 63° 30′ N and longitude 67° 00' W has been assigned a mean current of 20.6 cm/sec (0.40 knots).

The measurements that established these areas were taken over relatively short time periods from an anchored vessel. As such, they have tidal information associated with them. However, with a sufficient quantity of data points, these may average out, although the number of data points necessary to accomplish this averaging is uncertain. Thus, these values should be viewed with a certain amount of scepticism. In the next few years, additional field work in, and further analysis of, existing data for Norton Sound will be done. Its complexity is already evident. Over much of the year, its dynamics are dominated by tidal motions superimposed on a mean flow resulting from the Alaska Coastal Current. During ice-free periods, local winds have significant effects on the current regime. The Yukon River, no doubt, effects the physical oceanography of Norton Sound as does the formation and melting of the seasonal icepack.

11.1.4 Ice

The proposed lease area is ice free, on an average only four months of the year (Figure C-3, U.S. Weather Bureau and U.S. Navy Hydrographic Office, 1961). Average break-up and freeze-up periods, as seen in Figure C-4, are from late May to early June and from late October to mid-November, respectively (State of Alaska, 1974).

It has been reported that pack ice in the Bering Sea can be approximately 12 meters (40 feet) thick (Nelson, 1978). Nelson also reported that Norton Sound floe ice can be up to 2 meters (6.5 feet) thick. However, other estimates such as by the National Ocean Survey (Coast Pilot, 1979) suggest thicknesses less than this. The shorefast ice extends shoreward of the 10-meter (33 feet) contour. Pressure ridges form near the contact between the fast and floe ice. Keels on these ridges are quite capable of severely gouging the sea bottom. Such gouges are particularly prevalent across Norton Sound as illustrated in Figure C-5. Ice scars over 1 meter (3 feet) deep have been noted on side-scan sonar images (Nelson, 1978).

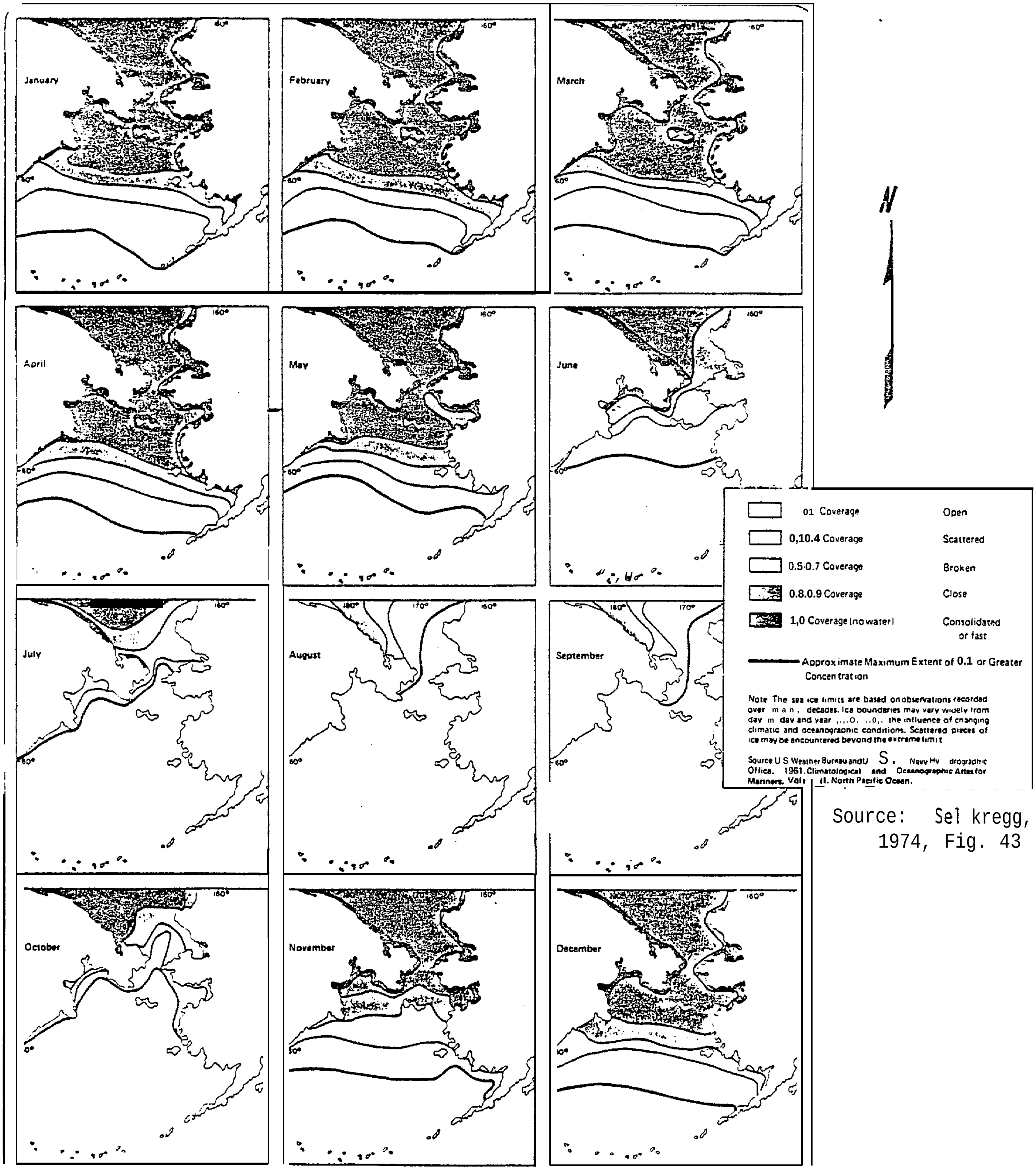
II.1.5 Tides

The tides in this northern portion of the Bering Sea, depicted in Figure C-6, are small with diurnal ranges from about 0.45 to 1.2 meters (1.5 to 4 feet). Except for the diurnal tides flowed in the southeast portion of Norton Sound, the tides are of the mixed type, that is, there are two unequal highs and two unequal lows during each lunar day. Tides, which are long progressive waves, propagate northward through the Bering Sea and Bering Strait. Upon approaching Norton Sound, they proceed around the bay in a counterclockwise direction.

As previously described, the circulation in Norton Sound is strongly influenced by tidal fluctuations. Tides in this shallow bay may be the primary force responsible for ice motion and scouring. The effect, if any, that ice might have on tidal currents is not known.

II.1.6 Waves and Storm Surge

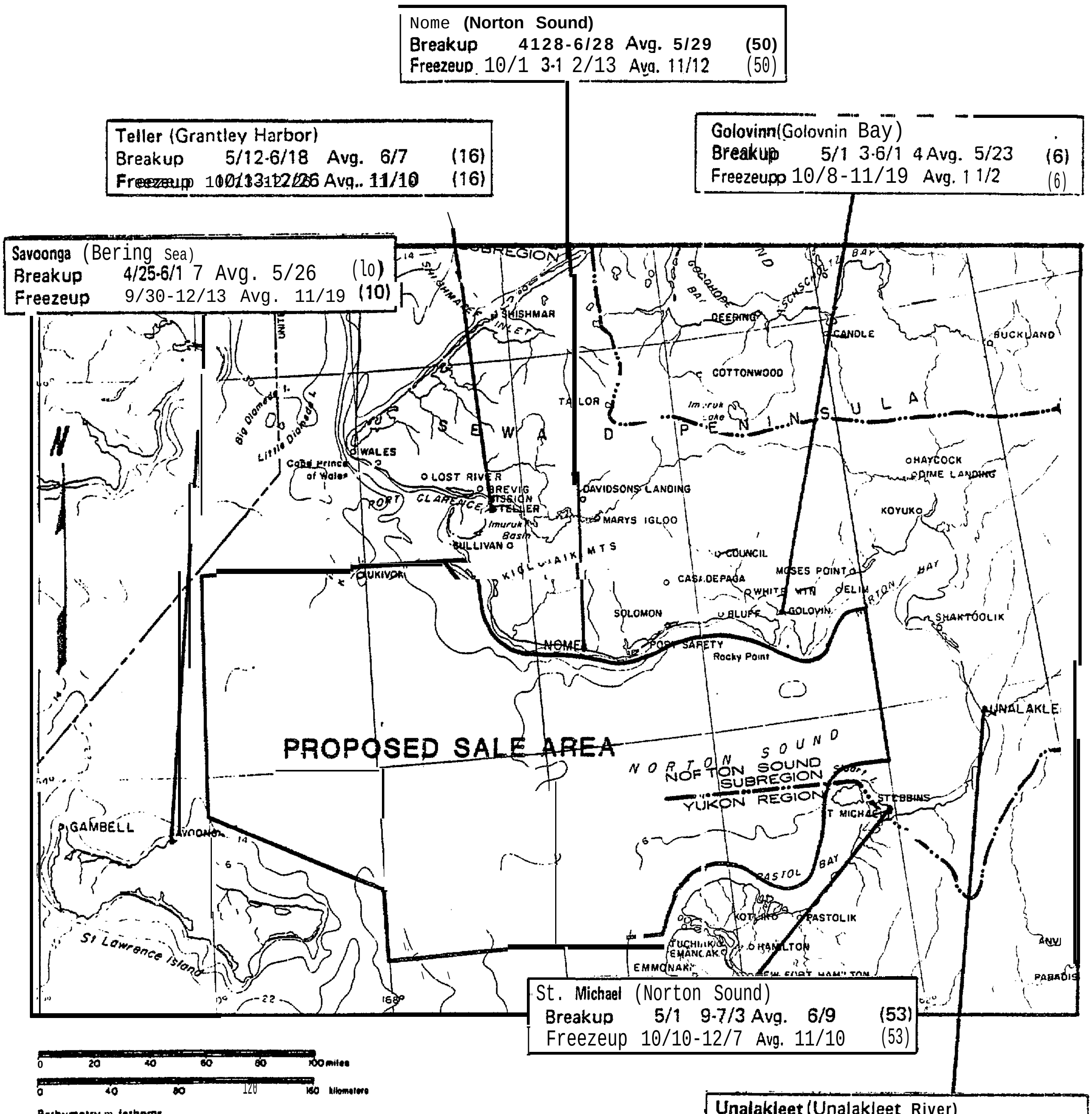
The generation of waves in deep water depends on fetch, wind speeds, and



Source: Sel kregg, 1974, Fig. 43

Figure C-3

SEASONAL ICE CONDITIONS IN THE BERING AND CHUKCHI SEAS



Source: U.S. Coast and Geodetic Survey, 1964. United States Coast Pilot 9, Pacific and Arctic Coasts, Alaska, Cape Spencer to Beaufort Sea and Alaska. University, 1975. Chukchi Sea: Bering Strait–Icy Cape: Physical and Biological Character of Alaskan Coastal Zone and Marine Environment. 31 maps.

Figure C-4

BREAKUP AND FREEZEUP DATA, NORTHWEST REGION

(Modified from Sel kregg, 1974, Figure 44)

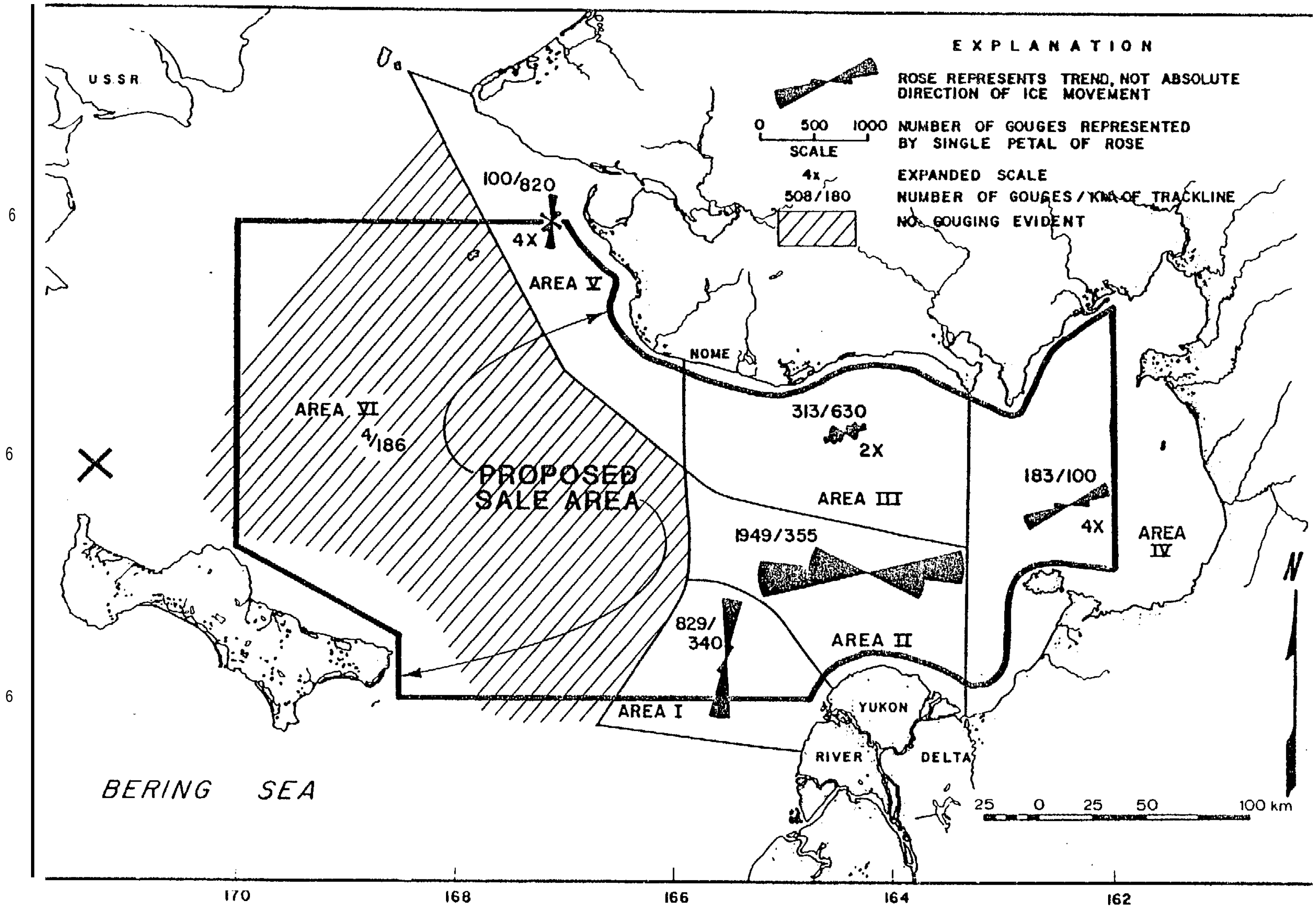
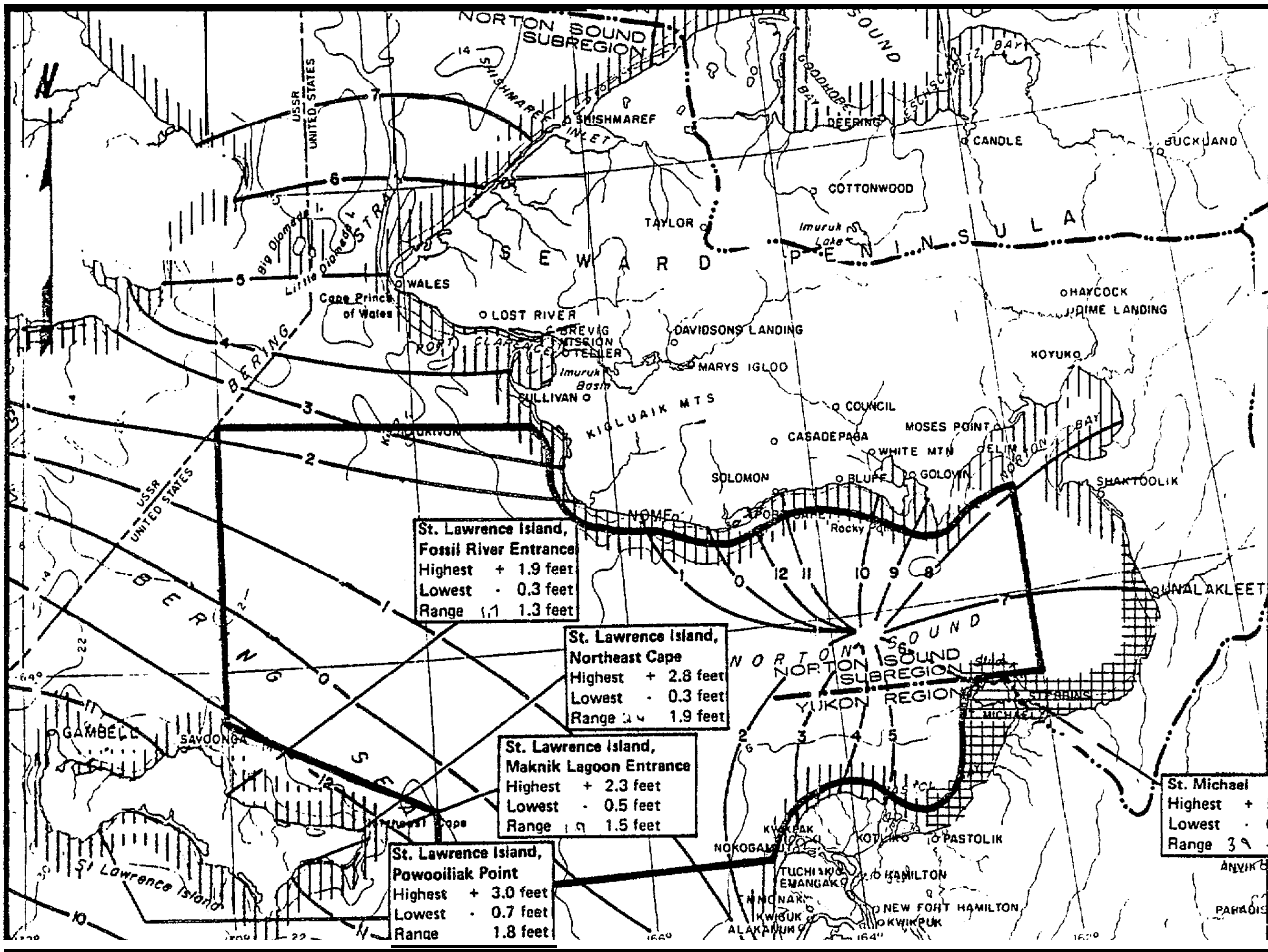


Figure C-5

ICE GOUGING IN NORTHEASTERN BERING SEA

Rose diagrams represent trend and number of gouges; data are trends and not indicators of absolute motion. Division into areas 1 - VI is based on zones of similar trending gouges. (Modified from Nelson, 1978, Figure E-6.)



0 20 40 60 80 100 miles

0 40 80 120 160 kilometers

Proposed Lease Sale Area Boundary

Diurnal tide

Mixed tide

—9- Cotidal lines (Numerals indicate time of high water of the principal lunar semidiurnal tide-lines connect points of equal time of high or low water.)

Note: Mean range = Average semidiurnal range occurring between mean high and mean low water.

Figure C-6

TIDAL ELEVATIONS AT SELECTED I-CICATIONS WITHIN AND NEAR PROPOSED SALE AREA

(Modified from Selkregg, 1974, Figure 47.)

wind duration. In the relatively shallow and protected waters of the northern Bering Sea, water depth and wave direction need also be considered. St. Lawrence Island restricts the propagation of sea waves from the west and southwest into much of the sale area. Norton Sound is exposed to waves from the southwest but these waves are severely attenuated owing to its shallow waters. The north-eastern portion of the sale area is exposed to waves from the south but again waves must develop in, and propagate through water depths of less than 30 meters (100 feet). The bottom friction associated with such shoal water does not permit waves to attain the deep water characteristics. For instance, according to the Sverdrup-Munk-Bretschneider wave prediction method (U.S. Army, CERC, 1975) a 74 km/h (40-knot) wind blowing over a 370 km (200 nautical mile) fetch for sufficient duration to utilize the entire fetch could generate waves with a significant height of almost 5 meters (16 feet). However, other conditions being equal, but with wave generation occurring in 29 meters (95 feet) of water (an appropriate value for this area) the significant height would be reduced to 2.3 meters (7.5 feet) (U.S. Army, CERC, 1975). This reduction is due only to bottom friction but additional diffraction caused by topographic features such as St. Lawrence Island and the Yukon Delta will further restrict waves in the Bering Sea.

A maximum significant wave height 2.3 or 2.4 meters (7.5 or 8 feet) given the appropriate set of meteorological conditions, could translate (assuming that these waves are Rayleigh distributed) into a maximum wave of about 4.3 meters (14 feet).

Waves are important to small boat operations, in moving sediments in shallow water and in the coastal and nearshore processes. They can also be important when coupled with storm surge. Such storm tides are increases in sea level above astronomical tide levels on or near the coast. The low-lying coastal regions and shallow water make much of the Bering Sea shoreline particularly susceptible to this type of storm flooding.

Records of storm surges are incomplete, however, Nome was severely damaged in 1913 and again in 1946 by such storms (Gute and Nottingham, 1974). In 1974, a major storm occurred in the northern Bering Sea. A surge from that storm has been noted from Port Clarence to St. Michael Island (Challenger et al., 1978). Elevations above mean sea level have ranged from over 3 meters (10 feet) in the Port Clarence to Cape Rodney area to over 4.6 meters (15 feet) in the eastern portion of Norton Sound. Also, a 1977 storm produced a debris line approximately 2 meters (6.5 feet) above MSL. Such surges would be particularly important to coastal development.

11.1.7 Oceanographic Comparisons with Upper Cook Inlet and Implications for Platform Design

To date the only offshore area sufficiently rich in petroleum resources to warrant development has been the upper Cook Inlet. It has been assumed, based on the available input from industry sources, that the offshore structures for the Bering/Norton region would likely be similar to those used in Cook Inlet. In light of this probability, it seems appropriate to compare the oceanographic conditions of the two areas.

Except for the majority of Norton Sound, Cook Inlet is the shallower area. However, tidal ranges within Cook Inlet are about on the order of magnitude greater than those in the Bering/Norton region.

Ice conditions may also be markedly different between the areas. In the northern region, ice is present six or seven months of the year and may be 30 cm (1 foot) or more thicker than in the south-central region. Also, ice coverage is probably more extensive than in Cook Inlet. Although the preponderance of the ice is continually in motion, fast ice does exist within a few kilometers of the shoreline. While ice strength and coverage may be less in Cook Inlet, the large tidal currents of over 420 cm/sec may create a structural loading situation as severe as any in the Bering/Norton region. Greater knowledge of ice conditions for the northern region needs to be obtained before this can be said with certainty.

Some structures in Cook Inlet have been designed for an extreme wave of 8.5 meters (28 feet). This wave may be larger than that which could actually develop within the Inlet but, in fact, the most severe loading condition probably results from the combined effects of ice and tidal currents. Owing to the presence of St. Lawrence Island and relatively shallow water, design waves within the northern lease area may be considerably less than 6.1 meters (20 feet). In any event, as with Cook Inlet, the greatest structural loads probably result from moving ice.

While conditions within the two regions appear to differ in several important areas, it may be that actual design characteristics between the two are not all that dissimilar. This means that knowledge gained from development in the Inlet will greatly facilitate development in the Bering/Norton area.

II.2 Geology and Geologic Hazards

11.2.1 Tectonic Setting

Norton Sound is a large coastal embayment approximately 250 kilometers (150 miles) long and 125 kilometers (75 miles) wide that is located in the northern part of the Bering Sea immediately south of the Seward Peninsula. The Norton Sound region lies within a Mesozoic fold belt. Although the region is located well away from the major plate boundaries in southern Alaska, the area does experience tectonic adjustment due to plate interaction. Major transcurrent faults, first active during the Mesozoic period, show significant right internal displacement through recent times. This tectonic adjustment is due to right lateral shear stress caused by a rotational component of the tectonic plate interaction (Woodward-Clyde Consultants, 1978). The major transcurrent fault in the area, the Kaltag fault and its offshore continuation are shown on Figure C-7.

The historic seismicity of the Norton Sound region has been compiled by Woodward-Clyde Consultants (1978) for the years 1964 through 1976. The 13-year record of seismicity, which includes 38 events, does not have any earthquakes within magnitudes of above 6. Major earthquakes with magnitudes of 6 or greater have been reported in the area prior to 1959; three occurred in one sequence between February and May 1928 and two in another

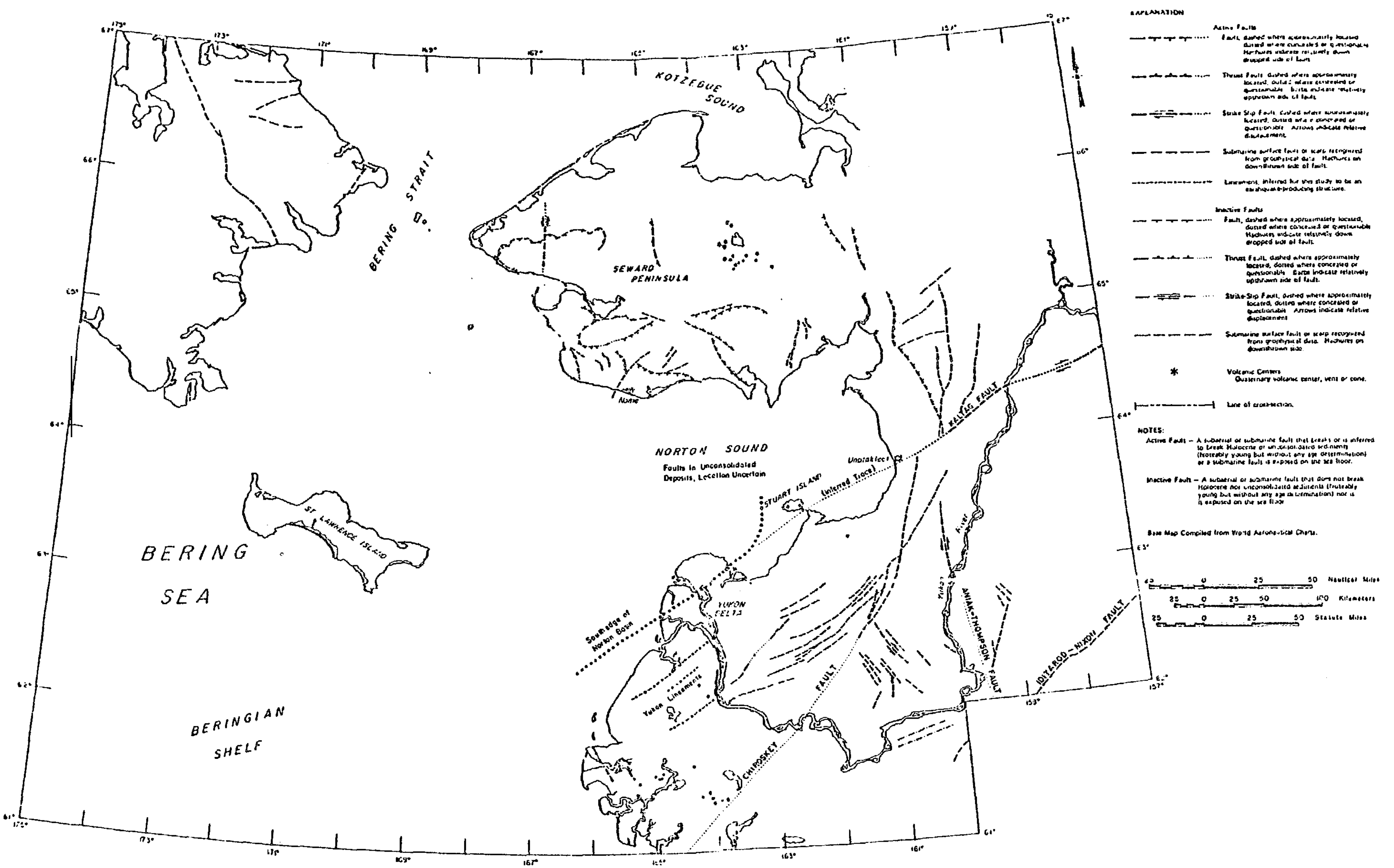


Figure C-7

NORTON SOUND REGION MAJOR FAULT ZONES
Source: Fisher et al., 1979.

sequence in April 1958 (Woodward-Clyde Consultants, 1978). The Kaltag fault and its unmapped projection into the Yukon-Kuskokwim delta area is considered as the major source of earthquakes in the Norton Sound region (Woodward-Clyde Consultants, 1978).

11.2.2 Regional Geology

The Norton Sound region is underlain by Precambrian through Quarternary strata of varying lithologies. These strata have been grouped into broad belts of rocks distinguishable by age and lithology (Fisher et al., 1979). Immediately north of Norton Sound, Precambrian slates and Paleozoic metamorphic and sedimentary rocks are exposed across much of the Seward Peninsula. West of Norton Sound and along its southern boundary, Mesozoic sedimentary volcanic rocks predominate. Localized intrusions of Mesozoic through Cenozoic plutonic rocks isolated patches of Tertiary sedimentary rocks and Quarternary basalts can be found throughout the Norton Sound region. The onshore geology of the Northern Bering Sea region is present on Figure C-8.

Projection of the described rock units offshore along structural trends is aided by interpretation of geophysical data which indicates that similar rock units probably underlie Norton Sound and its adjoining structural basin, the Norton Basin (Nelson et al., 1974; Fisher, 1979).

Norton Basin, a structural depression adjoining Norton Sound on the west, is filled with a thick sequence of probable late Mesozoic through Cenozoic strata. The basin, which began to develop during late Cretaceus, formed as a pull-apart feature (separation of structural blocks) along the right lateral Kaltag fault (Fisher et al., 1979). Associated west-northwest trending normal faults cut across the basin forming grabens which contain the thickest basin fill of up to 7 km (4 miles). These grabens separated by hosts over which basin fill is generally less than 3 km (1.9 miles) (Fisher et al., 1979).

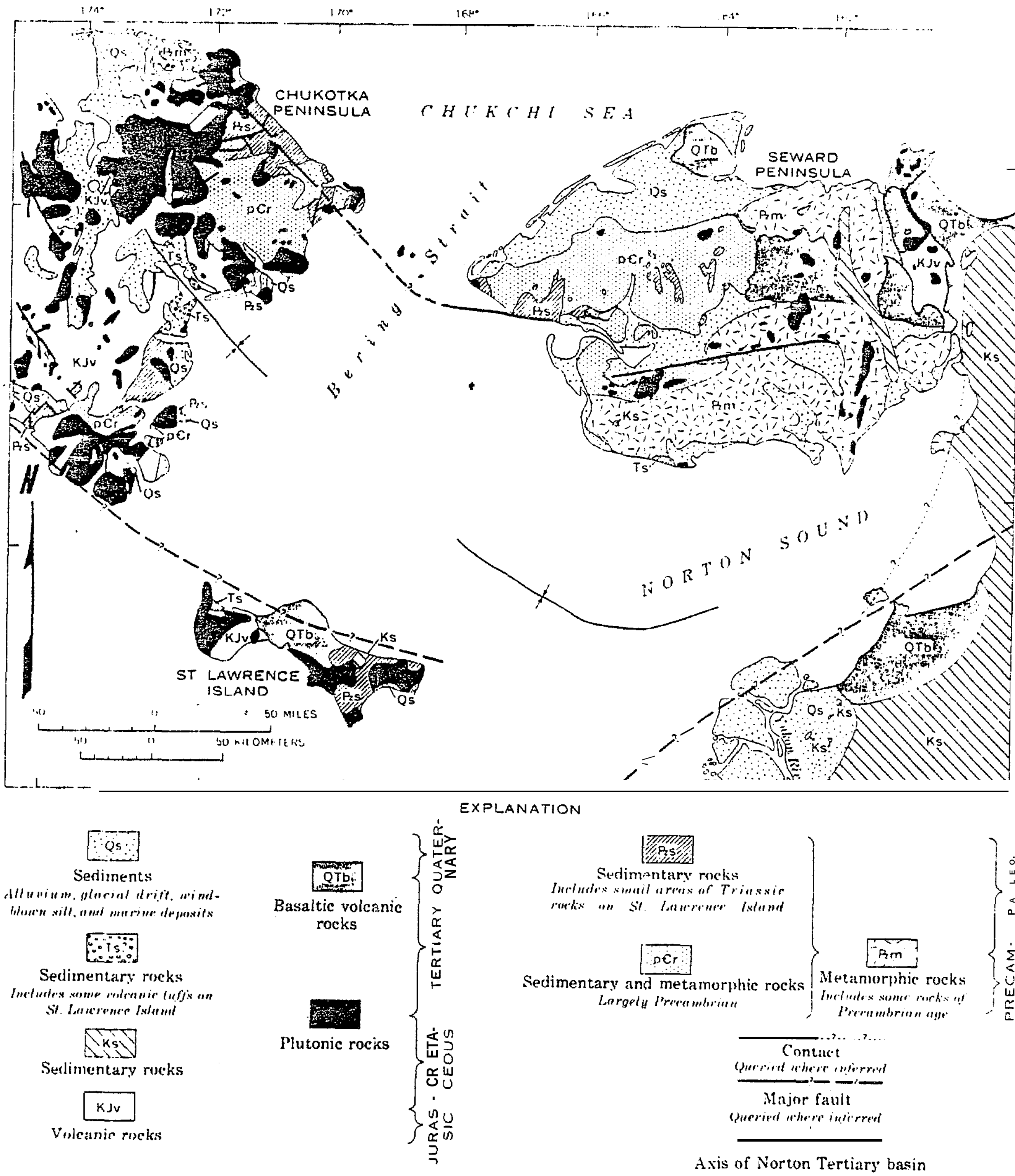


Figure C-8

GENERAL ⁝ED GEOLOGIC MAP OF THE NORTHERN BERING SEA REGION

Source: Nelson and Hopk ns 972)

Three major strati graphic units are recognized within Norton Basin. These major units described by Holmes et al., (1978) consist of:

(1) A lower unit of probable upper Cretaceus which occur in the deeper parts of the basin.

(2) Overlain by a thick sequence of lower to middle Tertiary sedimentary rocks.

(3) An upper unit of upper Tertiary and Quaternary sediment and sedimentary rocks.

The areas of Norton Sound not part of the structural basin are underlain by a comparably shallow bedrock platform which slopes gently basinward. The platform is cut into probable Paleozoic-Mesozoic bedrock and overlain by predominantly late Tertiary through Quarternary sediment.

Two styles of faulting are recognized within the Norton Basin (Fisher et al., 1979). To the west of the Yukon Delta, the west-northwest trending normal faults are easily connected among the seismic lines. The latter group of faults are either highly discontinuous or have variable strikes so they converge and diverge in a complex pattern (Fisher et al., 1979). Where strikes can be determined, the faults located north of the Yukon delta strike west-northwest, like those west of the delta (Fisher et al., 1979.

11.2.3 Surficial Geology

Pleistocene Ice Ages occurring during the past two to three million years have caused major world-wide fluctuations of sea level. During periods of lower sea level much of the Norton Sound area was subaerial, this indicated by the broad accumulations of organic rich peat deposits (Kvenvolden, 1978). The Yukon River and other rivers during this time extended their courses across the continental shelf and delivered most of their load to the deeper abysal basins. Glacial deposits immediately south of Nome and north of St. Lawrence Island indicate that glaciers extended beyond the present shoreline although the Pleistocene glaciation of the Seward Peninsula was far less extensive than that of the Brooks Range and southcentral Alaska. With rising sea level most of the sedimentary load was retained in the river channel or deposited in the river delta area. Holocene sediment from the Yukon River has blanketed most of the floor of the Norton Sound with several meters (5 to 15 feet) of silt. The modern delta of the Yukon river is a relatively young geologic feature having formed since 2500 years ago when the river course shifted north to where it enters the Norton Sound (Dupre and Thompson, 1979).

Interpretation of shallow, high-resolution geophysical records for the Norton Sound and Basin areas (Nelson and Hopkins, 1972) and for the offshore area south of Nome (Tagg and Green, 1973) indicate the presence of many relicit sedimentary features. Outwash fans, buried alluvial channels, beach ridge, and glacial moraines have been recognized in the geophysical records. The number of relief features, their form and aerial extent indicate a very complex Pleistocene history for the area.

Surface and nearshoe faults are prominent along the entire northern margin of Norton Basin, but Holocene fault activity is difficult to determine as strong current scour may be preserving or exhuming old scarps (Johnson and Holmes, 1978) . Some faults are believed to be from scarps on the sea floor, and some offsets of the acoustic basement can be correlated with fault traces in the overlying basin fill (Holmes et al., 1978).

11.2.4 Geologic Hazards

Potential geophysical hazards within Norton Sound have been investigated and reported upon by the U.S. Geological Survey (Nelson et al., 1978; Thor and Nelson, 1978; Fisher et al, 1979). Recognized potential geologic hazards can be grouped into the general categories of tectonic, sediment instability, and erosional and depositional hazards. Each of the described potential geologic hazards are discussed as well as any design implications that these hazards may represent for petroleum facilities primarily platforms, gravel islands, and pipelines sited in the area.

11.2.4.1 Tectonism

Surface and nearshore faults are prominent along the entire northern margin of Norton Basin and are present along its southern boundary. However, recent activity is difficult to determine as many of the fault scarps may be preserved or exhumed by current scour (Johnson and Holmes, 1978). Seismic events probably associated with the major transcurrent faults in the Norton Sound area and observed displacements of onshore features along the Kaltag fault east of the Yukon delta (Woodward-Clyde Consultants, 1978) indicate that the Kaltag fault and its associated faults are probably active. Dupre and Hopkins {1976) have recognized faults, photo linears, and joint sets within Quarternary deposits of the Yukon delta plain that are aligned with a parallel to some older, previously mapped bedrock faults.

When siting structures or routing pipelines in the Norton Sound, active fault zones should be avoided if at all possible. Rupturing of the ground surface along a fault zone can shear pipelines and damage platforms or gravel islands. In addition, ground shaking which is generally more severe closest to the earthquake source, can induce soil instabilities and cause the undermining of these structures.

11.2.4.2 Soil Instability

Surface and near surface soil instabilities in the Norton Sound region may occur in areas which have high concentrations of gas-charged sediment or in areas which have sediment susceptibility to liquefaction.

There are two types of gas-charged sediment in the Norton Sound area: (1) thermogenic, occurring in a local area 40 kilometers (25 miles) south of Nome, and (2} biogenic, in a wide area of north central Norton Sound (Thor and Nel son, 1979). Gas charged sediments can be recognized in a variety of ways; generally through geophysical, geochemical, or geotechnical means. The method of detection of gas-charged sediment is discussed at length in Nelson et al., 1978; Holmes et al., 1978; and Kvenvolden et al., 1978.

Thermogenic gas, predominantly CO_2, is generated deep within the basin probably through the thermal conversion of limestone. The gas migrates upward along fault planes. Geophysical records indicate a large accumulation of thermogenic gas (9 km [5.5 miles] in diameter) approximately 100 meters (339 feet) below the sediment surface in an area approximately 40 km (65 miles) south of Nome (Thor and Nelson, 1979).

Biogenic gas is generated within the organic-rich peaty muds which were formed subaerially in the Norton Sound area. Apparently, the high concentration of gas-charged sediment, as indicated by acoustic anomalies and by gas craters, occur only where the freshwater peaty muds are overlain in a relatively thin (1 to 2 m [3.3 to 6.6 feet]) layer of recent muds (Thor and Nelson, 1979). Gas craters are lacking where the recent mud is thick or where the mud grades into sand north of St. Lawrence Island (Fisher et al., 1979). Gas venting and crater formation commonly occur during peak storm periods when the surficial soils are subject to rapid changes in pore pressure. The rapid pore pressure changes are due to either the super elevation of the water level (storm surge) or to cyclic loading by storm waves.

The fine-grained sand and coarse-grained silt which form the substrate of Norton Sound are highly susceptible to liquefaction due to wave or seismically induced cyclic loading (Fisher et al., 1979). Waves which are generated over the long stretch of the Bering Sea appear capable of inducing sufficient loading to liquify Norton Sound sediment to a depth of 1 to 2 meters (3.3 to 6.6 feet) (Fisher et al., 1979).

The aerial extent of the gas crater fields and isopachs of Holocene muds are presented on Figure C-9. As shown on Figure C-9, large areas of the Norton Sound contain gas-charged sediment or have sediment susceptible to liquefaction. Platforms or gravel islands built on these types of soils may undergo rapid settlement due to the soils' low bearing strength or susceptibility to liquefaction, Due to the broad extent of these potential soil instabilities, it may not be possible to avoid these areas and, therefore, special design precautions should be taken for structures sited in the area. It may be possible to penetrate through the zone of

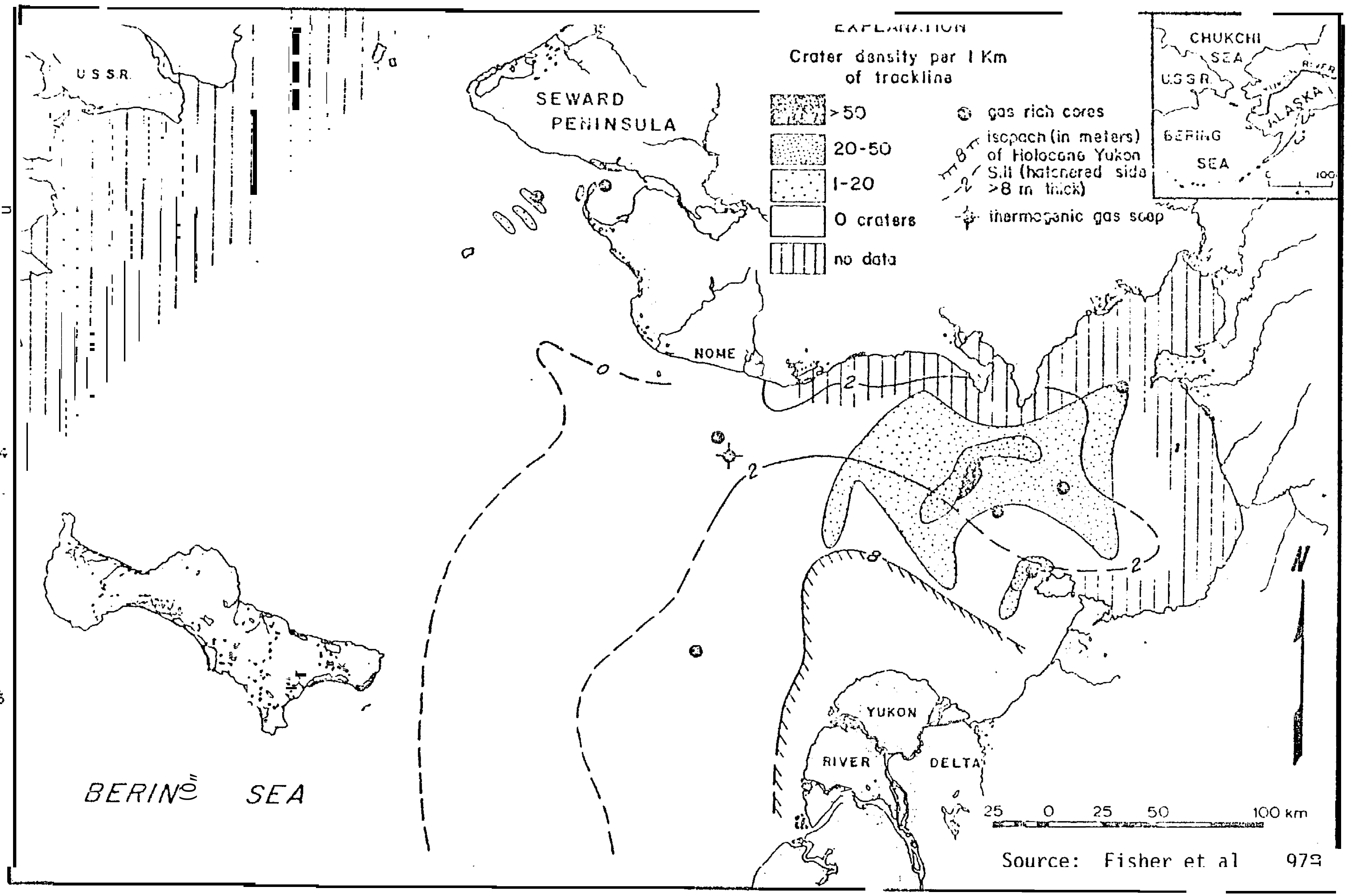


Figure C-9

DISTRIBUTION AND DENSITY OF CRATERS ON THE SEA FLOOR OF NORTON SOUND

Also shown are isopachs of Holocene mud (Yukon silt) derived from the Yukon River and deposited since Holocene, post-glacial sea level rise gas-charged sediment or sediment susceptible to liquefaction and reach deeper bearing strata. However, care should be exercised in siting as penetration to a deeper bearing strata may act as an avenue for release of gas from a deeper source.

11.2.4.3 Erosion and Deposition

Erosional features in the surficial sediment of Norton Sound are associated with ice gouging and/or bottom scour due to unidirectional current flow (wind induced current, oceanographic current) and to oscillating current flow (wave induced currents). These erosional features are shallow-generally developed into the upper meter (3.3 feet) of surficial sediment.

Ice gouging in bottom sediment is found everywhere throughout northeastern Bering Sea beyond the shorefast ice zones where water depths are generally less than 20 meters (66 feet) (Thor and Nelson, 1979). Ice gouging has been noted at depths as great as 30 meters (99 feet). Strong bottom current can maintain and enlarge the ice gouge furrows.

Scour depressions associated with bottom current occur most frequently in areas where there are micro and macro bathymetric obstructions which may cause construction of current flow and result in current scour. .

Structures such as pipelines or electrical lines should be placed below the maximum reach of current scour and/or ice gouging which is thought to be approximately 1 meter (3.3 feet). In the Norton Sound area there may be long-term, wide spread surficial sediment level changes, and consequently, a deeper burial depth may be required.

Structures such as platforms or gravel islands may intensify current flow around the structure and cause current scour to depths greater than observed around natural features. These structures should be protected to a depth beyond the maximum reach of current scour.

Much of the sediment introduced by the Yukon River into Norton Sound is bypassing the Sound and entering the Chukchi Sea to the north (McManus et al., 1977). Sediment pathways through Norton Sound are indicated by long linear features which commonly have bedform (ripple marks and/or sand waves) along their surface. Sand waves as high as 1 to 2 meters (3.3 to 6.6 feet) have been reported within Norton Sound. The sedimentary material introduced by the Yukon River is being transported through Norton Sound probably by some combination of oceanographic current and wind and wave induced currents.

Zones of ripple marks bedforms observed in Norton Sound are presented on Figure C-10. Structures such as gravel islands may impede current flow on the updrift side of the structure and cause the deposition of sediment. The may necessitate expensive maintenance dredging. Proper siting of the structure away from zones of active sediment transport and/or consideration of island shapes may mitigate many of the deposition effects. Pipelines laid across zones of sand waves may he undermined and unsupported during sand wave mitigation. These areas should be avoided if possible or the pipeline should be buried beneath the lowest probable sand level.

Figure C-10 presents a composite of potential geologic hazards recognized in the Norton Sound area. As shown on the figure, there are a wide variety of potential geologic hazards which span much of the Norton Sound area. Very few areas are free of potential geologic hazards. The negative effects of many of these hazards such as erosional/depositional processes and surficial sediment instabilities can be reduced or eliminated by burying pipelines or founding structures on the solid substrata beneath the surficial soils.

11.3 Biology

11.3.1 Terrestrial-Wetland Habitats of the Coastal Zone

The coastline along Norton Sound and the northwest Bering Sea is narrow, bench-like in formation, and mostly overlain with mud, sand or gravel substrates. The terrain often rises steeply beyond the tidal zone, forming a border of cliffs or bluffs. The associated foothills, drainage slopes, and plateaus support a variety of vegetative types including

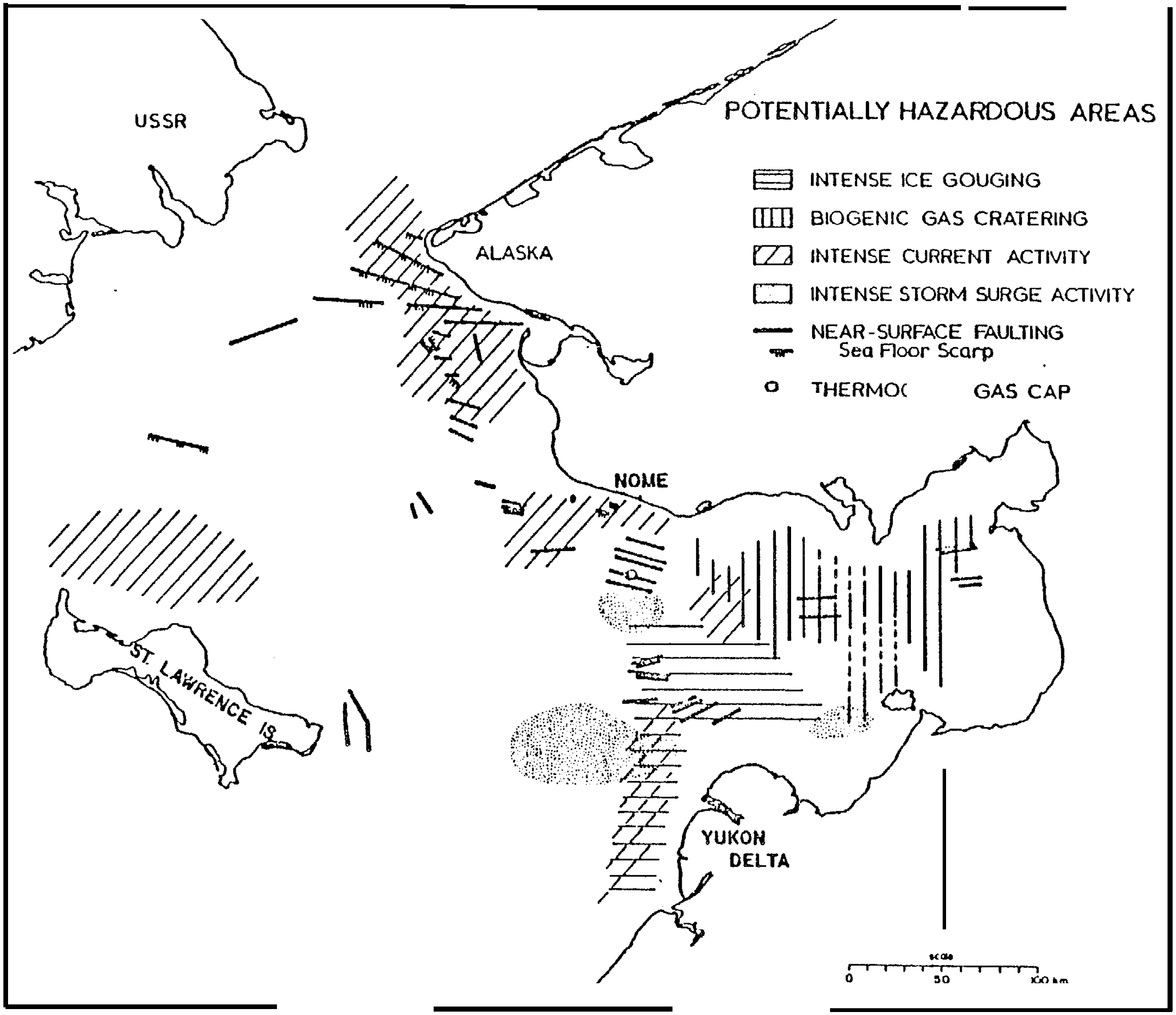


Figure C-10

POTENTIAL GEOHAZARDS IN NORTON SOUND af er Nelso? 1977 upland spruce-birch forest, high shrub, moist tundra, and alpine tundra. The low-lying areas of Pastol Bay, Norton Bay, from Cape Rodney to Point Spencer, and from Cape Prince of Wales to Shismaref Inlet provide extensive wetland habitat. In the northeast Bering Sea, Big and Little Diomede Islands, King, Sledge, St. Lawrence, and Punuk Islands, rising abruptly from the submarine plain, are bounded by rocky wave-cut cliffs. Seldom exceeding 305 meters (1,000 feet) in elevation, these islands are characterized " by rolling uplands of alpine and moist tundra. The eastern part of St. Lawrence Island is a lake-dotted lowland of wet tundra. Figure C-n shows the vegetative zones along the coastlines of the Norton Sound area.

Many small mammals are year-round residents of the Norton Sound coastal region. A few large mammalian species, e.g., brown bear and moose, are seasonally dense along the coast or in the nearby river valleys though some are also present throughout the year. hong small mammals the tundra hare, red fox, arctic fox, land otter, arctic ground squirrel, mink, wolverine, and weasels are found near shore from Ikpek Lagoon north of Cape Prince of Wales to the Yukon River Delta, i.e., throughout the entire length of mainland shoreline of the lease sale area. Muskrat, red squirrel, porcupine, snowshoe hare, beaver, and lynx are a"l so widely distributed though some species do not occur north of Cape Nome, or west of Cape Stephens. Marten and coyote are present in more 1 imited distribution (Kl inkhart, 1978; Somerville and Bishop, 1973).

Coastal beach and delta areas are the prime habitat of the arctic fox. St. Lawrence Island supports a large breeding population as do other offshore islands of the Norton Sound region. Arctic fox populations fluctuate widely, partly in response to the population cycles of lemmings. Other prey include seabird eggs and marine mammal carrion, both ashore and far out on pack ice. Arctic foxes are attracted to areas of human use by improper garbage disposal. The potential of a rabies epidemic and its spread to humans is created when fox numbers become large (Dames & Moore, 1978a).

Brown (grizzly) bears occur in low density throughout Seward Peninsula and the interior beyond Norton Sound. The population has been estimated

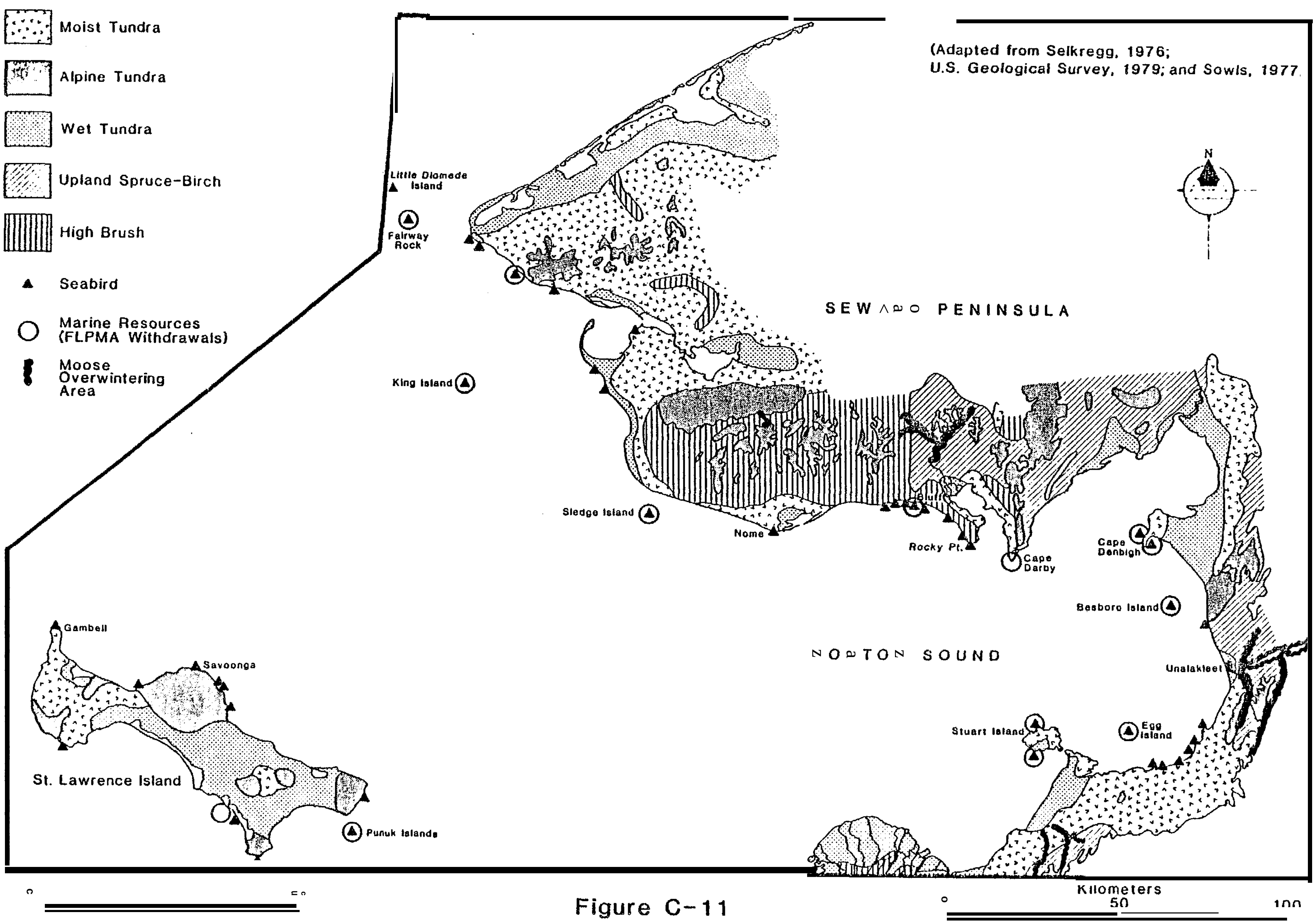


Figure C-11

VEGETION OF THE COASTAL ZONE, SEABIRD COLONIES, AND LOCATIONS OF MARINE RESOURCE AREAS PROPOSED UNDER FLPMA WITHDRAWALS FOR INCLUSION IN THE NATIONAL WILDLIFE REFUGE SYSTEM at about 400 individuals. In May or June, they tend to forage on carrion along the coast. Black bear are found along the eastern coast of Norton Sound between Shaktoolik and Kliktarik, and along the intervening river valleys into Nulato Hills. About 200 black bears are estimated to live in this area (Klinkhart, 1977).

Moose occur in river valleys throughout the coastal and interior lands of the Norton Sound region. Females also calve in floodplain areas. Of the five major overwintering areas, i.e., those containing about 70 percent of the moose population (Klinkhart, 1977), the Unalakleet River Valley is most likely to be affected by OCS development activities. Unlike in other drainages, the Unalakleet bottomland is used by moose down to the river mouth. The critical dependence of moose on bottomland for overwinterii and calving may constrain any OCS development in the Unalakleet drainage. Other important overwintering areas are shown in Figure C-11.

The overwintering grounds of the western Arctic caribou herd include the coastal region of Norton Sound approximately between Egavik in the north and Pastolik in the south (Somerville and Bishop, 1973). Beyond these locations, the herd ranges to the interior. Densities of caribou on the coast are low.

Musk oxen occur in small populations on Seward Peninsula, in the York and Kigluaik Mountains. They seasonally occupy coastal areas near Cape Rodney, Cape Douglas, and Ikpek Lagoon.

In low density and roaming in small packs, wolves are found-in the mainland coastal zone throughout the sale area, except west of Pastolik on the southern coast of Norton Sound. Their southern distribution coincides with that of caribou. On Seward Peninsula they are more sparsely distributed than in the Nulato Hills. About 100 to 150 wolves are thought to occupy this area (Klinkhart, 1977).

Among raptors, gyrfalcons, peregrine falcons, rough-legged hawks, golden eagles, bald eagles, ospreys, and snowy and short-eared owls are found throughout the Norton Sound region and, with the exception of peregrine falcons, also on St. Lawrence Island. Boreal and hawk owls, and goshawks are restricted to forest habitats on the mainland. Willow and rock ptarmigans are widespread in the coastal zone. More than 30 passerine bird species also occur here (Selkregg, 1976), ranging from ravens to redpolls to warblers, and occupying both tundra and forest habitats. Species found here which undergo intercontinental migrations include the wheatear, arctic warbler, blue throat, yellow wagtail, white wagtail, and three swallow species.

Within or adjoining the lease sale region are found major expanses of waterfowl habitat. The coastal region surrounding Ikpek Lagoon has been designated a key waterfowl area and classified as part of Bering Land Bridge National Monument under the proposed Federal LandPolicy Management Act (FLPMA) withdrawals of December 1, 1978. Much of the coastal area surrounding Pastel Bay is occupied in high density by waterfowl. Part of this area has been protected as the Yukon Unit of the Clarence Rhode Wildlife Range. The remainder is proposed for federal protection as the Yukon Delta wildlife refuge under the FLPMA withdrawals of November 16, 1978. Other high density waterfowl areas include the wetlands surrounding Cape Denbigh, Moses Point, Koyuk, and Imuruk Basin. Medium or low density waterfowl areas correspond to wet or moist tundra zones not already mentioned.

The Clarence Rhode National Wildlife Range and remaining Yukon delta produce nearly all of the whistling swans, emperor geese, cackling geese, and white-fronted geese migrating to the Pacific flyway. Densities of greater than 200 geese and black brant per square mile have been recorded. Other common wetland species of the Norton Sound region include the greater scaup, pintail, old squaw, American widgeon, green-winged teal, common scoter, and Steller's eider.

Bering Land Bridge National Monument encompasses critical habitat for many migrant and resident birds. Of the 352 species known to occur in Alaska, 137 have been recorded in this region. The wetlands of the reserve include prime habitat for ducks, whistling swans, geese, and sandhill cranes (Klinkhart, 1977).

II.3.2 Marine and Estuarine Systems

A common feature of many life histories of species strongly associated with the marine habitat is the seasonal movement or migration tied to ice cover in Norton Sound and the northeast Bering Sea. Movement of seals, whales, and walrus, timing of breeding and reproductive success in seabirds, and spawning of herring are among the phenomena keyed to position, formation, and break-up of ice. With results of the ongoing OCSEAP studies, knowledge is slowly accumulating as to the nature of the dependence of these patterns with regard to vulnerability to disruption by man. OCS development by challenging the time limits of the ice-free period may interfere with these patterns during critical times or at critical locations.

Seabirds

Seabird colonies of the lease sale area are concentrated on islands rising from deep waters (St. Lawrence, Little Diomede, Fairway Rock, King and Sledge Islands), and along the mainland shores north of Cape Douglas, between Nome and Rocky Point, at Cape Denbigh, and between Golovin and Cape Stephens. These areas and shallow water islands in Norton Sound (Stuart, Egg, and Berboro Islands) which also support bird colonies (Figure C-11) include 13 locations which have been proposed as marine resource preserves for inclusion in the national wildlife refuge system. As shown in Table C-1, the most dense and diverse colonies occur on deepwater islands.

In addition to nesting habitat, these islands afford access to offshore feeding areas in the northwest Bering Sea. In a study reported by Ramsdell and Drury (1979) auklets were observed to feed in a broad semicircular arc concentric with the western half of St. Lawrence Island. Other major feeding areas visited by seabirds lie between King and Sledge and Little Diomede Islands. The only major foraging activities observed east of Sledge island were found in a 32 kilometer (20-mile) band paralleling the Peninsular coast between Sledge Island and Golovin Bay. This area overlies a deep channel entering Norton Sound. Geographical variations in the use of forage areas

TABLE C-1

MAJOR SEABIRO COLONIES IN THE NORTON SOUND LEASE SALE REGION>
BASED ON COLONY CENSUSES IN THE PERIOD 1966-1976

Site	Colony Size (thousands)	No. of *Species*	Dominant Speci es* (descending rank)
St. Lawrence Island			
Southwest Cape	549	11	CA, LA
Sevuokok Mountain near Gambel 1	189	7	CA, LA
Cape Kagh-Kasal ik	22	9	CA, LA
Savoonga	89	5	CA, LA
Cape Myangee	631	3	CA, LA
Reindeer Camp	57	4	CA, LA
Other Offshore Islands			
Little Diomede	1,261.6	14	LA, CA, CM, BLK
Fairway Rock	46.7	12	LA, TBM, CA, CM
King Island	245.9	13	LA, CM, TBM, PA
Sledge Island	4.7	13	CM, BLK, TBM, PC
Mainland Area			
Bluff	46.0	9	CM, ELK, HP, TBM
Square Rock	3.9	7	CM, BLK, HP, GG
Cape Darby	1.4	6	IHP, PC, GG, TP
Cape Denbigh N.	5.2	9	CM, BLK, TBM, PC
Cape Denbigh S.	7.2	8	CM, BLK, TBM, PC
Egg Island	2.8	9	CM, BLK, HP, TBM

Source: Sowls and Nelson, 1977.

*Species abbreviations are as follows:

CA crested auklet
LA least auklet
PA parakeet auklet
CM common murre

TBM thick-billed murre
BLK black-legged kittiwake
GC glaucous gulls

PC pelagic comorant
HP horned puffin
PT tufted puffin

are keyed to drifting ice of the receding front, or to other areas of high biological productivity. In June, birds forage to the northeast of St. Lawrence Island, following masses of drifting ice as they move northwest past Sledge and King Islands. In July, many birds are feeding in broad zones around King Island, Fairway rock, and Little Diomede Island, north or northwest of Gambell, and along the mainland coast from Cape Woolley to Golovin Bay. In August, offshore feeding areas tend to shift to the west and south; the waters of Norton Sound south of the coastal band mentioned above are free of birds.

In winter the front of the ice pack is an important habitat for seabirds, especially murres. Productivity there is significantly higher compared with other Bering Sea waters (McRoy and Goering, 1974). Another ice-water interface habitat utilized as a refugium by birds is the polynya, or area of open water in the pack ice associated with islands (Divoky, 1977).

Breeding activities of seabirds in the Norton Sound region are cued by the receding of pack ice and evidence is accumulating that the earlier break-up occurs, the greater is seabird reproductive success (Ramsdell and Drury, 1979). At break-up birds follow lead systems near breeding sites or move to inshore areas that are free of ice. Early nesting allows birds more flexibility in the recoupment of eggs lost to predation. Important predators on eggs include humans, foxes, and ravens.

Intertidal and Shallow Benthos

The littoral and shallow sublittoral zones of the Norton Sound region are marginally developed owing to winter ice scour. Proportionally about half of the tidal zone substrates are soft (Table C-2). Removal or disturbance of sessile marine organisms from hard substrates by ice is a strong limiting factor in the development of rocky shoreline communities in the northwest Bering Sea. According to the observations reported by Zimmerman et al. (1977) in areas protected from ice scour, a typical mussel/barnacle/filamentous red algae assemblage is evident; hydroids, sponges, anemones, soft corals, bryozoans, green urchins, cucumbers, nudibranchs, limpets, gastropod, and tunicates round out this community.

Table C-2

SUBSTRATES OF THE LITTORAL ZONE FROM SHELDON'S POINT
(YUKON DELTA) TO CAPE PRINCE OF WALES
NORTON SOUND REGION

Type	Kilometers (Miles)	Percentage
Bedrock	241 (149.5)	11.0
Boulder	389 (242.0)	18.0
Gravel	515 (320.0)	24.0
Sand	332 (206.0)	16.0
Mud	548 (340.5)	26.0
Not Categorized	87 (54.0)	4.0

Source: Zimmerman et al., 1977..

Dominant invertebrate predators are a starfish (*Asterias* sp.) and a brachyuran crab (*Telmessus* sp.). In sandy areas polychaetes, clams, and sand dollars are the dominant groups.

The marine community of rocky intertidal and shallow zones is better developed around island perimeters despite similar 'levels of ice scour. Both sessile and midwater organisms are present in greater density and diversity around King Island than at mainland sites (Zimmerman et al., 1977). Presumably, greater circulation and access to nutrients held in deep water is partly responsible for the enhanced productivity of islands.

Compared with rocky sublittoral communities of the southern Bering Sea and Gulf of Alaska, there is a near absence of true kelp in the Norton Sound region. Zimmerman et al. (1977) noted the, occurrence of *Al aria* at Sledge Island and a diminutive stand of *Laminaria*-like algae at Bluff. Rockweed (*Fucus* species) is the common "kelp" of this area. Shallow water stands of eelgrass (*Zostera*) occur at several locations, notably Port Clarence, Grantley Harbor, and Imuruk Basin (Barton, 1978).

Results of a benthic survey of Norton Sound waters were reported by Feder and Jewett (1978). Samples were trawled from waters of about 6 to 40 m (20 to 130 feet) in depth. Unlike areas in the northeast Gulf of Alaska and southeast Bering Sea, echinoderms, not crustaceans, dominate invertebrate biomass on the floor of Norton Sound: echinoderm biomass fractions observed in these areas were 19.0, 17.5, and 80.3 percent, respectively (Feder and Jewett, 1978). Invertebrate diversity patterns for Norton Sound are shown in Figure C-12. Among the 187 species observed, dominant groups included molluscs (74 species), crustaceans (44 species), and echinoderms (27 species). In terms of biomass these groups ranked in reverse: echinoderms, mostly sea stars (80.3 percent), arthropods (9.6 percent), and molluscs (4.4 percent). Total epifaunal invertebrate biomass averaged 3.7g/m^2 in the Norton Sound region. Tanner crab, king crab, and shrimp are present in Norton Sound, though not in sufficient quantities to support commercial exploitation.

Sea stars and most other echinoderms are relatively long-lived and they

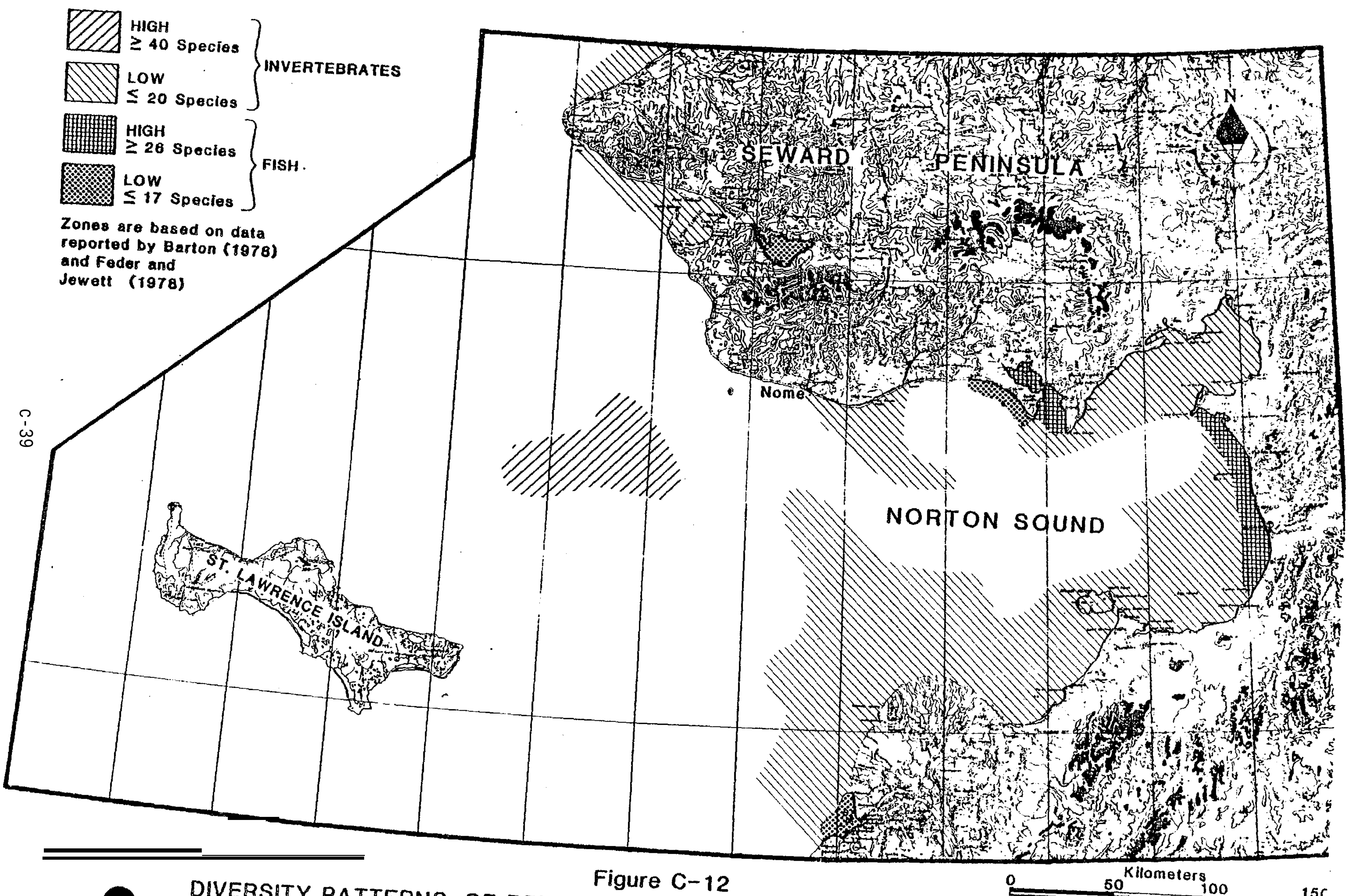


Figure C-12
DIVERSITY PATTERNS OF BENTHIC INVERTEBRATES AND NEARSHORE FISHES

have evolved effective predator defenses. Thus, their huge biomass reservoir is not directly a part of the food chain at higher trophic levels in Norton Sound. Feder and Jewett speculate that "a considerable portion of sea-star carbon is, in fact, returned to the sea annually as gamete production" (1978:433). Transfer of this portion is presumably through planktivores to higher trophic levels. If this representation is accurate, marine-based food chains, which ultimately lead to seals, walruses, sea birds, whales, and man, may be particularly sensitive to hydrocarbon pollution during seasonal peaks of sea star reproduction.

Fishes

Five species of salmon occur in the Norton Sound region. King, coho, pink, and chum salmon, in ascending order of importance, are commercially exploited and sockeye salmon are important in the subsistence fishery. The major commercial fishing areas and salmon spawning/rearing streams are shown in Figure C-13. Most fishing is by gill net near stream mouths.

The commercial season runs from June 15 to September 30. Efforts are first centered on king salmon (to mid-July) and then shifted to chum, pink, and coho salmon (Table C-3). Commercial processors terminate operation in August.

Though the commercial salmon fishery of Norton Sound is a minor source of income to the State as a whole, it is extremely important to the local cash economy. In 1975, the total local income from 239,849 salmon amounted to $437,000, and in nearly all areas the fishermen and process workers are eskimos (McLean and Delaney, 1978a). Fishing cooperatives have been organized in the Shaktoolik and Unalakleet districts and they have stabilized fishing efforts in recent years. Part of the commercial salmon catch is also utilized for subsistence purposes (see Section II.3.3 below).

The sockeye population spawning in the Salmon Lake-Pilgrim River area inland from Port Clarence is one of the northernmost populations of this

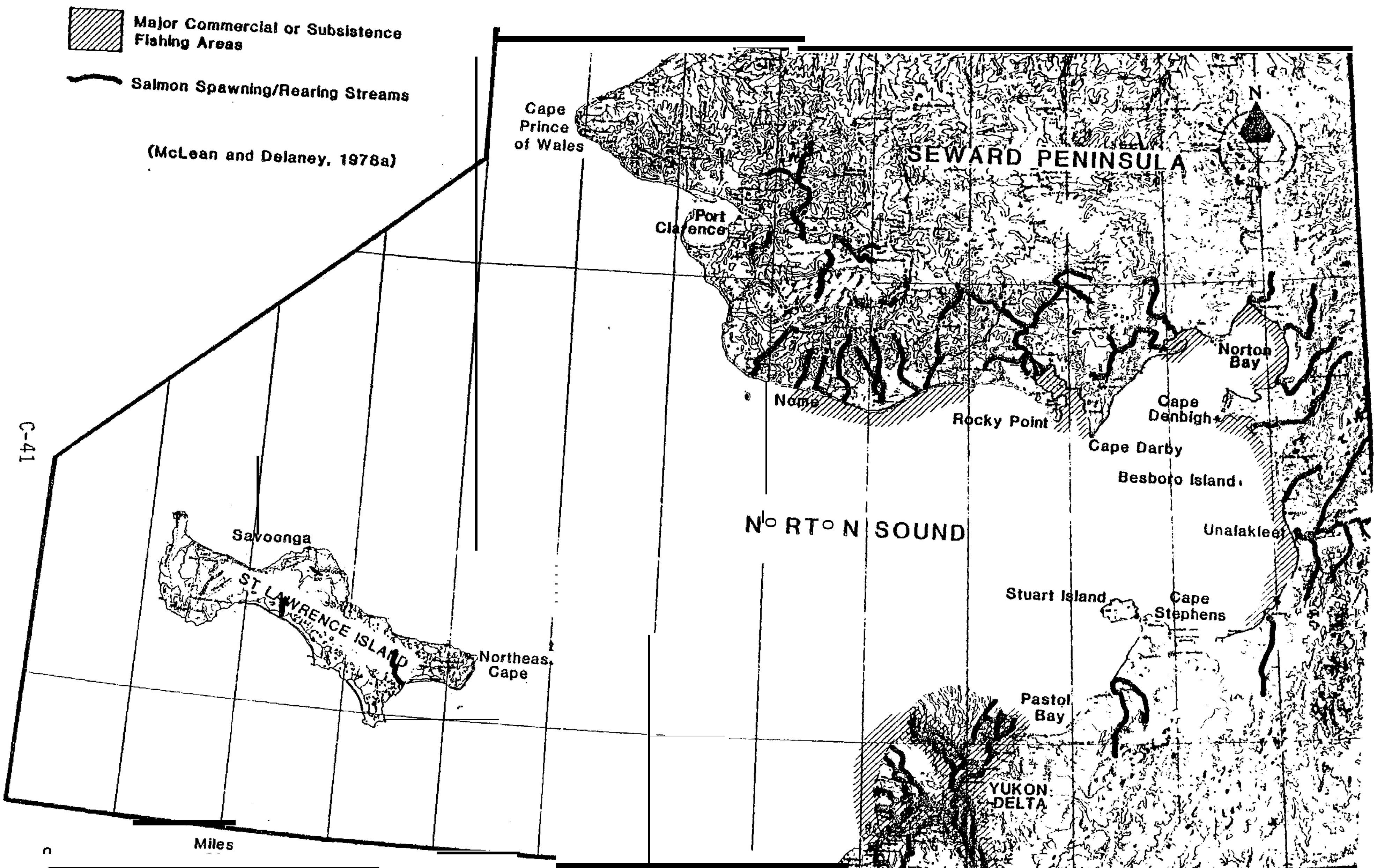


Figure C-13
SALMON FISHING ZONES AND STREAMS OF THE LEASE AREA

TABLE C-3

PERIODS OF CONCENTRATIONS OF SALMON IN
SHALLOW WATER BAYS OF THE NORTON SOUND REGION

Species	Period Available to Fishery
Chum	June 20-25 to July 20-25
Pink	June 25-July 1 to July 15-20
Coho	August 1 to August 20

Source: McLean and Delaney, 1977.

species in the State. The sockeye fishery was closed to commercial effort in 1974 but it is still heavily utilized for subsistence purposes (McLean and Delaney, 1977).

Pacific herring support a growing commercial fishery and important subsistence fishery in the Norton Sound region. In 1977, 9.5 metric tons were produced at" Unalakleet and this figure is expected to increase slowly as domestic fishermen gear up to replace yields garnered by the Japanese fleet prior to passage of the Fishery Management and Conservation Act of 1976 (Barton, 1978; Wespestad, 1978).

At present, the commercial gill net fishery is directed toward extraction of sac roe. Herring effort begins following break-up (late May to early June) and lasts two to three weeks. Some subsistence fishing effort occurs during fall (non-spawning) runs in Golovin Bay, Bluff, and Imuruk Basin. Spawning has been observed near St. Michael, Klikitarik, Cape Denbigh, Elim, Golovin Bay, Bluff, and Imuruk Basin at intertidal or shallow subtidal sites below exposed rocky headlands. Eggs are deposited on rockweed kelp (Fucus) or bare rock. In the Port Clarence area, spawning is in shallow brackish lagoons on eelgrass (Zostera) (Barton, 1978).

Nearshore fish surveys have been recently conducted in Norton Sound. More than 38 species in 15 families were collected by gill net, seine, or trawl, of which nine species were freshwater, 10 were anadramous, and the remainder were marine (Barton, 1978). Fish diversity patterns are shown in Figure C-12. In general, Norton Sound appears to be less productive for demersal fishes, both in diversity and abundance, than areas further south and east in the Bering Sea, and the Chukchi Sea may produce comparatively greater quantities of Pacific herring (Pereyra and Wolotira, 1977; Bakkala and Smith, 1978). Among non-commercial fish species, members of seven families (clupeidue, osmeridae, gadidae, pleuronectidae, salmonidae, coregonidae, and thymallidae) are used to some degree for subsistence by local residents. These amount to 90 percent of the anadramous fishes, 75 percent of the freshwater fishes, and 30 percent of the marine fishes occurring in the nearshore waters of Norton Sound (Barton, 1978). Other' species (e.g., sand lances) are major forage for seabirds.

Marine Mammals

Thirteen species of marine mammals are known to occur at least seasonally in the lease sale area, including among pinnipeds, bearded, spotted, ribbon, and ringed seals, and walrus; and among cetaceans, bowhead, fin, gray, humpback, beluga, and killer whales, and harbor porpoises (Braham, Fiscus, and Rugh, 1977). Polar bears are not abundant but they do occur commonly in winter in the St. Lawrence Island area, having moved south of the Bering Strait with the advancing ice. Since about 1975, polar bears have become more abundant in the southern range, and closer to shore, perhaps partly as a result of the cessation of aerial hunting in 1972 (Klinkhart, 1977). Polar bears are taken by subsistence hunters each year, though more often by natives of the Bering Strait and areas northward. The important subsistence uses of marine mammals will be discussed in 11.3.3 below. The spatial distributions of marine mammal characteristics in the sale area are shown for the months of March, April, and June in Figure C-14.

Bearded sea"ls are strongly associated with driftirg ice and in late winter to early spring most of the Bering-Arctic population is south of the Bering Strait. They seldom use shore-fast ice. In spring they follow the receding pack ice northward though some individuals remain throughout the summer in Norton Sound and around St. Lawrence Island (Lowryet al., 1978). Bearded seals, less social than other species, do not herd and are likely to be found singly (Burns and Frost, 1979). They feed primarily on spider and tanner crabs, and to a lesser extent on fishes, clams, and hermit and king crabs (Lowry et al., 1978).

The spotted or largha seal (as separate from the harbor seal following the distinction of Braham, Fiscus, and Rugh, 1977) utilize the ice front in the Bering Sea for whelping and molting in late winter and early spring. They may follow the ice northward but often take up residence in both mainland and island coastal waters. In summer and fall they are found along the entire coast of northern Alaska (Kl inkhart, 1977). They prey primarily on fish (Lowry et al., 1978).

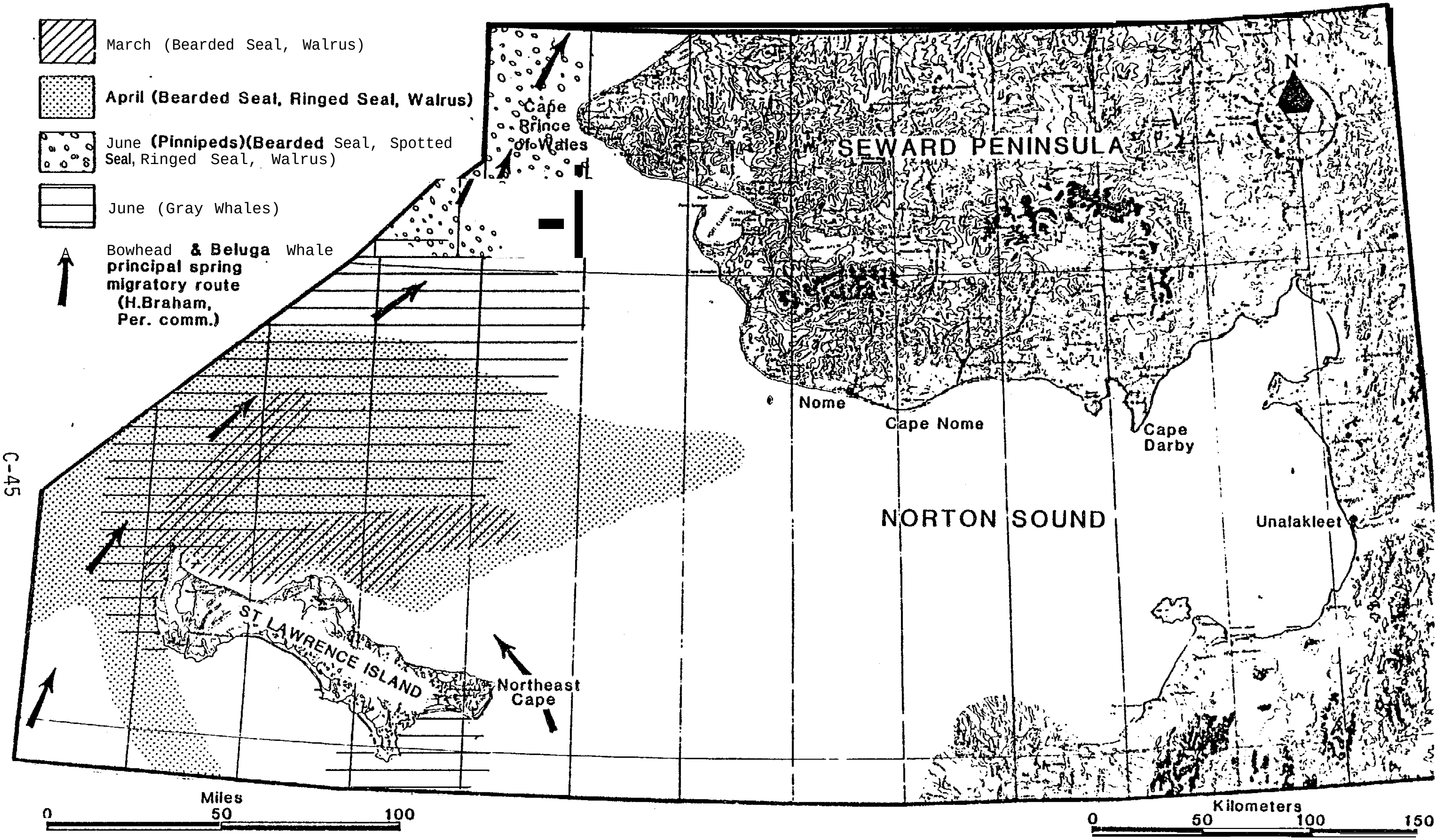


Figure C-1 4

APPROXIMATE EXTENT OF MAJOR MARINE MAMMAL CONCENTRATIONS IN THE LEASE AREA

(Basedon observations reported by Braham, Fiscus and Rugh,1977)

Ribbon seals are similar to spotted seals in their use of the pack-ice front in winter and early spring for whelping and molting. Unlike spotted seals, ribbon seals take up a pelagic habit in summer, where they prey mostly on fishes (gadids) and pandalid shrimp (Klinkhart, 1977; Lowry et al., 1978).

Ringed seals are widely distributed in the Bering and Chukchi Seas across areas of land-fast ice, where breeding takes place in spring. Though most adults migrate northward, juveniles may summer in Norton Sound. Their diet is varied. Stomach samples, which may strongly reflect local prey availability, have contained zooplankton, pandalid shrimp, cods, sculpins, and other fishes (Lowry et al., 1978; Klinkhart, 1977).

Walruses migrate seasonally with the ice front. Herds are absent from the lease sale area only in July and August, i.e., when the last of the drifting broken ice has receded north of the Bering Strait. Peak abundances are from January through June in the sale area. Areal abundance is centered on St. Lawrence Island in winter and the population moves directly northward in summer, appearing, for the most part, to avoid the waters of Norton Sound (Burns, Shapiro, and Fay, 1'377).

Less is known of the distribution and-seasonal migrations of whales in the lease sale area. Bowhead whales are an endangered and controversial species highly prized by natives of the Bering Strait and areas northward, and also to a lesser extent by St. Lawrence Islanders (Arctic Environmental Information & Data Center, 1979). They pass through the Bering Strait from March to June, and return again before freeze-up in fall. Their approximate travel routes follow ice leads in the spring around St. Lawrence Island (Figure C-14; H. Braham, personal communication).

Gray whales, also endangered, are found from the St. Lawrence area north to the Bering Strait in June (Figure C-14). In August and September, they feed in the inshore waters of Siberia and Alaska, and over the continental shelf. In the fall they return through the Bering Strait in a southward migration (Braham, Ficus, and Rugh, 1977).

Beluga (belukha, or white) whales are found year round in the lease sale area. They are known to ascend rivers and to concentrate in shallow estuarine and coastal areas. They feed on smelt or salmon (Klinkhart, 1977). "

Information on the temporal occurrences of marine mammals in Norton Sound is summarized in Table C-4.

11.3.3 Subsistence and Sport Hunting and Fishing

Natives of the lease sale area used a wide variety of logical biological resorces for subsistence. Year-to-year climatic and geographic variations in the relative harvest levels of important species and sparse published material make patterns of utilization difficult to characterize. In evalu-sting the impacts of OCS development, non-secular [1] (i. e., unpredictable) changes in demands on subsistence resources which result from government economic support, replacement of sled dogs by snow machines, participation in the local cash economy, and a rekindled awarnesss of the cultural benefits of subsistence hunting must be considered.

Among terrestrial species moose, black bear, red Fox, arctic fox, mink, land otter, beaver, snowshoe and tundra hare, willow and rock ptarmigan, and spruce grouse are important to the dietary, garment, and cash-exchange needs of natives. Other species, e.g., muskrats, are used on an incidental basis (KI inkhart, 1977).

Waterfowl and seabirds are also important contributors to the diets of natives. Canada, white-fronted, brant, emperor, and snow geese are heavily utilized, as are a variety of ducks. Eggs of ducks, geese, and a variety of cliff-nesting seabirds supplement summer diets, especially for natives on St. Lawrence Island (Burgess, 1974).

(1) The use of the term non-secular is used to convey the idea that certain events occur in a manner that does not assist in predicting the next event i.e., the events are not really linked to each other.

TABLE C-4

SUMMARY OF TEMPORAL USE OF THE NORTON SOUND LEASE SALE AREA BY PINNIPEDS AND CETACEANS

Species	Area Uses*		
	Migration	Reproduction	Feeding
Bearded seal	W Su	Sp	Y
Spotted (largha) seal	W Sp		Su F
Ribbon seal	Su		Su F
Ringed seal	W	Sp	Y
Walrus	W Sp	Sp	W Sp
Bowhead whale	Sp		
Fin whale	Su F		S
Gray whale	Sp F		Sp Su
Humpback whale	Su		Su
Beluga whale			Y
Harbor propoise	+		+
Killer whale	Su F		Su

Source: Braham, Fiscus, and Rugh, 1977.

* Key to entries:
Y = year round
W = January-March
Sp = April-June
Su = July-September
F = October-December
= behavior is not noted for this area
\+ = behavior is known to occur but details are unknown
Blank = gaps in information

Subsistence use of fishes varies among natives of the lease sale region. Villagers along the ease coast of Norton Sound and Seward Peninsula utilize salmon, and to the lesser extent, herring. Part of the commerical salmon catch, diverted to local use, supplements the subsistence harvest.

Chum and pink salmon are by far the most important subsistence species. The once important sockeye fishery in the Port Clarence area appears to be failing, though it has been closed to all but subsistence effort (McLean and Delaney, 1977).

The reliance on salmon declines and importance of herring increases greatly for villagers of St. Michael and the Yukon Delta region, who utilize the preserved summer catches of adult herring and kelp roe for a year-round food supply (Dames & Moore, 1978b). Other important subsistence fishes of the sale area include whitefishes, northern pike, burbot, sheefish, ciscos, saffron cod, and smelt (McLean and Delaney, 1977).

Among marine mammals, all of the four seal species, walrus, bowhead whale, and polar bear are hunted for meat, oil, skins, and ivory. Ringed seals account for more than haJf the annual seal harvest (Klinkhart, 1977). Villagers of the offshore islands and Bering Strait are the most avid hunters, though seal products are so valued that hunters from unfavorably located villages, e.g., on the Yukon Delta, travel at great expense and risk to hunt them (Dames & Moore, 1978c). Bowhead whales are hunted by St. Lawrence Islanders and natives of the Bering Strait. Gray whales are not taken to any great extent by subsistence users.

Other marine species contribute incidentally to the diet of natives including clams, tanner and king crabs, and shrimp (Alaska Dept. Fish & Game, 1978). Eelgrass plays an important subsistence role in its use in food preservation and storage (Dames & Moore, 1978c).

Virtually all of the species utilized by natives for subsistence purposes also support sport recreational activities. Moose, wolves, wolverine, grizzly bear, beaver, king salmon, silver salmon, and arctic char are among species that appear to be more actively pursued by non-native sportsmen and trappers than by eskimos of the sale area. With the increased price offered for lynx pelts in recent years, this species has become sought after by commercial trappers (Klinkhart, 1977). Sport hunting for walruses is no longer allowed by permit following the July 1, 1979 return of regulatory jurisdiction to the federal government. Sport hunting had provided a cash income for eskimos who served as hunting guides (Klinkhart, 1977).

11.3.4 Biological Constraints on OCS Petroleum Development

The development of petroleum resources in the Norton Sound area will unavoidably perturb local marine and coastal populations. Non-catastrophic impacts will arise from the direct effects of vessel traffic, aircraft noise, exploratory and construction activity, and loss of habitat to platforms or other facilities; indirect effects accrue from chronic low-level pollution near terminal facilities. These foreseeable impacts may be solved somewhat in early stages by imposing constraints on development in sensitive areas of the Norton Sound region. Avoiding catastrophic impacts, e.g., from a major crude oil spill, is more difficult to accomplish through the planning process.

The vagaries of biological systems are most easily accommodated by defining discrete time periods or critical geographic areas. For the Norton Sound region, two sensitive time periods clearly stand out:

(1) Early spring, when reduction of open water by ice cover is likely to force vessel traffic, sea birds, and marine mammals into close contact. Intolerance of vessel or aircraft noise may precipitate their avoidance of traffic lanes but in early spring when ice leads are heavily utilized, escape may not be possible: seals are likely to be struck by ships from April through June though mortality will be small (Burns and Frost, 1979). Constraints on use of their migratory lanes by vessels may be applied.

(2) Spring to early summer, when reproduction by marine species at all trophic levels initiates a period of accelerated growth in regional productivity. Eggs and larvae of herring, as do those of many other marine fishes and invertebrates, suffer high levels of mortality when exposed to petroleum hydrocarbons (Rice, Kern, and Karinen, 1978; Lowry et al., 1978). High risk operations may be curtailed during this period.

Dense aggregations of individuals are particularly vulnerable to direct disruption or pollution, and sites where aggregations dependably occur may be protected from development. Other bases for designation of critical geographic areas include centers of biotic diversity, sites of legislated state or federal protection, areas of productivity for commercial or subsistence species, and locations of critical habitat. Such sites for species in the sale area have been discussed in preceding sections of this report. A summary is provided in Table C-5.

Certain general features of exploration for and development of petroleum resources in Norton Sound need not reference specific locations or petroleum reserve levels for identification of their associated constraints and impacts. A brief evaluation of specific environmental considerations follows each of the scenarios; here it is noted that a petroleum find at any exploitable level would require:

- Vessel and aircraft support. The choice of traffic routes and schedules may be constrained by stipulations which protect marine mammals, migratory waterfowl and seabirds. Though walrus, seal, and whale migratory routes generally fall west of Norton Sound, the expansion of activities into the ice-bound months may enhance the potential for conflict. They may avoid summer vessel routes, but learn to frequent leads artifically maintained by ice-breakers. Conversely, seismic explosions during OCS exploratory phases are likely to prompt wholesale abandonment of nearby areas. Aircraft should also be routed away from known nesting areas of waterfowl and seabirds. Despite these precautions, increased noise from vessel and aircraft may still have a negative impact on marine mammal and bird populations.

TABLE C-5

SUMMARY OF LOCATIONS SENSITIVE TO DISRUPTION BY OCS PETROLEUM DEVELOPMENT Activities

Area	Basis for Selection	Reference
Yukon Delta and Adjoining coastal zone	Federally protected as a national wildlife range; critical habitat for fish and waterfowl production	Figure C-n
Salmon fishing zones	Critical cash base for local economy	Figure C-13
Salmon spawning streams	Critical habitat for commercial species	Figure C-13
Herring spawning zones	Critical habitat for subsistence resource	text; also Barton (1978)
Zones of invertebrate and fish diversity	Important in the maintenance of local ecosystem quality as a source of propagules to renew disturbed areas	Figure C-12
Bering Land Bridge National Park	Critical migratory bird and waterfowl habitat; proposed for federal protection	text; also Klinkhart (1977)
Little Diomede Sledge, King and Egg Islands, Fairway Rock, Bluff, Cape Denbigh, Square" Rock, and Cape Darby	Seabird colonies of high diversity; many proposed for federal protection	Figure C-II
Southwest Cape, Sevoukok Mountain, and Cape Myangee in St. Lawrence Island	Seabird colonies of high density	Figure C-11
Unalakleet River Valley	Critical moose habitat	Figure C-11
Offshore region north and west of St. Lawrence Island	March and April only: concentrations of marine mammals	Figure C-14
Bering Strait, north and south of Little Diomede Island	June only: concentrate ions of marine mammals	Figure C-14

- Gravel islands. Information contained in a review of potential impacts of artificial islands in the southern Beaufort Sea (Canada Department of the Environment, 1977) is partly relevant to Norton Sound. The process of construction of grave? islands w ll chiefly affect local populations though direct mortality during dredge and fill operations and by creation of turbidity plumes. T'ming and location may be critical: increased inshore turbidity may adversely affect aggregating salmon and herring during spawning runs and may interfere with the early development of herring larvae. Direct localized mortality during construction may be important if borrow or fill sites coincide with points-of high benthic productivity or invertebrate diversity. Post-construction effects include long-term changes in local communities induced by the addition or loss of habitat. Local fish resources and benthic diversity may be enhanced by the addition of vertical relief in habitat. In winter, if polynyi should form around gravel islands, they may attract overwintering seals. Finally, abandonment of gravel islands, without adequate precautions, may result in hazards to navigation.

- Onshore and offshore pipelines. Placement of offshore pipelines may be constrained by the location of commercial or subsistence fishing areas, which are inflexible in location and of high overall economic value. Offshore routes should also be considered which minimize harm from potential spills. Onshore pipelines paralleling the coastline bear enormous potential impact on fish populations, especially salmon. The economic importance of the salmon fishery requires that pipelines be constructed at stream crossings to allow unimpeded passage of migrating fish, and without disturbance of spawning and rearing areas. Use of non-fish stream gravel resources for construction will be a likely stipulation. Construction and maintenance costs relative to these restrictions may prove so high as to recommend substitution of offshore pipelines for onshore routes wherever possible.

- Compliance with state and federal regulations. The Alaska OCS Environmental Assessment Program has produced new information on lease-sale areas which will become the basis for environmental stipulations and regulations on petroleum exploitation. Results of lease-sale negotiations in progress for the Beaufort Sea may forecast the future of other sale areas. Important points of discussion include length of the permissible drilling period, types of offshore exploratory platforms, disposal of temporary facilities, vessel/aircraft routes, and spill/blowout contingencies. A review of the existing regulations governing OCS petroleum development follows.

11.3.5 Environmental Regulations

The U.S. Department of Interior, as administrator of outer continental shelf mineral resources, is mandated to protect marine and coastal environments via a number of legislative acts including: National Environmental Policy Act of 1969, Coastal Zone Management Act of 1972, Estuary Protection Act of 1973, Fish and Wildlife Coordination Act, and others. These various acts require that environmental impact be considered in the planning and the decision-making process relating to development of petroleum resources. Therefore, a coordinated industrial-governmental multidisciplinary effort will be involved in the evaluation of any proposed development activity. In addition to the general planning requirements, specific regulations" relating to offshore procedures are presented in the Outer Continental Shelf Lands Act (as amended in September, 1978), titles 30 and 43 of the Code of Federal Regulations, U.S.G.S. OCS operating orders, stipulations required to mitigate impacts, and the Environmental Protection Agency regulations pertaining to offshore oil and gas extraction. Some of the specific environmental regulations that could affect the course of development by restricting activities or making certain procedures impractical include:

- EPA discharge standards for production waters and other by-products of the drilling operation will affect the design of facilities and may affect the practicality of procedures such as offshore loading of oil.

- Stipulations require that areas of historical or archeological importance be protected.

- Stipulations require that facilities (including pipelines) not interfere with commercial fishing, marine mammals, or bird rookeries.

Federal regulations governing OCS activities are Incomplete and in the process of evolution. The forthcoming OCS Orders for the Bering Sea (which wil 1 include the Norton Sound lease sale area) wil 1 probably be . similar to those for the Gulf of Alaska (R. Smith, U.S. Geological Survey, personal communication). Furthermore, the controversy over federal lands withdrawn under the Federal Land Policy Management Act has yet to be decided. Thirteen locations, in or adjcining the lease sale area, may become part of the national wildlife refuge system.

In addition to those regulations that pertain specifically to OCS petroleum development, there are numerous general regulations and permit requirements that may apply to various aspects of onshore and offshore development. These are listed on Table C-6.

II.4 Gravel Resources

II.4.1 Introduction

A description of the gravel resources of the Norton Sound area is relevant in this report because the construction of petroleum facilities both onshore and offshore requires large quantities of gravel. Onshore construction in permafrost terrain necessitates significant quantities of gravel for foundation pads, roads, air strips, work pads, pipeline bedding, etc., while offshore gravel may be required for construction of artificial islands as drilling platforms or loading facilities. A summary of gravel requirements for various petroleum facilities is given in Table C-7.

A gravel resource can be classified as an accumulation of gravel of sufficient quantity which can be economically utilized. Inherent in the classification are the cost considerations of:

(1) Burial depth of the resource and stripping ratio of overburden to gravel.

TABLE C-6

PERMITS AND REGULATIONS CONCERNING PETROLEUM DEVELOPMENT

AGENCY	PERMIT/ACTIVITY	AUTHORITY
STATE OF ALASKA		
Department of Natural Resources	Oil and Gas Leases	Alaska Statute 38.05.180
	Pipeline Rights-of-May	Alaska Right-of-Way Leasing Act
	Gravel Pennits and Sales	Alaska Statute 38.05
	Water Use Permits	Alaska Water Use Act; Alaska Statute 46.15.010
Department of Fish & Game	Water Use Permits	Fish & Game Act of 1959; Alaska Statute 16.05.870
	Hydraulic Pennits	Fish & Game Act of 1959; Alaska Statute 16.05.870
	Authority to Remove Nuisance Wildlife	Fish & Game Act of 1959; Alaska Statute 16.05.870
Department of Environmental Conservation	Water Quality Standards	Alaska Water Quality Standards 1973
	Ballast Mater Discharge Pennit	Alaska Statute 46.03.750
	Surface Oiling Permit	Alaska Statute 46.03.050
	Solid Waste Management Permit	Alaska Statute 46.03.050
	Air Quality Standards	Alaska Statute 46.03.050
	Burning Permit	Alaska Statute 46.03.050
FEDERAL GOVERNMENT		
Army Corps of Engineers	Permit to Work in Navigable Maters	Refuse Act; Rivers & Harbors Act 1899, Title 33 Code of Federal Regulations Part 209
	Permit to Discharge into Nav. Waters	Water Quality Improvement Act 1972; Title 33 Code of Federal Regulations Part 209
U.S. Coast Guard	Bridge Permits-Navigable Waters	Title 33 Code of Federal Regulations Part 114
Bureau of Land Management	Protection of Critical Habitat	Federal Land Policy Management Act 1976
	Special Use Permits:	
	Gravel Mining	Title 43 Code of Federal Regulations, Part 2920
	Construction Camps	Title 43 Code of Federal Regulations, Part 2920
	Timber Disposal	Title 43 Code of Federal Regulations, Part 5400
	Communication Sites & Right-of-Way	Title 43 Code of Federal Regulations, Part 2920
	Construction Disposal Areas	Title 43 Code of Federal Regulations, Part 2920
	Gravel Disposal	Title 43 Code of Federal Regulations, Part 3610
	Airport Leases	Title 43 Code of Federal Regulations, Part 2911
	Oil and Gas Leases	Mineral Leasing Act of 1920 and Revisions
	Right-of-Way Permits	Federal Land Policy and Management Act 1976
	Off-Road-Vehicle Permits	Sikes Act
Environmental Protection Agency	Wastewater Discharge Permit	Water Pollution Control Act 1972
	Oil Pollution Prevention	Water Pollution Control Act 1972
	Control Oil Spill Clean-up	Water Pollution Control Act 1972
Fish & Wildlife Service	Protection of Fish, Wildlife & Habitat	Fish & Wildlife Coordination Act 1973
	Outer Continental Shelf Development	Fish & Wildlife Coordination Act 1973
	Estuary Protection	Estuarine Study Act of 1968
	Special Use Pennits -- Wildlife Ranges and Refuges	Title 50 Code of Federal Regulations
	Marine Mammal Protection	Marine Mammal Protection Act 1972 (Polar Bear, Walrus, Sea Otter)
	Endangered Species Protection	Endangered Species Act 1973
	Eagle Protection	Eagle Act of 1972
	Waterfowl Protection	Migratory Bird Treaty Act
National Marine Fishery Service	Protection of Anadromous Fish Habitat	Fish & Wildlife Coordination Act 1973
	Marine Mammal Protection	Marine Mammal Protection Act 1972 (Whales and Seals)
	Outer Continental Shelf Development	Fish & Wildlife Coordination Act 1973
Department of Transportation	Pipeline Safety & Valve Locations at Stream Crossings	Title 49 Code of Federal Regulations, Part 195

Source: Dames & Moore

TABLE C-7

SUMMARY OF GRAVEL REQUIREMENTS FOR VARIOUS PETROLEUM FACILITIES IN ARCTIC AND SUBARCTIC REGIONS

Facility	Dimensions/Specifications	Gravel Requirements cubic meters	Gravel Requirements cubic yards	Comments
Pipeline work pad	1.5 meters (5 feet) thick; 20 meters (65 feet) wide	30,177/km	63,555/mile	Typical Alyeska dimensions for above ground pipe; scenario work pads may be somewhat narrower since pipelines are smaller
Pipeline access road	1.5 meters (5 feet) thick; 8.5 meters (22 feet) wide	10,214/km	21,511/mile	
Pipeline haul road	1.5 meters (5 feet) thick; 9 meters (30 feet) wide	13,928/km	29,333/mile	
Airstrip (all weather)	1,523 x 40 meters (5,000 x 150 feet); 1.2 to 1.8 meters (4 to 6 feet) thick	84,955 - 126,159	110,000 - 165,000	
Camp and drill pad (onshore exploratory well)	128 x 98 meters (420 x 320 feet), 1.27 hectares (3.1 acres)	26,760 - 38,230	35,000 - 50,000	
Crude Oil Terminal				
Small-Medium (<250,000 b/d)	32 hectares (80 acres)	267,610 - 535,220	350,000 - 700,000	
Large (500,000 b/d)	120 hectares (300 acres)	1,146,900 - 1,911,500	1,500,000 - 2,500,000	
Very Large (>1,000,000 b/d)	202 hectares (500 acres)	1,835,040 - 3,440,700	2,400,000 - 4,500,000	
LNG Plant				
Small-Medium (400 MMCFD)	25 hectares (60 acres)	214,088 - 420,530	280,000 - 550,000	
Large (750-1,000 MMCFD)	100 hectares (250 acres)	917,520 - 1,529,200	1,200,000 - 2,000.000	
Construction Support Base	16 - 30 hectares (40 - 75 acres)	152,920 - 382,300	200,000 - 500,000	
Exploration Island	see Table C-12			
Production Island	see Table C-12			

Source: Dames & Moore estimates.

(2) Preparation and/or benefication of the gravel.

(3) Handling and transportation of the gravel to where it is being utilized.

Many large concentrations of gravel may not be “resources” as the mining and/or handling and transportation may be prohibitively expensive.

The development of gravel accumulations is dependent upon two conditions: (1) there must be a source area, such as pre-existing rock or formations/ deposits containing grave?, from which gravel may be derived; and (2) there must be some gravel concentration mechanism. In Arctic areas gravels are commonly derived from pre-existing rock or from formations/deposits containing gravels by alluvial and/or glacial processes. The derived gravel may be later concentrated in river channels or along beaches as current and/or wave sorting acts to segretate out and remove the finer fractions of sediments.

11.4.2 Distribution of Gravel Resources in Norton Sound

In the Norton Sound there are three general areas where gravel resources may be present. These areas are:

(1) The onshore coastal plain adjacent to Nome.

(2) The offshore areas immediately south of Nome.

(3) The offshore area north of St. Lawrence Island.

The gravels in the areas are probably glacial related. Outside these areas onshore and offshore gravel potential is probably poor because:

(1) Density of gravel deposits is probably low (onshore and offshore).

(2) The gravel accumulations are overlain by thick deposits of finer grained sediment (onshore and offshore).

{3) The gravel areas in a permafrost zone would require considerable thawing time before they could be mined (onshore).

Each of the potential gravel areas identified above is discussed below and possible gravel deposits within these areas are identified and evaluated. Figure C-15 shows the distribution of surface sediments in the northern Bering Sea including percentage of gravel in those sediments.

II.4.2.1 Coastal Plain at Nome

Many buried beaches are present along the coastal plain of Nome. The beaches, some buried to a depth approaching 33 meters (99 feet), are linear features containing goldbearing gravels. Currently the Alaska Gold Company is mining a number of these buried beaches. The tailings from the mining operation are being stockpiled in large piles, some over 15 meters (50 feet) in height. The material in the stockpiles is dominated by coarse sand through coarse gravel sized material but contains fines, cobbles, and boulders. The State Highway Department of Alaska is purchasing some of the tai' ing for maintaining and upgrading of roads in the Nome area.

Many buried beaches remain to be mined along the coastal plain. In the present state, these buried beaches are in the permafrost zone and are frozen. A period of up to three summers of processing time, generally by circulating water through the gravel deposits, is required before one summer's worth of to-be-dredged gravel is thawed.

11.4.2.2 Offshore Zone at Nome

The offshore zone at Nome contains a complex of relict deposits most recognizable by bathymetric expression and/or geophysical characteristics. Some of the features include glacial drift deposits, buried alluvial channels, beach ridges, and outwash fans (Tag and Greene, 1973).

Glacial drift deposits blanket large areas of the coastal plain and offshore zone at Nome. The material is dominated by sand, gravel, and

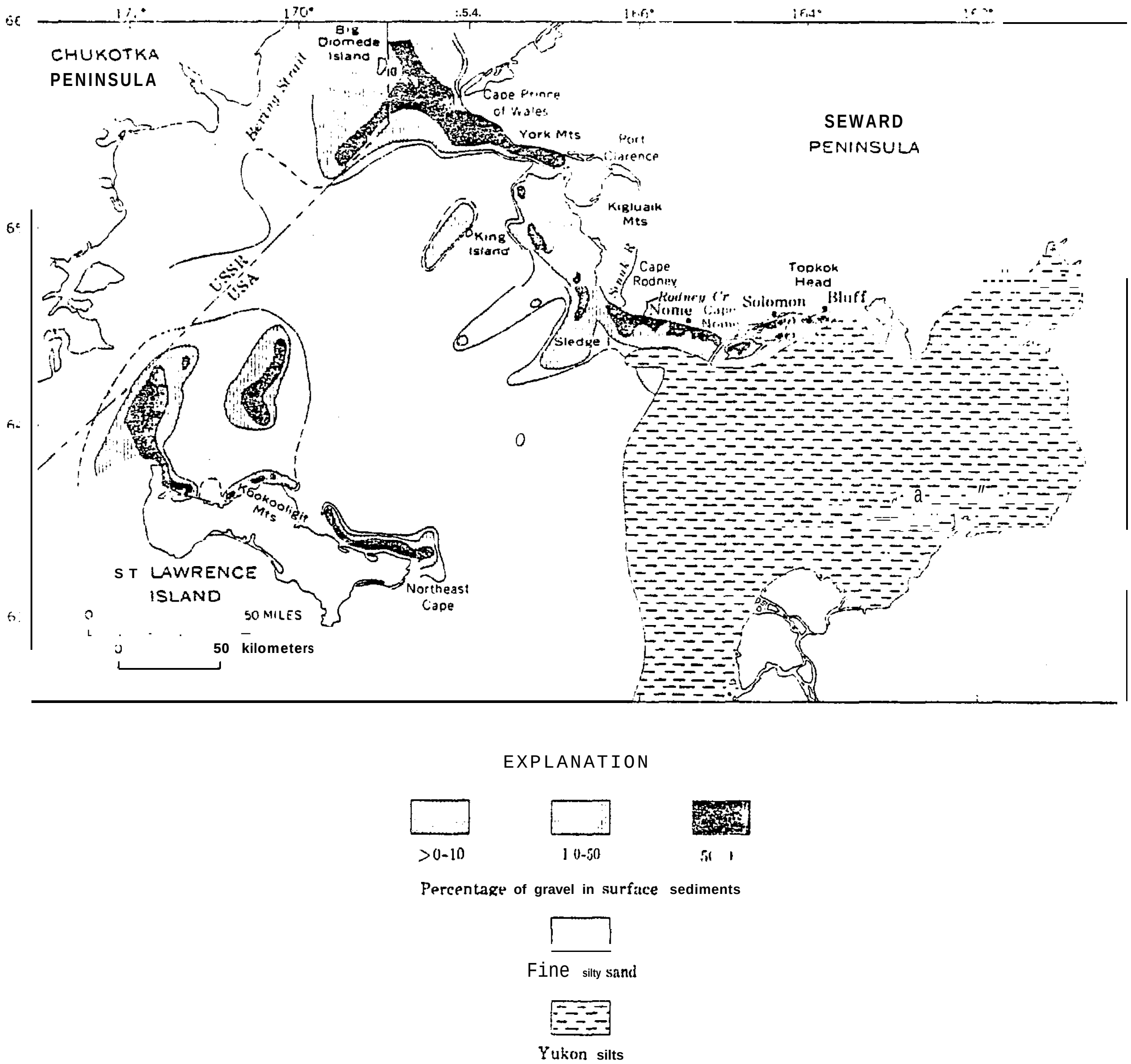


Figure C-15

DISTRIBUTION OF SEDIMENTS IN THE NORTHERN BERING SEA

(Distribution of Yukon silts and clay modified from McManus and others, 1969) Source: Nelson and Hopkins, 1972 glacial till but contains cobbles and boulders. The glacial drift deposits contain gold; however, the gold is generally not concentrated enough to make the deposits a target for gold mining.

Beach and alluvial processes acting upon the glacial drift can concentrate gravels. Beach ridges, outwash fan, and buried channels in the Nome offshore area are features in which gravels are concentrated. Many of the relict beach and alluvial deposit offshore of Nome show bathymetric expression. The linear submerged beach ridges contain concentrations of gold-bearing gravels. Generally, only the gravels occur as a thin veneer and consequently the volumes of gravel are not that large. Outwash fans from developed glacial deposits contain appreciable quantities of gravel. These deposits are both laterally extensive and thick (approximately 5 meters [18 feet]). The predominant material in the outwash fans is probably sands and gravel with some fines and cobble and boulders.

Buried channels are subbottom features which can be delineated on geophysical records. Approximately 20 buried channels or depressions have been recognized in the Nome offshore area (Tagg and Greene, 1973). Some of the channels are shallow while others are buried beneath a considerable thickness of sediment. The channels are trough-like in form and contain some gravels as indicated by their acoustical signal. The proportion of gravels in the buried channels and their lateral extent and thickness is not known.

11.4.2.3 North of St. Lawrence Island

During the Pleistocene, Siberian glaciers advanced beyond the present-day shore?inee north of St. Lawrence Island. Glacial drift deposits have been recognized in this area. Although no detailed geophysical work has been done to delimit relicit deposits, it is likely that relicit deposits similar to those offshore of Nome are present in the St. Lawrence Island area.

11.4.3 Availability of Gravel for Offshore Gravel Islands

Onshore sources of gravel are available from the tailing piles at the placer gold mining operation currently underway in Nome. The volume of gravel available can be easily determined; however, the price per cubic yard of gravel remains to be negotiated. The cost of transferring this gravel to an offshore site is undoubtedly great as the gravel will require at least two handlings including an onshore to offshore transfer system. Furthermore, it is likely that shallow draft barges will be used to transport the gravel from Nome to an offshore location as the waters around Nome are shallow. The lower volume shallow draft barges will add additional inefficiencies to the onshore to offshore transportation cost.

The gravel accumulations offshore of Nome which are contained in outwash fans, buried channels, and beach ridges offer another possible source of gravel. These deposits have the following attributes:

(1) They are probably free of permafrost.

(2) They are surface or nearsurface deposits.

(3) They can be easily mined by conventional offshore mining techniques.

(4) They would require minimal handling.

There may he competing interests for these offshore gravel accumulations as they contain placer gold and they are considered target areas.

Of the three offshore gravel deposits described above, the gravel accumulations in outwash fans represent probably the best potential gravel resource. The fans are laterally extensive fairly thick and probably contain appreciable quantities of gravel. The buried channels and beach ridges are linear features which undoubtedly contain lower volumes of gravel.

Gravel deposits similar to those offshore of Nome probably exist adjacent to the north side of St. Lawrence Island; however, many of the deposits remain to be verified. At the time these gravel deposits are verified, they can be evaluated as a potential gravel resource.

11.4.4 Conclusions

The two best potential gravel resources for gravel island construction are: (1) the onshore tailing piles at Nome, ard (2) the gravel accumulations in the outwash fans offshore of Nome. Much is known or can be determined concerning the composition and volumes of the gravel contained in the tailing piles; however, the cost of the gravel and the transportation costs to an offshore site have not been worked out. The gravel accumu'tions in the outwash fans are undoubtedly less costly to recover, handle and transport; however, the composition and volume of gravels in the deposit are not yet known. Until these unknowns are resolved and costing studies are made, it is not possible to make a determination as to whether or not these gravel accumulations constitute a developable gravel resource.

11.5 Water Resources

11.5.1 Water Resources Inventory

II.5.1.1 Surface Water

Surface water resources in the Norton Sound area include several river systems and many small streams. River systems include the Kuzitrin, Unalakleet, Inglutalik, Niukluk, Fish, and Agiapuk. Table C-8 lists and describes these rivers and many of the small streams in the area.

Surface runoff in this region is highly variable due to the lack of precipitation, the presence of permafrost, and the numerous low mountains. Mean annual runoff is estimated at 1.1 cubic meters/minute per square kilometer (1 cfs per square mile), with figures as high as 2.1 cubic meters/minute per square kilometer (2 cfs per square mile) in some areas.

TABLE c-8

INVENTORY OF SURFACE WATERS IN THE NORTON SOUND AREA

Name	Tributary to	Drainage Area sq. km.	Drainage Area sq. mi.	Estimated Average Annual Flow cu. m./min.	Estimated Average Annual Flow (Cfs)	Important to Anadromous Fish
Unalakleet	Norton Sound	5,387	2,080	3,398	2,000	Yes
South	Unalakleet R	1,290	498	816	480	Yes
North	Unalakleet R	321	i24	204	120	Yes
Chiroskey	Unalakleet R	803	310	510	300	Yes
Old Woman	Unalakleet R	793	306	500	294	Yes
Ulukuk	Unalakleet R	606	234	367	216	No
Shaktolik	Norton Sound	2,214	855	1,597	940	Yes
Ungalik	Norton Bay	1,792	692	1,291	760	Yes
Inglutalik	Norton Bay	2,598	1,003	1,920	1,130	Yes
Akul ik	Norton Bay	78	30	56	33	NO
Koyuk	Norton 8ay	5,097	1,968	3,679	2,165	Yes
East Fork	Koyuk	860	332	622	366	No
Peace R	Koyuk	552	213	398	234	Yes
Mukluktulik	Norton Bay	104	40	75	44	Yes
Miniatulik	Norton Bay	47	18	34	20	No
Kuiuktulik	Norton Bay	47	18	34	20	No
Kwi k	Norton Bay	531	205	382	225	Yes
Tubutulik	Norton Ray	1,044	403	1,014	597	Yes
Kwiniuk	Norton Bay	5,672	219	552	325	Yes
Youngl ik	Norton Sound	150	58	102	60	No
Niukluk	Norton Sound	5,670	2,189	3,823	2,250	Yes
Fox	Niukluk	192	74	129	76	No
Fish	Niukluk	3,069	1,185	2,073	1,220	Yes
Pargon	Fish River	363	140	245	144	No
Etchepuk	Fish River	549	212	370	218	Yes
Rathlatulik	Fish River	192	74	129	76	No
8ear	Niukluk	101	39	68	40	No
Casadepaga	Niukluk	601	232	408	240	Yes
Libby	Niukluk	409	158	277,	163	No
Klokerblok	Norton Sound	469	181	234	138	Yes
Skookum	Klokerblok	65	25	32	19	No
Topkok	Norton Sound	65	25	39	23	No
Solomon	Norton Sound	352	136	251	148	Yes
Bonanza	Norton Sound	321	124	263	155	Yes
Eldorado	Norton Sound	655	253	537	316	Yes
Flambeau	Eldorado	218	84	178	105	Yes
Nome	Norton Sound	420	162	391	230	Yes
Snake	Norton Sound	334	129	311	183	Yes
Penny	Norton Sound	88	34	82	48	Yes
Sinuk	Bering Strait	803	310	748	440	Yes
Stewart	Sinuk R	148	57	144	85	No
Feather	Bering Sea	189	73	107	63	Yes
Tisuk	Rering Sea	207	80	136	80	No
Bluestone	Bering Sea	300	116	144	85	Yes
Cobblestone	Bering Sea	189	73	93	55	Yes

TABLE C-8 (Cent.)

Name	Tributary to	Drainage Area sq. km.	Drainage Area sq. mi.	Estimated Average Annual Flow cu. m./min.	Estimated Average Annual Flow (cfs)	Important to Anadromous Fish
Kuzitrin	Bering Sea	6,734	2,600	3,254	1,915	Yes
Kruzgamepa	Kuzitrin	1,259	486	909	535	No
Grand Central	Kruzgamepa	135	52	195	115	Yes
Kaviruk	Kuzitrin	580	224	280	165	No
Kougarok	Kuzitrin	1,453	561	705	415	No
Noxapaga	Kuzitrin	1,238	478	544	320	No
Agiapuk	Bering Sea	2,896	1,118	1,538	905	Yes
American	Agiapuk	1,569	606	833	490	Yes
California	Bering Sea	161	62	92	54	No
Don	Bering Sea	287	111	161	95	No
Lost	Bering Sea	85	33	48	28	No
Rapid	Lost River	41	16	24	14	No
King	Bering Sea	28	11	14	8	No
Kanauguk	Bering Sea	65	25	31	18	No
Anikovik	Bering Sea	78	30	37	21	No
Mint	Chukchi Sea	414	160	187	110	No
Yankee	Mint River	75	29	34	20	No

Source: U.S. Geological Survey, Water Data Reports (various years)

Mean annual peak runoff ranges from 10.5 to 26 cubic meters/minute per square kilometer (10 to 25 cfs per square mile), being generally lower in the southern portion of the area. Peak flows typically occur in May through August with minimum flows 0.21 to zero cubic meters/minute per square kilometer (0.2 to zero cfs per square mile) occurring rom December through March.

Though area-wide estimates have been made, little data is available for specific streams. The U.S. Geological Survey is presently monitoring six sites in the area, all of which are located near Nome. Table C-9 shows some of these results.

Average annual surface runoff from the entire area is estimated at approximately 39,082 cubic meters/minute (23,000 cfs) annually or about 57 liters (15 million gallons) per day. Maximums minimums vary from almost 114 liters (30 million gallons) per day to 5.7 million liters (1.5 million gallons) per day respectively.

The chemical quality of the surface water in the area is generally good and is acceptable for domestic use. Dissolved solids are mostly of the calcium bicarbonate type and present in amounts less than 200mg/l. In coastal areas, the quality decreases due primarily to high levels of magnesium and sodium chloride.

Sediment loads tend to be low, primarily due to the lack of glaciers in the area and the low annual runoff rates.

11.5.1.2 Ground Water

The ground water availability in the area is severely limited. Yields from wells are usually less than 38 liters/minute (10 gpm), and are generally located beneath the channels of larger streams and adjacent to large lakes.

Springs are found in the area, including the Moonlight Springs used by the City of Nome which produces 374 to 1,136 liters (100 to 300 gpm) all year.

TABLE C-9

U.S.G.S. STREAM FLOW DATA FOR NORTON SOUND SUBREGION[1]

	Drainage Area		Average		Maximum		Minimum		Period of Record
	Kilometers	Miles							
Snake River near	221.9	85.7	302	178	7,137	4,200	<1.7	<1	12
Crater Creek near Nome	56.7	21.9	97	57.0	4,316	2,540	1.7	1	12[2]
Goldengate Creek near Nome	4.0	1.55	N/A	N/A	107	63	N/A	N/A	2[2]
Arctic Creek	4.6	1.76	N/A	N/A	338	199	N/A	N/A	10
Washington Creek near Nome	16.4	6.34	N/A	N/A	1,054	620	N/A	N/A	13
Star Creek near Nome	8.8	3.38	N/A	N/A	258	152	N/A	N/A	13

[1] Reference: U.S. Geological Survey, Water Data Reports, 1970-1977.
[2] *Intermittent data omissions.*

Two major difficulties encountered with the development of ground water in the area are seasonal limitations and quality degradation. Numerous wells developed in the past have proven inadequate for year-round use, as the wells have gone dry during the winter months. Improved siting techniques and the use of galleries under stream channels may avoid this problem.

Since most of the development in the region is near the coast, significant problems with saline water intrusion into the wells has occurred. Though the quality of water is expected to be higher away from the coast, available quantities may be decreased.

Inland, springs exist which have potential for providing year-round supplies. Little information is available on these sources except for those presently in use and those located within the proposed Chukchi Imuruk (Bering Land Bridge) National Reserve.

11.5.2 Water Use

11.5.2.1 Community Water Use

The population of the Norton Sound area is approximately 6,500, most of which live in communities or villages along the coast. Water supplies for community use include established treatment and distribution systems, central watering points often with laundromats and showers, and organized hauling and ice-cutting efforts. Table C-10 lists the communities, water use and supply facilities.

The communities shown in Table C-10 have populations ranging from a few individual families to in excess of 2,500 people. Forty percent of the communities have no system whatsoever. Another 30 percent have no distribution system, but merely communal facilities.

Many of the systems in use are functional only during the summer months due to freezing, saltwater intrusion, or lack of supply during the win-

TABLE C-10

WATER SUPPLIES IN NORTON SOUND COMMUNITIES

Communities and Localities	Present Population*	Present Water Use' gal./day)	Population' year 2000)	Projected Water Use* gal./day)	Present Water Source	Present Water System	Planned Improvements
Bluff	15[3]	300	17	340	None	None	None
Bonanza	15[3]	300	17	340	None	None	None
Boxer Bay	15[3]	300	17	340	None	None	None
Brevig Mission	194	6,790	220	7,700	Creek	Storage: 300,000 gal. wood tank; PHS Central Facility	Minor maintenance
Cape Nome	15[3]	300	17	340	None	None	None
Cape Prince of Wales	15[3]	300	17	340	None	None	None
Council	35	1,225	40	1,400	Well: 8-10 gpm winter 3-5 gpm summer	60' VSW windmill; watering point	Minor maintenance
Dime Landing	15[3]	300	17	340	None	None	None
Diomede (Inalik)	125	4,375	141	4,935	Spring	Storage: 120,000 gal. tank; watering point	None
Elim	288	"20,736	325	23,400	Spring; 80' standby well	Storage: 18,000 gal. wood tank; distribution system to all homes	None
Gambell	447	15,645	505	17,675	Spring; (dries up in winter)	Storage: 100,000 gal. steel tank; distribution system to new homes	Identify new source
Golovin	118	4,130	133	4,655	Haul ice; rain water well (closed)	Storage: 300,000 gal. tank watering point; PHS Central Facility	Locate new supply
Granite Mountain	15[3]	300	17	340	Wells; surface water	Storage tank (winter source) for government facilities	None
Haycock	15'	300	17	340	None	None	None
King Island (Ukivok)	summer only	--	summer only	--	None	None	None
Koyuk	160	5,600	180	6,300	90' well (2 gpm)	Storage: 2-800 gal. wood tanks; watering point	Distribution system to new homes improve supply and storage
Marys Igloo	15[3]	300	17	340	None	None	None
Moses Point	15[3]	300	17	340	16' well (2 gpm)	Serves FAA station	None

TABLE C-10 (Cont.)

Communities and localities	Present Population	Present Water Use (gal./day)	Population year 2000)	Projected Water Use gal./day)	Present Hater Source	Present Water System	Planned Improvements
Nome	2,550	185,000	5,000	360,000	Moonlight spring (380 gpm)	Stordge: 300,000 gal. concrete tank; distribution system to half of homes	None
Northeast Cape	50′	1,750	57	1,995	Wel 1s	Formerly served military site; present use unknown	None
Port Clarence	15′	300	17	340	Shallow wells	Storage for military site	None
Piligrim Springs	15′	300	17	340	None	None	None
St. Michael	283	9,905	320	11,200	Clear Lake	Storage: 120,000 gal. tank; watering point	None
Savoonga	409	14,315	462	16,170	156′ well	Storage: 103,000 gal. tank; watering point	Moo new watering point
Shaktool ik	163	5,705	184	13,248	Tagoonmenik Creek	Storage: 1,000,000 gal, tank; watering point; distribution to new homes	Expand distribution system
Shelton	15′	300	17	340	None	None	None
Snake River	15′	300	17	340	None	None	None
Sol omon	15′	300	17	340	None	None	None
Stebbins	326	11,410	368	12,880	Lake; well (school)	Storage tank; watering point; school has Reverse Osmosis Treatment	None
Teller	258	9,030	292	21,024	Coyote Creek	Distribution to new homes; watering point	Full use of system when power supply reliability established
Tin City	20 summer	700 summer	20 summer	700 summer	Wel 1	Storage tanks serves military site	None
Unalakleet	632	45,504	714	51,408	Powers Creek well	Storage: 1,000,000 gal. tank; distribution system	None
Ungal ik	15′	300	17	340	None	None	None

TABLE C-10 (Cont.)

Communities and Localities	Present Population[3]	Present Water Use[4] (gal ./day)	Population[1] (year 2000)	Projected Water Use[4] (gal./day)	Present Water Source	Present Water System	Planned Improvements
Wales	130	4,550	147	5,145	Spring (summer only)	Storage tank; watering point (summer only)	Add 500,000 gal. storage
White Mountain	115	4,025	13(I	4,550	Well (summer only)	Storage: two tanks watering point (summer only)	None
TOTAL	5,523	345,290	9,490	569.,825			

[1] Based on regional projections developed by University of Alaska, Institute of Social and Economic Research.
[2] Figures accepted by the Alaska Department of Community and Regional Affairs under the State's Municipal Revenue Sharing Program.
[3] Estimated.
[4] Estimated per capita use as follows: (a) complete water system, 72 g/c/d; (b) watering point, 35 g/c/d; (c) no system, 20 g/c/d.

ter. Several of the systems collect water during the summer for storage and use during the winter months.

As a consequence of the kinds of systems and the low populations, little information is available on actual water use. The City of Nome reports a per capita water consumption of 273 liters/day (72 gallons/day). Other data suggests that water use is significantly less in communities without watering points and less still where no system exists. Water use estimates of 132 liters/day (35 gallons/day) and 76 liters/day (20 gallons/day), respectively, have been used for these situations.

11.5.2.2 Other Water Uses

In addition to the community water use, water in the area is used for mining operations, fish processing, and agriculture in the form of reindeer herds.

Mining operations in the area consist primarily of placer mines with a few floating dredges in use. Though large amounts of water are used in these operations, very little is consumed. Thus, the effects from these operations are limited to some degradation of the water quality with little effect on flows.

A plan to extract and concentrate fluorite, tungsten, and tin ores is being implemented in Lost River. It is not known what water uses will be required for this development.

Fish processing activities are located in Unalakleet, Moses Point/Elim, Golovnin, Nome, Ungalik, and Shaktoolik. With the exception of the Nome facilities, sea water is used for fish processing in all locations. At Nome, a small amount of water may be taken from the city system, but this is included in the community water use.

The only reported agricultural activity in the area which utilizes fresh water is reindeer herding. Reindeer number about 17,000 in the area and consume as estimated annual average of 126,514 liters/day (33,425 gallons/

day). In summer, water for the herds is available from ponds and streams in the grazing area, and during the winter, the animals eat snow.

A pilot reindeer processing plant in Nome is used only sporadically, as the bulk of the slaughtering takes place in the field, and little water is used for this activity.

11.5.2.3 Restrictions on Water Use

Several other issues affect the use or development of water supplies, including water rights, minimum flow requirements for fish, and land designation. Winter construction activities have created problems in the past by utilizing water from pools beneath frozen streams. These pools often provide overwintering sites for various fish species and the removal of this water seriously impacts fish populations. Consequently, the Alaska Department of Fish & Game strictly controls water withdrawals from these streams. Since this restriction coincides with the low flow portion of the year, the availability of some sources for year-round use may be limited.

Other fish and wildlife restrictions may apply to streams important to anadromous fish, as shown in Table C-8. These limitations may affect stream diversion, reservoir construction, and ether construction activities.

The ongoing process of division of lands between the state, the U.S. Government, and native corporations presents some potentially restrictive land and resource use constraints. Proposed land designations in the Norton Sound ara include the Chukchi Imuruk National Reserve (Bering Land Bridge), the Unalakleet River, the Koyuk River, and numerous Marine Resources National Wildlife Refuges.

The proposed Chukchi Imuruk National Monument will occupy nearly three million acres in the center of the Seward Peninsula. The implication of this designation is that water resources within the monument or impacting this area are reserved for the purposes of the monument. This will undoubtedly complicate and perhaps prevent the use of the water resources located within the area.

Two rivers in the Norton Sound area are proposed to be designated as "Wild and Scenic". This designation effectively prohibits the development of these rivers. The Koyuk River from the mouth to where it enters the Chukchi Imurak National Monument is one of these rivers. and the Unalakleet River from twelve miles above the mouth to its source is the other. These rivers are listed in Table C-8.

The sites proposed for designation as Marine Resources National Wildlife Refuges are all on offshore islands or on the coastline. Consequently, little impact from these sites is expected on water resources on water supply development.

Following the resolution of the land withdrawal issues, the state is expected to establish a State Recreation Area at Salmon Lake north of Nome. This designation would complicate or prevent the development of the lake or its tributary streams for water supplies.

Water rights in Alaska have traditionally been controlled by the State Department of Natural Resources. Recent land withdrawals associated with the Alaska Native Claims Settlement Act have raised the issue of jurisdiction in the State's allocation of water rights. At the present time, one native corporation is suing the state, claiming aboriginal title to the water rights within the corporation boundaries.

If this claim is upheld, it is probable that all existing water rights within this village withdrawal areas would be voided, and subsequent water rights obtained through the native corporations. This could limit the availability of water for development, depending upon the attitude of the native corporation toward the development.

A similar situation exists with respect to former reservation areas, such as St. Lawrence Island and Elim. Though the state has been managing water rights in these areas, it is likely that, if contested, this jurisdiction would be returned to the villages. This could also limit the water available for development.

III. Drilling Platforms

This section describes the various offshore drilling structures and techniques that may be available to the oil industry in the Norton Basin OCS lease sale area. These options are discussed in the context of the dominant engineering constraints. It should be emphasized that many of the technological options described herein are in the conceptual, design, or prototype state of development, and thus, may require considerable lead time before introduction into an offshore petroleum development program.

Particular reference is made to the Canadian experience in the southern Beaufort Sea, arctic islands, and Davis Strait/Labrador Sea, since they are the only regions with significant offshore Arctic petroleum activity to date. This experience, discussed in Section I, includes:

- Exploratory drilling in the southern Beaufort Sea utilizing soil islands, sunken barges, and ice-strengthened drillships.
- Drilling from reinforced ice platforms off the arctic islands.
- Exploratory drilling from dynamically-positioned semi-submersibles and drillships in the iceberg-infested waters of the Davis Strait and Labrador Sea.
- Advanced technological research in all phases of arctic offshore petroleum-related activities.

In the Alaskan Beaufort Sea, as noted above, offshore exploration, activities have been restricted to one ice island and three winter-constructed gravel islands.

Review of the oceanographic conditions of Norton Sound (Section II.1) indicates that modified Upper Cook Inlet type platforms may be feasible in Norton Sound since overall oceanographic conditions are not significantly more adverse (also see discussion Section VII). A review of feasible exploration and development technologies for the OCS lease sale areas on the current five year leasing schedule by Exxon (Offshore, April, 1979) indicated that in Norton Sound exploration is seasonably feasible with mobile rigs and development can probably be accomplished with gravel islands to 18 meters (60 feet) and "ice-resistant structures" to 61 meters (200 feet). Given these considerations, this review of drilling platforms for exploration and/or production focuses on artificial (gravel) islands, Upper Cook Inlet type platforms and monotone/ cone structures. Off-ice exploratory drilling from reinforced ice platforms and ice islands is reviewed but is considered to be of very limited, if any, application to Norton Sound given ice characteristics and the other options available.

111.1 Artificial Islands

Artificial islands are generally constructed from locally mined soil (gravel, sand, silt) with or without bonding or cementing agents and suitably protected to resist ice forces and wave and current erosion. An artificial island may be designed as a temporary structure for an exploration well or as a permanent production platform with long-term protection against ice and waves. In the southern Canadian Beaufort Sea off the Mackenzie Delta, artificial islands have been the favored technique for offshore exploration drilling in shallow waters. A total of 17 have been constructed there to date, mainly by Imperial Oil, Ltd.

The factors which favor this type of structure are (Riley, 1975):

- Shallow water. The Imperial Oil, Ltd. lease acreage extends to about. the 20-meter (66-foot) isobath.
- Minimum sea ice movement. Most of Imperial's acreage 1 ies within the landfast ice zone.
- Weather. Standby costs are very high for floating rigs during the winter due to the short working season (2-1/2 to 3 months).
- Ice forces. Islands were considered to be the safest means of resisting ice forces.

- cost* The initial capital investment for most other types of structures was considered to be high compared with artificial islands. This is especially important when the number of prospective locations is small and very dependent on the ratio of success.

- Limited risk. Construction of artificial islands is a proven technology utilizing standard construction equipment.

- Governmental regulations. Environmental laws in Canada favor this approach and do not require the removal of these islands after their use for unsuccessful exploration drilling.

To date, artificial islands in the southern Canadian Beaufort Sea have been built in water depths of up to 20 meters (66 feet) although such structures may be feasible in water depths up to 30 meters (100 feet) using caissons. Two islands were constructed in the summer of 1976, including one in a water depth of about 12 meters (40 feet), and one in the summer of 1977 in 15 meters of water (50 feet) of water (Croasdale, 1977). The most recent artificial island is "Issungnak" which is located in 20 meters (65 feet) of water and took summer seasons (1978 and 1979) to construct.

111.1.1 Design and Construction Techniques

Artificial islands are basically comprised of two parts: (a) a body of the island which forms the base for drilling operations, with a minimum surface radius of 50 meters (160 feet); and (b) side slopes designed to protect the island from waves in summer and ice in winter (deJong, Stigter, and Steyn, 1975; Ocean Industry, October, 1976). Croasdale (1977) reports a typical island diameter of about 100 meters (330 feet) at the working surface and 5 to 6 meters (17 to 20 feet) freeboard.

Island design is influenced by materials and techniques available for construction as dictated by location and season. The surface area is dictated by that required for drilling, and the freeboard by ice and wave conditions. These factors will, therefore, determine island size and fill requirements. Beach slopes, which also affect fill requirements, are decided partly by construction techniques and foundation conditions and partly by the requirement to protect the island against wave erosion.

Slope protection materials that are normally used, such as concrete blocks, quarry stone, and bitumen mixtures, are very expensive in the Beaufort Sea due to transportation distances. Short-term exploration islands, however, can use such temporary methods as:

- Sand bags.
- Gabions (wire mesh enclosures) filled with sand bags.
- Sand-filled plastic tubes, and filter cloth held down by wire netting.

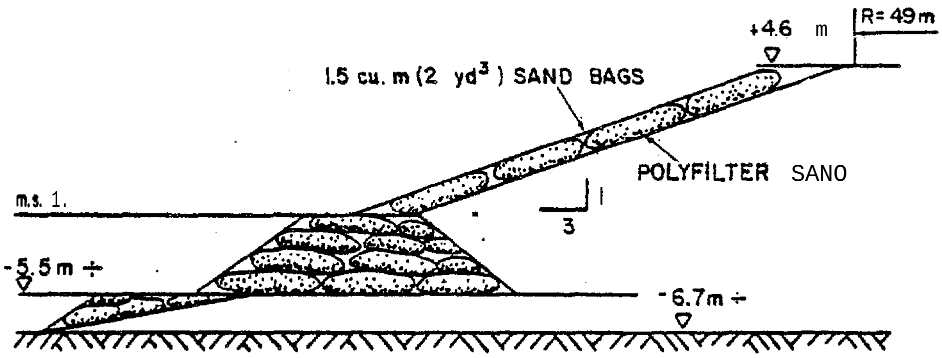
Typical island profiles are shown on Figure C-16; a sand bag retaining wall was utilized for Netserk F-40, B-44, and Kugmal lit N-59, while a sacrificial beach design was employed for Arnak L-30, Kannerk G-4, and Issungnak (Croasdale and Marcellus, 1977, MacLeod and Butler, 1979).

Three basic sand bag-retained island designs have been employed by Imperial Oil to date (Riley, 1976; deJong, Steiger, and Steyn, 1975):

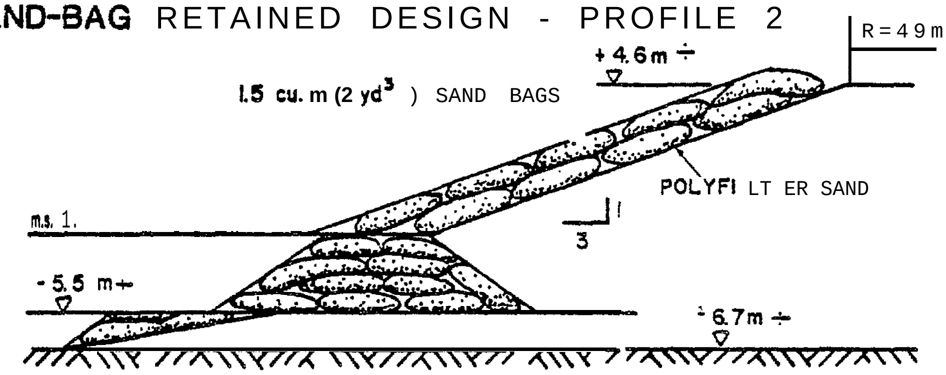
- Immerk type. Granular fill was hydraulically placed by suction dredge, with a natural slope of 1:20. The Immerk B-48 island was built during two summer construction seasons by pumping sand and gravel from a submarine borrow site directly onto the island site. The island was built to a height of 4.5 meters (15 feet) above sea level in 3 meters (10 feet) of water.

- Netserk type. Mechanically-placed granular fill was dumped inside and outside a retaining ring of sand bags; the side slopes were 1:3. Netserk B-44 was built in 4.5 meters (15 feet) of water with sand dredged from a borrow site 32 kilometers (20 miles) from the island. A second island, Netserk NF-40, was built in the same manner but in 7 meters (23 feet) of water. Netserk was desinged for year-round drilling.

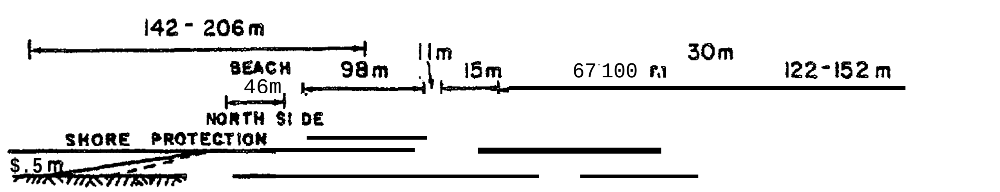
SAND-BAG RETAINED DESIGN - PROFILE 1



SAND-BAG RETAINED DESIGN - PROFILE 2



SACRIFICIAL . BEACH DESIGN



CONSTRUCTION 40-45 DAYS
FILL 1.2 million cu. m (1.6 million cu.yds.)

SOURCE: CROASDALE ANO MARCELLUS, 1977; CROASDALE, 1977.

FIGURE C-16 - TYPICAL ISLAND PROFILES

- Adgo type. Primarily silt was placed within a retaining wall of sand bags by clamshell equipment. Adgo F-38 and P-25 were constructed for winter season operations only and depended upon freezing of silt to provide stable bases for equipment. Adgo F-28 and P-25 were built with a limited freeboard to a mean sea level (MSL) of +1 meter (+3 feet) in 2 meters (7 feet) of water.

Two islands, Adgo C-15 and Pullen E-17, were built during the winter season by trucking sand and gravel over the ice from shore borrow sources to the proposed island sites. Ice was cut and removed in blocks and the excavation backfilled with sand and gravel. Slope protection was provided by small sand bags. The islands were constructed to an elevation of MSL +3 meters (+10 feet) so that they could be used during the summer. In very shallow water in which barge-based equipment cannot operate, this construction method has to be adopted. In the Alaskan Beaufort, all the exploratory islands to date have been of the winter-constructed design using onshore fill materials.

The sacrificial beach design protects the island through gradually sloping (1:20 underwater slope) beaches which force waves to break so that their energy is dissipated before they reach the island. The beach is thus sacrificed to protect the island. Since massive amounts of sand are contained in the beaches, the island will remain intact for several storms* If necessary, the beach material can be replenished by additional dredging.

In the summer of 1976, Imperial Oil constructed two sacrificial beach islands, Anark L-30 and Kannerk G-42 (Engineering Journal, July/August, 1977) . The Anark Island, which is located in 8.5 meters (28 feet) of water, was constructed of local sand borrow using a 32-inch stationary cutter suction dredge. Sand was transferred to the island by floating pipeline.

The Issungnak island currently holds the record for water depth and fill requirements. It is located in 20 meters (65 feet) of water, 25 kilometers (15.5 miles) from shore. The island required 3.5 million cubic meters (4.6 million cubic yards) of fill which was mainly obtained hydropically from adjacent submarine borrow pits using the suction dredge "Beaver Mackenzie". During the 1978 construction season, 1.5 million cubic meters of material were placed on the island by the suction dredge which pumped fill at an average hourly rate of 1,136 cubic meters. Some additional borrow materials were obtained from the Tuft Point site and hauled in by dump scow. Two summer construction seasons were required to complete the island.

In 1975, Imperia? Oil's construction spread in the Beaufort Sea was comprised of (deJong, Stigter, and Steyn, 1975):

24-inch cutter dredge
34-inch stationary suction dredge
five 1,520-cubic meter (2,000-cubic yard) bottom dump barges
three 228-cubic meter (300-cubic yard) bottom dump barges
four 1,500-horsepower tugs
two 600-horsepower tugs
one floating crane
four 5-cubic meter (6-cubic yard) clamshell cranes on spudded barges
one barge loading pontoon
floating pipelines

The equipment requirements for a 20-island, 10-year exploration program are shown in Table C-11.

111.1.2 Construction Materials

The design of artificial islands in the southern Canadian Beaufort Sea has been determined in part by the availability and type of borrow materials. Because the sea bed west of 134°W longitude consists predominately of silt, for which the consolidation process is slow, use of local material is suited only to winter operations when the silt is frozen. Consequently, except in a few cases where local sand was available, borrow material had to be hauled by barge for some distance for island construction. In the construction of Netserk B-44, for example,

TABLE C-n

ARTIFICIAL ISLAND CONSTRUCTION SPREAD

In order to construct and support a 20-island, 10-year program based primarily on caisson-retained islands, Imperial Oil, Ltd. suggest the following (Canada Department of the Environment, 1977):

1977	Stationary suction dredge Cutter suction dredge 4 - 1,500-hp tender tugs 3 - 2,200-hp tugs 4 - 4,000-hp dump barges 4 - 7,000-yd dump barges 3 flat barges 2 floating camps Support equipment
1978	Cutter suction dredge 3 - 1,500-hp tender tugs 4 - 2,200-hp tugs 5 - 4,000-yd dump barges 3 flat barges Floating camp Caisson Barge unloading dredge - caisson filled Support equipment
1979	Add 1 - 2,200-hp tug 4 - 4,000-yd dump barges
1980	Add 1 - 2,200-hp tug 1 caisson 3 flat barges Caisson filling equipment
1981-1986	Same as for 1980

fill had to be hauled 32 kilometers (20 miles). The enormous fill requirements and economics of the sacrificial beach design require that most borrow materials come from sources adjacent to the site.

Representative fill requirements for various types of gravel islands are given in Table C-12.

111.1.3 Ice Action on Islands

The Canadian Beaufort Sea artificial islands have been located in the landfast ice zone, Landfast ice is relatively stable, although movements of several meters (feet) can occur. This amount of movement is sufficient to impose significant loads on fixed structures. Ice action on ice islands has been discussed in detail by Croasdale and Marcellus (1977) and Croasdale (1977), and will be addressed only briefly here.

Islands in shallow, sheltered locations in the Canadian Beaufort (less than 3 meters [10 feet] of water) are not subject to significant ice action since the ice becomes stable soon after freeze-up; subsequent movements are small and slow, with few observable cracks and ridges. Ice movements are believed to be small enough and slow enough to allow the ice to 'flow' or 'creep' around the island.

Ice around these islands during break-up generally melts in place. In summer, the threat of encroachment from the polar pack ice is minimal because the ice with its ridges tends to ground in deep water.

In deeper water at exposed locations in the fall in the Canadian Beaufort, ice takes longer to become truly landfast, and freeze-up is characterized by large ice movements. This causes extensive ice rubble to form around the islands, although the ice is too thin to ride up. When the ice becomes landfast in November or December, ice movements are cyclical and occur on the periphery of the ice rubble which has refrozen in place to form a solid annulus around the island. Initially, the ice fails by bending but as it becomes thicker it fails by crushing. At break-up the ice rubble surrounding the island rapidly melts away, leaving the island

TABLE C-12

ARTIFICIAL ISLAND SPECIFICATIONS AND FILL REQUIREMENTS

A. SPECIFICATIONS OF SOME EXPLORATION ISLANDS CONSTRUCTED IN SOUTHERN CANADIAN BEAUFORT SEA [1]

Island Name	Year	Water Depth meters	Water Depth feet	Fill Volume cu. meters	Fill Volume cu. yards	Freeboard meters	Freeboard feet	Type
Adgo	1973	21	7	38,230	50,000	1	3	Sandbag Retained
Immerk	1973	3	10	183,504	240,000	4.6	15	Sacrificial Beach
Netserk	1974	4.6	15	305,840	400,000	4.6	15	Sandbag Retained
Netserk N	1975	7	23	290,548	380,000	4.6	15	Sandbag Retained
Arnak	1976	8.5	28	1,146,900	1,500,000	5.2	17	Sacrificial Beach
Kannerk	1976	8.5	28	1,146,900	1,500,000	5.2	17	Sacrificial Beach
Kugmallit	1976	5.2	17	237,000	310,000	4.6	15	Sandbag Retained
Isserk	1977	13	43	1,911,500	2,500,000	4.6	15	Sacrificial Beach

B. COMPARISON OF FILL REQUIREMENTS FOR DIFFERENT EXPLORATION ISLAND DESIGNS [1]

Water Depth meters	Water Depth feet	Sacrificial Beach Island cu. meters	Sacrificial Beach Island cu. yards	Retained Fill Island (Sandbags) cu. meters	Retained Fill Island (Sandbags) cu. yards	Caisson Retained Island 30 Ft. Set-Down Depth cu. meters	Caisson Retained Island 30 Ft. Set-Down Depth cu. yards
6	20	611,680	800,000	191,150	250,000	114,690	150,000
9	30	1,299,822	1,700,000	382,300	500,000	114,690	150,000
12	40	1,911,500	2,500,000	688,140	900,000	229,380	300,000
18	60	3,823,000	5,000,000	1,911,500	2,500,000	688,140	900,000

C. ESTIMATED REQUIREMENTS FOR PRODUCTION ISLANDS [2]

Water Depth meters	Water Depth feet	Dimensions	Fill Volume cu. meters	Fill Volume cu. yards
7.6	25	213 meters (700 feet) diameter working surface, 7.6 meters (25 feet) freeboard; 4:1 side slopes	665,202	870,000
15	50	213 meters (700 feet) diameter working surface, 7.6 meters (25 feet) freeboard; 4:1 side slopes	1,376,280	1,800,000

Sources: [1] deJong and Bruce, 1978a and b.
[2] Dames & Moore estimates from various sources.

exposed to potential ice ride-up but such ride-up instead forms rubble on the island beach. Within the landfast ice zone, therefore, ice movement does not appear to be a significant problem. Research into the problem continues since at exposed locations where polar pack ice may encroach, the potential exists for ice ride-up.

111.1.4 Cellular Sheet Pile Island and Caisson Retained Island

A cellular sheet pile island has been proposed as a feasible exploration or production platform for arctic waters (Forssen, 1975). This concept involves a "cells-in-a-cell" arrangement of sheet piling which is filled with clean granular materials. To provide the requisite strength, the fill is allowed to freeze back and, in the case of a permanent production platform, is artificially refrigerated to maintain freezing. Thermopiles could be utilized to accelerate freeze-up of the internal mass.

The minimum size of an exploration island is dictated primarily by the minimum diameter acceptable to resist overturning, sliding, or internal shear failure by ice loadings of up to 703,000 kilograms per square meter (1,000 pounds per square inch); this diameter was determined to be 60 meters (198 feet). In the case of a production island with only the peripheral cells and annular space between the peripheral cells and streamlined bulkhead containing frozen fill, a minimum of 150 meters (495 feet) was calculated. In both the exploration and production island designs, the interlocking cells would be 23 meters (76 feet) in diameter. A freeboard of 8 meters (26 feet) is estimated to be sufficient to resist overtopping by ice rafting.

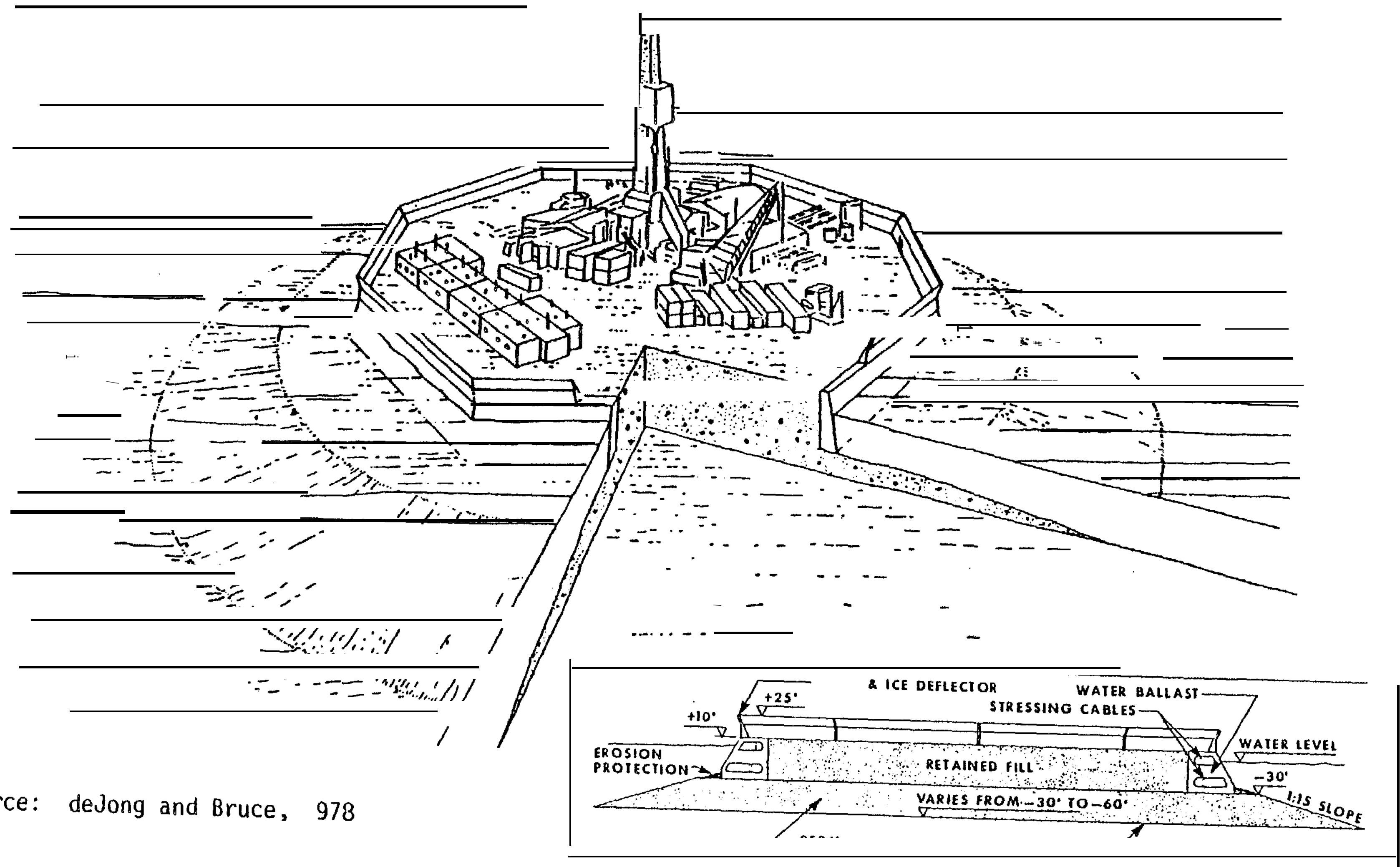
For an exploration island, construction would take 40 to 50 summer days in one continuous operation. Fill would be dredged and barged in, and piling would be taken from onshore stockpiles. The construction spread would include a clamshell dredge, work barge, supply barge, and camp for about 50 men. Construction of a production island would take two seasons and would involve six crews with six driving templates and cranes. As much work as possible would be done on the island from completed cells.

The advantages of a cellular sheet pile island include:

- Reduction of fill requirements (over an artificial island).
- Strength against pack ice movement provided by cellular design and frozen fill.
- Traditional construction techniques and readily available components (piling, soil, ice).

Imperial Oil, Ltd. (Canada) has designed a caisson retained island for exploratory drilling in the Beaufort Sea (deJong and Bruce, 1978a, 1978b) (Figure C-17). The caisson retained island consists of eight trapezoidal ly-shaped caissons, 43 meters (142 feet) long, 12 meters 40 feet) high, and 13 meters (43 feet) wide at the base. The caisson units are upheld together in a ring by two sets of stressing cables. The design of this particular set of caissons is for 9 meters (30 feet) of water with the caissons seated on the sea floor; in deeper water an underwater berm would have to be constructed to an elevation of 9 meters (30 feet) below sea level as a base for the caisson ring. The floating caissons would be towed to the site in one of several possible configurations (single, back to back, rhombic or full octagonal), reassembled to the octagonal configuration and ballasted on to the sea floor or berm. Erosion protection material would be placed in the caisson ring with a hydraulic dredge. The caisson ring is designed so that it can be relocated each year. Disassembly would involve thawing of ice in the ballast chambers, deballasting, removal of caisson connecting pins when the caisson is afloat, and pulling of the two halves of the caisson ring off the island, and transport for reassembly in rhombic configuration. Representative fill requirements for the caisson retained island are given in Table C-12, which demonstrates the significant reduction in fill requirements for this design. The capital costs for the caisson units (delivered) one estimated at $27 million (1978).

While the advantages of the caisson retained island for exploration are re-use and significant fill reduction (over other gravel islands), the



Source: deJong and Bruce, 978

Figure C-17 - CAISSON RETAINED SLAND

caisson retained island also has obvious merit for application as a permanent production island with suitable modification for long term protection from ice and waves.

Imperial Oil has proposed a 20-location, 10-year exploration program mainly using caisson contained islands. These islands would be used principally in water depths in excess of 8 meters (26 feet) or where there is a lack of suitable onsite fill to construct conventional artificial soil islands.

111.1.5 Membrane Contained Island (Hydrostatically Supported Sand Island)

A variant of the artificial island discussed above, which may have arctic applications, is a prototype sand island field tested off the south coast of England in 1976 (Ocean Industry, November, 1976; Dowse, 1979). The island, which could also be classified as a gravity structure, consists of an impermeable rubber membrane filled with hydraulically placed sand supporting a deck unit. The membrane and deck were fabricated on land and towed to the site (at a 15-meter [50-foot] water depth) where the fill was placed. Installation on site took less than 48 hours.

The design of the island is based upon the principle that at any depth below the sea surface, the lateral pressure exerted by the sand is about half that of the confining hydrostatic pressure. Thus, the sand behind the membrane will always be stable, provided pore water pressure is relieved; this is done by dewatering the sand through pumping during placement of the fill and, when necessary, during operation by a permanent pumping system. The dynamic response or energy absorption of the sand island occurs through microstraining of the sand particles. This energy absorption within the sand mass reduces the loading transmitted to the structure foundation.

Unfortunately, the prototype, christened "Sandisle Anne", was destroyed during a storm in October 1976, which brought 10.6-meter (35-foot) waves -- over 50 percent higher than the 6.4-meter (21-foot) waves predicted

(Ocean Industry, December 1976). No costs have been given for construction of this type of sand island.

Two other types of ice-resistant versions of this sand island have been designed. One consists of two concentric retaining walls; the other an outer wall sand structure surrounding a conventional gravity structure. In both cases, the outer sand structure absorbs the shock while the inner concrete or sand column supports the deck. The deck unit would be designed to break ice. More recently, somewhat different designs have been proposed for an arctic production drilling sandisle and arctic exploration drilling sandisle (Dowse, 1979). The production sandisle, designed for water depths up to 61 meters (200 feet) consists of a deck mounted on a number of steel cylinders forming a peripheral ring (about 18 meters [50 feet] high). Primary and secondary membrane bags would be attached to the base of each cylinder. The construction sequence would involve:

(1) Tow in of the deck, with bags attached, on the site.

(2) Anchoring of the deck, inflating the bag with water and installing the drainage system.

(3) Installation of a gravel base layer in the bag, sand filling and pumping.

(4) Completion of sand filling and installation of ground anchors.

As additional protection, a dredged sand berm could be placed around the base of the structure. It is estimated that construction of a 16-ring structure in 81 meters (200 feet) of water could be completed and drained in two weeks. Development drilling would be conducted through the central section of the island. Apart from the novel system of maintaining structural integrity and resisting ice forces, and rapid construction time, a major advantage of this structure is that it significantly reduces fill requirements with its non-vertical walls.

III.2 Ballasted Barges

This technique employs a barge floated to the well location where it is then ballasted to sit on the sea floor. A gabion/sand bag-contained silt berm or sea ice thickening techniques are then used to provide protection against waves and ice.

This ballasted barge technique was used successfully in construction of the Pelly artificial island located in 2.3 meters (7-1/2 feet) of water off the Mackenzie Delta (Brown, 1976). The Pelly island location consisted of a drilling barge, base camp, dredge, and supply barges. The drilling rig was mounted on two rail barges, each 11 x 73 meters (36 x 241 feet), tied together with a superstructure to make a slotted barge 27 x 73 x 4 meters (89 x 241 x 13-feet). The artificial island was constructed with a gabion berm set on to the sea floor to form a rectangle 155 x 164 meters (512 x 211 feet). The berm served as protection against waves and as a retainer for silt fill which was placed around the drilling barge.

The drilling barge system has the advantage of mobility (reuse) and extension of the drilling season beyond that provided by an ice or silt island. The Pelly island used conventional barges; their application is dependent upon their size and draft. Modified conventional barges are, therefore, restricted to a certain depth range which is probably on the order of 1.5 to 5 meters (5 to 7 feet). To use them closer to shore in shallower water would require the dredging of a channel.

The ballasted barge technique could have greater application through the development of a specially-designed drilling barge with a greater depth range capability and possibly, protection against ice movement that would obviate the need for a protective berm.

The ballasted barge concept also has possible application for production facilities in conjunction with gravel or caisson-retained islands. Modularized barge-mounted process units, fabricated in the lower 48, would be towed to the site where they would be ballasted down or docked in a basin located within a partially completed island. A berm or caissons would then be placed around the barge mounted process units. Such a concept is being considered by Beaufort Sea operators in Alaska for production islands.

III.3 Reinforced Ice Platforms[1]

There are two types of reinforced ice platforms that have been produced by thickening of the parent ice sheet through successive flooding of its upper surface. In shallow water, successive flooding and freezing of water on top of the parent ice sheet rapidly thickens and eventually grounds the sea ice. Drilling can then be conducted from the thickened and grounded ice sheet or artificial ice island. In deeper water, this thickening technique has been used to gain the requisite buoyancy to support exploration drilling equipment.

111.3.1 Artificial Ice Island

The "ice island" concept involves the thickening of the parent ice sheet to produce a grounded ice island (MacKay et al., 1975). Factors limiting the usefulness of this concept include:

(1) Water depth.
(2) The rate of movement of the parent ice sheet.
(3) Rate of "artificial" ice growth.
(4) Ice strength properties of artificially grown ice.
(5) Sea floor soil conditions.
(6) Winter access only for construction.
(7) Maintenance required by a quasi-permanent structure.

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(1) Ice platforms and artificial ice islands are probably not feasible in Norton Sound due to large amount of ice movement in most cases, short winter season (relative to the Beaufort Sea) and winter temperature limitations in the amount of possible artificial ice formation. The discussion of artificial ice islands and reinforced ice platforms is included here to provide a comprehensive treatment of Arctic petroleum technology.

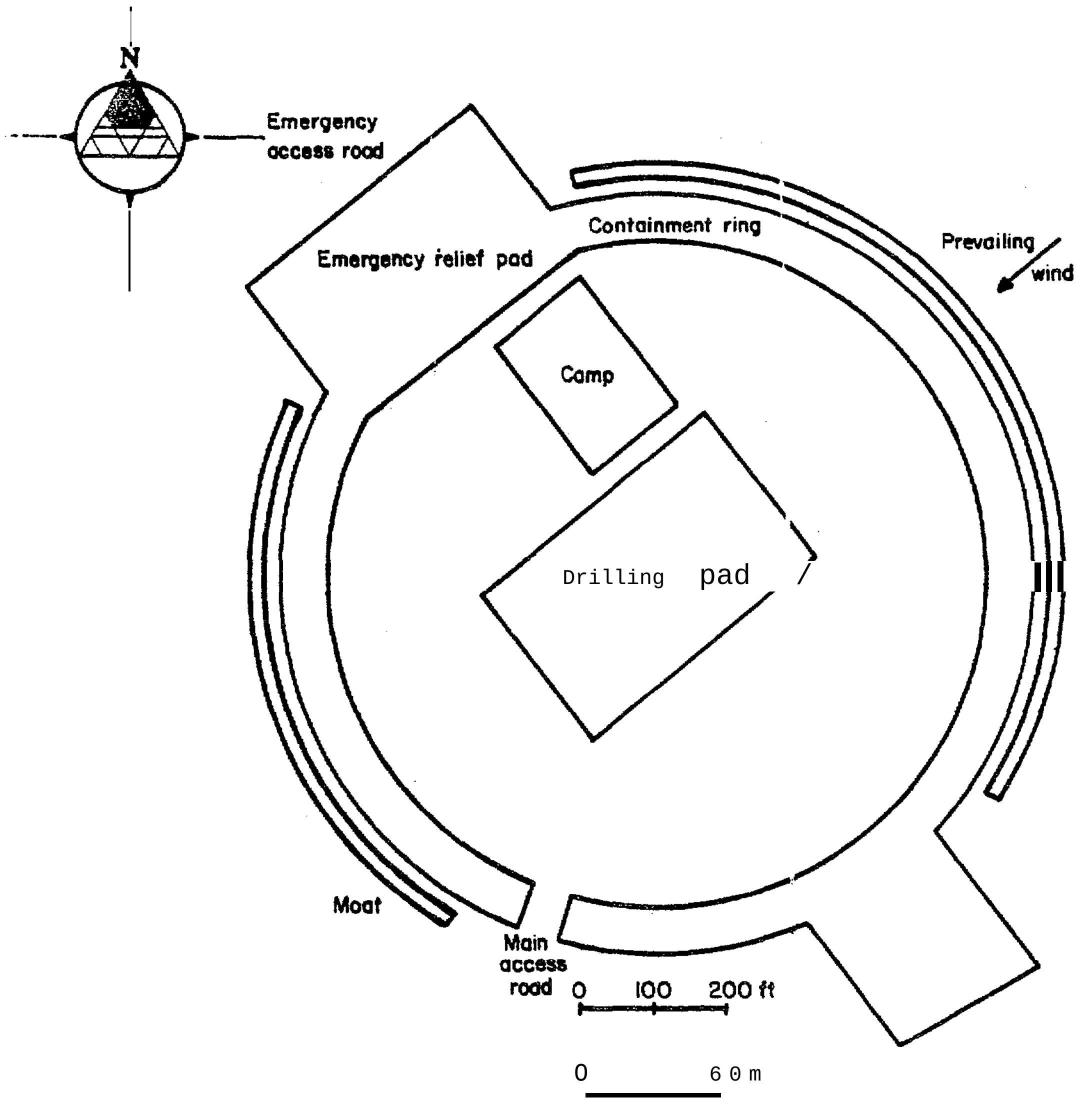
Advantages include minimum environmental impact, relatively low construction cost in comparison to alternative structures, and no removal or minimal restoration cost once the structure has completed its usefulness.

The key to the success of this concept is economical manufacture of high-strength ice at a rapid rate. Since the number of ice-making days is limited (40to 50 days) at 50 percent operating time during Janurary through May), spraying or sprinkling of water has been suggested in order to increase growth rates (Fitch and Jones, 1974). However, in most ice growth concepts, the rate of ice growth appears to be inversely proportional to ice strength in that more brine, which degrades strength, is included in rapid growth.

The most useful offshore areas for this concept appear to be in the landfast ice zone in water depths shallower than approximately 10 meters (33 feet), where sea floor soils are capable of developing adequate resistance to shear forces. Use of an artificial ice island for exploration drilling appears to have more advantages than disadvantages. This seems particularly true for winter exploration inside the barrier islands. The cost of building, an ice island (excluding development costs) has been estimated at less than $5 million (Fitch and Jones, 1974).

In the Alaskan Beaufort Sea, ice islands have been pioneered by Union Oil Company of California, which constructed a prototype during the winter of 1975-76, and an operational island from which an exploration well was drilled during the winter of 1976-77 (Dutweiler, 1977; Oil and Gas Journal, July 11, 1977) (Figure C-18). The operational island was located about 19 kilometers (12 miles) north of Anachlik Island in Harrison Bay about 64 kilometers (40 miles) west of Prudhoe Bay. The island, which was located in 2 meters (8 feet) of water, consisted of an outer ice ring, 140 meters (462 feet) inside radius, and an inner rectangular 'drill pad, 60 x 120 meters (198 x 396 feet). Surface flooding by gasoline-powered pumps in augered ice holes was used to thicken the drill pad from the natural ice thickness of one meter to four meters (3 to 13 feet), i.e. an addition of 3 meters (10 feet).

The outer ring was designed to protect the inner pad from ice movement and act as an containment barrier in case of an accidental spill. The ring was



SOURCE: OIL AND GAS JOURNAL, JULY II , 1977.

Figure C-18 - ICE ISLAND PLAN (UNION OIL) constructed by placing snow berms on both sides of the ring rim and then pumping water in the space to form ice. A 3.5-meter (12-foot) moat was cut around 70 percent of the containment ring and kept ice-free for the duration of drilling as further protection against ice movement.

The drilling rig equipment and supplies were brought to the site by Hercules aircraft (total of 338 trips) which landed on a 2,000-meter (6,600-foot) ice strip 0.6 kilometers (1 mile) from the ice island. The construction spread for both islands was minimal relative to the normal equipment demands of a land-based North Slope exploration well and included bulldozers, clamshell crane, and pumps.

Construction of the ice island took from November 1 to January 15. The well was spudded on February 17, drilling was completed on April 6 and rig down and move-out accomplished by April 16. The island broke up in early July.

As a safety precaution, in the event of movement of the island, the well was equipped with a release mechanism to permit rapid disconnect of the well. At the edge of the ice ring, a second ice pad was constructed as a relief drilling pad in the event a relief well had to be drilled to halt a blowout.

The disadvantage of an ice island is that the island only lasts for one season and can only be used for one average depth well. In addition, in the event of a late-season drilling problem such as blowout, there is not the safety margin that a more permanent structure could provide.

111.3.2 Reinforced Floating Ice Platform

In the Canadian arctic islands, the Arctic Ocean is covered with ice 10 to 11 months of the year. About 12 wells in up to 305 meters (1,000 feet) of water have been drilled off the ice from reinforced ice platforms by Panarctic Oils, Ltd. since 1974. The Panarctic program was pioneered by the Helca N-52 well located off the Sabine Peninsula of Melville Island. It was drilled by a conventional dryland Arctic rig with a subsea blowout preventer (BOP) stack and riser (Baudais, Watts, and Masterson, 1976). The ice sheet was artificially thickened from 2 to 5 meters (7 to 17 feet) by free flooding with sea water over a period of 42 days.

The single most important factor governing the feasibility of drilling from an ice platform is horizontal ice movement. Consequently, such platforms are restricted to areas of landfast ice where horizontal ice movement is not more than 5 percent of the depth of water over the design life of the island. This can be explained by the fact that the three-degree riser angle, which is the maximum that can usually be tolerated in drilling operations, corresponds to a lateral motion in 200 meters (660 feet) of water of 10 meters (33 feet) (Croasdale, 1977). By contrast, in 20 meters (66 feet) of water, the permissible maximum lateral ice motion would be only 1 meter (3 feet). Deep water, therefore, mitigates the effects of any fast ice movement. Conversely, drilling from a floating ice platform in shallow water, such as that which occurs in the proposed State-Federal lease sale area of the Alaskan Beaufort and inner Norton Sound, is generally not feasible.

The main disadvantage of the ice platform system in the Canadian Arctic Ocean around Melville Island and adjacent islands is the time limitation (and hence depth of we? 1 completion) imposed by the length of the season of minimal ice movement (January to May). The [construction completion date of the thickened ice platform is unlikely to be before the end of December. Also, it should be noted that water depth must be great enough that pack ice damage to the BOP stack is not a problem.

To produce the offshore gas reserves that have been discovered at Melville Island, a pilot project involving subsea completion and a subsea pipeline, was completed in 1978.

111.4 Ice-Strengthened Drillships

Dome Petroleum currently has three ice-strengthened drillships operating in the Canadian Beaufort Sea (Jones, 1977) and a fourth was scheduled to join the fleet in August, 1979 (Oilweek, February 26, 1979). The Canmar fleet will then consist of four drillships, seven ice breaker supply boats, three ocean-going barges, a supply vessel, a new class 4 ice breaker (scheduled to join the fleet also in August, 1979), and a leased ice breaker.

The drill ships, which were moved into the Beaufort in the summer of 1976, have the capability of drilling up to 6,000 meters (19,800 feet) in water depths between 30 and 300 meters (99 and 990 feet) (Brown, 1976). They are 115 meters (380 feet) long and 21 meters (66 feet) wide, with a light draft of 4 meters (13 feet) and a drilling draft of 7 meters (23 feet). Each have a dead weight of5,486 metric tons (5,400 long tons). The drillships are anchored at the drill siteith a quick disconnect mooring system which permits rapid release and reconnection of the mooring lines in the event that a move off location is required due to ice or other factors.

The Dome drillships are accomplished by seven ice-breaker supply ships which have the capacity to break up to 1 meter (3 feet) of solid sea ice. Each ship has the following specifications (Brown, 1976; Oilweek, July 3, 1978):

Length	- 63 meters (208 feet)
Width	- 14 meters (46 feet)
Draft	-4.4 meters (14.5 feet)
Cargo capacity	- 1,016 metric tons (1,000 tons)
Horsepower	- 7,000 twin screw
Speed	- 26 kph (14 knots)

Another proposed drillship design is an ice breaking system using a pneumatically-induced pitching system (PIPS) which allows drilling while ice breaking (Ocean Industry, April, 1976; McClure and Michalopoulos, 1977). A detailed description of a Beaufort Sea ice breaking drillship, including design and safety considerations and environmental parameters, is provided by Jones and Schaff (1975).

Ice-strengthened drillships could also be used in winter by maintaining an ice-free "lake" in the landfast ice within which the ship could operate. Methods proposed to maintain ice-free or thin-ice areas up to 300 meters (1,000 feet) in diameter include protective canopies, insulating agents, hot water, air bubble generators, and the use of guardian ice breakers (Jones, 1977).

111.4.1 Drilling Program and Problems

A drilling season of about 112 days from July to October was planned for the Dome ships in 1976. However, in order to leave sufficient time to drill a relief hole in case of an emergency, Canadian authorities limited the drilling season by setting a mandatory completion date before the projected end of the season (Jones, 1977). The 1977 drilling season was longer since the ships wintered in the area at Herschel Island, and drilling could commence immediately upon breakup without waiting for the freeing of the Point Barrow entrance to the Beaufort Sea. From 1976 to the end of the 1978 season, Dome had only been able to drill a total of 135 days (Oilweek, February 26, 1979).

By the end of the 1977 drilling season, Dome's drillships had drilled (completed or partially completed) six exploratory wells in the Canadian Beaufort Sea. In 1977, three wells were spudded: Kopanoar D-14, Tingmiark K-91, and Nektorolik K-59. The original plans required a work barge to install a 6-meter (20-foot) diameter caisson (for BOP protection) before the drillships arrived on location. However, due to problems experienced during preliminary work in 1975, Dome used the simpler technique of placing well heads and BOP stacks in scooped-out depressions in the sea floor out of reach of scouring ice [Jones, 1977).

The Hunt Dome Kopanoar D-14 well was drilled to a depth of 1,150 meters (3,795 feet) but was abandoned aftera high-pressure water flow was encountered which rose to the sea floor outside the casing (OCS Environmental Assessment Program, 1977a). A well was drilled alongside the abandoned casing to the water-producing formation at 558 meters (1,840 feet); by the time the relief well had been drilled, the water flow had ceased of its own accord. Dome was required to reinspect the well, where a small water flow had started again, in the summer of 1977 prior to drilling at the new Kopanoar location (OCS Environmental Assessment Program, 1977b). A replacement well, Kopanoar M-13, was spudded 200 meters (660 feet) away and casing was set at 380 meters (1,254 feet) prior to suspension at the end of the 1976 drilling season (Oil and Gas Journal, June 13, 1977).

The Tingmiark K-91 well was suspended and shut in after a high-pressure natural gas zone was encountered. Subsequently, a leak of salt water was discovered issuing from a fissure in the sea floor 6 meters (20 feet) from the well head.

In 1977, drilling started again at the Kopanoar M-13 and Nektoralik K-59 wells, and a new well, Ukalerk C-50, was spudded. Gas was discovered at all three 1977 wells, and oil was discovered at a depth of about 2,590 meters (8,547 feet) at Nektoralik K-59 (Oil and Gas Journal, September 26 and October 10, 1977). A drilling extension beyond a September deadline for the Nektoralik well was granted priorto the oil discovery by the Canadian government in order to permit Dome to complete drilling through the gas zone and set casing. After operations for the 1977 season were suspended at the Kopanoar M-13 and Ukalerk C-50 gas discovery wells, the drillships were released to set surface casing at the Natsek E-56 and Nerlerk M-98 well locations which had received preparatory work earlier in 1977 prior to the termination of the shallow drilling season at the end of October; (Oil and Gas Journal, October 10, 1977). The 1977 discovery wells were scheduled to be tested in 1978. The water depths at the three 1977 wells range from 27 meters (89 feet) at Ukalerk, 56 meters (185 feet) at Kopanoar, and 63 meters (208 feet) at Nektoralik.

The 1978 season, which ended October 5 as mandated by the Canadian government, involved re-entry of three of the earlier wells and spudding of four new wells. In 1979, re-entry of four of the earlier wells, including the major discovery Kopanoar M-13 (originally spudded in the first season -- 1976), and spudding of four new wells was planned. The Kopanoar M-13 well was completed to a depth of4,485 meters (14,714 feet) and tested at 6,000 b/d of oil from a 61 meter (200 feet) pay zone at 3,505 meters (11,500 feet). To date four oil and gas and condensate discoveries had been made by Dome.

Dome believes that it is technically feasible to drill narly year-round with ice breaker support.

111.4.2 Application to Norton Sound

The use of ice-strengthened drillships permits exploration drilling in deeper water than do artificial islands. However, there is a minimum water depth (about 20 meters [66 feet]) in which drillships can operate due to limitations on lateral motion of the vessel that are dictated by the riser- angle.

Ice-strengthened drillships and conventional drillships will both have application in the Norton Basin lease sale. While water depths in the inner and central sound are generally too shallow for drillships (18 meters [60 feet] or less), water depths in the outer sound -- northern Bering Sea area are within the operational capabilities of drillships.

Although the open water season is longer than that in the southern Canadian Beaufort Sea, the length of the season will still restrict the number of wells that can be drilled (see discussion below). To accelerate the exploration program and field delineation, the use of ice-reinforced drillships with ice breaker support may be economically justified in the northern Bering Sea.

As the Canadian program has demonstrated, it can take up to three seasons to drill and test (in the event of a discovery) an exploration well.

III.5 Ice-Resistant Structures

111.5.1 Monopod

The monopod platform is one configuration of a variety of gravity structures that are grounded on the sea floor after being floated to the site. The base of the platform may be attached to the sea floor by piles. The monopod design was employed successfully by Union Oil for a production platform in Cook Inlet in 1966 where seasonal ice moved by strong currents can be encountered from November to May (Oil and Gas Journal, March 2, 1970). The platform was designed for 20 meters (66 feet) of water, a 9-meter (30-foot) tidal range,. a design wave of 8.5

meters (28 feet) with a period of 8.5 seconds, steady force loads of 21,090 kilograms per square meter (43,200 pounds per square foot), and a bearing area based on a 2-meter (7-foot) ice thickness. The monopod consisted of a single column (in which the wells were located) resting on twin pontoons. The pontoons were connected by horizontal bracing members through which pilings were driven. The drilling deck and production deck, total ling 1,114 square meters (12,254 square feet), were located 33 meters (109 feet) above the pontoons.

The advantages of the monopod are (Croasdale, 1977):

(1) The amount of frontal area that is exposed to moving ice is minimized and does not vary with water depth.

(2) Ice action on the structure involves crushing failure, for which structures in sub-arctic regions such as Cook Inlet have been designed.

(3) An increase in ice forces due to ice freezing to the structure will not be as great as that which might be expected with adfreeze on a sloping surface.

(4) There is no chance of ice-ride onto the platform+s working surface.

Recent research on ice loading in the Beaufort Sea, which indicates that in water depths greater than 10 meters (33 feet) thick multi-year ridges might impose loads as much as 300 MN (67 x 10^6 lbf), coupled with research that indicates conical structures could resist such ice features better than cylindrical structures, would suggest that monopod structures may be of limited use in the Beaufort Sea but feasible in Norton Sound where ice forces are less. Canadian research emphasis has, therefore, been on conical structures.

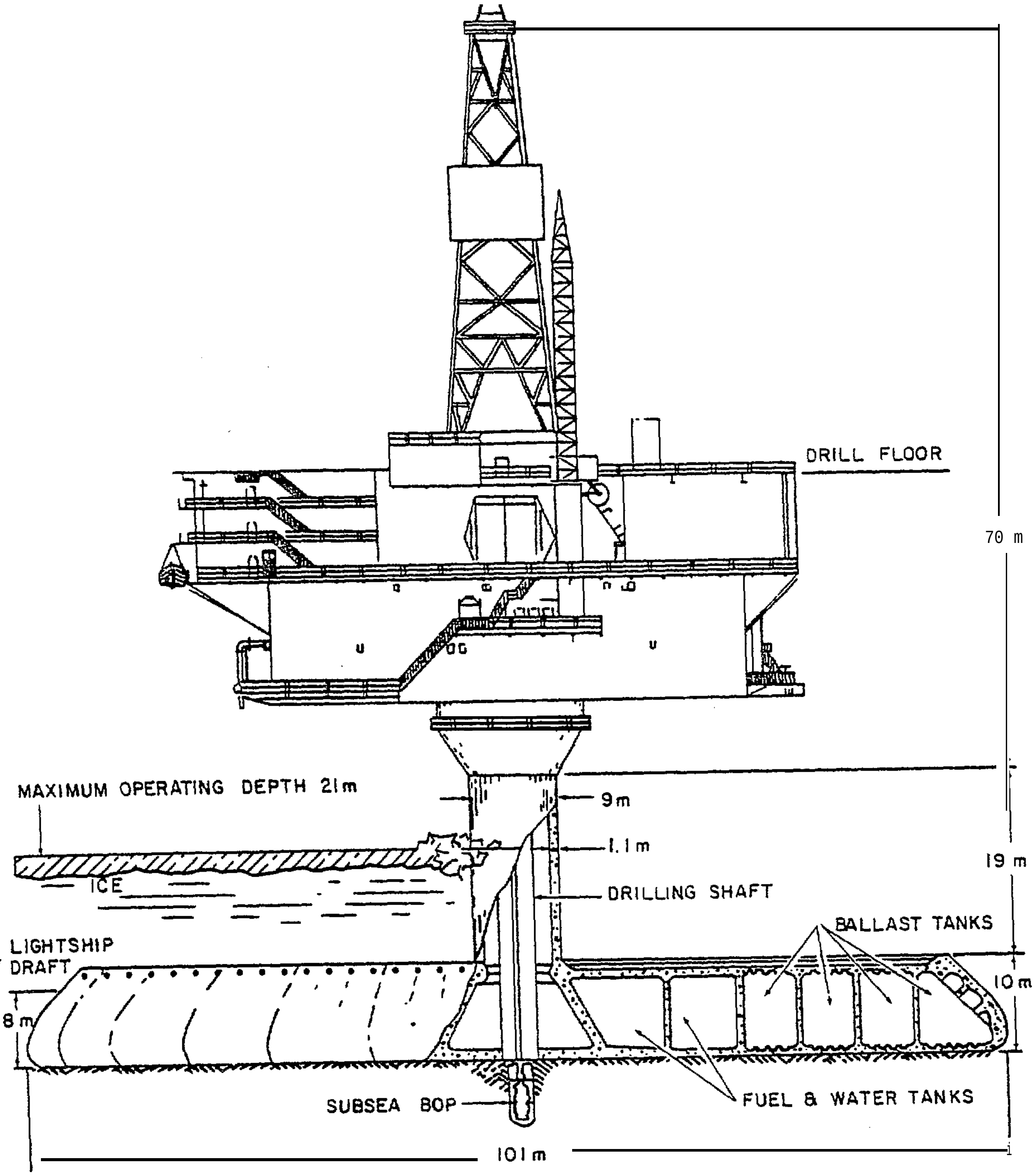
Imperial Oil of Canada has designed a monopod platform for year-round exploration drilling in the southern Beaufort Sea (Brown, 1976). This monopod is a one-legged platform supported by a broad submersible base and is designed for the. environmental and soil conditions existing out to 12-meter (40-foot) water depths. The monopod structure consists of three main components: the hull, shaft, and superstructure. On location, only the shaft is exposed to ice loading since the hull is totally concealed in a previously prepared excavation on the sea floor. The monopod is set down on the sea floor or floated by ballasting or deballasting tanks contained in the hull. Beyond 12-meter {40-foot} water depths, it is postulated that concealment of the hull and pressure-ridge keels is remet e. A similar design described by Jazrawi and Davis (1975) is presented in Figure C-19.

A mobile gravity structure such as the monopod provides operating flexibility for exploration and could probably operate in greater water depths than can he served by gravel islands. All of the well casings must be placed in the single shaft.

111.5.2 Cone

An alternative configuration to the monopod is a cone which causes a moving ice sheet to ride up and fail in tension with both radial and circumferential cracks (Gerwick, 1971). The conical shape reduces the ice force on the structure by causing the ice to fail by bending rather than crushing. This is particularly important in areas affected by multi-year ice ridges. In order to prevent excessive ice ride-up, the cone would recurve at the top beneath the superstructure. A cone structure could be of concrete construction designed to be ballasted on the sea floor.

Considerable research on the cone structure, including model testing with ice, has been conducted by Imperial Oil, Ltd. under a coordinated program of Arctic research sponsored by the Arctic Petroleum Operators Association (APOA). The reader is directed to papers by Croasdale (1975; 1977) , Croasdale and Marcellus (1977), Ralstan (1977), and Pearce and Strickland (1979) for discussions on ice forces and ice interaction with offshore structures such as the cone.



SOURCE: CROASDALE, 1977; JAZRAWI ANO DAVIS , 1975.

Figure C-19

CONCRETE MONOPOD

A variant of the cone design is an "ice island" (not to be confused with a thickened ice sheet), which consists of a 76-meter (250-foot) tall hour-glass-shaped steel-plated platform capable of operating in waters up to 20 meters (66 feet) deep (Oil and Gas Journal, September 14, 1970). The steel plate shell is supported by ice-filled tubes in compartments. The structure is floated to location during the open water season and ballasted to the bottom with seawater, which is then refrigerated to provide the strength for additional resistance to ice forces. Refrigeration requirements have been calculated for initial freezing and for maintenance of the ice through the winter and following summer seasons. To move off location to another drilling site, the frozen fill is thawed, and the internal compartments emptied. The cost of this structure was estimated at $40 million in 1970.

The cone design, unlike many of the options described in this chapter, is one that is being considered for operations outside the landfast ice zone, in areas subject to ice ridge movement (i.e. ground ridge zone and seasonal pack ice zone).

111.5.3 Monotone

A hybrid design of the monopod and cone is the monotone which consists of a monopod within a conical collar attached at the ice line. The monotone configuration is expected to be less expensive in deeper water than a cone and also has a smaller diameter at the water line to keep ice friction and adhesion low.

At the 1979 Offshore Technology Conference specifications on an arctic production monotone were presented (Stenning and Schumann, 1979). This platform has been designed for year-round operation in the Beaufort Sea in medium water depths of up to 76 meters (250 feet) (in the shear ice zone). The structure comprises three basic components: (1) a doughnut-shaped base which can either be a gravity base or piled unit depending on soil conditions, (2) a bottle-shaped superstructure that can be disconnected from the base to avoid ice-island collision, and (3) a removable jack-up deck. The structure pierces the surface with a vertical shaft rather than a sloped cone.

The structure, minus the deck, would be towed to the site vertically (three 9,000 horsepower tugs would be required to tow the monotone at a speed of 3 knots) and ballasted down to the sea floor in several submergence stages. The deck consists of two Integrated barge units which are towed to the site and attached to the shaft and jacked into position. The deck is a four-story, fully integrated unit with an overall dimension of 75 x 58 x 18 meters (150 x 190 x 60 feet) sized for the assumed 120,000 bpd production.

Construction scheduling would involve towing the structure around Point Barrow in the early summer (with ice breaker support) and installation on site, deck installation the same summer and commissioning in winter. This schedule would be somewhat shorter than the offshore construction time for a large North Sea platform. The integrated barge deck combined with the unique jacking system for deck installation minimizes offshore construction time. Specifications and design parameters on the Arctic production monotone are given in Table C-13.

An alternate design involves three slim conical legs supporting the deck.

The arctic production monotone could have application in Norton Sound if ice forces were found to exceed the design capabilities of the monopod and other Cook Inlet-type platforms.

In the Beaufort Sea, the economic cut-off for utilization of a caisson-retained island vs. gravity structure such as the monotone is uncertain. Caisson-retained islands are technically and economically feasible to a maximum depth of about 46 meters (150 feet) assuming adjacent borrow materials. Beyond this depth, gravity structures are the principal economic and technical option. In intermediate water depths (18 to 46 meters [60 to 150 feet], selection of the prefered system would depend upon gravel availability and technical design considerations such as ice movement, sea bottom soils, reservoir characteristics and transportation strategies.

TABLE C-13

SPECIFICATIONS AND DESIGN CRITERIA - ARCTIC PRODUCTION MONOCONE

TABLE 1
WEIGHT SUMMARY

Superstructure:	Weight in Kips
Steel	37,300
Concrete	24,800
	62,103
Piled Base (excluding piles) !	
Steel	26,400
Concrete	9,600
	36,000
Piles (soft clay soil):	
Steel	70,300
Gravity Base (without ballast)	
Steel	32x(3
Concrete	14,300
	46,600
Deck (not including equip. weight):	
Structural Weight of Deck	15,000
Jacking System	500
	15,500
. ..*	
TOTAL STRUCTURE WEIGHT (no equipment):	
Gravity Structure	1?4<200
Piled Structure	183.000

1. **Design Water Depth:** 200 feet
2. **Service Life:** 25 years
3. **Design Temperatures:**
   - Minimum Air Temperature -60°F
   - Maximum Air Temperature +80°F
   - Minimum Water Temperature 27'F
4. **Ocean Currents:**
   - Maximum Surface Current 3 knots
   - Maximum Bottom Current 1,5 knots
   - NOM: Operating currents were taken as 2/3 of Maximum.
5. **Seismic Conditions:**
   - Maximum Firm Ground Accelarations as a percentage of gravity 8.8%
   - Note: This corresponds to NBC zone 3
6. **Sea State:**
   - Maximum Wave Height 35 feet
   - Predominant Wave Period 10 seconds

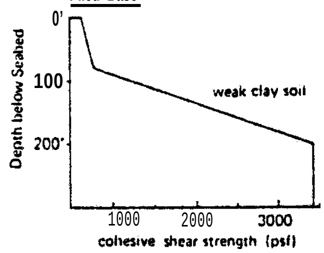
TABLE 2
GENER.,L DESIGN CRITERIA

'. **Soil Condition**

Gravity Base

An over consolidated clay soil with an un-drained shear strength of 2500 PSF.

Piled Base



%.. **Ice Conditions:**

Maximum. A 115' thick multi-year ridge combined with a 10 [hick multi-year ice sheet

Operating. A SO' thick multi-year ridge combined with a 10' thick multi-year ice sheet

9. **Operating Conditions:**

Production Rate: 120,000 BOPD

Required No. of Wells: 40

No. of Wells Drilled per Re-supply: 2

Source: Stenning and Schumann, 1979.

111.5.4 Upper Cook Inlet Type Platforms

Fourteen platforms have been installed in Upper Cook Inlet. Of these, most were four-legged structures, two had three legs, and Union installed a single-legged monopod platform (Visser, 1969). The environmental forces for which these platforms have been designed include: a lateral load of 10,000 kips and vertical load of 10,500 kips. In the final design, wind, wave, and earthquake forces were neglected because they were found to be small compared to ice forces. Tidal variations in Upper Cook Inlet are in excess of 9 meters (30 feet).

To accommodate these environmental forces, Cook Inlet platforms incorporate these design principals:

- Columnar legs without cross bracing and tidal zone, reinforced with concrete inside.
- Risers located within the legs.
- Special "pulltubes" installed within the structural members to reduce dependence on diver assistance in pipeline hook-ups and the amount of underwate welding, and protect pipelines from possible ice damage.

If forces are not significantly greater in Norton Sound, then Cook Inlet type platforms may be the favored platform option. Given the Cook Inlet experience, such platforms can be submerged, piled down, and have deck and modules installed within a four month open water season. Development drilling could commence in the following fall or winter.

111.6 Other Platforms

There are several offshore drilling systems proposed for ice-infested areas that are in the conceptual or design stages.

One such system is a semi-submersible drilling rig design studied by APOA. The design consists of a lower hull located well below the water surface, a monopod column supporting an ice-cutting cylinder, and a superstructure containing the drill rig, crew quarters, etc. The semi-submersible is evisioned to be a self-propelled and dynamically positioned drilling system. In shallow water areas, the semi-submersible system could be employed as a gravity structure resting on the sea floor by ballasting.

Another system is the dynamically positioned floating arctic drilling platform, "Rock Oil", designed by a Norwegian engineer (Ocean Industry, March, 1976). The platform is a partially submerged steel tank in the form of a 32-side rhomb, 11.3 meters (373 feet) in diameter, and with a total height of 120 meters (396 feet) from the bottom of the tank to the top of the drilling derrick, which supports a deck and steel tower. A propulsion system with driving propellers set at the base of the tank 45 meters (149 feet) below water level, coupled with ballasting/deballasting capabilities, would provide the structure with ice breaking capability.

For operation in landfast ice areas, an air cushion drill barge (ACDB) has been proposed (Jones, 1977). The ACDB is a drill rig mounted on an amphibious air cushion platform which can be used on ice or in a lake previously prepared in the ice sheet by removal of ice blocks.

IV. Pipelines

Offshore pipelines in Norton Sound will be laid by conventional lay barge or reel barge equipment in the summer open water season. For the representative distances to shore from hypothetical Norton Sound discovery sites, most trunk lines could be laid in one summer season given an average laying rate of about 1.6 kilometers (1 mile) per day for large diameter lines and up to 3.2 kilometers (2 miles) per day for small diameter lines. If extensive burial was required for the longer lines, i.e. on the order of 128 kilometers [80 miles], however, a project may take more than one season to complete. The maximum offshore pipeline distance that can reasonably be anticipated in Norton Sound is about 128 kilometers (80 miles).

Offshore pipeline design in Norton Sound would have to take into consideration the geologic hazards described in Section 11.2 such as unstable (liquefiable) soils and sand wave zones and ice gouges in shallow water dress dnd at shore approaches. Special insulation would probably be required for pipelines in these frigid waters.

A particular problem for pipelaying activities, as with other offshore construction, in Norton Sound will be the logistics of resupply and the provision of pipe storage and pipecoating facilities. While the Aleutian Islands provide several potential sites for such support bases, supply lines are long and re-supply turnaround correspondingly protracted. Such delay may be preferable, however, to the significant investment costs for a Norton Sound facility with generally unfavorable conditions for port siting. Alternatively, floating support bases, barges, or freighters could be adopted.

V. Offshore Loading

To develop potential Beaufort Sea reserves, Dome Petroleum has proposed a marine delivery system that involves offshore processing and loading of crude or LNG from an artificial island to ice breaking oil or LNG tankers support by an arctic class 10 ice breaker called the "Arctic Marine Locomotive" or AML (Dome Petroleum, 1977, 1978). Dome believes that such a system is economically and technically feasible and preferable to pipelining production to a shore terminal or Mackenzie Valley oil pipeline.

Dome has designed and costed a steel wall earth-filled caisson production/storage/loading island for 21 meters (70 feet) water depth. The structure consists. of an outer ring well wall and inner ring wall with the inter-annular space filled with sand. The caisson modules would be ballasted down on a submerged fill berm about 6 meters (20 feet) high, the outer ring caisson, consisting of 12 modules, would be about 27 meters (90 feet) high, allowing for a 12 meter (40 feet) freeboard, and 55 meters (181 feet) wide, and have a diameter of 244 meters (800 feet). The inner ring consists of a central storage tank with a 3 million barrel capacity, made from 2 to 4 curved modules, and has a diameter of 131 meters (700 feet).

With three million barrels of crude storage and an assumed peak production of 100,000 b/d, the field would be served by two-200,000 DWT ice breaking tankers built to arctic class 7 standards. The ships would operate year-round between the Beaufort field and the U.S. east coast -- 8,385 kilometers (7,525 nautical miles). Each ship would average 12.6 trips per year carrying 1.5 million barrels with an effective delivery rate of 50,000 b/d. An arctic class 10 ice breaker, the AML, would support the tanker operations to assure year-round transportation capability. The 100,000 b/d system would cost about $425 million (1978) including $91 million for the caisson island with processing and docking facilities, $38 million for the crude oil storage tank, and $296 million for two ice breaking tankers.

Dome has also proposed a similar offshore LNG system consisting of a caisson-retained island with modularized liquefaction plant (one BCF capacity in four trains) and three 80,000 cubic meter cryogenic storage tanks. A fleet of eight 125,000 cubic meter ice-strengthened LNG carriers would be required to transport the LNG to a U.S. east coast destination. Total system cost is estimated at $2,290 mil lion (1978).

Dome believes that such systems are technically and economically feasible for the Alaskan OCS areas with significant sea ice.

VI. Application of Offshore Loading in Norton Sound

Most potential discovery locations in Norton Sound are probably within economic pipeline distance to shore (Table 3-2). Generally when discoveries are made close to shore and in the vicinity of other fields, pipelining to a shore terminal is the favored development strategy due to the technical constraints of offshore processing and loading. Furthermore, sea ice would present special engineering design problems to offshore loading hardware over and above those experienced in open-water areas such as the North Sea.

However, in some adverse discovery locations where a field is distant from a suitable shore terminal and remote from other discoveries (with which it could share infrastructure) offshore loading may be a limited option. Two areas of the potential Norton Basin lease sale area are distant from suitable shore terminal sites: the Yukon Delta and the northern Bering Sea mid-way between St. Lawrence Island and the Seward Peninsula.

VII. Production System Selection for Economic Analysis

In an oceanographic comparison with Upper Cook Inlet, on the one hand, and the Beaufort Sea on the other, Norton Sound and adjacent areas of the Bering Sea have certain attributes and problems of both and yet are unique in other aspects. Table C-14 compares the design-related oceanographic conditions of Norton Sound and Upper Cook Inlet. Norton Sound is shallower than Upper Cook Inlet, deeper in general than the Beaufort Sea lease sale area, and has ice conditions in terms of duration intermediate to both. Water depths range from 7.5 meters (25 feet) off the Yukon Delta (i.e. at the three-mile limit) to over 46 meters (150 feet) in the outer sound between St. Lawrence Island and the Seward Peninsula. Pack ice up to 12 meters (40 feet) thick has been reported in the Bering Sea although floe ice within Norton Sound is generally up to 2 meters (6.5 feet) thick. Shorefast ice extends shoreward of the 10-meter (33-foot) isobath. A maximum wave of about 4.3 meters (14 feet) can be anticipated in Norton Sound. These preliminary oceanographic findings, in conjunction with design criteria for Upper Cook Inlet steel platforms, indicate that modified Upper Cook Inlet type-platforms may be feasible for operation in Norton Sound. This conclusion is tentative since sufficient oceanographic data to adequately assess platform design requirements does not yet exist. However, such platforms, as opposed to the monotone proposed for Beaufort Sea operations, may be the more likely development strategy.

Integrated barged-in deck units may be utilized to reduce offshore construction time due to the short summer weather window.

In the shallower waters of the Norton Sound (23 meters [75 feet]), depending upon gravel availability and environmental sensitivity, gravel islands and caisson-retained gravel islands may be technically feasible. Modularized barge-mounted process units, ballasted down and surrounded by gravel berms

TABLE C-14

COMPARISON OF DESIGN RELATED OCEANOGRAPHIC CONDITIONS IN NORTON SOUND & UPPER COOK INLET

Oceanographic Condition	Norton Sound	Upper Cook Inlet
Water Depths	15-49m (50-160 ft.)	9-137m (30-450 ft.) (1)
Tidal Currents	36 $^{cm}/sec$ (0.7 Kts)	420. $^{cm}/sec$ (8 Kts)
Tidal Ranges	0.5-1.3m (1.5-4.2 ft.)	4.9-9.0m (13.8 -29.5 ft.)
Ice Coverage	100% - complete	50-70% - broken
Ice Thickness	2m (6.5 ft.)	1.5m (5 ft.)
Max. Ice Forces	Unknown	21 $^{Kg}/cm^2$ (300 psi)
Max. Sign. Design Wave	6.1m (20 ft.)	8.5m (28 ft.)

(1) Extreme depth near West Foreland; most of Upper Cook Inlet has water depths less than 76 meters (250 feet).

Sources: See references cited in text

or caissons may be the favored engineering strategy for gravel or caisson-retained production islands.

In summary, the following platform types and representative water depths were selected for economic evaluation:[1]

platform Type	Water Depth meters	feet
Ice reinforced steel platform (modified Upper Cook Inlet Design)	15	50
	30	100
	46	150
Gravel Island	7.6	25
	15	50

Pipeline distances representative of potential discovery situations (in the context of geography) were identified for eocnomic screening as shown in Table 3-2. In addition to development cases assuming pipelines to an onshore crude oil terminal for LNG plant, offshore loading from a production/storage/loading island was selected for consideration of the economic analysis for comparative purposes although the costs of such a system are especially speculative.

(1) Subsea completions were not evaluated in the economic analysis due to the great uncertainty of costs for equipment to operate in such a harsh environment. That is not to say subsea completions would not have a role in Norton Sound petroleum development. Subsea completions can be used (1) in conjunction with fixed platforms to drain isolated portions of a field that cannot justify installation of a fixed platform, (2) in conjunction with floating platforms (e.g. North Sea Argyll field --we evaluated such systems in our Gulf of Alaska reports), or (3) as an integral part of complete subsea production system. Year round maintenance and ice scour in shallow water areas are two of the problems that would have to be considered in the selection and design of such subsea systems in Norton Sound.

Given the estimated oil and gas resources of the Norton Basin, all the development options considered in the analysis assumed tankering of crude or LNG to lower 48 markets.

As discussed in Appendix B, construction schedules and manpower estimates developed in this study assumed extensive modularization and integration of onshore and offshore facilities to minimize local construction and speed construction schedules because of the short summer weather window of four to six months.

Exploration and production platform options and their application are summarized in Table C-15.

TABLE C-15

SUMMARY OF EXPLORATION AND PRODUCTION PLATFORM OPTIONS

	Water Depth[1] meters	Water Depth[1] feet	Application of Norton Sound Area/Comments
EXPLORATION			
Jack-up rig	3+	10+	Summer only
Semi-submersible	46+	150+	Summer only, water generally too shallow
Gravel island	0-4.5	0-15	Little of lease sale area in these water depths
Gravel island-summer	3-18	10-60	Use restricted by gravel availability and environmental problems
Caisson retained	9-18	30-60	Use restricted by gravel availability and environmental problems
Monotone	7.6	25-150+	Possible, could extend drilling season (only in design stage)
Drillship	21+	70+	Summer only
Ice-resistant drillship	21+	70+	Yes, could extend drilling season with ice breaker support; most of central and inner Norton Sound too shallow for use of drill ships
PRODUCTION			
Gravel island	3-18	10-60	Use depends on gravel availability and environmental acceptability
Caisson retained island	9-46	30-150	Use depends on gravel availability and environmental acceptability
Monotone	46+	150+	Use depends on ice forces; caisson islands, and other structures may be more economic
Cook Inlet type	6+	20+	Use depends on ice forces

[1] Range of water depths specified reflects technical and probable economic feasibility.

Source: Dames & Moore compilation from various sources (see text).

APPENDIX D

APPENDIX D "

PETROLEUM FACILITIES SITING

I. Introduction

In Norton Sound most, if not al?, the crude will be exported to the lower 48 states. Some oil may be destined for refining in Alaska (e.g. Upper Cook Inlet) but that will also be shipped by tanker due to lack of onshore transportation facilities. Onshore pipeline terminals will serve, therefore, as transshipment facilities. Depending on the type of crude produced, the terminal will complete stabilization of the crude, recover liquid petroleum gas (LPG), treat tanker ballast, provide storage for about ten days production, and have loading jetties for crude and LPG tankers. The cost of the terminal will be borne by the offshore field(s) it serves. Given the U.S.G.S. resource estimates, it is unlikely that a pipeline would be constructed across western Alaska to the Fairbanks area to take Norton Sound crude to the trans-Alaska pipeline (assuming that the trans-Alaska pipeline had surplus capacity, at the time Norton Sound production commenced - Beaufort Sea discoveries may extend the period of full capacity of the pipeline).

Similarly, a western Alaska gas pipeline to take Norton Sound gas to the Northwest pipeline near Fairbanks may not be economically feasible given the estimated Norton Sound gas resources even assuming that the Northwest pipeline can accommodate additional throughput.

Our analysis, therefore, assumes tanker export of crude, and liquefaction of natural gas and tanker shipment to the lower 48. Consequently, an important part of the scenario analysis is the identification of suitable shore sites for crude oil terminals and LNG plants along with support bases for exploration, field construction, and field operation activities.

The requirements for shore facilities in support of offshore petroleum development are extremely varied. It is probably reasonable to assume that if the economics are favorable most adverse siting conditions could be overcome. For example, vessel draft requirements can be accommodated by dredging, extension of piers and offshore loading; the Drift River oil terminal is an example of the latter. Land can be leveled for the construction of facilities; construction of Alyeska's Valdez terminal involved considerable earth and rock excavation. Breakwaters can be constructed to provide sheltered waters. Marine and overland pipelines can be extended to accommodate facility siting. It would be desirable to have road access to marine oil terminal and LNG plants (the principal onshore petroleum facilities that may be required by Norton Sound OCS development) but it is also possible to build these facilities without this transportation convenience and rely more heavily on air and sea transport. Norton Sound's particular constraints to siting include hydrographic limitations, sea ice, and onshore permafrost.

While the most economical shore facility site would probably be that with none of the limitations cited above, facility siting in many cases is a compromise between various technical criteria and environmental and socioeconomic suitability, This analysis, however, focuses on the technical feasibility of sites while Section 11.3 of Appendix C comments on the environmental sensitivity of petroleum development in Norton Sound (subsequent studies of the Alaska OCS Socioeconomic program will evaluate the socioeconomic impacts of various sites).

II. Previous Studies

In response to pending D-2 legislation, the Federal-State Land Use Planning Commission for Alaska contracted for the feasibility assessment for 29 potential port sites in Alaska that could be used to load crude oil (Engineering Computer Optecnomics, Inc., 1977). It was assumed for that study that the trestle lengths would be limited to 1,830 meters (6,000 feet). This restriction, however practical, severely limits the size of tankers that can be accommodated at pierside for most of the Bering/Norton area. Nome and Cape Darby were both evaluated as possible ports; with Nome receiving a slightly higher rating in overall economics. However, several environmental and technical considerations which could significantly impact port development economics were not evaluated in a relative sense. Differences among these factors could become important when other differences are small. While recognizing the magnitude of the problem, we believe that a comparative cost analysis should consider in more depth the technical components than were done in that study.

An in-depth report prepared for the U.S. Department of Commerce by the Arctic Institute of North America (1973) investigated several possible terminal port sites within the Bering/Norton study area. Only one (Lost River) was given a high priority rating while the sites along the north coast of Norton Sound were rated as medium priority. In all cases, the tanker draft requirements were considerably less than those envisaged for the present study, but certainly within the scheme of available options for the transshipment of crude out of the Bering/Norton area. That report stated that an additional advantage of a port at the Lost River location is that it could be used as a multipurpose facility for transporting minerals as well as oil.

Many unknowns concerning construction in the Arctic were addressed in the Institute's report (some of which have been adequately answered by the construction of the trans-Alaska pipeline). As an approach to answering some of the uncertainties, that study suggested the actual construction of an experimental port.

Distance to deep water is a very real concern for the development of marine oil terminals and liquefied natural gas (LNG) plants in the present study area. It appears, and this seems to be borne out by the previous studies, that for very deep-draft tankers 18 to 21 meters (60 to 70 feet) offshore loading must be provided. The 1977 study addressed the economics of a single-point-mooring/storage tanker possibility. Singlepoint-moorings with onshore storage were considered by the 1973 study. These systems would have the capability of' being withdrawn below the level of the ice when not in use. It also mentioned the possibility of a rigid platform for offshore loading.

A study prepared for the Maritime Administration (Global Marine Engineering Company, 1978) assessed the economic feasibility of various transportation systems. For that study a sea-island pier was envisaged. That stricture was composed of standard breasting dolphins and loading facilities but was connected to shore via a buried pipeline rather than with a trestle. These latter two systems probably would prove more reliable.

Suitable sites for the placement of onshore petroleum facilities are limited in the Bering/Norton area. The primary restriction which results in the elimination of most locations is water depth. Marine terminals require depths adequate to service tankers with drafts of about 18 meters (60 feet). To accommodate the vessels in most of the Bering/Norton region would require extremely long trestles, extensive dredging, or a system which employ an offshore loading principle. Most of the lease area close to the Yukon delta region can be eliminated because of this restriction. Also excluded are the eastern portions of Norton Sound and most of the south and east coasts of the Seward Peninsula, including the naturally sheltered Port Clarence. However, even at those sites where depth allows their consideration as viable choices, the loading facilities that will need to be built must be protected from severe ice loading. As was demonstrated in Appendix C, Section 11.1 (Oceanography), there is diverse opinion as to the nature of the ice regime in this area. This apparent data gap will need to be filled prior to petroleum development in the area.

In this siting study, it is assumed that major ice problems are within the state of technology and that the required engineering is economically viable. The sites that are considered herein were selected initially because.: (1) they best conform to the depth limitation, and (2) they are strategically located to best accommodate finds in any portion of the lease area. For example, locations on both St. Lawrence Island and in the Lost River area have been included because, even though these sites have serious drawbacks on several other grounds, they do possess reasonable water depths and are situated in areas that might make them the only ones practical given certain discovery locations.

III. Facility Siting Requirements

Following is a brief discussion of the facilities and their siting requirements (see Table D-l). This is then followed by a description of the sites that have been selected.

111.1 Temporary Service Base

These form the real vanguard of the petroleum complex. Such facilities service the exploration, field delineation, and operation phases. At the exploration stage of development, the industry generally attempts to moderate extensive financial commitment by, when, and where possible using existing facilities. Distances to the marine activities often dictate this approach. In remote areas, such as the Bering/Norton region, existing facilities are extremely limited. A few airports are scattered throughout the area but all, with the possible exception of Nome, would require extensive work to become suitable for continual use by large, heavily-laden aircraft. Docks and harbors would have to be built and in most of the sites housing and associated services would have to be provided. It appears that two options are presently available, both of which have severe limitations. The first is that supply and service to the offshore activities could be handled out of the Aleutian Islands (see discussion in Section IV.7). However, this represents an extremely distant area with turn-around times to be measured in days rather than hours. The other possibility might be to use large barges or semi-submersibles as service bases. These could be located essentially anywhere within the lease area and provide the necessary support to the 'drill rigs. To our knowledge this has not been attempted but appears, at this time, to be a likely option.

111.2 Permanent Service Bases

As the offshore activities intensify, the services provided by a temporary service base must be expanded and/or relocated. A more permanent base, better able to support this increased level of activity, may be required. Several rigs may have to be serviced, communication and transportation links with less remote areas improved, and greater storage provided. Table D-1

TABLE D-1

SUMMARY OF PETROLEUM FACILITY SITING REQUIREMENTS

Facility	Land Hectares (Acres)	Water Depths - Meters (Feet) Harbor Entrance	Channel	Turning Basin	Berthing Area	No. of Jetties/ Berths	Jetty/ Dock Frontage Meters (Feet)	Minimum Turning Basin Width Meters (Feet)	Comments
Crude Oil Terminal[1]									Required space in turning basin can be reduced substantially should tug assisted docking and departures be required
Small-Medium (<250,000 bd)	30 (75)	15-23 (50-75)	14-20 (46-66)	13-19 (42-61)	12-18 (40-58)	1	457 (1500)	1220 (4000)	
Large (500,000 bd)	138 (340)					2-3	914-1371 (3000-4500)	1220 (4000)	
Very Large (<1,000,000 bd)	300 (740)					3-4	1371-1829 (4500-6000)	1220 (4000)	
LNG Plant[2]									In addition to throughput, size of plant will also depend on amount of conditioning required for gas
(400 MMCFD)	24 (60)	13-16 (43-54)	11-14 (37-46)	10-13 (34-42)	10-12 (33-40)	1	304-610 (1000-2000)	1220 (4000)	
(1,000 MMCFD)	80 (200)	13-16 (43-54)	11-14 (37-46)	10-13 (34-42)	10-12 (33-40)	2			
Construction Support Base[3]	16-30 (40-75)	9.1 (30)	6 (20)	6 (20)	5.5 (18)	5-10	304-610 (1000-2000)	304-457 [1000-1500	Requires additional 61 m of dock space for each pipelaying activity being conducted simultaneously and each additional 4 platform installation per year

[1] Trainer, Scott and Cairns. 1976: Sullom Voe Environmental Advisory Group, 1976: Cook Inlet Pipeline Co. . 1978; NERBC, 1976; State of Alaska, 1978.
[2] Dames & Moore, 1974; State of Alaska, 1978.
[3] Alaska Consultants, 1976.

lists the land and depth requirements for such a facility. At times, permanent service bases are simply extensions of a temporary facility, but more often they require a completely separate location in greater proximity to field development.

111.3 Construction Support Base

platform installations and pipelaying operations are generally supported from a construction support base. Table D-1 lists the depth and land requirements for such a facility, assuming it would be land-based. The minimum of 61 meters (200 feet) of berthing space must be increased by another 61 meters (200 feet) for each additional pipeline spread that is operating coincidental with other pipelaying activities from the base. Similarly, increased space would be necessary for every additional platform installation per season.

Seasonal constraints on pipelaying and platform installations are extremely severe in the Bering/Norton Basin. Coupled with the lack of facilities and the expense of constructing them may lead to the use of a floating-type structure to support construction operations. These have already been mentioned as possible substitutes for land-based temporary service bases. Alternately, some construction support facilities, such as pipe storage and pipe coating, may utilize an Aleutian Island site even though resupply turnaround would be significantly lengthened.

III.4 Marine Oil Terminal

The crude product will ultimately be transported to a centralized point for transshipment. Here stabilization of the crude may be completed, LPG recovered, tanker ballast water treated, and storage provided. Marine oil terminals serve these purposes and represent large investments. The number and size of these facilities are dictated primarily by throughput capacity and discovery location.

The scenarios for the Bering/Norton area address several throughput and field location options. Should two major finds occur sufficiently distant from each other, two terminals may be required. The land and depth requirements for marine terminals are shown on Table D-1. Figure D-1 shows a plot of harbor depth and vessel draft requirements as a function of dead-weight tonnage. A study performed by the Global Marine Engineering Company (1978) for the U.S. Maritime Administration indicated that for ice-strengthened tankers the increase in draft to provide the same capacity as conventional tankers would be from 2-4 percent depending on vessel size.

Most of a terminal's land requirements are used for crude oil storage. It is likely that in such a hostile environment as the Bering/Norton Basin, weather could hamper the progress of crude oil loading and vessels in transit more than in any other area heretofore developed. This greater uncertainty about arrivals and departures might require added space for additional storage.

Trestles are a possibility for transporting the crude from the terminal to deep water for loading. Offshore loading, using a marine pipeline from shore, is also a possibility, but it would seem that the severe ice conditions would preclude the use of buoy-type (e.g. Drift River) or compliant structures. Steel platforms built to similar ice-resisting specifications as drilling and production platforms might well serve as an alternative.

111.5 Liquefied Natural Gas Plants

Should dry gas in economic quantities be found, an LNG plant will be required. The alternatives to liquefying the natural gas are flaring, direct distribution to consumers or as feedstock for petrochemical feedstock within the State. Flaring is generally not permitted, there is no market for direct distribution, and a petrochemical plant in this part of Alaska is highly unlikely. Therefore, the scenarios postulated herein assume conversion of non-associated gas to LNG and transport out of Alaska.

Table D-1 also gives the major siting requirements for an LNG plant. As with the marine terminal, land requirements are extremely sensitive to plant capacity. Land requirements for an LNG plant vary according to type of gas and quantity of gas to be processed. A plant with a total

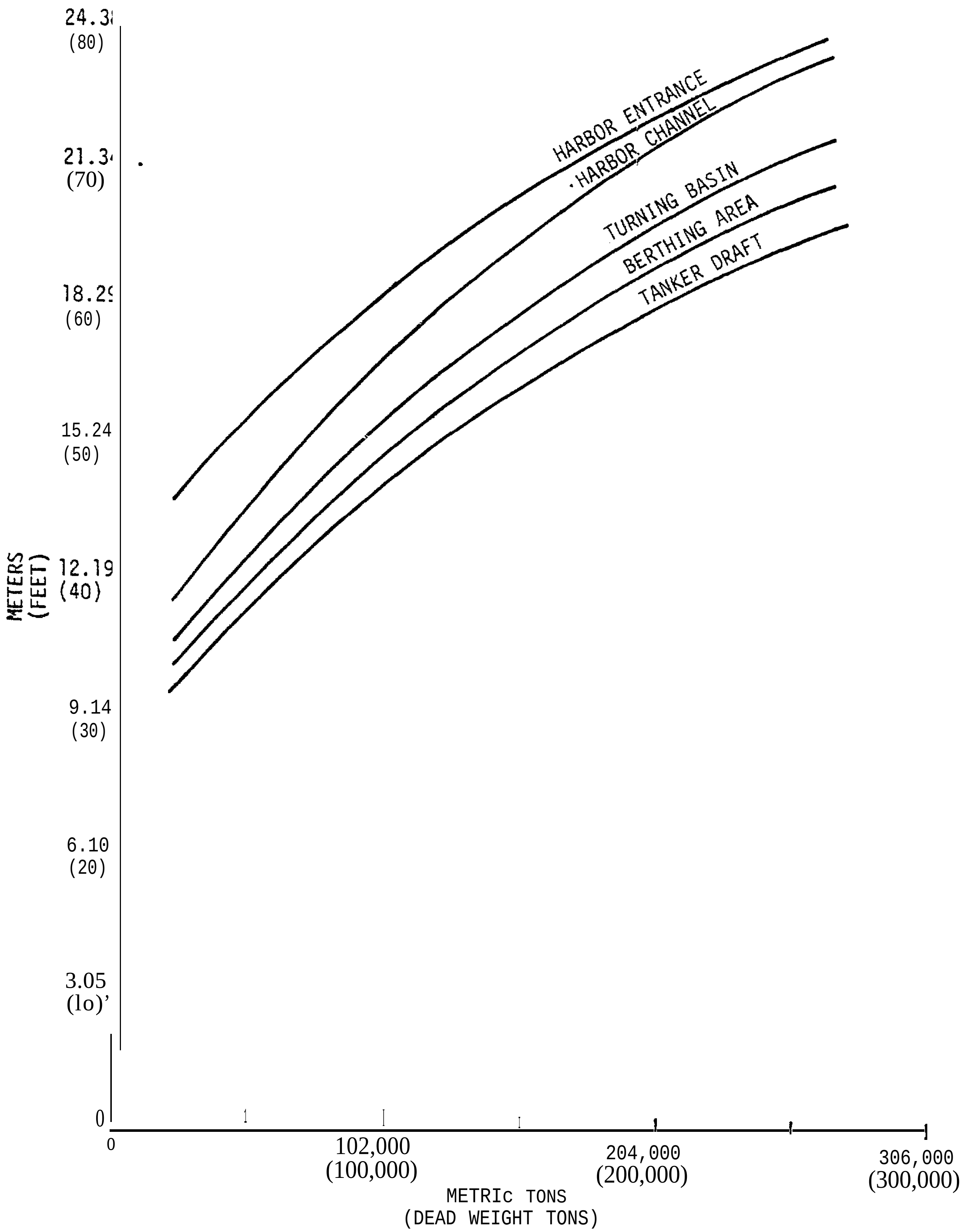


FIGURE D-1
REQUIRED **DEPTHS** FOR TANKERS AT **MARINE** TERMINAL

vaporization capacity of 400 MMcfd of gas would require about 24 hectares (60 acres) of land with an all-weather wharfage. The site should be relatively flat lying, with good drainage. Facilities at the site will include administration facilities, shop and warehouse, utilities, water filtration facilities, sanitary facilities, control house, compressor stations, and a gate house. A plant processing 400 MMcfd would probably require LNG tanks with a total capacity of 1.1 million barrels. Most of the space utilized at an LNG plant is for safety, and storage.

IV. Potential Shore Facility Sites in the Norton Basin Lease Sale Area

IV.1 General

Given the constraints outlined in the previous section, five technically feasible sites have been identified in the Bering/Norton Basin:

- Nome
- Cape None
- Cape Darby
- Northwest Cape
- Lost River

The first three are located on the northern coast of Norton Sound, Northeast Cape is on St. Lawrence Island, and Lost River is west-northwest of Port Clarence. Both Nome and Cape Nome are close to existing transportation and social facilities and while such infrastructure is beneficial, it is not crucial; on-site services and accommodations can be provided.

IV.2 Nome

Sufficient water depths to accommodate deep-draft tankers lie in excess of 4.8 km (3 miles) from shore in the direct vicinity of the City of Nome. Owing to the possibility of extreme ice-loading conditions, this distance appears excessive to permit the construction of trestle-pier-type facilities along side of which tankers could receive oil and LNG from shore. The preponderance of the land nearshore on the south coast of the Seward Peninsula is low-lying and storm surges of several meters have occurred. Coastal activity is quite extensive. Even shore-based service bases would require approximately 1 km (0.6 mile) or more of trestle to reach water sufficiently deep to accommodate vessels of 5 to 6 meter (17 to 20 foot) drafts. Tide ranges are significantly less than 1 meter (3.3 feet) along this coast with flood currents of less than 51 cm/sec (1 knot) being directed to the east and ebb currents to the west. Because of the importance of Nome to any type of development in the Bering/Norton region, this site might be selected to locate onshore facilities provided the distance to the finds did not favor other sites.

At present, the city of Nome has a small boat harbor at the mouth of the Snake River. It has a turning basin 76.2 meters (250 feet) wide and 183 meters (600 feet) long. A 23 meter- (75 feet-) wide entrance channel connects the harbor to Norton Sound. The depth of the turning basin and entrance is maintained to a depth of minus 2.5 meters (8 feet) below mean lower low water (MLLW) by annual dredging. The basin is subjected to sedimentation from both the Snake River and material transported into the harbor from the sound.

To use this facility as a support/construction service base would require a minimum depth of approximately 6.1 meters (20 feet) which would carry out to deeper water. Such a condition would require an extensive amount of dredging which probably would not be economically feasible.

However, another concept to accommodate vessels with similar draft requirements was explored by Gute & Nottingham (1974) in a feasibility study prepared for the Alaska Department of Public Works. The schemes described in that report considered gravel causeways out to a dock at the appropriate water depth. They found that approximately 'a 1000-meter causeway would be required at Nome and a causeway length of less than 500 meters would be necessary at Cape Nome. Mainly for this reason, but also for others outlined in the report, they concluded that the Cape Nome site would be more appropriate for development than adjacent to the city.

The availability of sufficient amount of open space to construct facilities should not be an overriding consideration at either Nome of Cape Nome.

In considering more extensive facility development such as marine terminals or LNG plants, the depth requirements are even more demanding being approximately 19 meters (62 feet) below MLLW. A causeway built to this depth would more than double their length. Perhaps an offshore loading facility could be used with pipelines buried below the depth of ice scour. This would require a well-insulated pipeline in the case of LNG transport, and we do not have data on the state-of-the-art of such an operation.

IV.3 Cape Nome

Located approximately 16 km (10 miles) east of Nome, Cape Nome, is perhaps closer to deep water than Nome by approximately 1.5 km 1 mile). The topography in this area is somewhat higher than around Nome and facilities developed at Cape Nome could utilize the infrastructure provided at the city. Suitable land for potential facilities locations ies immediately to the west of Cape Nome itself (Cape Nome itself is a prominent headland with high cliffs). Currents, winds, and waves and tidal range are essentially the same as those found at Nome. Because of its location relative to the City and the shorter distance to deep water, this area should be considered as a prime candidate for the location of onshore petroleum facilities.

IV.4 Cape Darby

Lying further to the east approximately 130 km (80 miles) from Nome is Cape Darby, on the east side of the entrance to Golovnin Bay. Water depths of approximately 18 meters (60 feet) occur almost at the shoreline in Cape Darby but these are not connected to the deep water on the western side of Norton Sound. Depths of less than 18 meters (60 feet) are encountered between these two deep water regions. The topography is high in this area and steep cliffs border the coastline. Being further toward the inner Sound, ice coverage occurs somewhat longer than at Nome and Cape Nome. The principal attraction of this area is that with a slight reduction in tanker draft, development at Cape Darby would preclude construction of a lengthy pier system or the need for offshore loading systems. A possible disadvantage of Cape Darby is Its location near Golovnin Bay. This bay has been identified as a biologically important area which may suffer severely from either catastrophic or accumulated oil spills.

IV.5 Northeast Cape (St. Lawrence Island)

Most of the land within 2.5 to 3.5 km (1.5 to 2.2 miles) of the shoreline is of low elevation, probably composed primarily of tundra. Judging by the continuity of the barrier islands, it appears that the coastal processes are extremely active. A site probably having a sufficient amount of high ground can be found directly on Northeast Cape. Offshore of this site it appears that sufficiently deep water occurs approximately 3.5 km (2.2 miles) offshore. Since the prevailing winds are from the southwest during the ice-free period, this area should be relatively protected from storm surges and intense wave activity. There is essentially no infrastructure near this site (Nome is 215 km [133 miles] to the northeast). It is ice-free approximately six months of the year.

IV.6 Lost River

The final site considered in this analysis is near the mouth of Lost River lying within the northern portion of the proposed lease area. Its isolated location probably would allow it to be a viable site only if the field(s) was within close proximity. A possible advantage to this site is the continued interest shown over the last few years in developing it as a multipurpose port. This has been suggested principally because of its location relative to mineral-rich areas onshore on the Seward Peninsula.

Deep water lies approximately 2.5 km (1.5 miles) off the shoreline. The shore itself appears to be quite active in terms of sediment transport as indicated by the nearby barrier islands and the spit at the mouth of Port Clarence. Much of the area is low-lying and storm surge could represent a possible hazard. Of the areas selected, Lost River has ice break-up later in the summer and freeze-up earlier in the fall.

IV.7 The Role of an Aleutian Island Support Base in Norton Basin Petroleum Development

The lack of suitable port sites and the presence of seasonal ice make logistics support for offshore drilling, construction and production operations a major problem for petroleum development in Norton Sound.

In the scenarios described in Chapters 5.0, 6.0, 7.0 and 8.0, the possibility has been mentioned of the use of an Aleutian Island port in support of Norton Basin petroleum development activities. For manpower estimation, however, we made the assumption of locally provided support facilities with the expansion of Nome and/or construction of a new support base in the Cape Nome area following significant discoveries; exploration support would be provided by existing facilities at Nome combined with the use of storage barges and vessels moored in Norton Sound. This is, of course, only one possible scenario.

Extensive use of a rear Aleutian Island support base for exploration and field construction (platform installation, pipe-laying, etc.) is also a reasonable possibility. The development of such a facility is better considered, however, in the context of the strategic position of the Aleution Islands with respect to several Bering Sea lease sale areas in addition to Norton Sound including the St. George Basin, North Aleutian Shelf, and Navarin Basin sales which are currently scheduled for 1982, 1983, and 1984, respectively. If major facilities are developed in the Aleutian Islands, they are more likely to be developed in response to the needs of several sales than Norton alone especially for those in close proximity (St. George and North Aleutian).

The advantages of the Aleutian Islands with respect providing support facilities for Bering Sea petroleum development include:

- Existing deepwater anchorages, some with infrastructure, such as Dutch Harbor;
- Numerous deepwater anchorages, including several potential undeveloped sites in the Dutch Harbor area itself;
- Ice-free coastline.

The principal disadvantage of an Aleutian Island support base with respect to Norton Sound is "that Dutch Harbor, for example, is about 1207 kilometers (750 miles) from Nome; this distance represents about 65 hours sailing time (one way) for a typical supply boat cruising at 10 knots. Regular resupply of a platform or pipeline barge would, therefore, tie up a considerable number of boats and make resupply an abnormally expensive operation. Thus one of the major criteria for a supply (service) base site--proximity to offshore fields--is lacking in Aleutian sites with respect to Norton Sound activities. More likely, however, are somewhat different roles than regular direct resupply and service of offshore platforms, pipeline activities, etc. It may be that an Aleutian port would serve as a transshipment point for oil field exploration and construction supplies destined for Norton Sound; until adequate draft facilities were available in the Nome area, supplies could be transferred form large freighters in transit from the lower 48 to shallower draft vessels for transport to Norton Sound. Another possible function of an Aleutian support base would be an extension of the transshipment facility role whereby extensive storage of materials [destined for Norton Sound) brought in by year-round traffic from the lower 48 would be provided. Such material stockpiles would permit optimal use of the short summer weather window in Norton Sound.

It is difficult to predict the role(s) of an Aleutian support base related to Norton Sound with respect to the different phases of petroleum development (exploration, development, production). Support during construction (development) activities in the roles indicated above appears to be more likely than regular resupply functions required by exploration and production activities. Another important role for an Aleutian port may be as an oil transshipment terminal where oil is transformed from ice-reinforced or ice-breaking tankers to conventions? tankers for shipment to the U.S. West Coast as postulated in a report by Global Marine Engineering Company (1978). In terms all the Bering lease sales scheduled for the early mid-1980's, one or more Aleutian port sites will serve as support bases, transshipment facilities, crude oil terminals, and LNG plants. Thus the Aleutian Islands are probably destined to provide a variety of important facilities in the support and development of Bering Sea OCS oil and gas resources even if their role relative to Norton Sound was somewhat more limited than the other lease areas.

IV.8 Results

Selection of these five sites has been made on the basis of limited oceanographic and coastal information; the Bering/Norton region is far removed from areas of active scientific and engineering study. The possibility of significant petroleum finds could well prompt more environmental studies including port site evaluations that would more clearly define potential impacts. The entire Norton Sound region has land-fast ice within a few kilometers of the shore during the winter and, except for Cape Darby, is quite distant from deep water. Nome, Cape Nome, and the Lost River sites are probably prone to periodic storm surges. Northeast Cape (St. Lawrence Island), Lost River, and Cape Darby are isolated relative to existing infrastructure. Cape Nome lies on higher ground and is closer to deep water than Nome. These factors, although certainly not sufficiently complete to make an indisputable priority selection, do suggest the following ranking in order of decreasing technical desirability:

- Cape Nome
- Nome
- Northeast Cape
- Cape Darby
- Lost River

The order of this list could be completely altered depending on the location and magnitude of any petroleum finds. That is, the Lost River site could vault to the top of this list should it be substantially closer to the developing field.

As was discussed in the siting requirements, none of the sites would represent ideal areas for exploration bases. It is probable that no such base would be constructed in the Bering/Norton area; such support would come from an Aleutian base, or converted barges or drilling platforms towed into Norton Sound.

APPENDIX E

APPENDIX E

EMPLOYMENT

I. Introduction

This section provides a general introduction to the subject of manpower requirements for offshore petroleum development as well as the definitions, assumptions, and methods used to generate the manpower estimates for each scenario described in Chapters 5.0, 6.0, 7.0, and 8.0. Refer to these chapters for the results of the analysis described in this section.

II. Three Phases of Petroleum Exploitation

Exploitation of a petroleum reserve involves three distinct phases of activity -- exploration, development, and production. The exploration phase encompasses seismic and related geophysical reconnaissance, wildcat drilling, and "step out" or delineation drilling to assess the size and characteristics of a reservoir. The development phase involves drilling the optimum number of production wells for the field (many hundreds of wells are used to produce a large field) and construction of the equipment and pipelines necessary to process the crude oil and transport it to a refinery orto tidewater for export. The production phase involves the day-to-day operation and maintenance of the oil wells, production equipment, and pipelines, and the workover of wells later in their producing life.

The three phases of petroleum exploitation overlap and all three may occur simultaneously. Exploration for additional fields continues in the vicinity of a newly discovered field as that field is developed and put into production. On the North Slope, for example, where the Prudhoe Bay field is in production, exploratory and delineation drilling will continue for several more years. Development activity typically continues after the initial start-up of production. Operators need to start production as soon as possible to begin to recover expenses of field development (Milton, 1978). In the North Sea, for example, production from some fields was initiated with temporary offshore loading systems while development drilling continued and before underwater pipeline construction began.

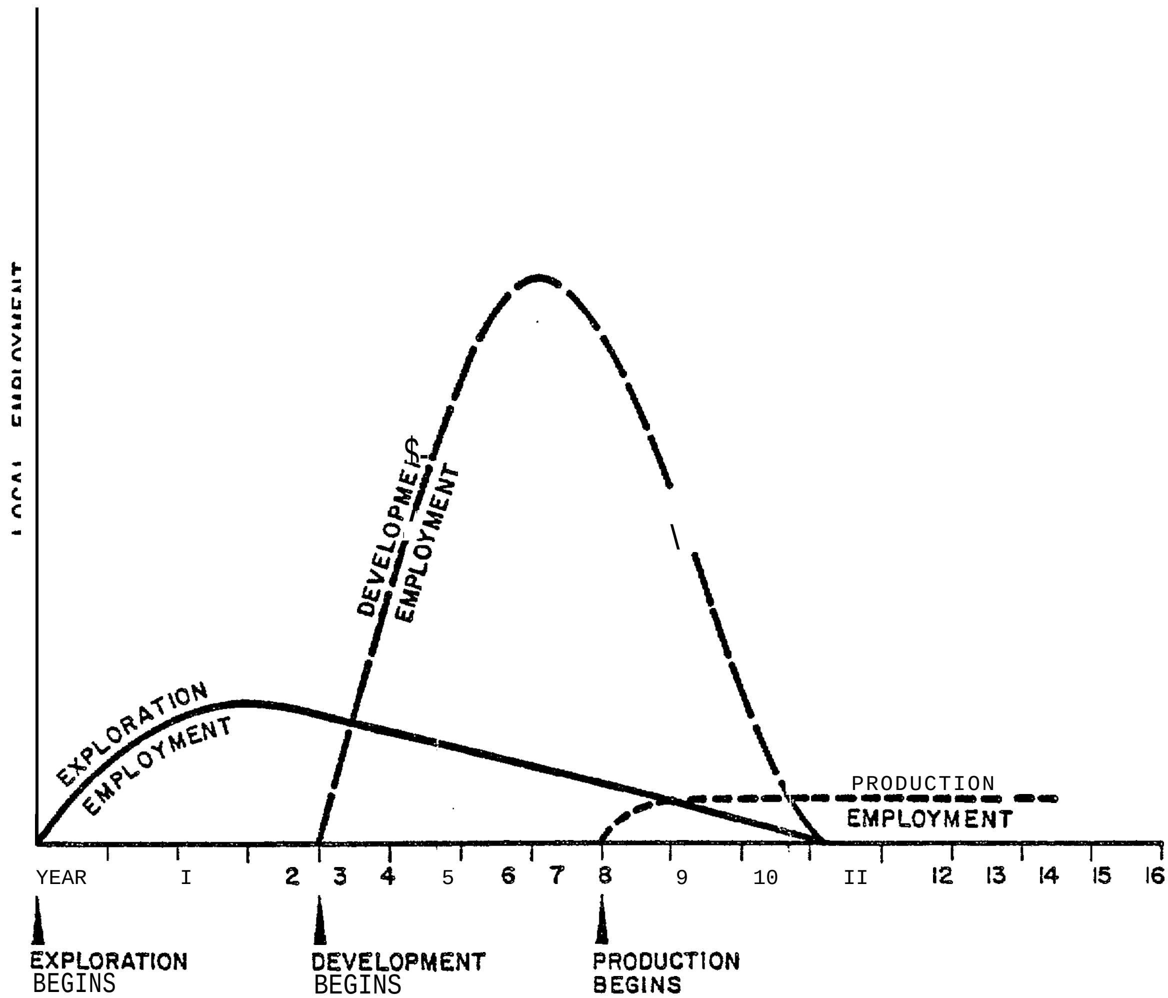
Local employment[1] created by each phase of the petroleum exploitation process tends to have characteristic magnitude and attributes. For example, exploratory work is not particularly labor intensive, and wildcat crews come and go with drilling contractors. Local residents are most likely to benefit indirectly from expenditures made for exploration programs rather than from direct employment in the oil field. The development phase creates the highest levels of employment locally, and much of this employment is in the construction and transportation industries. Labor directly associated with drilling and installing crude processing equipment is highly skilled. Because of automation, the production phase does not require a substantial workforce. This workforce will include many experienced oil field operators recruited from outside the area or transferred from other fields by the owner companies.

Figure E-1 depicts a very general and hypothetical temporal relationship of the exploration, development, and production phases and the relative magnitude of local employment created by each. Particular oil fields differ in their own development schedule and requirements for production and transportation facilities.

III. Manpower Utilization in an Arctic Environment

Although Norton Sound is technically a subarctic region (the entire area is below the Arctic Circle), conditions there are generally similar to

(1) Local employment refers to employment at or near the petroleum reservoir. It does not include the manufacturing and construction employment created away from the site, such as that involved with the building of process equipment and offshore platforms, nor does it include professional, administrative, and clerical work that occurs in regional headquarters (London and Aberdeen in the case of North Sea fields and Anchorage in the case of Alaska fields, for example).



SOURCE: DAMES & MOORE

Figure E-1

LOCAL EMPLOYMENT' CREATED BY THE THREE PHASES OF PETROLEUM EXPLOITATION, A HYPOTHETICAL CASE those of true arctic environments from a point of view of labor productivity and support. The area is remote; freezing temperatures and ice-bound water prevail for much of the year. Generalizations about manpower utilization in arctic environments certainly apply to Norton Sound.

III.1 Expense of Labor in the Arctic

Every effort is made to reduce the amount of manpower required for construction and operation of the facilities in the Arctic because of its very high cost. The high cost of labor in the Arctic is not simply a matter of higher than usual wage rates that must be paid to workers in a remote, inhospitable environment; more significantly, it is because labor in cold regions tends to be extremely inefficient and creates a tremendous burden of support. Efficiency of manual labor in the arctic is reduced by the long hours worked each day (productivity decreases sharply after 8 hours of effort) and the long number of days worked consecutively without a break (efficiency drops as the length of rotation increases). Manual labor performed out of doors during the long periods of cold is slowed greatly by temperature and darkness. It has been estimated that the cumulative affect of these factors can reduce the manual productivity of a worker 250 percent in the Arctic (Chandler, 1978). Indoor work in heated, well lighted buildings in the Arctic and summer out door work, does not, of course, suffer the massive inefficiencies of out door work in the cold and darkness. Overall labor inefficiency means that more manpower is required in the Arctic because either the rate of progress for regular crews is slower than normal or the lower productivity of workers must be offset by more workers.

A workforce in the arctic is also expensive because it requires enormous support: providing food, shelter, and transportation for workers is complicated by distance from urban centers and the long periods of extreme cold and darkness that prevail much of the year. A preliminary design-study by the Department of Public Works Canada of an arctic marine terminal at Herchel Island (Public Works of Canada, 1972) notes that support operations in the Arctic require a significantly greater effort than less severe environments. The study sites the Canadians experience on the Shoran Survey conducted between 1946 and 1957. These surveys were carried out in four distinctly different climatic zones. It was found that in "normally habitable" areas of the subarctic, four tons of supplies were required per man year; elsewhere south of the treeline, eight tons per man year; between the treeline and the arctic mainland coastline in northern Labrador and Quebec and southern Baffin Island, 12 tons per man year; in the Arctic Basin and the Archipelago, 16 tons per man year. Although sealift was used to supply as much of this material as possible, a considerable amount of air freighting was also required. The report stated that placing supplies in the field by sealift cost approximately $0.06 per pound in constrast to $0.50 per pound by airlift (while these costs are no longer applicable, the magnitude of the differential is still representative).

111.2 Labor Saving Techniques

In discussions with industry representatives about the likely technology and construction methods to be used in Norton Sound, they have made it clear that industry will strive to keep field manpower requirements as low as possible through the maximum use of prefabrication and modular construction. Other labor saving techniques may also be available. For example, it is interesting to note that Canadian Marine Drilling, Ltd., (Canmar), is using an ocean-going bulk carrier as a floating supply base for its northern Beaufort Sea exploratory drilling program, and that Imperial Oil is presently using a floating operation headquarters for its artificial island construction program in the southern Beaufort Sea. These floating bases reduce the scale of activity as well as the socioeconomic impact of temporary onshore supply bases.

Initially developed for small scale applications, the modular approach to construction has now been broadened to very large projects. In describing a recent use of prefabricated process equipment modules to build a substantial gas plant in Mexico, Oil and Gas Journal noted these important advantages of the technique:

> Statistics have proven that construction labor is much more efficient in fabrication centers than at typical field construction sites. More than one project is normally in progress simultaneously. Work loads can be leveled. Use of fewer people means less-crowded conditions, which are more efficient and safer.
>
> Another economic advantage is that labor rates in fabrication centers generally are lower than those required to attract labor to a remote plant site where craftsmen must live away from home. Since living in one location is preferable to most workers, a larger labor force is available and better craftsmen can be selected. Quality is improved (Oil and Gas Journal, August 20, 1979).

The article also reported that the gas treatment plant was erected on site in only three months, which was substantially shorter than a conventionally built plant. These savings occurred in a temperate zone, so they would be multiplied at a cold region site.

Modular construction techniques are well known in Alaska. Prefabricated modular oil and gas processing components have been used extensively in the development of offshore petroleum resources in Cook Inlet. Large prefabricated units of processing equipment were also used in the development of the Prudhoe Bay field. If oil fields are developed in Norton Sound, the modular approach to construction will be used extensively, perhaps in ways that are now little more than design concepts. For example a very likely application of the modular approach is the construetion of a LNG plant.

111.3 Prefabricated, Barge-Mounted LNG Plant

It seems likely that if an LNG Plant is required for gas production in Norton Sound, it would be built on a series of barges which would be towed to a protected shore site, post-tensioned together, and moored or sunk on a prepared bed for operation. Conventional LNG plants are extremely labor intensive to build on site; large plants have required in excess of 5,000 workers (Pipeline and Gas Journal, 1977). Floating concrete LNG plants were first proposed by Global Marine for offshore gas fields that could not support the high cost of long submarine pipelines to shore and that were remote from industrial fabrication yards. Engineering and design of barge-mounted LNG plants has progressed to the point that this technique seems feasible for gas fields of modest size. An arctic application of the concept of a barge-mounted LNG plant is currently planned by Petro-Canada to produce gas reserves of the high arctic islands. This scheme involves three ice-strengthened barges that will float in specially constructed land-locked tical slips. A concrete barge mounted LPG plant was recently fabricated in Tacoma by Concrete Technology, Inc. for ARCO Indonesia. The pre-stressed concrete barge measured 142 x 41 x 18 meters (465 feet x 135 feet x 58 feet), and had a capacity of 65,000 tons. The barge-mounted plant was towed to an offshore site in the Java Sea.

For purposes of this report, it is assumed that a prefabricated, floating, shore-based, barge-mounted LNG plant would be used to exploit gas resources in Norton Sound. This assumption lowers considerably the projected development phase manpower requirements from levels that would be created by conventional onsite construction of a LNG plant. In this case, field labor would be limited to that necessary for site preparation, construction of a marine loading dock, an airfield, roadway, and shore facilities including a dormitory-type camp for construction and operational personnel (some of this infra-structure might be shared with other facilities). This construction would probably require two season; and involve a peak work force of some 300 people and a monthly average work force of about 150 people for a large plant. These are, of course, no more than educated guesses of the level of effort required, as there is no previous experience with this technology. Actual manpower requirements would depend upon the capacity of the plant, the number of loading berths, and the length of the loading jetty, the availability of ground water, location and geomorphology of the site, the extent of which support infra-structure was shared and so on.

III.4 Labor Intensive Arctic Construction

Modularization of equipment can greatly reduce field manpower requirements and speed installation of offshore platforms, onshore oil and gas treatment plants, pump and compressor stations, and other facilities that process oil and gas. However, the labor saving modular approach to construction is not applicable to much of the effort required to build pipelines or a marine terminal. Conventional construction techniques must be used for these essential facilities, and in the Arctic, conventional techniques demand more manpower than required in less severe environments[(1)]. This is because of the low productivity of manual labor for much of the year, and because construction is generally more difficult in the presence of permafrost and sea ice.

The experience of the trans-Alaska pipeline has shown that construction of crude oil pipelines in cold regions requires different techniques and significantly more manpower than in temperate zones. Pipe can be burled only in frost stable soil (gravel, sand, or rock), and ditching for large diameter pipe requires drilling, blasting, and removal of spoil by large hydraulic backhoes rather than by one pass of a trenching machine. Select backfill may be required, which means mining, processing, and hauling large quantities of crushed rock or gravel. In permafrost zones the pipe must be built above ground and insulated. Work pads and roads require insulation and considerable gravel overlay. Much work must be done in the winter (for example, river crossings) when labor ineffiency is greatest..

There are only limited opportunities for use of the labor saving modular approach to construction of a marine terminal. Metering and pumping equipment, power generators, and vapor recovery facilities can be prefabricated and shipped to the site as skid-mounted modules. . However, construction of crude oil storage tanks, piping, ballast treatment tanks and facilities, and site preparation are unavoidably

(1) This may not be true of offshore pipelaying in Norton Sound. While special construction techniques may be necessary at landfall to protect buried pipe from ice scour, the process will be a conventional one that uses a standard laybarge spread during the summer, open-water season.

labor intensive. Manpower requirements for construction of tanker berths may be reduced by a design that utilizes prefabricated floating buoys, tressels, and other components, but this segment of the marine terminal will also tend to be labor intensive.

III.5 Construction of Artificial Islands

It is possible that man-made sand or gravel islands may be used for exploratory drilling near shore and for production platforms if commercial discoveries are made in shallow water (artificial islands are discussed in Appendix C). Estimating the manpower needed to construct these items is very difficult because several factors effect the amount of equipment and length of time required for construction. These factors are:

- Size of the island.
- Depth of the water.
- Proximity of suitable fill to island site.
- Clown-time caused by weather and equipment failure.
- Construction technique used (reinforced sandbag, artificial beach, etc.).

The only experience with these islands that can serve as the basis for estimating manpower requirements is that of Imperial Oil, Ltd., which has built over a dozen artificial sand islands in the Beaufort Sea. These islands have been used only as exploratory drilling pads. Thus, they are much smaller and less permanent than islands that would be necessary for production purposes.

Imperial Oil is presently (summer 1979) building the largest of its artificial islands -- a structure requiring from 3.5 million cubic meters (4.6 million cubic yards) of fill in 20 meters (64 feet) of water. The construction spread consists of:

* One 24-inch cutter dredge.

- One 34-inch stationary suction dredge.
- One 20-inch stationary suction dredge.
- Five 2,000-cubic yard bottom dump barges.
- Three 300-cubic yard bottom dump barges.
- Four 1,500-h.p. tugs.
- Two 600-hop. tugs.
- One floating crane.
- Four 6-cubic yard clamshell cranes on spudded barges. Barging loading pontoon, sandbagging machines, and floating pipelines.
- One 320-foot barge fitted with 70-man camp, repsir shop, communications, and office space.
- Several other barges, launches, and auxillary equipment.

Onshore Imperial Oil has a supply base at the village of Tuktoyaktuk, which is also the supply base of Canadian Marine Drilling, Ltd. (Canadian Marine Drilling, Ltd. also uses an ocean-going bulk carrier as a floating supply base.) Personnel at the supply base primarily handle fuel and material. Operations headquarters, communications equipment, repair shop, helicopter crews, and transient personnel are housed offshore in the floating camp located at the work site.

Imperial Oil's 3.5 million cubic meter island will take two seasons of approximately 60 days each to build. This schedule will require an average production rate of 1,215 cubic meters per hour (1,215 x 24 x 60 x 2 = 3,499,200). Last year the largest dredge ("Beaver McKenzie") dredged only 44 of the actual 66 days that it was on site. During that time, it pumped fill at an average hourly rate of 11,036 cubic meters per hour. Non-productive time was caused by mechanical failure (18 days) and weather (4 days).

Rate of progress of the suction dredges depends upon the characteristics of the fill and other factors. A significantly faster rate of production was obtained on another island (Arnak), where at 1.5 million cubic meters of sand was placed in 36 days (an average hourly production rate of over 1,700 cubic meters per hour).

In the middle of the current season, with work progressing on the largest of the islands to date, Imperial Oil has approximately 65 men offshore and about 90 men in the supply base camp at Tuk (this camp has quarters for 120 men) . The rotation schedule varies somewhat among contractors but most employees work 28 days and take 10 days off. This is a rotation factor of 1.35, so the total work force at mid season is in the neighborhood of 210 people. During mobilization and demobilization more manpower is needed, but Imperial Oil reports that at no time has their been over 250 men on site (Butler, personal communication, August 10, 1979).

Labor force estimates for artificial islands in Norton Sound have been based on the foregoing information and additional information about productivity found in technics? articles about these artificial islands (for example, Garratt and Kry, 1978; Riley, 1975; and deJong, Stigter and Steyn, 1975).

IV. Additional Factors Effecting Labor Utilization

The foregoing discussion has identified several factors that can effect labor utilization the low productivity of labor in an arctic environment, the extent of which prefabricated field development components are used (a completely prefabricated LNG plant mounted on barges would greatly reduce field labor requirements), availability of sand and gravel (exploration for and evaluation of subsea borrow material could take a month or more), and weather. Several other factors also influence labor utilization.

One such factor that can influence the utilization of manpower is the construction schedule. To a large degree, manpower can be substituted for time. The decision to complete a project in two seasons instead of three or in one season instead of two, would result in significantly more labor than would be necessary with a more leisurely schedule. Also, it is not unusual for large, remote projects to get behind schedule (schedule slippage) because of delays in material delivery or other unexpected problems. In this case, more labor and equipment are added to the project to speed up progress.

Manpower requirements may also be influenced by environmental stipulations contained in State and federal leases, right-of-way agreements, and permits for various construction activities. For example, stipulations frequently require work in the arctic to be done in the winter in order to protect damage to the tundra surface, interference with migrating fish, etc., and winter work is the least productive for labor. Also, work may be suspended for environmental reasons during the open water months when labor is most efficient.

Because of these and other variables, the manpower estimates in this report are necessarily "best guesses", and the actual manpower requirements of wildcat drilling, field development, and production of oil in Norton Sound could vary significantly from these estimates.

The manpower estimates shown in this report have not been rounded. They are unrounded so that they can be replicated by the reader. Use of these numbers is not meant to imply the level of accuracy of the estimates.

IV.1 Manpower Estimates

Employment estimates for each scenario are generated by a computer model developed specifically for this series of scenario studies., Exploration, field development, and production activities have been broken down into some 38 tasks, such as well drilling, terminal construction, and platform maintenance, for which a reasonable estimate of employment is possible. These general estimates are then matched to the specific characteristics of the activities in each scenario. Thus, the manpower estimates reflect such factors as the number, type and size of shore facilities, miles of onshore pipeline, the number of development wells drilled, etc.

The OCS manpower model is described fully in Section VII of this Appendix.

V. Definitions

It is very important that terms are defined before describing the OCS manpower model in detail. It is interesting to note that although several studies of OCS petroleum impact have now been made which include manpower estimates, neither a uniform set of definitions nor an anticipated methodology has emerged (see, for example, NERBC, 1976). Indeed, no attempt has been made in these to define such basic terms as jobs and employment, and the methods used by them to calculate manpower totals are opaque at best[1]. The following definitions are used in the present study:

Job

A job is a position, such as driller, roustabout, or diver, rather than a specific task or a person who performs the task or fills the position.

Crew

A crew is a group of individuals who fill a set of jobs; a drilling crew, for example, is a group of men who fill generally standardized jobs necessary to accomplish the task of drilling a well. The term crew is also used to refer to an estimated monthly shift labor force (below).

(1) Because terms are not clear, manpower estimates are not readily comparable. It is seldom evident, for example, if all crews are counted (most offshore work has more than one crew on site) and if off site employment is counted.

Estimated Shift Labor Force

This is the average number of people employed per shift per month over the life of the task. This estimate is made when several crews are combined into a composite estimate of workforce size and/or when the task for which an estimate is being made has a fluctuating monthly labor force.

Shift

Shift refers to the hours worked by each crew each day; a normal shift of offshore crews is 12 hours, and there are two shifts per day.

Rotation Factor

The rotation factor is defined as $(1 + \frac{\text{number of days off duty}}{\text{number of days on duty}})$; if a crew worked for 14 days and then took 14 days off, the rotation factor would be two $(1 + \frac{14}{14}$ 2); if a crew worked 28 days and took 14 off, the rotation factor would be 1.5 $(1 + \frac{14}{28} = 1.5)$.

Total Employment

Total employment is the total number of men employed, and it is found by the formula: jobs (crew size) x number of shifts/day x rotation factor; for example, if a new task creates 10 positions, and two crews each work connective 12-hour shifts, and the men work 14 days and take 7 off, then total employment is 30 (10 x 2 x 1.5); thus, total employment includes on site employment and off site employment.

On-site Employment

On-site employment is composed of the workmen who are not on leave rotation, or two complete crews if two shifts are worked per day.

Off-site Employment)

Off-site employment is the group of employees who are on leave rotation and not physically present at the work site.

Man-Months

A man-month is the employment of *one* man for month(1). Thus, a man-month is a measure of work that incorporates the element of duration of work., This unit of measure is necessary to compare labor that varies in length, Suppose a project had three components: component A employed 100 men for two months; component B employed 50 men for three months; and component C employed 80 men for 12 months. To say the project resulted in employment of 230 is to say little about it because there is no indication of how long the employment lasted. Although component C employed only 80 men, it was responsible for over four times as much employment as component A, which employed 100 men for a shorter period (960 man-months vs. 200 man-months).

Measurement of employment in man-months avoids confusion between manpower requirements of a project and the total number of individuals who are involved in it at one time or another over its life. While some workers will work steadily from the beginning to end, many will not,

(1) A month of employment (30 days) can involve very different amounts of work depending upon the hours worked during the week. Notice, for example, that 8,000 man-hours of work are accomplished by 50 men working 40 hours per week for four weeks, while 16,800 *are* accomplished by 50 men working 84 hours per week (equivalent of seven 12-hour days) for four weeks. Both cases might be said to represent 50 man-months of employment, since both *involve* 50 men for one month. However, one could argue that the first case represents 50 man-months and the second roughly twice that amount since men must have a reasonable amount of time to recuperate from their labor. In the case of the OCS employment at hand, men normally work long shifts for long periods, and then have a long rest break. Thus, in the example used above, it. would be likely that 50 men would work 12 hours per day for the first 15 days and then take the second 15 days off, while a second group would rest the first 15 days and work the second 15-day period. This would be the equivalent of 100 man-months (509 men x 1 shift x rotation factor of 2 x 1 month) based *on* a work week of some 40 hours.

Nevertheless, in the example above, there were no more than 50 men physically present on the worksite at one time, nor were there more than 50 men on the employer's payroll at one time. Therefore, on the basis of a definition of a man-month that involves solely the duration of workers' paid presence at the site, there were only 50 man-months of employment.

especially on a long or remote project. Thus, the total number of men employed will be larger than the man-months of effort demanded by the project. For example, a study of field employment during the 1976 summer exploratory drilling program of Canadian Marine Drilling, Ltd. (Canmar) in the Beaufort Sea revealed that 15 percent of the employees worked the entire season and 15 percent worked a week or less. Approximately twice as many people were hired as there were positions (Collins, 1977).

In this report a distinction is made between on site man-months of employment and total man-months. On site man-months represent the number of men physically present at the worksite and on the payroll (workers on leave rotation are not typically paid) during the project.

This number represents actual labor expenditures for tasks (such as building an oil terminal, installing a platform, etc.). Total man-months include on site workers and off site workers. This number indicates the overall labor force requirements of the project. Monthly average total labor force levels -- that is, the monthly average number of men engaged in all phases or work during the year -- can be derived by dividing the total number of man-months x 12[1].

VI. The OCS Manpower Model

Estimated manpower requirements for each scenario presented in Chapters 5.0, 6.0, 7.0, and 8.0 are the product of an employment model originally developed for projecting the manpower requirements of petroleum development in the Gulf of Alaska(2). The model has been

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(1) If on a project that involved one shift per day, a crew of50men worked 12 hours per day for the first half of each month for one year, and a second crew worked for the second half of each month for the year, on site employment would be 600 man-months (50 x 12 months); total employment would be 1,200 man-months (50 men x 2 x 12 months); and the average monthly labor force would be 100 men (1,200 divided by 12).

(2) Northern Gulf of Alaska Petroleum Development Scenarios", Alaska OCS Socioeconomic Studies Program Technical Report No. 29 (Dames & Moore, 1979a) and "Western Gulf of Alaska Petroleum Development Scenarios", Alaska OCS Socioeconomic Studies Program Technical Report No. 35 (Dames & Moore, 1979b).

further refined and adapted for use in Norton Sound[1]. It is assumed that offshore labor requirements for several tasks in Norton Sound will be comparable to those projected for Lower Cook Inlet, but not as large as those foreseen for petroleum development in the Gulf of Alaska, which are more clearly related to the experience of the North Sea. Labor force estimates for construction of onshore facilities are assumed to approximate or exceed those used in' the Gulf of Alaska scenarios, except for LNG plant construction, which is assumed to he a. prefabricated, barge-mounted unit requiring little onsite manpower.

The crew size and length of time required to accomplish a task can vary enormously from one site, or one situation, to another. Requirements for building an oil terminal of a certain capacity, for example, will depend to a large extent upon the site available for the facility. The massive labor requirements of the Valdez terminal built for the trans-Alaska pipeline were due in large part to the need to excavate and reinforce a rock mountainside. Offshore construction activity such as pipelining also depends upon the physical environment (subsea soil conditions, weather, etc.). The uncertainty of these operations is reflected in the fact that construction contracts are typically executed on a reimbursable day rate plus fixed fee basis, since contractors dare not quote a per unit (mile, ton, etc.) basis. The manpower model used in this report is based upon very general assumptions about labor productivity, the physical environment, the range and relative scale of operations, and many other factors.

The scope of employment covered in this model is that which is generated in the field, that is, direct employment on the platforms, on the supply boats, barges, and helicopters, at the shore bases, and at field construction sites if there are any. The clerical, administrative, engineering, and geological work that occurs off the site or away from the shore support bases is not included. Neither is indirect or induced labor included in this analysis.

(1) Special assumptions adapting the OCS model for Norton Sound appear in Table E-la.

VII. Description of Model and Assumptions

For maximum analytical utility, manpower estimates are needed for each month of the year; for onshore as well as offshore employment; for on site as well as off site employment; and for each major industrial sector.

Monthly estimates are required because it is necessary to know employment levels for the months of January and July. Per capita distributions of state revenue sharing programs are based on the populations of municipalities in these months. However, since offshore population cannot be counted for this purpose, nor can off site population (that is, workers on leave rotation), it is also necessary to distinguish between these" categories of employment. Also, for impact analysis generally it is necessary to distinguish between offshore and onshore labor force levels, because offshore workers have very little or no contact at all with the local economy.

To enhance the sophistication of the effort generally and to increase its usefulness for impact analysis, employment is categorized by the four main industries that are involved in petroleum development: petroleum, construction, transportation, and manufacturing. Probably over 98 percent of the field labor associated with the exploration, development, and production of petroleum fall within one of these four Standard Industrial Classification (SIC) sectors(1).

The first step in model building was to identify the basic tasks of each phase of petroleum development that generate significant employment. A unit of analysis, such as a well, platform, or construction spread, was established for each of these labor-generating tasks, which are the basic "building blocks" of the system. Manpower requirements for each unit of analysis were estimated, as were the number of shifts worked each day, and the labor rotation factor for that task. This information is presented in Table E-1.

(1) Environmental engineering consulting services, and contract communications work are sources of minor employment that come to mind that do not fall within these four industrial sectors.

TABLE E-1

OCS MANPOWER **EMPLOYMENT** MODEL

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis' (in months)	Crew Size Unit of Analysis² (number of people) Offshore	Onshore	Number of Shifts/ Oay	Rot at ion Factor	Scale Factor
xplorat ion	A. Petroleum	1. Exploration wel 1	Rig	Assigned	28 0	0 6	2 1	2 1	Crew Size
		2. Geophysical and geologic survey	Crew	5	25 0	0 2	1 1	1 1	N/A
	B. Construction	3. Shore base construct ion	Base	Assigned	Assigned		1	1.11	N/A
		301. Artificial Island	Spread.	Assigned	100	15	2 1	1.5 1.11	Crew Size
	C. Transportation	4. Helicopter for Rigs	Wel 1	Same as Task 1	0	5	1	2	N/A
		5. Supply/anchor boats for rigs	Wel 1	Same as Task 1	26 0	0 2	1 1	1.5 1	N/A
	D. Manufacturing								
envelopment	A. Petroleum	6. Devel opment dri 11 i ng	Platform	Assigned	28 if 1 rig 56 if 2 rigs	6 if 1 rig 12 if 2 rigs	2	2	N/A
	B. Construction	7. Steel jacket installation and commissioning	Pl atform	10	125 0	0 25	2 1	2 1.11	Crew Size
		8. Concrete Installation and commissioning	Pl at form	10	200 0	0 25	2 1	2 1.11	Crew Size
		9. Shore treatment plant	Plant	6	0	40	2	1.11	
		10. Shore base	Base	Assigned	0	Assigned monthly	0 1	0 1.11	Ass i gned
		11. Single leg mooring system	System	' 6	50 0	0 10	2 1	2 1.11	Crew Size
		12. Pipeline offshore, gathering, oil and gas	Spread	Assigned	100 0	0 25	2 1	2 1.11	Assigned
		13. Pipeline offshore, gathering, oil and gas	Spread	Assigned	125 0	0 35	2 1	2 1.11	Assigned
		14. Pipeline onshore, trunk, oil and gas	Spread	Assigned	0	300	1	1.11	Ass i gned
		15. Pipe coating	Pipe coating operation	Assigned	0	175	1	1.11	Crew Size

TABLE E-I (Cent.)

Phase		Task	Unit of Analysis	Duration of Employment/ Unit of Analysis' (in months)	Crew Size Unit of Analysis' (number of people) Offshore	Onshore	Number of Shifts/ Oay	Rotation Factor	Scale Factor
		16. Marine terminal	Terminal	Assigned	o	Assigned monthly	1	1.11	Assigned
		17. LNG plant	Plant	Assigned	0	Assigned monthly	1	1.11	Assigned
		18. Crude oil pump station onshore	Station	8	0	100	1	1.11	Crew Size
		19. Gravel island	Spread	Assigned	100		2	1.5	Crew Size
		20. Gravel, island	Spread	Assigned		15	1	1.11	Crew Size
	C. Transportation	21. Helicopter support for platform	Platform; same as Tasks 7 & 8	Same as Tasks 7 & 8	0	5	1	2	N/A
		22. Helicopter support for lay barge	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	0	5	1	2	N/A
		23. Supply/anchor boats for platform	Platform; same as Tasks 7 & 8	Same as Tasks 7 & 8	39 0	0 12	1 1	1.5 1	N/A
		24. Supply/anchor boats for lay barge	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	65 0	0 12	1 1	1.5 1	N/A
		25. Tugboats for installation and towout	Platform	Same as Tasks 7 & 8	40	o	1	1.5	N/A
		26. Tugboats for lay barge spread	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	20	0	1	1.5	N/A
		27. Longshoring for platform construction	Platform; same as Tasks 7 & 8	Same as Tasks 7 & 8	0	20	1	1	Crew Size
		28. Longshoring for lay barge	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	0	20	1	1	Crew Size
		29. Tugboat for SLMS; (Task 11)	Same as Task 11	Same as Task 11	10	0	1	1.5	N/A
		30. Tugboat for SLMS; (Task 11)	Same as Task 11	Same as Task 11	13	0	1	1.5	N/A
	D. Manufacturing								

TABLE E-1 (Cont.)

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/ Day	Rotation Factor	Scale Factor
Production	A. Petroleum	31. Operations and maintenance (routine preventive)	Platform	Assigned	36 0	0 4	2 1	2 1	Crew Size
		32. Oil well workover and stimulation	Platform	Assigned	15	0	1	2	N/A
	B. Construction	33. Maintenance and Repair for platform and supplyboats (replacement of parts, rebuild, painting, etc.)	Platform	Assigned	8 0	0 8	1 1	2 1	Crew Size
	C. Transportation	34. Helicopters for platform	Platform	Same as Task 31	0	5	1	2	N/A
		35. Supply boats for platform	Platform	Same as Task 31	12	0	1	1.5	N/A
		36. Terminal and pipeline operations	Terminal	Assigned	0	Assigned	2	2	N/A
		37, Longshoring for platforms	Platforms	Same as Task 31	0	4	1	1	Crew Size
	D. Manufacturing	38, LNG operations	LNG plant	Assigned	0	Assigned	2	2	N/A

[1] Different labor force values may be substituted for these if deemed appropriate by site-specific characteristics.
[2] This is the crew size or estimated average monthly shift labor force over the duration of the project. "Assigned" means that scenario-specific values are used, and that no constant values are appropriate,
Additional notes on next page.

Source: Dames & Moore

NOTES TO TABLE E-1

Task	
1	Average 28-man crew per shift on dri 1 ling vessel and six shore-based positions (clerks, expediters, administrators); shift on dri lling vessel includes catering and oi 1 field service personnel. Num-ber of rigs per year is determined by the number of wel is/year x months required to dril 1 each wel 1 divided by the number of months in the drilling season.
2	Approximately one month of geophysical work per wel 1 based on 200 miles of seismic 1 ines per wel 1 at approximately 15 miles/day x 2 (weather factor); 25-man crew and two onshore positions, crew can work from May through September.
3	Requirements for temporary shore base construction varies with lease area.
4	One helicopter per dri 1 li ng vessel ; two pilots and three mechanics per helicopter; considered ons here emp loyment.
5	Two supply anchor boats per rig; each with 13-man crew.
6	One or two dri 1 ling rigs per platform; average 28-man dri ll i ng crew and six shore-based positions per rig; shift on drilling vesses includes catering and oil field service personnel.
7, 8, 9	Includes al 1 aspects of towout, placement, pile driving, module installation, and hookup of deck equipment; also includes crew support (catering personnel).
10	See Table 5-7.
11	This task includes all subsea tie-ins of underwater completions.
12	Rate of progress assumed to be average af one mile per day for all gathering lines; scale factors not applied to gathering line.
13	Rate of progress averages .75 mile per day of medium-sized trunk line in water of medium depth; scale factors applied in shallow or deeper water and for pipe diameter; rate of progress makes allowance for weather down time, tie-ins, and mobilization and demobilization.
14	Rate of progress averages .3 mile per day of buried medium-sized onshore trunk line in moderate terrain; scale factors applied for elevated pipe or rocky terrain and for pipe diameter.
15	Rate of progress for pipe coating is *one* mile/day for 20- to 36-inch pipe; 1.5 mile for 10- to 19-inch pipe.
16	See Table 5-7.
17	See Table 5-7.
20	See Table 5-7.
21	One helicopter per platform.
22	One helicopter per lay barge spread.
23	Three supply/anchor boats per platform.
24	Five supply/anchor boats per lay barge spread.
25	Four tugs for towout per platform; 10-man *crew* per boat.
26	Two tugs per lay barge spread; 10-man crew,
30	One helicopter per platform.
31	Assumed to begin fn first year of platform production (also tasks 33, 34, 35, and 37).
32	Assumed to begin five years after well production.
33	This maintenance activity is assumed to begin two years after start-up of production.
35	One supply boat per platform.

TABLE E-1a
(Attachment of Table E-l)

SPECIAL MANPOWER ASSUMPTIONS FOR NORTON SOUND

Task	Special Assumptions
1	Length of drilling seasons is eight months on the average; ice breakers will allow rigs to operate from April 1 to November 31. Gravel islands will permit year round drilling. Drilling start date on gravel islands is either two months or four months from the start of island construction (see task 301 below).
3	Exploratory drilling will be supplied from Nome.
301	One equipment spread can build an island in 7.5-m (25-foot) water depth in two months, or an island in 15-meter (50-foot) water depth in four months.
6	Assumes 45 days per well, or eight wells per year for both oil and gas production wells.
7	Scale factor of .7.
13	All offshore pipelining is entered under this task with scale factor of .7 and a rate of progress of .4 mile per day (partial months are rounded up) . Productivity shown in the notes to Table E-1 are based on large, modern, highly efficient equipment currently used in the North Sea and Gulf of Mexico. This equipment (e.g. reel lay barges) is very expensive, and because total offshore pipelining requirements in Norton Sound are not large, and because the work season is short, it is assumed that smaller, less efficient lay barges will be used. These will require less manpower <ban the larger equipment spreads.
14	Scale factor of 1.3 because of arctic conditions.
15	Rate of progress assumed to be .75 mile per day (approximately 100 lengths of 40-foot pipe per day or 8.25 per hour). Scale factor is .7. This reduced productivity and manpower is based on underlying assumption in task 13 above.

Crew size or the length of employment for some activities is not influenced by the size of the oil field or physical conditions such as water depth. Transportation crew sizes, for example, are the same for offshore platforms in shallow and deep water for large and small fields. This is not the case with other activities such as platform installation or pipelaying. Here, the size of the field (which determines the size and number of platforms used) and the depth of water are critical determinants of crew size and duration of employment. To account for these variations, a general set of scale factors was used to increase or decrease labor requirements when field size and other conditions required that adjustments be made. Scale factors are shown in Table E-2. Scale factors are applied to the crew size.

Scale factors are a necessary element of the manpower model to reduce to a manageable number of inputs required by it, and also to generate estimates for which specific references are not available in the literature. Scale factors in Table E-2 were derived by a process of trial and error from a wide variety of information about crew sizes and manpower requirements of petroleum activities of a different nature and scale. They represent a single set of factors that seem to best express the relationships that exist between manpower demands of disparate projects and activities. For example, in the case of platform operating personnel (task 31, Table E-1), the small offshore platform of Marathon Oil Company in Upper Cook Inlet (Dolly Varden) has an offshore crew of approximately 23 per shift (46 total, Marathon Oil Company, 1978), while the very large North Sea platforms have crews of approximately 60 per shift (120 total, Addison,1978). Thus, these two crew sizes have a relationship that generally matches the scale factors in Table E-2. They also suggest a crew size for a platform of moderate and large size. The scale factor of 1.0 corresponds to a crew of 35 (derived), a scale factor of .7 corresponds to a crew of 25 (contrasted to 23 of Marathon platform), and a scale factor of 1.7 corresponds to a crew size of 61(1). While the use of a

(1) An actual platform operating crew will depend upon the volume of gas and liquids produced, the extent of secondary recovery (water flood pumps, gas life compressors, etc.), and the extent of primary processing. Even a large near shore platform without secondary recovery could operate with a relatively small operating workforce. Also, a producing platform will have a larger day crew than a night crew (i.e. shifts are not the same size). However, total platform population is divided into two crews of equal size to simplify the modeling of this employment.

TABLE E-2

SCALE FACTORS USED TO ACCOUNT FOR INFLUENCE OF
FIELD SIZE AND OTHER CONDITIONS ON MANPOWER REQUIREMENTS

	Scale Factor	Field Size	Water Depth	Pipelay Conditions Offshore and Onshore
	0.7	Small	Shallow	Easy
(Base Case)	1.0	Moderate	Moderate	Moderate
	1.3	Large	Deep	Difficult
	1.7	Very Large	Very Deep	Very Difficult

Source: Dames & Moore

single general set of scale factors introduces a measure of distortion into the manpower estimating process, the distortion seems to be within an acceptable overall range of accuracy.

Occasional deviation from the scale factors in Tables E-2 is necessary, as for example in the construction and operation of major onshore facilities which do not appear to have a simple, linear relationship between project size and labor force requirements. Also, in the case of these onshore facilities, monthly construction labor force levels vary greatly, so it was necessary to develop complete sets of monthly employment figures. These estimates are shown in Tables E-3a and E-3b. The numbers in Tables E-3a and E-3b are general estimates derived from available infor- information about the length of construction, peak" workforce, and operating crew size in similar facilities [1]. It was assumed that peak employment on a construction project of this type would reach a brief plateau of approximately midway through the project, and that it would steadily increase prior to the peak and steadily decrease after the peak had been reached. Thus, a graph of the manpower requirements for these projects would generally approximate an equilateral triangle with a blunt tip. This assumption allowed monthly manpower estimates to be calculated once the peak level and construction period were identified.

Identifying typical crew size and reasonable monthly average workforce levels for the various labor-generating activities constituted the major research task. Information was obtained from many sources -- trade journals (advertisements as well as articles), industry equipment specifications, interviews with contractors experienced in offshore work, government studies including offshore petroleum impact assessment, professional papers, and cost estimating manuals.

(1) Among the more helpful references are: Sullom Voe Environmental Advisory Group (1976); El Paso Alaska Co. (1974); Dames & Moore (1974); Crofts (1978); Akin (1978); Pipeline and Gas Journal (1978a); Larminie (1978); Addison (1978) ; Duggan (1978); Trainer et al. (1976); Alaska Construction (1966); Alaska Construction (1967b); Bradner (1969). These sources provided information about peak workforce levels and/or construction periods for oil terminals or LNG plants. Shore base construction estimates in Tables 5-6a and 5-6b are by Dames & Moore.

TABLE E-3a

MANPOWER ESTIMATES FOR MAJOR ONSHORE FACILITIES, SUMMARY[1]

Facility	Size	Approximate Capacity	Duration of Construction	Approximate Peak Construction Employment (number of people)	Operating Personnel (Crew Size)[2]
Oil Terminal (BD)	Small	200,000 minus	18	350	16
	Medium	200,000 - 500,000	24	750	42
	Large	500,000 - 1,000,000	36	1,200	55
	Very Large	1,000,000 plus	36	3,500	70
LNG Plant (MMCFD)	Small	500 minus	24	400	20
	Medium	500- 1,000	24	800	30
	Large	1,000 - 1,500	36	2,000	50
	Very Large	1,500 plus	36	4,000	125
Shore Base (field production in MMBD)	Medium	1.5 minus	12	400	--
	Large	1.5 minus	16	700	--

[1] Monthly manpower requirements presented in Table E-3b.
[2] Two shifts and a rotation factor of two are assumed.

Source: Dames & Moore

TABLE E-3b

MONTHLY MANPOWER LOADING ESTIMATES, MAJOR ONSHORE CONSTRUCTION PROJECTS

Facility: Oil Terminal
Size: Small
Duration of Construction: 18 months
Approximate Peak Employment (number of people): 350

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Workers:	39	78	117	156	195	234	273	312	351	351	312	273	234	195	156	117	?8	39

Facility: Oil Terminal
Size: Medium
Duration of Construction: 24 months
Approximate Peak Employment (number of people): 750

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	62	124	186	248	310	372	434	496	558	620	682	744	744	682	620	558	496	434	372	310	248	186	124	62

Facility: Oil Terminal
Size: Large
Duration of Construction: 36 months
Approximate Peak Employment (number of people): 1200

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	67	134	201	268	335	402	469	536	603	670	73?	804	871	938	1005	1072	1139	1206	1206	1139	1072	1005	938	871

Month:	25	26	27	28	29	30	31	32	33	34	35	36
Workers:	804	737	670	603	536	469	402	335	268	201	134	67

Facility: Oil Terminal
Size: Very Large
Duration of Construction: 36 months
Approximate Peak Employment (number of people): 3500

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	194	388	582	776	970	1164	1358	1552	1746	1940	2134	2329	2522	2716	2910	3104	3298	3500	3298	3298	3104	2910	2716	2522

Month:	25	26	27	28	29	30	31	32	33	34	35	36
Workers:	2328	2134	1940	1746	1552	1358	1164	970	776	582	388	194

Facility: Barge-Mounted LNG Plant
Size: Small
Duration of Construction: 12 *months*
Approximate Peak Employment (number of people): 150

Month:	1	2	3	4	5	6	7	8	9	10	11	12
Workers:	25	50	75	100	125	150	150	125	100	75	50	25

TABLE E-3b (Cont.

Facility: Barge-Mounted LNG Plant
Size: Medium
Duration of Construction: 16 months
Approximate Peak Employment (number of people : 225

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Workers:	28	56	84	112	140	168	196	225	225	196	168	140	112	84	56	28

Facility: Barge-Mounted LNG Plant
Size: Large
Duration of Construction: 20 months
Approximate Peak Employment (number of people): 300

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Workers:	30	60	90	120	150	180	210	240	270	300	300	270	240	210	180	150	120	90	60	30

Facility: Shore Base
Size: Smallm
Duration of Construction: 8 months
Approximate Peak Employment (number of people): ?5

Month:	1	2	3	4	5	6	7	8
Workers:	44	88	132	175	175	132	88	44

Facility: Shore Base
Size: Medium
Duration of Construction: 12 months
Approximate Peak Employment (number of people : 300

Month:	1	2	3	4	5	6	7	8	9	10	11	12
Workers:	50	100	150	200	250	300	300	250	200	150	100	50

Facility: Shore Base
Size: Large
Duration of Construction: 16 months
Approximate Peak Employment (number of e): 4°°

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Workers:	50	100	150	200	250	300	350	400	400	350	300	250	200	150	100	50

A computer was utilized to calculate and sum the manpower requirements for each scenario. It used the following basic formula for each task, all of which were coded by industry:

Number of units x crew size x duration of task x number of shifts x rotation factor x scale factor

The information in Table E-1 comprises the framework of the computer model. For each task, inputs were provided for the number of units, the starting year and month, and if necessary the duration of employment for the unit. Because most tasks involved units which started and ended at different times, a separate entry was usually required for each unit. For example, platforms are built and go into production at different times, so each platform was entered separately with approximate dates, lengths of operation, scale factors, etc.

Off site employment is derived from the rotation factor. If the rotation factor is two, then one-half of the total manpower requirement for the task would be off site each month; if 1.5, one-third would be off site each month; and if 1.11, slightly more than ore-tenth would be off site each month.

Transportation requirements are triggered by petroleum and construction activity. Thus, the input for number of units, starting dates, and duraation of work for the transportation tasks were tied to the same inputs for each petroleum and construction task. For example, each pipelaying spread requires tug and supply boat service for the same length of time the spread is working. Thus, for each pipelaying spread entered (tasks 12 and 13), its transportation requirements were automatically calculated and assigned to the same months.

A hand calculated example that illustrates in detail the computations made by the model is presented in a companion report(1).

(1) Alaska OCS Socioeconomic Studies Program, Northern Gulf of Alaska Petroleum Development Scenarios, Appendix D, Dames & Moore, 19/9a).

Summary employment tables in Chapter 2.0 show total man-months of labor for each year. Employment for each month has been calculated separately and is available if needed.

VIII, Alternative Scenario Manpower Estimates and Scenario Specifications

After completion of a draft of this report, certain modifications were made to the OCS manpower model and scenario oil and gas Production specifications that warranted a second run of the computer model.

The modifications to the manpower model are contained in Tables E-4 (Revised Table E-l), E-4a (Revised Table E-la), and E-5 (Revised Table 8-17). The principal modifications include:

- Introduction of seasonality assumptions into platform maintenance and resupply activities (Tasks 31, 33, and 35);
- Reduction in the numbers of helicopters servicing platforms and related employment (Task 30);
- Reduction of onshore freight handling employment for platforms (Task 37).

These revisions mainly affect onshore service base employment which is reduced as a result.

The second set of factors that have altered the scenario employment estimates are changes in the scenario oil and gas production specifications. Some explanation is required.

The scenario oil and gas production flows shown in Tables 6-12, 6-13, 7-12, 7-13, 8-12, and 8-13 do not reflect rigid application of the results of the economic analysis to production flows. The production profiles have not been cut off when the field economic limits have been reached, i.e., when incremental per barrel costs first exceed incremental per barrel revenue. The calculated field shutdown points are as follows:

11.5 BCF/year - Single gas platform system
23.0 BCF/year - Two gas platform system
2.2 MMBBL/year - Single oil platform system
4.4 MMBBL/year - Two oil platform system
6.3 MMBBL/year - Three oil platform system

Applying these cutoffs to the field producing profiles (the tota? resources of the fields equals the U.S.G.S. resource estimate) would have "produced" approximately 3 to 4 percent less oil and gas than the USGS estimates. Conversely, to "produce" the total USGS resource estimates would have required total field reserves somewhat larger than the USGS estimate.

Applying the economic results to the scenario production statistics causes field production to be terminated somewhat earlier and the aggregate production to be reduced in later years as shown in Tables E-6, E-7, E-8, E-9, E-10, and E-n, which are revisions of Tables 6-12, 6-13, 7-12, 7-13, 8-12, and 8-13. In turn, the operational life of the platforms and major shore facilities is reduced as shown in Tables E-12, E-13, E-14, E-15, E-16, and E-17, which are revisions of scenario Tables 6-11, 6-17, 7-11, 7-14, 8-11, and 8-14, respectively.

These scenario specification changes, along with the OCS manpower model modifications, were entered in the computer to produce an alternative set of manpower estimates for the scenarios. The overall reduction in manpower requirements reflects the sensitivity of the model to changes in assumptions about the ability to conduct resupply operations year-round by sea. The reduction also reflects the significant changes that can result in what would appear to be a relatively minor reduction (3 to 4 percent) in the oil and gas produced. The main reason for this significant impact is that reduction or cutoff of production occurs at the tail end of the field lives where the impact is greatest,

The alternate manpower estimates based on these modifications for the scenarios described in Chapters 5.0, 6.0, 7.0, and 8.0 are presented in Tables E-18 through E-33.

TABLE E-4

OCS MANPOWER EMPLOYMENT MODEL

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/ Day	Rotation Factor	Scale Factor
ploration	A. Petroleum	1. Exploration well	Rig	Assigned	28 0	0 6	2 1	2 1	Crew Size
		2. Geophysical and geologic survey	Crew	5	25 0	0 2	1 1	1 1	N/A
	B. Construction	3. Shore base construction	Base	Assigned	Assigned		1	1	N/A
		301. Artificial Island	Spread	Assigned	100	15	2 1	1.5 1.1	Crew Size
	C. Transportation	4. Helicopter for Rigs	Well	Same as Task 1	0	5	1	2	N/A
		5. Supply/anchor boats for rigs	Well	Same as Task 1	26 0	0 2	1 1	1.5 1	N/A
	D. Manufacturing								
Development	A. Petroleum	6. Development drilling	Platform	Assigned	28 if 1 rig 56 if 2 rigs	6 if 1 rig 12 if 2 rigs	2	2	N/A
	B. Construction	7. Steel jacket installation and commissioning	Platform	10	25 0	0 25	2 1	2 1.11	Crew Size
		8. Concrete Installation and commissioning	Platform	10	200 0	0 25	2 1	2 1.11	Crew Size
		9. Shore treatment plant	Plant	6	0	40	2	1.11	
		10. Shore base	Base	Assigned	0	Assigned monthly	0 1	0 1.11	Assigned
		11. Single leg mooring system	System	6	50 0	0 10	2 1	2 1.11	Crew Size
		12. Pipeline offshore, gathering, oil and gas	Spread	Assigned	·00 0	0 25	2 1	2 1.11	Assigned
		13. Pipeline offshore, gathering, oil and gas	Spread	Assigned	25 0	0 35	2 1	2 1.11	Assigned
		14. Pipeline onshore, trunk, oil and gas	Spread	Assigned	0	300	1	·1.11	Assigned
		15. Pipe coating	Pipe coating operation	Assigned	0	175	1	1.11	Crew Size

TABLE E-4 (Cont.)

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit OF Analysis[2] (number of people) Offshore	Onshore	Number of shifts/ Day	Rotation Factor	Scale Factor
		16. Marine terminal	Terminal	Assigned	0	Assigned monthly	1	1.11	Assigne
		17. LNG plant	Pl ant	Assigned	0	Assigned monthly	1	1.11	Assigne
		18. Crude oil pump station onshore	station	8	0	100	1	1.11	Crew Size
	."	19. Gravel island	Spread	Assigned	100		2	1.5	Crew Size
		20. Gravel island	Spread	Assigned		15	1	1.11	Crew Size
	C. Transportation	21. Hal icopter support for platform	Platform; same as Tasks 7 & 8	Ssme as Tasks 7 & 8	0	5	1	2	N/A
		22. Helicopter support for lay barge	Lay barge spread; same a Tasks 12 & 13	Same as Tasks 12 & 13	0	5	1	2	N/A
		23. Supply/anchor boats for platform	Pl atform; same as Tasks 7 & 8	Same as Tasks 7 & 8	39 0	0 12	1 1	1.5 1	N/A
		24. Supply/anchor boats for lay barge	LSy barge spread ; same a Tasks 12 & 13	Same as Tasks 12 & 13	6S 0	0 12	1 1	1.s 1	N/A
		25. Tugboats for instal- la tio n and towout	Platform	same as Tasks 7 & 8	40	0	1	1.5	N/A
		26. Tugboats for lay barge spread	LSy barge spread; same a Tasks 12 & 13	Same as Tasks 12 & 13	20	0	1	1.5	N/A
		27. Longshoring for platform construction	Platform; same as Tasks 7 & 8	Same as Tasks 7 & 8	0	20	1	1	Crew Size
		28. Longshoring for lay barge	Lay barge spread ; same a Tasks 12 & 13	Same as Tasks 12 & 13	0	20	1	1	Crew Size
		29. Tugboat for SLMS; (Task 11)	Same as Task 11	Same as Task 11	10	0	1	1.5	N/A
		30. Supply for SLMS; (Task 11)	Same as Task 11	Same as Task 11	13	0	1	1.5	N/A
	D. Manufacturing								

TABLE E-4 (Cont.)

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) 7@T&zu-		Number of shifts/ Day	Rotation Factor	Scale Factor
						Onshore			
roduction	A. Petroleum	31. Operations and maintenance (routin preventive)	Platform	Assigned	36 0	0 2	2 1	2 1	Crew Size
		32. Oil well workover and stimulation	Platform	Assigned	15	0	1	2	N/A
	B. Construction .	33. Maintenance and Re-pair for platform and suppl y boa ts (replacement of parts, rebuild, painting, etc.)	Platform	Assigned	8 0	0 4 + seasonal 12 months - 6-9 months	1 1	2 1	Crew Size
	C. Transportation	34. Hel icopters for platform	Pla tform	Same as Task 31	0	3	1	2	N/A
		35. Supply bests for platform	Platform	Assigned	12-seasonal 6 month	0	1	1.5	N/A
		36. Terminal and pipe-line operations	Terminal	Assigned	0	Assigned	2	2	N/A
		37. Freight handling platforms	Platforms	Same as Task 31	0	3	1	1	Crew Size
	D. Ma nuf acturing	38. LNG operations	LNG plant	Assigned	0	Assigned	2	2	N/A

[1] Dif ferent labor force values may be substituted for these if deemed appropriate by site-specific characteristics.

[2] This is the crew size or estimated average monthly shift labor force over the duration of the project. "Assigned" means that scenario-specific values are used, and that no constant values are appropriate.

Additional notes on next page,

Source: Dames & Moore

NOTES TO TABLE E-4

W

1	Average 28-man crew per shift on drilling vessel and six shore-based positions (clerks, expediters, administrators); shift on drilling vessel includes catering and oil field service personnel. Number of rigs per year determined by the number of wel ls/year x months required to dri 11 each wel l divided by the number of months in the dri 11 i ng season.
2	Approximately one month of geophysical work per wel 1 based on 200 miles of seismic 1 ines per wel 1 at approximately 15 miles/day x 2 (weather factor); 25-man crew and two onshore positions, crew can work from May through September.
3	Requirements for temporary shore base construction varies with l ease area.
4	One hel icopter per dri 11 ing vessel ; two pi lots and three mechanics per helicopter; considered onshore employment.
5	Two supply anchor boats per rig; each with 13-man crew.
6	One or two drilling rigs per platform; average 28-man dri 1 ling crew and six shore-based positions per rig; shift on drilling vesses includes catering and oil field service personnel.
7, 8, 9	Includes al 1 aspects of towout, placement, pile driving, module installation, and hookup of deck equipment; also includes crew support (catering personnel).
10	See Table 5-7.
11	This task includes al 1 subsea tie-ins of underwater completions.
12	Rate of progress assumed to be average of one mile per day for al 1 gathering l ines; seal e factors not appl ied to gathering line.
13	Rate of progress averages .75 mile per day of medium-sized trunk 1 ine in water of medium depth; scale factors appl ied in shal low or deeper water and for pipe diameter; rate of progress makes allowance for weather down time, tie-ins, and mobil ization and demobilization.
14	Rate of progress averages .3 mile per day of buried medium-sized onshore trunk l ine in moderate terrain; scale factors appl ied for elevated pipe or rocky terrain and for pipe diameter.
15	Rate of progress for pipe coating is one mile/day for 20- to 36-inch pipe; 1.5 mile for 10- to 19-inch pipe.
16	See Table 5-7.
17	See Table 5-7.
20	See Table 5-7.
21	One helicopter per platform.
22	One helicopter per lay barge spread.
23	Three supply/anchor boats per platform.
24	Five supply/anchor boats per 1 ay barge spread.
25	Four tugs for towout per platform; 10-man crew per boat.
26	Two tugs per 1 ay barge spread; 10-man crew.
30	.5 helicopter per pl atform (3 man crew/platform).
31	Assumed to begin in first year of platform production (also tasks 33, 34, 35, and 37).
32	Assumed to begin five years after wel 1 product ion.
33	This maintenance activity is assumed to begin two years after start-up of production.
35	One supply boat per platform.

TABLE E-4a
(Attachment of Table E-4)

SPECIAL MANPOWER ASSUMPTIONS FOR NORTON SOUND

Task	Special Assumptions
1	Length of drilling seasons is eight months on the average; ice breakers will allow rigs to operate from April 1 to November 31. Gravel islands will permit year round drilling. Drilling start date on gravel islands is either two months or four months from the start of island construction (see task 301 below).
3	Exploratory drilling will be supplied from Nome.
301	One equipment spread can build an island in 7.5-m (25-foot) water depth in two months, or an island in 15-meter (50-foot] water depth in four months.
6	Assumes 45 days per well, or eight wells per year for both oil and gas production wells.
7	Scale factor of .7.
13	All offshore pipelining is entered under this task with scale factor of .7 and a rate of progress of .4 mile per day (partial months are rounded up) . Productivity shown in the notes to Table E-1 are based on large, modern, highly efficient equipment currently used in the North Sea and Gulf of Mexico. This equipment (e.g. reel lay barges) is very expensive, and because total offshore pipelining requirements in Norton Sound are not large, and because the work season is short, it is assumed that smaller, less efficient lay barges will be used. These will require less manpower than the larger equipment spreads.
14	Scale factor of 1.3 because of arctic conditions.
15	Rate of progress assumed to be .75 mile per day (approximately 100 lengths of 40-foot pipe per day or 8.25 per hour). Scale factor is .7. This reduced productivity and manpower is based on underlying assumption in task 13 above.
33	This activity is assumed to occur seasonally; from June through September.
35	Supply boats are assumed to operate only from May through October; helicopter supply platforms during ice season.

TABLE E-5
LIST OF TASKS BY ACTIVITY

ONSHORE

Activity		
1	Service Bases	(Onshore Employment - which would include all onshore administration, service base operations, rig and platform service

Task 1 - Exploration Well Drilling
Task 2 - Geophysical Exploration
Task 5 - Supply/Anchor Boats for Rigs
Task 6 - Development Drilling
Task 7 - Steel Jacket Installation and Commissioning
Task 8 - Concrete Installations and Commissioning
Task 11 - Single-Leg Mooring System
Task 12 - Pipeline-Offshore, Gathering, Oil and Gas
Task 13 - Pipeline-Offshore, Trunk, Oil and Gas
Task 20 - Gravel Island Construction
Task 23 - Supply/Anchor Boats for Platform
Task 24 - Supply /Anchor Boats for Lay Barge
Task 27 - Longshoring for Platform
Task 28 - Longshoring for Lay Barge
Task 31 - Platform Operation
Task 33 - Maintenance and Repairs for Platform
Task 3? - Longshoring for Platform [Production)
Task 301 - Gravel Island Construction

2 Helicopter Service
Task - Helicopter for Rigs
Task 21 - Helicopter Support for Platform
Task 22 - Helicopter Support for Lay Barge
Task 34 - Helicopter for Platform

Construct ion
3 Service Base
Task 3 - Shore Base Construction
Task 10 - Shore Base Construction

4 Pipe Coating
Task 15 - Pipe Coating

5 Onshore Pipelines
Task 4 - Pipeline, Onshore, Trunk, Oil and Gas

6 Terminal
Task 16 -Marine Terminal (assumed to be oil terminal)
Task 18 - Crude Oil Pump Station Onshore

7 LNG Plant
Task 17 - LNG Plant

8 Concrete Platform Construction
Task 19 - Concrete Platform Site Preparation
Task 20 - Concrete Platform Construction

9 Oil Terminal Operations
Task 36 - Terminal and Pipeline Operations

10 LNG Plant Operations
Task 8 - LNG Operat ions

OFFSHORE

Activity
11 Survey
Task 2 - Geophysical and Geological Survey

12 Rigs
Task 1 - Exploration Well

13 Platforms
Task 6 - Devel opment Drilling
Task 31 - Operations
Task 32 - Workover and Well Stimulation
Task 33 - Maintenance and Repairs for Platforms

14 Platform Installation
Task 7 - Steel Jacket Installation and Commissioning
Task 8 - Concrete Installation and Commissioning
Task 11 - Single-Leg Mooring System
Task 20 - Gravel Island Construction
Task 301 - Gravel Island Construction

15 Offshore Pipeline Construction
Task 12 - Pipeline Offshore, Gathering, Oil and Gas
Task 13 - Pipeline Offshore, Trunk, Oil and Gas

16 Supply/Anchor/Tug Boat
Task 5 - Supply/Anchor Boats for Rigs
Task 23 - Supply/Anchor Boats for Platform
Task 24 - Supply/Anchor Boats for Lay Barge
Task 25 - Tugboats for Installation and Towout
Task 26 - Tugboats for Lay Barge Spread
Task 29 - Tugboats for SLMS
Task 30 - Supply Boat for SLMS
Task 35 - Supply Boat for SLMS

TA8LE E-6 (6-12)*

HIGH FINO SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR B / ELD SIZE (MMBBL)							Totals
		ner Sound			Centril Sound		Outer ound		
		509	00	Z00	500	200	750	250	
1983	1								
1984	2								
1985	3								
1986	4								
1987	5								
1988	6								
1989	7				7.008				7.008
1990	8				24.528	7.008	7.008		38.544
1991	9	7.008			45.552	14.016	24.528	7.008	98.088
1992	10	24.528	7.008		56.064	21.024	52.560	17.520	178.704
1993	11	45.552	14.016		56.064	28.032	73.584	28.032	245.280
1994	12	56.064	21.024	7.008	54.005	27.050	84.096	28.032	277.279
1995	13	56.064	28.032	14.016	46.354	22.401	84.096	28.032	278.995
1995	14	54.005	27.050	21.024	38.598	17.432	76.708	27.982.	262.799
1997	15	46.354	22.401	28.032	32.168	13.897	62.453	24.906	230.211
1998	16	38.598	17.432	27.050	26.840	11.000	51."293	20.647	192.860
1999	17	32.168	13.897	22.401	22.420	8.886	40.869	17.116	157.757
2000	18	26.840	11.000	17.432	18.757	6.835	33.885	14.187	128.936
2001	19	22.420	8.886	13.897	15.221	5.250	28.094	11.763	105.531
2002	20	18.757	6.835	11.000	12.703	4.154	23.293	9.751	86.493
2003	21	15.221	5.250	8*886	10.616	3.286	19.312	8.084	70.655
2004	22	12.703	4.154	6.835	8.886	2.600	16.012	6.701	57.891
2005	23	10.616	3.286	5.260	7.452		13.274		39.888
2006	24	8.886	2.600	4.154	6.263		11.007		32.910
2007	25	7.452		3.286 ,	5.328		9.126		25.192
2008	26	6.263		2.600	4.417		7.566		20.846
2009	27	5.328					7.088		12.416
2010	28	4.417							4.417
2011	29								
2012	30								
2013	31								
2014	32								
2015	33								
2016	34								

Peak 011 Production = 764,400 b/d.

Source: Dames & Moore

•Number in Parentheses is that of the original table which has been revised

TABLE E-7 (6- 13)*

HIGH FIND SCENARIO PRODUCTION **BY YEAR** FOR INDIVIDUAL FIELDS AND TOTAL - **NON-ASSOCIATED GAS**

Calendar Year	Year After Lease Sale	PRODUCTION [illegible] Central Sound 1000		1200	Totals
1983	1				
1984	2				
1985	3				
1986	4				
1987	5				
1988	6				
1989	7	21.024			21.024
1990	8	42.048	21.024		63.072
1991	9	63.072	42.048		105.120
1992	10	84.096	63.072	21.024	168.192
1993	11	84.096	84.096	42.048 .	210..240
1994	12	84.096	84.096	63.072	231.264
1995	13	84.096	84.096	84.096	252.288
1996	14	84.096	84.096	84.096	252.288
1997	15	84.096	84.096	84.096	, 252.288
1998	16	84.096	84.096	84.096	252.288
1999	17 '	72.423	84.096	84.096	240.615
2000	18	54.122	72.423	84.096	210.641
2001	19	40.521	54.122	84.096	178.739
2002	20	30.310	40.521	84.096	154.927
2003	21	22.672	30.310	84.096	137.078
2004	22	16.958	22.672	69.600	109.23
2005	23	12.685	16.958	54.680	84.323
2006	24	9.788	12.685	42.933	65.106
2007	25	7.097		33.710	50.295
2008	26	5.309		26.468	38.874
2009	27			20.782	26.091
2010	28			16.317	16.317
2011	2 9			12.812	12.812
2012	30				
2013	31				
2014	32				
2015	33				
'2016	34				
2017	35				

Peak Gas Production = 691.200 mmcfd.

Source: **Dames & Moore**

* Number in Parentheses is that of the original table which has been revised

TABLE E-8 (7-12)*

MEDIUM FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL)					Totals
		Inner Sound		Central Sound		Outer Sound	
		200	200		250	250	
1983	1						
1984	2						
1985	3						
1986	4						
1987	5						
1988	6						
1989	7			7.008			7.008
1990	8			24.528	7.008	7.008	31.536
1991	9	7.008		45.552	17.520	7.008	77.088
1992	10	14.016	7.008	56.064	28.032	17.520	122.640
1993	11	21.024	14.016	56.064	28.032	28.032	147.168
1994	12	28.024	21.024	54.005	28.032	20.032	159.125
1995	13	27.050	28.032	46.354	27.982	28.032	157.450
1996	14	22.401	27.050	38.598	24.906	27.982	140.937
1997	15	17.432	22.401	32.168	20.647	24.906	117.554
1998	16	13.897	17.432	26.840	17.116	20.647	95.932
1999	17	11.000	13.897	21.420	14.187	17.116	77.620
2000	18	8.886	11.000	18.757	11.763	14.187	64.593
2001	19	6.835	8.886	15.221	9.751	11.763	52.456
2002	20	5.250	6.835	12.703	8.084	9.751	42.623
2003	21	4.154	5.250	10.616	6.701	8.084	34.805
2004	22	3.286	4.154	8.886		6.701	23.027
2005	23	2.600	3.286	7.452			13.338
2006	24		2.600	6.263			8.863
2007	25			5.328			5.328
2008	26			4.417			4.417
2009	27						
2010	28						
2011	29						
2012	30						
2013	31						
2014	32						
2015	33						
2016	34						

Peak Oil Production = 436,000 b/d.

Source: Dames & Moore

* Number in Parentheses is that of the original table which has been revised

TABLE E-9 (7-13) •

MEDIUM FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL NON-ASSOCIATED GAS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound 1300	1000	Totals
1983	1			
1984	" 2			
1985	3			
1986	4			
1987	5			
198a	6			
1989	7	26.280		26.280
1990	8	63.072		63.072
1991	9	84.096	21.024	105.120
1992	10	84.096	42.048	126.144
1993	11	84.096	63.072	147.168
1994	12	84.096	84.096	168.192
1995	13	84.096	84.096	168.192
1996	14	84.096	84.096	168.192
1997	15	84.096	84.096	168.192
1998	16	84.096	84.096	168.192
1999	17	84.096	84.096	168.192
2000	18	84.096	84.096	168.192
2001	19	76.846	72.423	149.269
2002	20	61.980	54.122	116.102
2003	21	49.936	40.521	.90.477
2004	22	40.265	30.710	70.575
2005	23	32.454	22.672	55.126
2006	24	26.157	16.958	43.115
2007	25	21.002	12.685	33.772
2008	26	16.992		16.992
2009	27	13.696		13.696
2010	28			
2011	29			
2012	30			
2013	31			
2014	32			
2015	33			
2016	34			

Peak Gas Production = 460. U' MMCFD.

Source: Dames & Moore

• Number in parentheses is that of the original table which has been revised

TABLE E-10 (8-12)*

LOW FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL) Central Sound		Totals
		200	180	
1983	1			
1984	2			
1985	3			
1986	4			
1987	5			
1988	6			
1989	7			
1990	8	7.008	7.008	14.016
1991	9	14.016	14.016	28.032
1992	10	21.024	21.024	42.048
1993	11	28.032	28.032	56.064
1994	12	27.050	26.962	54.012
1995	13	22.401	20.788	43.189
1996	14	17.432	16.028	33.460
1997	15	13.897	12.357	26.254
1998	16	11.000	9.527	20.527
1999	17	8.886	7.346	16.232
2000	18	6.835	5.663	12.498
2001	19	5.250	4.366	9.616
2002	20	4.154	3.366	7.520
2003	21	3.286	2.595	6.881
2004	22	2.600		2.600
2005	23			
2006	24			
2007	25			
2008	26			
2009	2?			
2010	2a			
2011	29			
2012	30			
2013	31			
2014	32			
2015	33			
2016	34			

Peak Oil Production = 153,600 b/d

Source: Dames & Moore

* Number in parentheses is that of the original table which has been revised

TABLE E-11(8-13)*

LOW FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL AS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound 200	Totals
1983	1		
1984	2		
1985	3		
1986	4		
1987	5		
1988	6		
1989	7		
1990	8	21.024	21.024
1991	9	42.048	42.048
1992	10	63.072	63.072
1993	11	84.096	84.096
1994	12	84.096	84.096
1995	13	84.096	84.096
1996	14	84.096	84.096
1997	15	84.096	84.096
1998	16	84.096	84.096
1999	17	84.096	84.096
2000	18	84.096	84.096
2001	19	84.096	84.096
2002	20	69.600	69.600
2003	21	54.680	54.680
2004	22	42.933	42.933
2005	23	33.710	33.710
2006	24	26.468	26.468
2007	25	20.782	20.782
2008	26	16.317	16.317
2009	27	12.812	12.812
2010	28		
2011	29		
2012	30		
2013	31		
2014	32		
2015	33		
2016	34		

Peak Gas Production = 230.[illegible]4 MMCFD.

Source: Dames & Moore

• Number in parentheses Is that of the original table which has been revised

TABLE E-12 (6-11)*

FIELD PRODUCTION SCHEDULE - HIGH FIND SCENARIO

Location	Field Oil (MMBBL)	Field Gas (BCF)	Peak Production Oil (MBD)	Peak Production Gas (MMCFD)	Year After Lease Sale Production Start Up	Year After Lease Sale Production Shut Down	Year After Lease Sale Peak Production	Years of Production
Inner Sound	500	--	153.6	--	9	28	12-13	20
Inner Sound	200	--	76.8	--	10	24	13	15
Inner Sound	200	--	76.8		12	26	15	15
Central Sound	500	--	153.6	--	7	26	10-11	20
Central Sound	200	--	76.8	--	8	22	11	15
Outer Sound	750	--	230.4	--	8	27	12-13	20
Outer Sound	250	--	76.8	--	9	22	11-13	14
Central Sound	--	1.000	--	230.4	7	23	10-16	17
Central Sound	--	1,000	--	230.4	8	24	11-17	17
Central Sound	--	1,200	--	230.4	10	29	13-21	20

Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms in the same field.

Source: Dames & Moore

* Number parentheses is that of the original table which has been revised

TABLE E-13 (6-14)*

MAJOR SHORE FACILITIES START UP AND SHUT DOWN DATES - GH FIND SCENARIO

Facility	Year After Lease Sale	
	Start Up Date	Shut Down Date
Cape Nome Oil Terminal	7	28
Cape Nome LNG Plant	7	34

For the purposes of manpower estimation start up is assumed to be January 1.

For the purposes of manpower estimation shut down is to be December 31.

Source: Dames & Moore

* Number parentheses is that of the original table which has been revised

TABLE E-14 (7-11)*

FIELD PRODUCTION SCHEDULE - MEDIUM FIND SCENARIO

Location	Field		Peak Production		Year After Lease Sale			Years of Production
	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	
Inner Sound	200	---	76 Q		[illegible]	26	10-11	20
Central Sound	250	--	76.8	--	8	21	10-12	14
Outer Sound	250	--	76.8	--	9	22	11-13	14
Central Sound	--	1,300	--	230.4	7	27	9-18	21
Central Sound	--	1,000	--	230.4	9	25	12-18	17

Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms in the same field.

Source: Dames & Moore

* Number in parentheses is that of the original table which has been revised

TABLE E-15 [7-14)*

MAJOR SHORE FACILITIES START UP AND SHUT DOWN DATES - MEDIUM FIND SCENARIO

Facility	Year After Lease Sale	
	Start Up Date	hut Down Date
Cape Nome Oil Terminal	7	26
Cape Nome LNG Plant	7	27

For the purposes of manpower estimation start up is assumed to be January 1.

For the purposes of manpower estimation shut down is to be December 31.

Source: Dames & Moore

* Number in parentheses is that of the original table which has been revised

TABLE E-16 (8-11) *

FIELD PRODUCTION SCHEDULE - LOW FIND SCENARIO

Location	Field Oil (MMBBL)	Field Gas (BCF)	Peak production Oil (MBD)	Peak production Gas (MMCFD)	Year After Lease Sale Production Start Up	Year After Lease Sale Production Shut Down	Year After Lease Sale Peak Production	Years of Production
Central Sound	200	--	76.8	--	8	22	11	15
Central Sound	180	--	76.8	--	8	21	11	14
Central Sound	--	1,200	--	230.4	8	27	11-19	20

Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms.

Source: Dames & Moore

* Number parentheses is that of the original table which has been revised

TABLE E-17 (8-14)*

MAJOR SHORE FACILITIES STARTUP AND SHUT DOWN DATES -
LOW FIND SCENARIO

Facility	Year After Lease Sale		Years of Operation
	Start Up Date	Shut Down Date	
Cape Nome Oil Terminal	8	27	15
Cape Nome LNG Plant	8	32	20

For the purposes of manpower estimation start up is assumed to be January 1.
For the purposes of manpower estimation shut down is to be December 31.

Source: Dames & Moore

* Number parentheses is that of the original table which has been revised

TABLE E-18

EXPLORATION ONLY
12/21/79

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER LEASE SALE	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	498.	52.	0.	0.	208.	56.	0.	706.	108.	814.
2	996.	104.	400.	30.	416.	12.	0.	1812.	246.	2058.
3	498.	52.	400.	30.	208.	56.	0.	1106.	138.	1244.

TABLE E-19

EXPLORATION ONLY
12/21/79

.) ANuA1i% JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0.	0.	164.	138.	26.	10*	338.	6	365.
2	0.	0.	0.	0.	0.	389.	238.	43.	12.	682.	6	682.
3	0.	0.	0.	0.	0.	364.	238.	41.	12.	655.	6	682.

TABLE E-20

EXPLORATION ONLY
12/21/79

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	68.	40.	0.	0.	o*	0.	0.	0.	0.	0.	50.	448.	0.	o*	0.	208.
	OFFSITE	0.	40.	0.	0.	0.	0.	0.	0.	0.	o*	o.	448.	0,	0.	0.	104.
2	ONSITE	166.	80.	0.	0.	0.	0.	0.	0.	0.	n.	100.	896.	o.	400.	0.	416.
	OFFSITE	3.	80.	0.	o*	0.	0.	0.	0.	0.	0.	n.	896.	0.	200.	0.	208.
3	ONSITE	98.	40.	0.	0.	0.	0.	0.	0.	0.	0.	50.	448.	o*	400.	0.	208.
	OFFSITE	3.	40.	0.	0.	0.	0.	n.	0.	0.	0.	0.	44a.	0.	200.	0.	104.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE E-21

EXPLORATION ONL
12/21/79

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL (MAN-MONTHS)			TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE)		
	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL
1	706.	108.	814.	1258.	148.	1406.	105.	13.	118.
2	1812.	246.	2058.	3116.	329.	3445.	260.	28.	288.
3	1106.	138.	1244.	1858.	181.	2039.	155.	16.	170.

** TOTAL INCLUDES ONSITE AND OFFSITE

TABLE E-22

HIGH FIND SCENARIO
12/21/79

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER LEASE SALE	PETROLEUM OFFSHORE	PETROLEUM ONSHORE	CONSTRUCTION OFFSHORE	CONSTRUCTION ONSHORE	TRANSPORTATION OFFSHORE	TRANSPORTATION ONSHORE	MFG ONSHORE	ALL INDUSTRIES OFFSHORE	ALL INDUSTRIES ONSHORE	ALL INDUSTRIES TOTAL
1	1494.	156.	0.	0.	624.	168.	0.	2118.	324.	2442.
2	2988.	312.	400.	30.	1248.	336.	0.	4636.	678.	5314.
3	4482.	468.	2400.	180.	1872.	504.	0.	8754.	1152.	9906.
4	4980.	520.	800.	5286.	2080.	560.	0.	7860.	6366.	14226.
5	3486.	364.	2025.	15525.	2009.	609.	0.	7520.	16498.	24018.
6	3996.	420.	7725.	10374.	4037.	1421.	0.	15758.	12215.	27973.
7	8592.	778.	11075.	3625.	4561.	3083.	1200.	24228.	8686.	32914.
8	15264.	1224.	5450.	4258.	2188.	2434.	1200.	22902.	9116.	32018.
9	20712.	1602.	3139.	975.	1693.	2371.	1200.	25544.	6148.	31692.
10	21144.	1374.	1517.	209.	1173.	2349.	1200.	23834.	5132.	28966.
11	17952.	1032.	463.	169.	1021.	2287.	1200	19436.	4688.	24124.
12	14976.	606.	416.	208.	1008.	2328.	1200	16400.	4342.	20742.
13	14520.	480.	416.	208.	1008.	2328.	1200	15944.	4216.	20160.
14	14052.	372.	448.	224.	1008.	2328.	1200	15508.	4124.	19632.
15	14436.	336.	448.	224.	1008.	2328.	1200	15892.	4088.	19980.
16	14436.	336.	448.	224.	1008.	2328.	1200	15892.	4088.	19980.
17	14616.	336.	448.	224.	1008.	2328.	1200	16072.	4088.	20160.
18	14616.	336.	448.	224.	1008.	2328.	1200	16072.	4088.	20160.
19	14616.	336.	448.	224.	1008.	2328.	1200	16072.	4088.	20160.
20	14616.	336.	448.	224.	1008.	2328.	1200	16072.	4088.	20160.
21	14616.	336.	448.	224.	1008.	2328.	1200	16072.	4088.	20160.
22	14616.	336.	448.	224.	1008.	2328.	1200	16072.	4088.	20160.
23	12528.	288.	384.	192.	864.	2184.	1200	13776.	3864.	17640.
24	11484.	264.	352.	176.	792.	2112.	1200	12628.	3752.	16380.
25	9396.	216.	288.	144.	648.	1968.	1200	10332.	3528.	13860.
26	9396.	216.	288.	144.	648.	1968.	1200	10332.	3528.	13860.
27	6264.	144.	192.	96.	432.	1752.	1200	6888.	3192.	10080.
28	3132.	72.	96.	48.	216.	1136.	1200	3444.	2456.	6300.
29	1044.	24.	32.	16.	72.	72.	1200	1148.	1312.	2460.

TABLE E-23

HIGH FIND SCENARIO
12/21/79

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0.	0.	271.	207.	41.	15.	534.	5	561.
2	0.	0.	0.	0.	0.	742.	514.	57.	32.	1385.	6	1412.
3	0.	0.	0.	0.	0.	838.	621.	125.	45.	1629.	3	3800.
4	0.	0.	67.	7.	74.	1120.	790.	622.	103.	2635.	9	2784.
5	0.	0.	871.	96.	967.	1103.	798.	1607.	203.	3710.	8	3724.
6	254.	215.	1523.	169.	2160.	2330.	1802.	1056.	144.	5331.	6	5657.
7	1272.	1114.	432.	244.	3062.	3126.	2412.	1158.	334.	7030.	6	7030.
8	1952.	1794.	506.	256.	4508.	2370.	2052.	1007.	302.	5731.	6	5731.
9	1954.	1715.	822.	287.	4778.	2606.	2370.	529.	253.	5758.	6	5758.
10	2310.	2271.	483.	256.	5319.	2068.	1890.	431.	251.	4640.	1	5319.
11	1664.	1664.	392.	249.	3969.	1666.	1590.	404.	249.	3911.	6	4452.
12	1542.	1542.	376.	252.	3712.	1422.	1338.	386.	252.	3398.	1	3712.
13	1210.	1210.	334.	252.	3006.	1482.	1398.	386.	252.	3518.	6	3518.
14	1255.	1255.	334.	252.	3096.	1423.	1339.	378.	252.	3392.	6	3392.
15	1203.	1203.	322.	252.	2980.	1483.	1399.	378.	252.	3512.	6	3512.
16	1203.	1203.	322.	252.	2980.	1483.	1399.	378.	252.	3512.	6	3512.
17	1218.	1218.	322.	252.	3010.	1498.	1414.	378.	252.	3542.	6	3542.
18	1218.	1218.	322.	252.	3010.	1498.	1414.	378.	252.	3542.	6	3542.
19	1218.	1218.	322.	252.	3010.	1498.	1414.	378.	252.	3542.	6	3542.
20	1218.	1218.	322.	252.	3010.	1498.	1414.	378.	252.	3542.	6	3542.
21	1218.	1218.	322.	252.	3010.	1498.	1414.	378.	252.	3542.	6	3542.
22	1218.	1218.	322.	252.	3010.	1498.	1414.	378.	252.	3542.	6	3542.
23	1044.	1044.	305.	246.	2640.	1284.	1212.	354.	246.	3096.	6	3096.
24	957.	957.	298.	243.	2455.	1177.	1111.	342.	243.	2873.	6	2873.
25	783.	783.	282.	237.	2085.	963.	909.	318.	237.	2427.	6	2427.
26	783.	783.	282.	237.	2085.	963.	909.	318.	237.	2427.	6	2427.
27	522.	522.	254.	228.	1530.	642.	606.	282.	228.	1758.	6	1758.
28	251.	251.	234.	219.	975.	321.	303.	246.	219.	1089.	6	1089.
29	87.	87.	105.	103.	355.	107.	101.	112.	103.	423.	6	423.

TABLE E-24

HIGH FLOW SCENARIO
12/21/79

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY			2	3	4	5	6	7	8	9	0		2	13	14	15	16 **
	ONSITE	204.	120.	0.	0.	0.	0.	0.	0.	0.	0.	150.	344.	0.	0.	0.	624.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	344.	0.	0.	0.	312.
2	ONSITE	438.	240.	0.	0.	0.	0.	0.	0.	0.	0.	300.	2688.	0.	400.	0.	1244.
	OFFSITE	3.	240.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2688.	0.	200.	0.	624.
3	ONSITE	752.	360.	0.	0.	0.	0.	0.	0.	0.	0.	450.	4032.	0.	2400.	0.	872.
	OFFSITE	20.	360.	0.	0.	0.	0.	0.	0.	0.	0.	0.	4032.	0.	1200.	0.	936.
4	ONSITE	740.	400.	0.	0.	0.	5226.	0.	0.	0.	0.	500.	4480.	0.	800.	0.	2080.
	OFFSITE	7.	400.	0.	0.	0.	575.	0.	0.	0.	0.	0.	4480.	0.	400.	0.	1040.
5	ONSITE	840.	315.	1800.	0.	0.	12462.	1080.	0.	0.	0.	350.	3136.	0.	2025.	0.	2009.
	OFFSITE	20.	315.	198.	0.	0.	1371.	119.	0.	0.	0.	0.	3136.	0.	1625.	0.	1005.
6	ONSITE	2166.	415.	1800.	368.	0.	5226.	2220.	0.	0.	0.	300.	2688.	1008.	7025.	700.	4037.
	OFFSITE	44.	415.	198.	40.	0.	575.	244.	0.	0.	0.	0.	2688.	1008.	6225.	700.	2019.
7	ONSITE	3146.	457.	0.	612.	950.	0.	0.	0.	1320.	1200.	200.	1792.	6600.	10200.	875.	4561.
	OFFSITE	117.	457.	0.	67.	215.	0.	0.	0.	1320.	1200.	0.	1792.	6600.	8600.	875.	2281.
8	ONSITE	2538.	326.	0.	612.	3120.	0.	0.	0.	1320.	1200.	0.	0.	15264.	4925.	525.	2188.
	OFFSITE	56.	325.	0.	67.	343.	0.	0.	0.	1320.	1200.	0.	0.	15264.	4125.	525.	1094.
9	ONSITE	2604.	389.	0.	245.	390.	0.	0.	0.	1320.	1200.	0.	0.	20776.	2550.	525.	693.
	OFFSITE	34.	389.	0.	27.	43.	0.	0.	0.	1320.	1200.	0.	0.	20776.	2150.	525.	847.
10	ONSITE	2129.	483.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	21336.	1325.	0.	173.
	OFFSITE	12.	483.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	21336.	925.	0.	587.
	ONSITE	1655.	473.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	18240.	0.	175.	021.
	OFFSITE	3.	473.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	18240.	0.	175.	511.
12	ONSITE	13 [illegible]	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15392.	0.	0.	008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15392.	0.	0.	504.
13	ONSITE	1192.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14936.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14936.	0.	0.	504.
14	ONSITE	1100.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14500.	0.	0.	008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14500.	0.	0.	504.
15	ONSITE	864.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	4884.	0.	0.	008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	4884.	0.	0.	504.

TABLE E-24
(continued)

HIGH FIND SCENARIO
12/21/79

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	1064.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14884.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	14884.	0.	0.	504.
17	ONSITE	1064.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	504.
18	ONSITE	1064.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	504.
19	ONSITE	1064.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	504.
20	ONSITE	1064.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	504.
21	ONSITE	1064.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	504.
22	ONSITE	1064.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	1008.
	OFFSITE	0.	504.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	15064.	0.	0.	504.
23	ONSITE	912.	432.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	12912.	0.	0.	864.
	OFFSITE	0.	432.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	12912.	0.	0.	432.
24	ONSITE	836.	396.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	11836.	0.	0.	792.
	OFFSITE	0.	396.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	11836.	0.	0.	396.
25	ONSITE	684.	324.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	9684.	0.	0.	648.
	OFFSITE	0.	324.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	9684.	0.	0.	324.
26	ONSITE	684.	324.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	9684.	0.	0.	648.
	OFFSITE	0.	324.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	9684.	0.	0.	324.
27	ONSITE	456.	216.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	6456.	0.	0.	432.
	OFFSITE	0.	216.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	6456.	0.	0.	216.
28	ONSITE	228.	108.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	108.	0.	0.	0.	0.	0.	0.	1320.	1200.	0.	0.	3228.	0.	0.	108.
29	ONSITE	[illegible]	36.	0.	0.	0.	0.	0.	0.	0.	1200.	0.	0.	1076.	0.	0.	72.
	OFFSITE	0.	36.	0.	0.	0.	0.	0.	0.	0.	1200.	0.	0.	1076.	0.	0.	36.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE E-25

HIGH FIND SCENARIO
12/21/77

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE MAN-MONTHS OFFSHORE	ONSITE MAN-MONTHS ONSHORE	ONSITE MAN-MONTHS TOTAL	TOTAL (MAN-MONTHS) OFF SHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	2118.	324.	2442.	3774.	444.	4218.	315.	37.	352.
2	4636.	678.	5314.	8148.	921.	9069.	679.	77.	756.
3	8754.	1152.	9906.	14922.	1532.	16454.	1244.	128.	1372.
4	7860.	6366.	14226.	13780.	7347.	21127.	1149.	613.	1761.
5	7520.	16498.	24018.	13286.	18520.	31806.	1108.	1544.	2651.
6	15758.	12215.	27973.	28398.	13771.	42169.	2367.	1148.	3514.
7	24228.	8686.	32914.	44375.	12062.	56437.	3698.	1006.	4704.
8	22902.	9116.	32018.	43910.	12431.	56341.	3660.	1036.	4695.
9	25544.	6148.	31692.	49841.	9161.	59003.	4154.	764.	4917.
10	23834.	5132.	28966.	46682.	8147.	54829.	3891.	679.	4569.
11	19436.	4688.	24124.	38362.	7683.	46045.	3197.	641.	3837.
12	16400.	4342.	20742.	32296.	7366.	39662.	2692.	614.	3306.
13	15944.	4216.	20160.	31384.	7240.	38624.	2616.	604.	3219.
14	15508.	4124.	19632.	30512.	7148.	37660.	2543.	596.	3139.
15	15892.	4088.	19980.	31280.	7112.	38392.	2607.	593.	3200.
16	15892.	4088.	19980.	31280.	7112.	38392.	2607.	593.	3200.
17	16072.	4088.	20160.	31640.	7112.	38752.	2637.	593.	3230.
18	16072.	4088.	20160.	31640.	7112.	38752.	2637.	593.	3230.
19	16072.	4088.	20160.	31640.	7112.	38752.	2637.	593.	3230.
20	16072.	4088.	20160.	31640.	7112.	38752.	2637.	593.	3230.
21	16072.	4088.	20160.	31640.	7112.	38752.	2637.	593.	3230.
22	16072.	4088.	20160.	31640.	7112.	38752.	2637.	593.	3230.
23	13776.	3864.	17640.	27120.	6816.	33936.	2260.	568.	2828.
24	12628.	3752.	16380.	24860.	6666.	31528.	2072.	556.	2628.
25	10332.	3528.	13860.	20340.	6372.	26712.	1695.	531.	2226.
26	10332.	3528.	13860.	20340.	6372.	26712.	1695.	531.	2226.
27	6888.	3192.	10080.	13560.	5928.	19488.	1130.	494.	1624.
28	3444.	2856.	6300.	6780.	5484.	12264.	565.	457.	1022.
29	1148.	1312.	2460.	2260.	2548.	4808.	189.	213.	401.

** TOTAL INCLUDES ONSITE AND OFFSITE

TABLE E-26

MEDIUM FIND SCENARIO
12/21/79

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER LEASE SALE	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	1619.	166.	0.	0.	624.	168.	0.	2243.	334.	2577.
2	3486.	364.	400.	30.	1456.	392.	0.	5342.	786.	6128.
3	3984.	416.	800.	60.	1664.	448.	0.	6448.	924.	7372.
4	2988.	312.	800.	3396.	1248.	336.	0.	5036.	4044.	9080.
5	1096.	112.	2025.	6697.	969.	329.	0.	4090.	9138.	13229.
6	2004.	212.	7900.	3091.	3290.	1228.	0.	13194.	4531.	17726.
7	5692.	470.	4300.	375.	1092.	1524.	720.	11084.	3089.	14173.
8	10176.	816.	5475.	4487.	1351.	1699.	720.	17002.	7722.	24724.
9	13440.	960.	2989.	655.	741.	1605.	720.	17170.	3940.	21110.
10	12288.	768.	2528.	244.	576.	1584.	720.	15392.	3316.	18708.
11	9096.	426.	2624.	292.	576.	1584.	720.	12296.	3022.	15318.
12	7608.	228.	2656.	308.	576.	1584.	720.	10840.	2840.	13680.
13	7632.	192.	2656.	308.	576.	1584.	720.	10864.	2804.	13668.
14	8172.	192.	2656.	308.	576.	1584.	720.	11404.	2804.	14208.
15	8352.	192.	2656.	308.	576.	1584.	720.	11584.	2804.	14388.
16	8352.	192.	2656.	308.	576.	1584.	720.	11584.	2804.	14388.
17	8352.	192.	2656.	308.	576.	1584.	720.	11584.	2804.	14388.
18	8352.	192.	2656.	308.	576.	1584.	720.	11584.	2804.	14388.
19	8352.	192.	2656.	308.	576.	1584.	720.	11584.	2804.	14388.
20	8352.	192.	2656.	308.	576.	1584.	720.	11584.	2804.	14388.
21	8352.	192.	2656.	308.	576.	1584.	720.	11584.	2804.	14388.
22	7308.	168.	2624.	292.	504.	1512.	720.	10436.	2692.	13128.
23	6264.	144.	2592.	275.	432.	1440.	720.	9288.	2580.	11868.
24	5220.	120.	2560.	260.	360.	1368.	720.	8140.	2468.	10608.
25	4176.	96.	2528.	244.	288.	1296.	720.	6992.	2356.	9348.
26	3132.	72.	2496.	228.	216.	1224.	720.	5844.	2244.	8088.
27	1044.	24.	2432.	196.	72.	72.	720.	3548.	1012.	4560.
28	0.	0.	2400.	180.	0.	0.	0.	2400.	180.	2580.
29	0.	0.	2400.	180.	0.	0.	0.	2400.	180.	2580.
30	0.	0.	2400.	180.	0.	0.	0.	2400.	180.	2580.

TABLE E-27

MEDIUM FIND SCENARIO
12/21/79

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0.	0.	296.	207.	43.	15.	561.	5	588.
2	0.	0.	0.	0.	0.	849.	583.	112.	37.	1581.	6	1581.
3	0.	0.	0.	0.	0.	931.	652.	125.	42.	1750.	6	1750.
4	0.	0.	0.	0.	0.	742.	514.	371.	62.	1689.	9	1937.
5	0.	0.	696.	77.	773.	668.	453.	859.	103.	2083.	6	2121.
6	254.	215.	584.	66.	1118.	1977.	1526.	376.	55.	3933.	6	4100.
7	1272.	1114.	366.	178.	2930.	985.	748.	234.	153.	2120.	1	2930.
8	880.	760.	233.	158.	2051.	1866.	1560.	888.	230.	4545.	6	4545.
9	1574.	1435.	719.	216.	3944.	1420.	1278.	289.	167.	3154.	1	3944.
10	1392.	1292.	289.	170.	3143.	1296.	1148.	291.	170.	2895.	1	3143.
11	1166.	1068.	265.	170.	2671.	1040.	892.	263.	170.	2365.	1	2671.
12	916.	818.	235.	170.	2141.	966.	818.	255.	170.	2209.	6	2209.
13	836.	736.	223.	170.	1965.	996.	848.	255.	170.	2269.	6	2269.
14	881.	781.	223.	170.	2055.	1041.	893.	255.	170.	2359.	6	2359.
15	896.	796.	223.	70.	2085.	1056.	908.	255.	170.	2389.	6	2389.
16	896.	796.	223.	70.	2085.	1056.	908.	255.	170.	2389.	6	2389.
17	896.	796.	223.	70.	2085.	1056.	908.	255.	170.	2389.	6	2389.
18	896.	796.	223.	70.	2085.	1056.	908.	255.	170.	2389.	6	2389.
19	896.	796.	223.	70.	2085.	1056.	908.	255.	170.	2389.	6	2389.
20	896.	796.	223.	70.	2085.	1056.	908.	255.	170.	2389.	6	2389.
21	896.	796.	223.	70.	2085.	1056.	908.	255.	170.	2389.	6	2389.
22	809.	709.	215.	67.	1900.	949.	807.	243.	167.	2166.	6	2166.
23	722.	622.	207.	164.	1715.	842.	706.	231.	164.	1943.	6	1943.
24	635.	535.	199.	161.	1530.	735.	605.	219.	161.	1720.	6	1720.
25	548.	448.	191.	158.	1345.	626.	504.	207.	158.	1497.	6	1497.
26	461.	361.	183.	155.	1160.	521.	403.	195.	155.	1274.	6	1274.
27	287.	187.	83.	65.	622.	307.	201.	87.	65.	660.	6	660.
28	200.	100.	15.	2.	317.	200.	100.	15.	2.	317.	1	317.
29	200.	100.	15.	2.	317.	200.	100.	15.	2.	317.	1	317.
30	200.	100.	15.	2.	317.	200.	100.	15.	2.	317.	1	317.

TABLE E-28

MEDIUM FIND SCENARIO
12/21/79

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	214.	120.	0.	0.	0.	0.	0.	0.	0.	0.	275.	1344.	0.	0.	0.	624.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1344.	0.	0.	0.	312.
2	ONSITE	506.	280.	0.	0.	0.	0.	0.	0.	0.	0.	350.	3136.	0.	400.	0.	1456.
	OFFSITE	3.	280.	0.	0.	0.	0.	0.	0.	0.	0.	0.	3136.	0.	200.	0.	728.
3	ONSITE	504.	320.	0.	0.	0.	0.	0.	0.	0.	0.	400.	3584.	0.	800.	0.	1664.
	OFFSITE	7.	320.	0.	0.	0.	0.	0.	0.	0.	0.	0.	3584.	0.	400.	0.	832.
4	ONSITE	406.	240.	1600.	0.	0.	1736.	0.	0.	0.	0.	300.	2688.	0.	800.	0.	1248.
	OFFSITE	7.	240.	176.	0.	0.	191.	0.	0.	0.	0.	0.	2688.	0.	400.	0.	624.
5	ONSITE	506.	115.	500.	0.	0.	7006.	1009.	0.	0.	0.	200.	896.	0.	2025.	0.	969.
	OFFSITE	20.	115.	55.	0.	0.	771.	111.	0.	0.	0.	0.	896.	0.	1625.	0.	485.
6	ONSITE	965.	260.	0.	368.	0.	930.	1009.	0.	0.	0.	100.	896.	1008.	7025.	875.	3299.
	OFFSITE	66.	260.	0.	40.	0.	102.	111.	0.	0.	0.	0.	896.	1008.	6225.	875.	1645.
7	ONSITE	1229.	132.	0.	0.	0.	0.	0.	0.	1008.	720.	100.	0.	5592.	4300.	0.	1092.
	OFFSITE	41.	132.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	5592.	3200.	0.	546.
8	ONSITE	1807.	209.	0.	657.	3120.	0.	0.	0.	1008.	720.	0.	0.	10176.	4425.	1050.	1351.
	OFFSITE	56.	209.	0.	94.	343.	0.	0.	0.	1008.	720.	0.	0.	10176.	2825.	1050.	676.
9	ONSITE	555.	267.	0.	0.	390.	0.	0.	0.	1008.	720.	0.	0.	13504.	2925.	0.	741.
	OFFSITE	26.	267.	0.	0.	43.	0.	0.	0.	1008.	720.	0.	0.	13504.	1725.	0.	371.
10	ONSITE	1300.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	12416.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	12416.	1200.	0.	288.
11	ONSITE	606.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	9320.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	9320.	1200.	0.	288.
12	ONSITE	626.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	7864.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	7864.	1200.	0.	288.
13	ONSITE	768.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	7888.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	7888.	1200.	0.	288.
14	ONSITE	768.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8428.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8428.	1200.	0.	288.
15	ONSITE	768.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6608.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6608.	1200.	0.	288.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE E-28
(continued)

MEDIUM HIGH SCENARIO
12/21/79

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	1	2	3	4	15	16 **
6	ONSITE	788.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	1200.	0.	288.
7	ONSITE	788.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	1200.	0.	288.
8	ONSITE	788.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	1200.	0.	288.
9	ONSITE	788.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	1200.	0.	288.
20	ONSITE	788.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	1200.	0.	288.
21	ONSITE	788.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	2400.	0.	576.
	OFFSITE	20.	288.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	8608.	1200.	0.	288.
22	ONSITE	712.	252.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	7532.	2400.	0.	504.
	OFFSITE	20.	252.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	7532.	1200.	0.	252.
23	ONSITE	636.	216.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6456.	2400.	0.	432.
	OFFSITE	20.	216.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	6456.	1200.	0.	216.
24	ONSITE	560.	180.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	5380.	2400.	0.	360.
	OFFSITE	20.	180.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	5380.	1200.	0.	180.
25	ONSITE	484.	144.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	4304.	2400.	0.	288.
	OFFSITE	20.	144.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	4304.	1200.	0.	144.
26	ONSITE	408.	108.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	3228.	2400.	0.	216.
	OFFSITE	20.	108.	0.	0.	0.	0.	0.	0.	1008.	720.	0.	0.	3228.	1200.	0.	108.
27	ONSITE	[illegible]	36.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1076.	2400.	0.	72.
	OFFSITE	20.	36.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1076.	1200.	0.	36.
28	ONSITE	80.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2400.	0.	0.
	OFFSITE	20.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1200.	0.	0.
29	ONSITE	80.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2400.	0.	0.
	OFFSITE	20.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1200.	0.	0.
30	ONSITE	80.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2400.	0.	0.
	OFFSITE	20.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1200.	0.	0.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE E-29

MEDIUM FIND SCENARIO
12/21/79

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	2243.	334.	2577.	3899.	454.	4353.	325.	38.	363.
2	5342.	786.	6128.	9406.	1069.	10475.	784.	90.	873.
3	6448.	924.	7372.	11264.	1251.	12515.	939.	105.	1043*
4	5036.	4044.	9080.	8748.	4658.	13406.	729.	389.	1118.
5	4090.	9139.	13229.	7095.	10210.	17306.	592.	851.	1443.
6	13194.	4531.	17726.	23843.	5132.	28975.	1987.	428.	2415.
7	11084.	3089.	14173.	20422.	4990.	25412.	1702.	416.	2118.
8	17002.	7722.	24724.	31729.	10153.	41881.	2644.	846.	3491
9	17170.	3940.	21110.	32770.	6003.	38772.	2731.	501.	3231.
10	15392.	3316.	18708.	29296.	5352.	34648.	2442.	446.	2888.
11	12296.	3022.	15318.	23104.	5058.	28162.	1926.	422.	2'347.
12	10840.	2840.	13680.	20192.	4876.	25068.	1683.	407.	2089.
13	10864.	2804.	13668.	20240.	4840.	25080.	1687.	404.	2090.
14	11404.	2804.	14208.	21320.	4840.	26160.	1777.	404.	2180.
15	11584.	2804.	14388.	21680.	4840.	26520.	1807.	404.	2210.
16	11584.	2804.	14388.	21680.	4840.	26520.	1807.	404.	2210.
17	11584.	2804.	14388.	21680.	4840.	26520.	1807.	404.	2210.
18	11584.	2804.	14388.	21680.	4840.	26520.	1807.	404.	2210.
19	11584.	2804.	14388.	21680.	4840.	26520.	1807.	404.	2210.
20	11584.	2804.	14388.	21680.	4840.	26520.	1807.	404.	2210.
21	11584.	2804.	14388.	21680.	4840.	26520.	1807.	404.	2210.
22	10436.	2692.	13128.	19420.	4692.	24112.	1619.	.391.	2010.
23	9288.	2580.	11868.	17160.	4544.	21704.	1430.	379.	1809.
24	8140.	2468.	10608.	14900.	4396.	19296.	1242.	367.	1608.
25	6992.	2356.	9348.	12640.	4248.	16888.	1054.	354.	1408.
26	5844.	2244.	8088.	10380.	4100.	14480.	865.	342*	1207.
27	3548.	1012.	4560.	5860.	1788.	7648.	489.	149.	638.
28	2400.	180.	2580.	3600.	200.	3800.	300.	17.	317.
29	2400.	180.	2580.	3600.	200.	3800.	300.	17.	317.
30	2400.	180.	2580.	3600.	200.	3800.	300.	,17.	317.

** TOTAL INCLUDES ONSITE AND OFFSITE

TABLE E-30

LOW FIND SCENARIO
12/21/79

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	996.	104.	0.	0.	416.	112.	0.	1412.	216.	1628.
2	1494.	156.	400.	30.	624.	168.	0.	2518.	354.	2872.
3	1992.	268.	800.	60.	832.	224.	0.	3624.	492.	4116.
4	2988.	312.	800.	60.	248.	336.	0.	5036.	708.	5744.
5	996.	104.	800.	938.	416.	112.	0.	2212.	1154.	3366.
6	498.	52.	2450.	1912.	1314.	490.	0.	4262.	2454.	6716.
7	2016.	216.	2800.	3461.	1282.	496.	0.	6098.	4173.	10272.
8	5784.	414.	525.	53.	453.	693.	480.	6762.	1640.	8401.
9	5952.	432.	0.	0.	216.	600.	480.	6168.	1512.	7680.
10	3936.	216.	96.	48.	216.	600.	480.	4248.	1344.	5592.
11	2760.	90.	96.	48.	216.	600.	480.	3072.	1218.	4290.
12	2592.	72.	96.	48.	216.	600.	480.	2904.	1200.	4104.
13	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
14	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
15	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
16	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
17	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
18	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
19	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
20	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
21	3132.	72.	96.	48.	216.	600.	480.	3444.	1200.	4644.
22	2088.	48.	64.	32.	144.	528.	480.	2296.	1048.	3384.
23	1044.	24.	32.	16.	72.	72.	480.	1148.	592.	1740.
24	1044.	24.	32.	16.	72.	72.	480.	1148.	592.	1740.
25	1044.	24.	32.	16.	72.	72.	480.	1148.	592.	1740.
26	1044.	24.	32.	16.	72.	72.	480.	1148.	592.	1740.
27	1044.	24.	32.	16.	72.	72.	480.	1148.	592.	1740.

TABLE E-31

LOW FIND SCENARIO
1/22/79

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0.	0.	149.	138.	28.	10.	365.	5	365.
2	0.	0.	0.	0.	0.	471.	397.	56.	17.	851.	6	851.
3	0.	0.	0.	0.	0.	578.	376.	71.	22.	1047.	6	1047.
4	0.	0.	0.	0.	0.	742.	514.	97.	32.	1385.	6	1412.
5	0.	0.	0.	0.	0.	389.	238.	175.	26.	828.	8	876.
6	0.	0.	0.	0.	0.	590.	498.	238.	33.	1359.	10	1572.
7	508.	429.	534.	62.	1533.	738.	656.	446.	50.	1889.	6	1932.
8	694.	655.	169.	81.	1605.	532.	514.	126.	81.	1253.	1	1605.
9	496.	496.	126.	81.	1199.	532.	514.	126.	81.	1253.	5	1253.
10	496.	496.	126.	81.	1199.	332.	314.	114.	81.	841.	1	1199.
11	272.	272.	102.	81.	727.	276.	258.	108.	81.	723.	1	727.
12	215.	215.	96.	81.	609.	276.	258.	108.	81.	723.	6	723.
13	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
14	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
15	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
16	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
17	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
18	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
19	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
20	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
21	261.	261.	96.	81.	699.	321.	303.	108.	81.	813.	6	813.
22	174.	174.	88.	76.	514.	214.	202.	96.	76.	590.	6	590.
23	87.	87.	48.	43.	265.	107.	101.	52.	43.	303.	6	303.
24	87.	87.	48.	43.	265.	107.	101.	52.	43.	303.	6	303.
25	87.	87.	48.	43.	265.	107.	101.	52.	43.	303.	6	303.
26	87.	87.	48.	43.	265.	107.	101.	52.	43.	303.	6	303.
27	87.	87.	48.	43.	265.	107.	101.	52.	43.	303.	6	303.

TABLE 32

[illegible] FLOW SCENARIO
[illegible]

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/SITE		[illegible]	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	[illegible]	[illegible]	0.	0.	0.	0.	0.	0.	0.	0.	100.	896.	0.	0.	0.	416.
	OFFSITE	0.	[illegible]	0.	0.	0.	0.	0.	0.	0.	0.	0.	896.	0.	0.	0.	208.
2	ONSITE	234.	120.	0.	0.	0.	0.	0.	0.	0.	0.	150.	1344.	0.	400.	0.	624.
	OFFSITE	3.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1344.	0.	200.	0.	312.
3	ONSITE	332.	160.	0.	0.	0.	0.	0.	0.	0.	0.	200.	1792.	0.	800.	0.	832.
	OFFSITE	7.	160.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1792.	0.	400.	0.	416.
4	ONSITE	466.	240.	0.	0.	0.	0.	0.	0.	0.	0.	300.	2688.	0.	600.	0.	1248.
	OFFSITE	7.	240.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2688.	0.	400.	0.	624.
5	ONSITE	196.	80.	878.	0.	0.	0.	0.	0.	0.	0.	00.	896.	0.	800.	0.	416.
	OFFSITE	7.	80.	97.	0.	0.	0.	0.	0.	0.	0.	0.	896.	0.	400.	0.	208.
6	ONSITE	677.	110.	0.	0.	0.	1092.	575.	0.	0.	0.	50.	448.	0.	2450.	0.	1314.
	OFFSITE	27.	110.	0.	0.	0.	120.	63.	0.	0.	0.	0.	448.	0.	2450.	0.	657.
7	ONSITE	933.	80.	0.	368.	0.	2418.	375.	0.	0.	0.	0.	0.	2016.	2275.	525.	1282.
	OFFSITE	33.	80.	0.	40.	0.	266.	41.	0.	0.	0.	0.	0.	2016.	2275.	525.	641.
8	ONSITE	[illegible]	123.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	5744.	525.	0.	453.
	OFFSITE	[illegible]	123.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	5744.	525.	0.	227.
9	ONSITE	[illegible]	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	5952.	0.	0.	216.
	OFFSITE	0.	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	5952.	0.	0.	108.
10	ONSITE	[illegible]	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	4032.	0.	0.	216.
	OFFSITE	0.	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	4032.	0.	0.	108.
11	ONSITE	[illegible]	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	2856.	0.	0.	216.
	OFFSITE	0.	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	2856.	0.	0.	108.
12	ONSITE	[illegible]	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	2688.	0.	0.	216.
	OFFSITE	0.	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	2688.	0.	0.	108.
13	ONSITE	[illegible]	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
14	ONSITE	[illegible]	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
15	ONSITE	228.	104.	0.	0.	0.	0.	0.	0.	384.	450.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	104.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.

** [illegible]

LOW FIND SCENARIO
12/21/79

TABLE 32
(continued)

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10		12	13	14	15	16 **
16	ONSITE	228.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
17	ONSITE	228.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
18	ONSITE	228.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
19	ONSITE	228.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
20	ONSITE	228.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
21	ONSITE	228.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	216.
	OFFSITE	0.	108.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	3228.	0.	0.	108.
22	ONSITE	152.	72.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	2152.	0.	0.	144.
	OFFSITE	0.	72.	0.	0.	0.	0.	0.	0.	384.	480.	0.	0.	2152.	0.	0.	72.
23	ONSITE	76.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	72.
	OFFSITE	0.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	36.
24	ONSITE	76.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	72.
	OFFSITE	0.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	36.
25	ONSITE	76.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	72.
	OFFSITE	0.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	36.
26	ONSITE	76.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	72.
	OFFSITE	0.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	36.
27	ONSITE	76.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	72.
	OFFSITE	0.	36.	0.	0.	0.	0.	0.	0.	0.	480.	0.	0.	1076.	0.	0.	36.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE E-33

F NO SCENARIO
12/77

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	1412.	216.	1628.	2516.	296.	2812.	210.	25.	235.
2	2518.	354.	2872.	4374.	477.	4851.	365.	40.	405.
3	3624.	492.	4116.	6232.	659.	6891.	520.	55.	575.
4	5036.	708.	5744.	8748.	955.	9703.	729.	80.	809.
5	2212.	1154.	3366.	3716.	1337.	5053.	310.	112.	422.
6	4262.	2454.	6716.	7817.	2774.	10591.	652.	232.	883.
7	6099.	4173.	10272.	11555.	4634.	16189.	963.	387.	1350.
8	6762.	1640.	8401.	13298.	2632.	15930.	1109.	220.	1328.
9	6168.	1512.	7680.	12228.	2484.	14712.	1019.	207.	1226.
10	4248.	1344.	5592.	8388.	2316.	10704.	699.	193.	892.
11	3072.	1218.	4290.	6036.	2190.	8226.	503.	183.	686.
12	2904.	1200.	4104.	5700.	2172.	7672.	475.	181.	656.
13	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
14	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
15	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
16	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
17	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
18	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
19	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
20	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
21	3444.	1200.	4644.	6780.	2172.	8952.	565.	181.	746.
22	2256.	1088.	3344.	4520.	2024.	6544.	377.	169.	546.
23	1148.	592.	1740.	2260.	1108.	3368.	189.	93.	281.
24	1148.	592.	1740.	2260.	1108.	3368.	189.	93.	281.
25	1148.	592.	1740.	2260.	1108.	3368.	189.	93.	281.
26	1148.	592.	1740.	2260.	1108.	3368.	189.	93.	281.
27	1148.	592.	1740.	2260.	1108.	3368.	189.	93.	281.

** TOTAL INCLUDES ONSITE AND OFFSITE

APPENDIX F

APPENDIX F

THE MARKETING OF NORTON BASIN OIL AND GAS

(This was conducted separately from the remainder of the scenario study and will be incorporated later when review of a draft is complete).