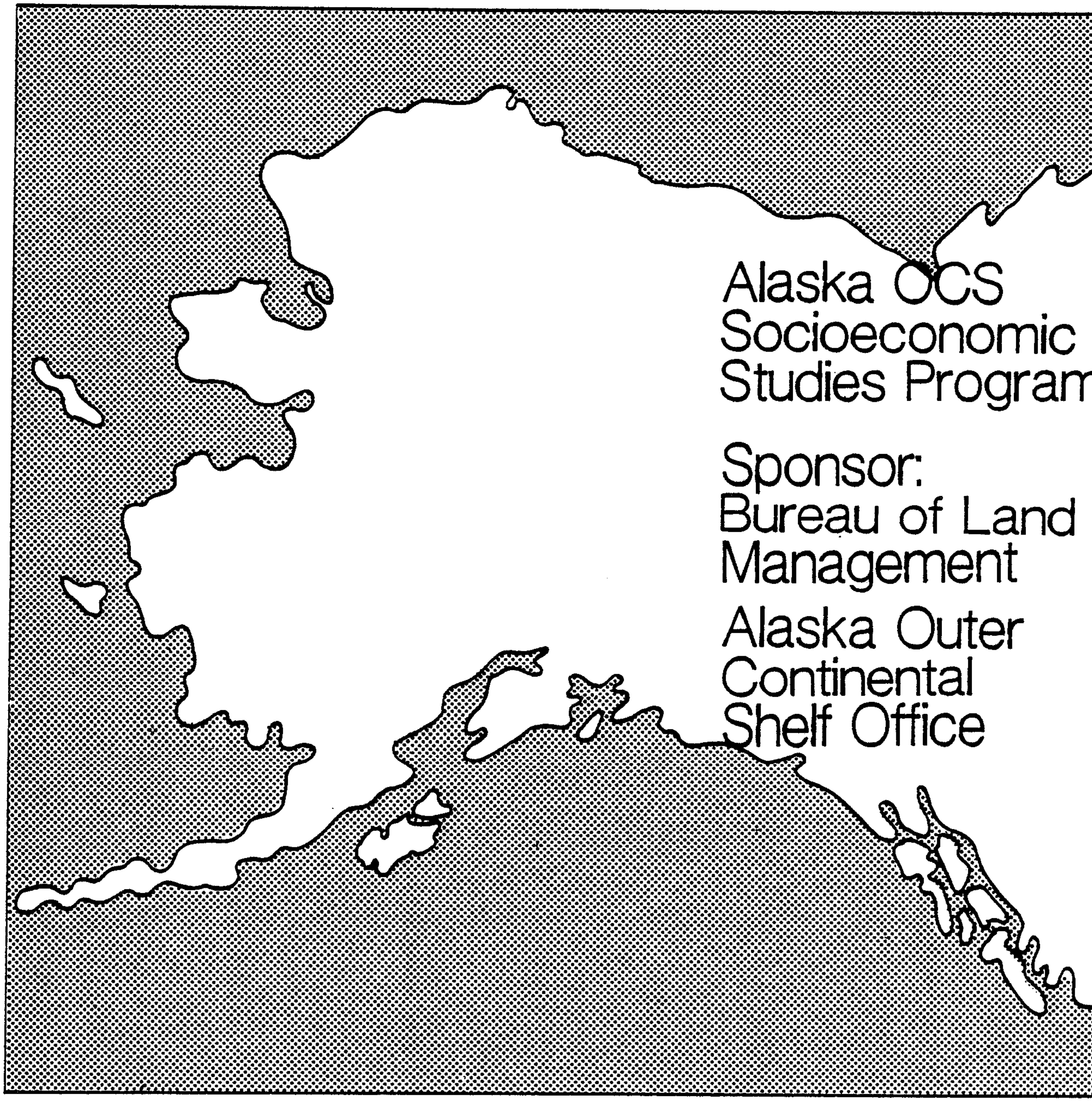
Technical Report Number 79



Alaska OCS
Socioeconomic
Studies Program

Sponsor:
Bureau of Land
Management
Alaska Outer
Continental
Shelf Office

Chukchi Sea
Petroleum Technology Assessment

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 (NEPA) 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

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
BARROW ARCH PLANNING AREA
(CHUKCHI SEA)
PETROLEUM TECHNOLOGY ASSESSMENT
OCS LEASE SALE NO. 85

Prepared for

MINERALS MANAGEMENT SERVICE
ALASKA OUTER CONTINENTAL SHELF OFFICE

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1.0 INTRODUCTION

1.1 Purposes

The principal purpose of this study is to identify the petroleum technology that may be used to develop oil and gas resources for the Barrow Arch OCS Lease Sale No. 85. This analysis focuses on both the individual field development components (types of platforms, pipelines, etc.) and the overall field development and transportation strategies. An evaluation of the environmental constraints (oceanography, geology, etc.) defines the most suitable engineering strategies.

The second purpose of this study is to assess the economic viability of various development strategies. In view of the severe ice conditions, harsh environment and remote location of the Barrow Arch planning area, the economic analysis has focused on the economic viability of different combinations of exploration and production concepts along with various transportation alternatives. The third purpose is to estimate the manpower required to construct and operate the facilities selected for analysis.

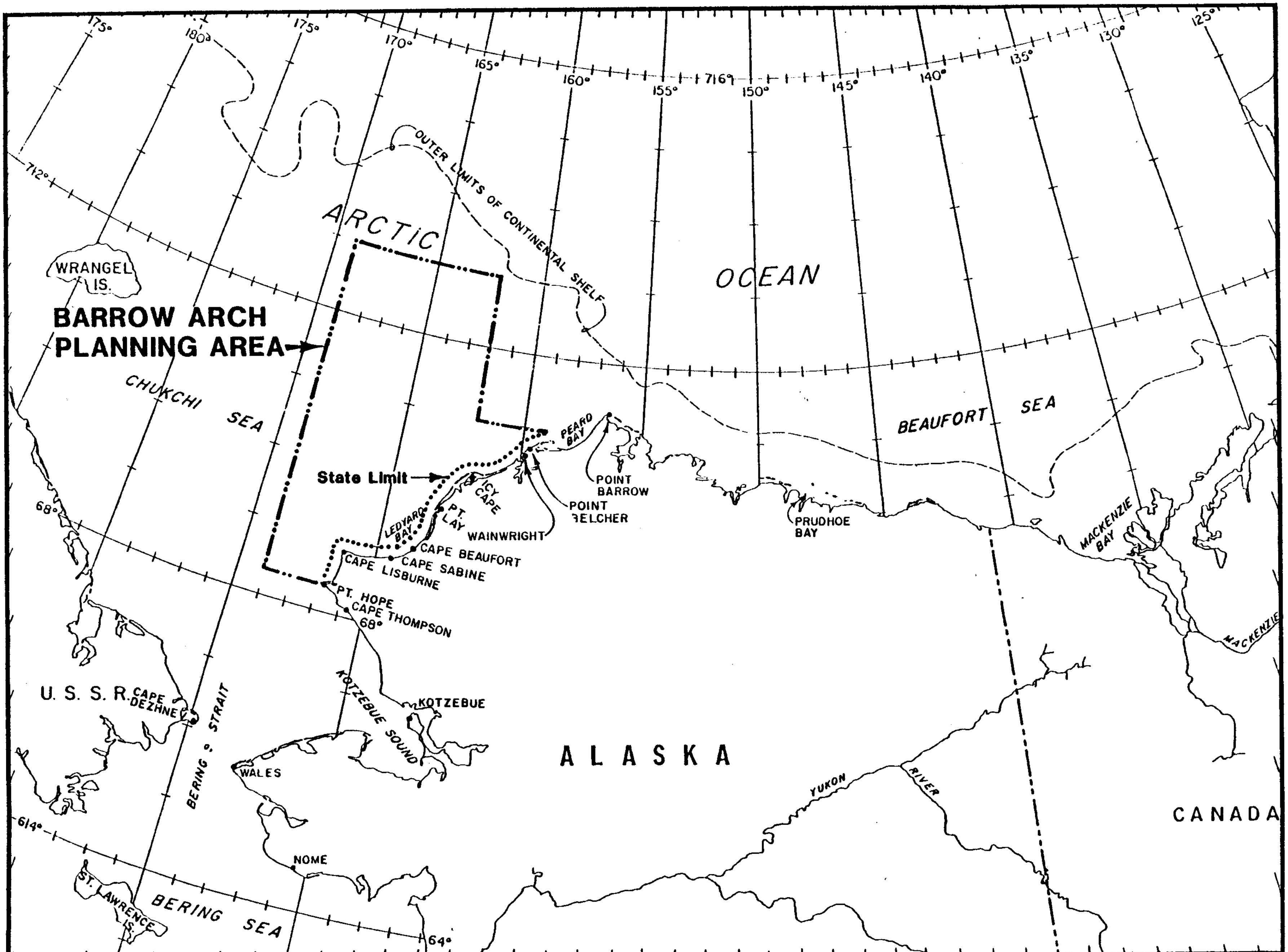
1.2 Background and Scope

This petroleum technology assessment is for the Barrow Arch Lease Sale No. 85. Scheduled for February 1985, it will be the first lease sale in the Barrow Arch planning area, one of three arctic planning areas. It will be preceded by two sales in the Diapir Field arctic planning area, Diapir Field Lease Sale No. 71 and Diapir Field Lease Sale No. 87 (scheduled for September 1982 and June 1984, respectively). A proposed lease sale for the third arctic planning area, the Hope Basin, was recently deleted from the 5-year OCS oil and gas leasing schedule. Barrow Arch planning area, the subject of this report, was formerly called the Chukchi Sea planning area until its boundaries were modified to better represent underlying geologic structures. It was reduced in size so that certain geologic formations could be consolidated into the Diapir Field, formerly called the Beaufort Sea planning area. The present Barrow Arch planning area encompasses the area shown in Figure 1-1, which is bounded on the north by 73° N latitude, on the east by the 162° W meridian running south to 71° N latitude where the boundary runs eastward until it reaches the 3-mile limit of Alaska waters; it is roughly bounded on the south by a line westward from Point Hope (about 68° 15'N latitude) and to the west by the U.S.-Russia Convention Line of 1867 (about 169° W longitude).

This study is structured to provide "building blocks" of the petroleum facilities, equipment, costs, and employment that can be used by Minerals Management Service Alaska OCS Region staff to evaluate nominated lease tracts. Six scenarios involving a total of 12 feasible field development strategies for oil and gas (types of platforms, transportation options, etc.) were examined; all of these development strategies, while technically feasible, are uneconomic to marginally sub-economic under the assumptions given.

Petroleum technology, in conjunction with the regulatory framework and any stipulations, will influence or determine the scheduling of offshore and onshore activities, the local employment and infrastructure support requirements, and the potential risks involved in the production and transportation of hydrocarbons and related potential for environmental impacts. Thus, this petroleum technology assessment provides a key part of the necessary framework to assess the environmental and socioeconomic impacts of petroleum development in the Barrow Arch planning area.

This report provides early information for the Minerals Management Service to initiate planning for the lease sale. As such, this is part of the regulatory process for OCS development, but specific stipulations regarding this lease sale are not known at this time. Therefore, our scheduling assumptions for development scenarios (specifically Sections 6.2.3 and 7.2) make only a general allowance for the permit process. We make the optimistic assumption that permits are not the critical path to a field's development (see discussion in Section 6.3). It is basically assumed that permits can be successfully obtained simultaneous with other early development steps. This is feasible to a point (Pritchard 1982), but



Source: Webster 1982

Figure 1-1
GENERAL LOCATION MAP
OF PROPOSED BARROW ARCH OCS LEASE SALE NO. 85 IN THE NORTHEAST CHUKCHI SEA

the ultimate commitment of the decision to develop is significantly affected by permitting requirements.

It should be emphasized that this report is specifically designed to provide petroleum development data for the Alaska OCS socioeconomic studies program. This study, along with other studies conducted by or for the Minerals Management Service, including environmental impact statements, is required to use U.S. Geological Survey estimates of recoverable oil and gas. However, at the time this report was prepared, no U.S. Geological Survey resources report was available specifically for the Barrow Arch planning area. Therefore, estimates of recoverable oil and gas were obtained from the recent National Petroleum Council's report on U.S. Arctic Oil and Gas (1981) and an independent evaluation of the area's petroleum geology (Appendix A). Therefore, the assumptions used in the analysis may be subject to revision as new data become available.

The principal components of this study are:

- An evaluation of the environmental constraints (oceanography, geology) that will influence or determine petroleum engineering field development and transportation strategies (Chapter 3.0).
- A review of state-of-the-art and conceptual technology for exploration, production and transportation of oil and gas from arctic regions (Chapter 3.0).
- A description of various field development components, strategies and related technical problems (Chapter 3.0).
- A discussion of facilities siting to identify suitable shore sites for petroleum facilities such as crude oil terminals, LNG plants and support bases (Chapter 4.0).

- An analysis of the manpower requirements to explore, develop, and produce Barrow Arch petroleum resources in the context of projected technology, and environmental and logistical constraints. This includes specification of manpower requirements by individual tasks and facilities. (Chapter 5.0).

- A review of the petroleum geology of the Barrow Arch planning area to formulate reservoir and production assumptions necessary for the economic analysis (Appendix A).

- An economic analysis of Barrow Arch petroleum resources in the context of projected technology, facility and equipment costs, and assumed reservoir characteristics (Chapter 6.0).

- Specification of the facility, equipment requirements and probable production for a hypothetical development case corresponding to the National Petroleum Council's statistical mean oil and gas resource estimate for the basin's central Chukchi shelf (Chapter 7.0).

1.3 Data Gaps and Limitations

Results of this study are preliminary and should be reviewed in the context of the constraints imposed on the analysis by significant data gaps. This study is based upon available data such as the geophysical records of the U.S. Geological Survey and the results of the oceanographic surveys conducted by the National Oceanic and Atmospheric Administration and other agencies. No proprietary data were available to this study, although both agency and industry reviews of important technical, geologic, and economic assumptions were made.

The principal data gaps include:

- Oceanography -- Data on the seasonal extent and annual variation of landfast ice and multiyear pack ice coverage for the Chukchi Sea are still limited. Even more limited are data on dynamic ice movement and forces generated, critical data for platform design and overall production feasibility.

- Petroleum Geology -- Geophysical data for the Barrow Arch planning area are extremely limited and deficient. Seismic data is of a reconnaissance nature and was collected from U.S. Coast Guard icebreakers with limited equipment. Seismic lines obtained are few and relatively short. No attempts were made to define structural traps. In addition, seismic coverage of the Chukchi Sea was limited by ice coverage in several areas. While more recent geophysical data has been obtained by the U.S. Geological Survey, it had not been analyzed at the time this report was prepared.

- Facility Cost -- The petroleum facility cost estimates (for platforms, pipelines, terminals, etc.) are tentative; no petroleum exploration and production has yet taken place with the same conditions that may provide direct operational and cost experience.

1.4 Report Content and Format

This report was written as one of two reports assessing oil and gas development technologies for the two proposed Chukchi Sea lease sale planning areas. In addition to the Barrow Arch planning area, which is the subject of this report, the Hope Basin planning area, recently deleted from the Interior Department's proposed 5-year OCS oil and gas leasing schedule, was also studied. The study methodology is basically the same as that employed by Dames & Moore in preparing previous petroleum technology assessments for other Alaska OCS lease sale planning areas. However, the report's analytical approach was structured to accommodate both Chukchi Sea study areas. While appropriate sections of previous studies in this series are incorporated by reference, the basic data set for this analysis is unique to the Chukchi Sea and was specifically assembled for this report. Contrasts between this area and other Alaska OCS lease sale areas have been identified where appropriate.

This report commences with a summary of findings (Chapter 2.0). The results of the petroleum technology assessment are presented in Chapter 3.0. Onshore sites for petroleum facilities are discussed in Chapter 4.0. Chapter 5.0 details the manpower requirements by task, activity, and facilities for the particular technologies described in Chapter 3.0. The results of the economic analysis are presented in Chapter 6.0. Chapter 7.0, based upon the resources estimates for the central Chukchi shelf assembled by the National Petroleum Council (1981) concludes the main body of the report with a description of a hypothetical development case.

Appendix A presents a description of the Barrow Arch petroleum geology and the reservoir assumptions of the technology assessment. Appendix B gives the economic parameters, petroleum development costs and scheduling assumptions upon which the economic analysis is based.

2.0 SUMMARY OF FINDINGS

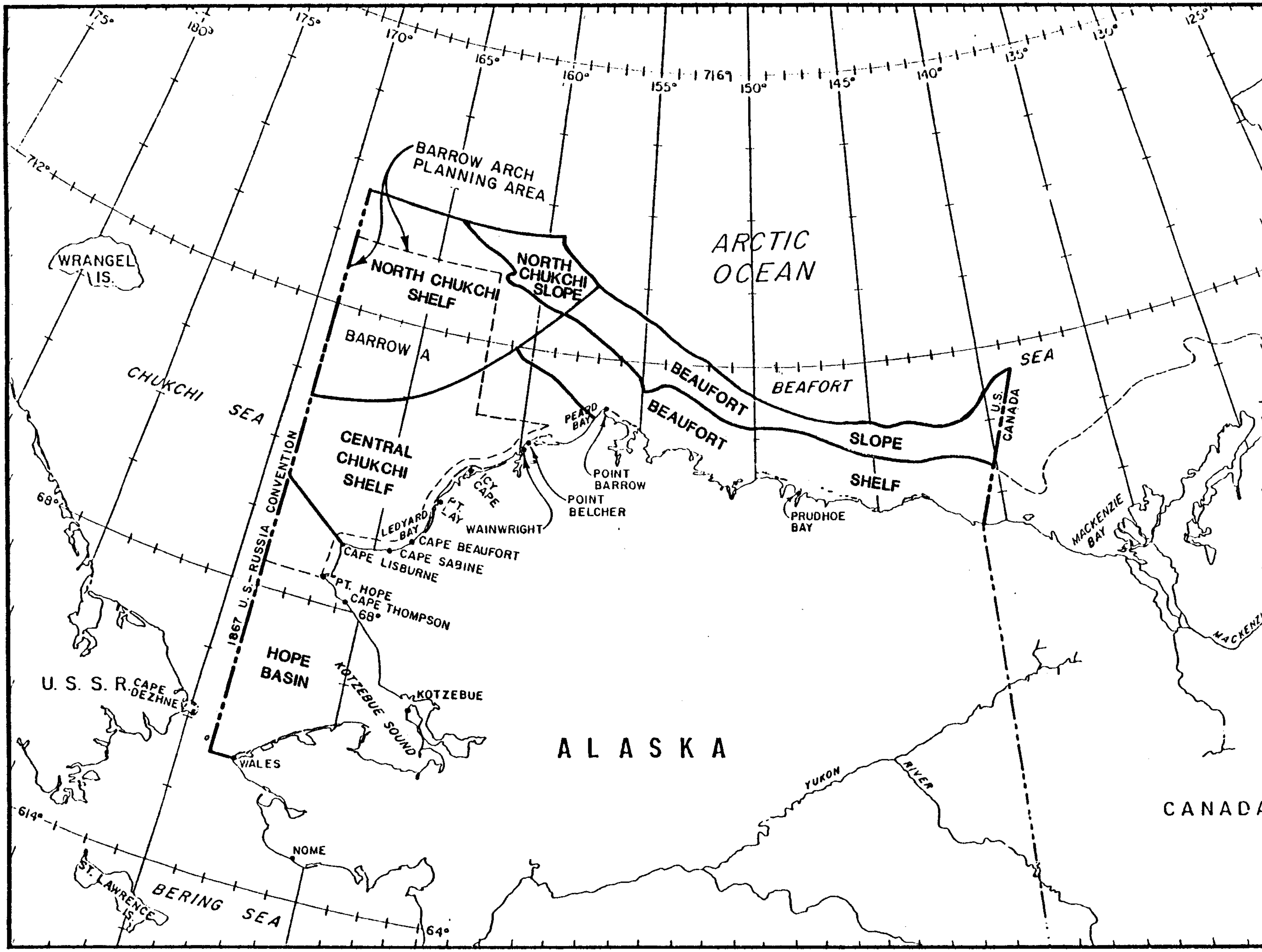
Throughout the course of this study, we have selected assumptions regarding oil production characteristics, schedules and economic parameters that are realistic but favorable for Barrow Arch planning area oil development. Therefore, our findings should be used with these favorable assumptions in mind.

2.1 Petroleum Geology

The Barrow Arch planning area covers a vast area of outer continental shelf below the Chukchi Sea. Within this area, we have identified three zones with favorable prospects for hydrocarbon accumulation. The most favorable is located in the geologic subregion referred to as the central Chukchi shelf (Figure 2-1). This includes a very thick sedimentary section and many anticlines in the offshore extension of the Colville Trough -- the province of North Slope oil and gas. The most promising area in the central Chukchi shelf is along the northern coast. This area is also attractive for petreolum development because much of it is nearshore, extending from the shoreline across the shallowest federal waters. Within this coastal strip, the northern sector of the central shelf is by far the most favorable of all the Chukchi Sea.

Two other zones with petroleum potential were considered secondary candidates for oil development. One is the southern part of the central Chukchi shelf, which is an overthrust zone associated with the Herald Arch. The other is the north Chukchi shelf, which is comprised of great thicknesses of (inferred) Cretaceous and Tertiary rocks containing shale diapirs. This latter zone is in deeper water, further from shore and to the north.

Our study concentrated on conditions in the most favorable area on the validated assumption that major petroleum finds would be needed to encourage initiation of petroleum development in this arctic region. It does indeed appear geologically possible that a giant oil field (on the order of one



Source: National Petroleum Council 1981; Webster 1982.

Figure 2-1
ARCTIC OFFSHORE OIL & GAS PROVINCES

billion barrels) could occur in this zone. Potential reservoir rocks here include major North Slope producers such as the Sadlerochit Formation and the Kuparuk River sandstones.

These reservoirs should range from 1,500 to 7,500 meters (5,000 to 25,000 feet) deep with an average well depth of around 3,000 meters (10,000 feet), which is favorable for maximum drainage from a single platform.

A USGS resources report has not been published specifically for Barrow Arch planning area at this writing. From our analysis of the petroleum geology, including conversations with USGS and review of the National Petroleum Council (1981) estimates, we utilized the following tentative values for the central Chukchi shelf:

Oil	1.5 billion barrels
Gas	4.5 trillion cubic feet.

2.2 Environmental Constraints

There are several stringent environmental characteristics of the Barrow Arch planning area, and the clearly dominating factor constraining offshore activities is sea ice. Great forces are generated by moving ice, and in this area the strong multi-year pack ice is the controlling design parameter. The sea ice also constrains marine construction operations since most of these require open-water conditions; the open-water season is brief and its duration unpredictable.

When the sea ice has retreated, there is then the potential for large storm waves. Fog is also most common during the summer season. There are virtually no natural harbors along this entire 700-kilomter (450-mile) coastline that offer significant depths and protection, only some shallow lagoons behind low barrier beaches.

Storms and extremely low temperatures will reduce the efficiency and increase attention to safety for all operations in this area.

Water depths in the Barrow Arch planning area range from 10 to 100 meters (30 to 300 feet) -- not great by world standards of offshore oil operations. However, even shallow depths are costly to develop because of the sea ice. The seafloor is generally of low relief; it can be characterized as having a narrow nearshore strip, about 15 meters (50 feet) deep, along the 3-mile state-federal offshore boundary and a large area beyond that averaging close to 37 meters (120 feet) of water. The transition zone between these typical depths occurs over a relatively short distance; 27 meters (90 feet) is a representative depth for this thin zone. Thirty meters (100 feet) may be considered the start of "deep water" conditions for offshore development in the Chukchi Sea.

Seafloor conditions are believed to consist of generally stable clastic sediments. Some areas of sands and gravels, desirable as construction materials, occur in the area, particularly nearshore. Seismic activity is not unknown, but is low.

Environmental hazards in the area include bottom scour from pressure ridges and tabular icebergs, river flooding of shorefast ice, strudel scouring, high storm tides, rapid currents in tidal passes, rapid coastal erosion, ice ride-up and override events.

Remoteness and the complete lack of infrastructure will also constrain exploration operations and production developments. This and other environmental conditions require that if any oil is delivered from this area, it will entail major projects.

2.3 Petroleum Technologies and Production Strategies

Unlike non-arctic OCS areas, the Barrow Arch planning area will include exploration technologies of a scale and magnitude approaching that of the production platforms elsewhere. Exploration techniques appropriate to Chukchi Sea conditions have begun to be applied in the Canadian and Alaska Beaufort Sea. Exploration drilling at shallower sites will rely mainly on artificial fill islands (with caisson-retained designs being more favored as depths increase) and special arctic drilling platforms that are bottom-founded, especially towards the north. More conventional exploration from ice-designed floating drilling platforms will be considered, especially towards the south; these will have to restrict their schedules around the short open-water season and are limited by shallow waters since a minimum depth is necessary for floating drilling. Based on information published by the National Petroleum Council (1981), oil and gas resources are not considered recoverable with present technology in areas of Arctic pack ice where water depths are greater than 60 meters (200 feet).

Marine support bases will have to be built from scratch at remote sites. Dredging may be needed to provide suitable harbor facilities.

Production platforms will be either artificial fill construction or a concrete or steel monocone design. The latter would be constructed in a deepwater shipyard and towed to the site for installation. These designs provide ice resistance by breaking the floes in flexure (rather than crushing ice-like Cook Inlet-type designs).

Artificial fill islands will most likely be constructed by dredging methods using coarser sediments from nearby seafloor sources. Unretained natural (angle-of-repose) slopes must be provided protection from ice and wave attack, and these islands will be used mainly in shallower sites. Caisson-retained fill islands may be used for shallow or deep sites and will be the favored design for deeper areas. This concept is intermediate in construction techniques, requiring shipyard manufacture, tow-out, and fill placement. Dredging will be needed to both fill the cassion and to provide an underwater berm to set it on.

The two transportation modes -- tankers or pipeline -- have relatively restricted options in the Chukchi Sea for their implementation. Ice-breaking tankers will require a marine terminal constructed for sea ice operation. In the Barrow Arch planning area, there are no ideal natural sites for such a facility, and the most favorable conditions are found to the north in the Wainwright vicinity.

Ice-breaking tankers would be a dedicated fleet to carry Chukchi Sea oil to an Aleutian Island transshipment terminal. From there the oil would be moved to market in very large crude carriers (VLCC).

Marine pipelines must be constructed if the oil is to come ashore for tankers or for onshore pipeline transport to market. These offshore pipelines must be buried over most of their length to protect them from moving ice keels. Nearshore routes and shoreline crossing are not only vulnerable to frequent and deep ice-gouging, they may also encounter subsea permafrost conditions. Further, the marine pipelines can be constructed only during the open-water season.

A major onshore arctic pipeline to carry Chukchi Sea oil to market would be similar in concept and effort to the proven trans-Alaska pipeline system (TAPS). This analysis focuses on the scenario of a 500-kilometer (300-mile) pipeline running eastward across the North Slope to link up with the existing TAPS. A shorter overland pipeline southward to a new marine terminal at Cape Thompson is also addressed in connection with a discovery toward the southern central Chukchi shelf.

The APLA (for artificial [or arctic] production and loading atoll) concept combines production platform and marine terminal functions in a single massive offshore facility. This concept would be constructed by new very high capacity dredging operations and would require significant seafloor sources of fill materials.

Tanker loading in the presence of ice, whether offshore or at a coastal site, is an operation requiring experience with specific new designs.

2.4 Manpower

Manpower needs for Chukchi Sea offshore exploration, construction and production tasks have been estimated in this study. Significant considerations are the harsh arctic conditions, strong seasonal constraints on construction period, and the remoteness requiring long transit to the area and the need for enclave living. The labor needs and conditions are generally analogous to the establishment of the Prudhoe Bay field.

All phases of offshore petroleum development will probably take longer to accomplish than similar operations elsewhere.

2.5 Economics of Oil and Gas Development

The economic feasibility of developing discovered oil in the central Chukchi shelf of the Barrow Arch planning area is very much associated with mega-concepts -- mega-fields, mega-dollars, and mega-production and transportation hurdles. Production technologies, although technically feasible, are extremely costly even in the more favorable geologic and environmental locations. Hence, billion-barrel fields show only marginal economic results given the assumptions and estimated values used in this analysis.

Our analysis indicates that development of a very nearshore billion-barrel field offers a real after-tax rate of return (ROR) of about 10 percent and would cost approximately $6 to $7 billion (1982) to develop. At the 37-meter (120-foot) water depths more typical of the central Chukchi shelf, ROR's are on the order of 8 percent for an investment of about $8 billion (1982).

Assuming a 12 percent real after-tax hurdle rate is sufficient to attract multi-billion dollar oil industry investments in the Chukchi Sea, minimum field sizes to justify development will have to exceed 1.0 billion barrels (about 1.25 billion in shallow water and 1.5 billion in deeper waters).

In general, the caisson-retained gravel islands and concrete monocones appear to be economically preferred offshore systems. Unretained gravel islands are attractive in only the shallower waters. APLA's are so expensive as to be uneconomic at this time.

In order for the deeper water portions of the Barrow Arch planning area to become commercial, an offshore loading system more cost-effective than the APLA must be developed. If such a system were developed, it might also render the central Chukchi shelf more economic by obviating the need for costly shore terminals and pipelines.

Assuming that offshore oil development does occur (and barring a breakthrough in technology of offshore loading in sea ice), our analysis shows that a pipeline to TAPS is competitive with an ice-breaking (Class 7) shuttle tanker fleet for transporting crude to an ice-free VLCC port. If more detailed cost analyses bear out our estimates, the decision between the two approaches may turn not on economics, but on the trade-off between the environmental considerations of a long onshore arctic pipeline connecting the Barrow Arch planning area to TAPS versus the risks of tanker operations in the ice-infested waters of the Chukchi and Bering Seas.

Even giant natural gas fields (in the 4 trillion cubic feet range) are far from commercial under current technologies and prices. Under the most favorable conditions, our analysis indicates real, after-tax ROR's in the 5 to 7 percent range. Even substantially larger gas fields would not show appreciably higher rates of return because the largest cost components -- offshore equipment and tankers -- offer only limited economies of scale. For gas resource development to become economic, either a 50 percent (real) cost escalation in gas prices or a technical break through in gas transportation systems is required. This means gas would have to sell in excess of $10.00 per thousand cubic feet in 1982 dollars.

It is essential to keep in mind the large number of interactive assumptions and estimated parameter values that drive our economic analysis. A great many geologic assumptions, estimated platform and reservoir engineering considerations, as well as prices and costs, are derived in our research. In most cases the values for the variables that drive the economic results are realistic but favorable. Thus, our results are optimistically biased. The analysis is done in constant 1982 dollars; that is, the relationship between prices and costs is assumed to hold constant. The oil price assumed is $31.50 FOB Aleutians. LNG, valued at its diesel equivalent, is assumed to be worth $6.75 per thousand cubic feet, C.I.F. southern California. To the extent that energy prices escalate faster than development costs, our results are conservative, and development would be more favorable than indicated. If, however, costs inflate faster than energy prices, our results become even more optimistic.

3.0 RESULTS OF THE PETROLEUM TECHNOLOGY ASSESSMENT

3.1 Introduction

The technology assessment for the Barrow Arch planning area has four major elements:

- An assessment of the environmental forces and operating conditions that will influence the design, selection and location of offshore facilities, including platforms and pipelines, and the overall field development and transportation strategy.

- A description of selected field development components, their design parameters and installation techniques.

- Identification of field development strategies that may be adopted to develop oil and gas resources in the eastern Chukchi Sea. The field development strategy involves the sum of the various field development components (platforms, wells, process equipment, pipelines, terminals, etc.) and the transportation system for either oil or gas. Included in this evaluation is a discussion of such areas as: trade-offs between artificial islands and other platforms, ice-breaker tanker transport vs. pipelines to ice-free ports, techniques to develop marginal fields, and the application of subsea systems.

- Identification and selection of field development components and strategies as scenarios to be used for the economic analysis.

In previous technology assessments in this series, Dames & Moore has presented more detailed descriptions of different types of arctic and sub-arctic petroleum technologies. The reports on Beaufort Sea Petroleum Development Scenarios (Dames & Moore 1978) and Bering-Norton Petroleum

Development Scenarios (Dames & Moore, 1980a) contain an extensive discussion of arctic and sub-arctic petroleum technologies. These reports presented descriptions of artificial islands, cones and monocones that are relevant to this study. Rather than reiterate these descriptions, the reader is referred to these technical discussions that provide background for the conclusions in this report.

From this broad evaluation of arctic oil and gas technologies, a subset of specific exploration, production and transportation technologies and systems tailored to the environment and operational conditions of the Chukchi Sea was selected. Assembled into a technology model incorporating assumptions about field size, location and alternate production strategies, it formed the basis for the economic analysis contained in Chapter 6.0. Each of the technological components included in this subset for economic analysis is discussed later in this chapter.

This chapter commences with an evaluation of environmental constraints. It is important to note that this discussion of environmental constraints is based upon current, publicly available data. In comparison to other OCS lease sale planning areas, this data base is very limited. In particular, data on sea ice characteristics and behavior, critical factors affecting exploration and production concepts, are very limited. Our study team includes industry expertise in sea ice engineering to provide experienced judgment regarding ice design parameters. Several proprietary data collection efforts by industry have been completed or are being planned; however, these were not available for this analysis, hence our conclusions should be regarded as preliminary. In particular, our approach with respect to platform design and operational constraints is conservative. The chapter concludes with a discussion of field development strategies for the Chukchi Sea that warrant economic evaluation.

3.2 Environmental Constraints to Petroleum Development

3.2.1 Meteorology and Oceanography

3.2.1.1 Meteorology

The climate of Alaska's northern and northwestern coast is classified as arctic by the National Weather Service. Summer weather is characterized by cool marine winds, frequent but light precipitation and considerable cloudiness and fog. In winter the cloudiness decreases and very cold winds prevail. A light snow cover is established by mid-September and persists until June or July. Below freezing air temperatures are the rule except in June, July, August and early September.

Although meteorological information has been systematically collected in the Arctic from coastal stations since World War II, available data records are still somewhat limited, relative to sub-arctic OCS areas. Particularly lacking are data from offshore areas due to the limited vessel traffic in the area. Nevertheless, a reasonable picture of the area's general meteorological setting has been assembled.

Air temperatures in the lease sale region tend to be persistently low for most of the year. The U.S. Coast Pilot for the Arctic Ocean area provides a general description of the region's weather. Winters are cold and summers are cool. In November, average daily maximums drop to around -10°C (14°F) or below, while average minimums are around -18°C (0°F). February is generally the coldest month. Average maximums range from just above -17°C (1°F) at Kotzebue to -25°C (-13°F) east of Cape Lisburne. Low temperatures in the -30°C (-22°F) range are common. Extremes of -45°C (-49°F) or colder have been recorded.

Table 3-1 lists representative temperature information for several coastal stations along the northern Chukchi Sea coast. Air temperatures over the arctic land mass are less stable than those over the polar ice pack; air temperatures over the pack ice are usually uniform and deviate little from day to day. In summer the temperature over the pack ice remains relatively stable, near the freezing point.

Annual precipitation over most of the arctic coastal region is very light, ranging from 10 to 40 centimeters (4 to 16 inches) annually in the northern Chukchi Sea. Annual snowfall can range from 30 to 150 centimeters (12 to 59 inches) depending upon location and elevation. Some form of measurable precipitation falls on about 200 to 300 days per year, with

TABLE 3-1

AIR TEMPERATURES AT ARCTIC COASTAL STATIONS

Station	Mean Annual °C (°F)	Summer Seasonal Maximum °C (°F)	Winter Seasonal Maximum °C (°F)	Record High °C (°F)	Record Low °C (°F)	Mean Number of Days 0°C (32°F) or Below
Cape Lisburne	-7.8 (18.0)	11.1 (52)	-28.9 (-20)	23.3 (73.9)	-43.9 (-47.0)	268
Point Lay	-10.6 (12.9)	11.6 (53)	-32.7 (-27)	25.6 (78.1)	-48.3 (-54.9)	284
Wainwright	-11.8 (10.8)	10.0 (50)	-31.1 (-24)	26.7 (80.1)	-48.9 (-56.0)	306
Barrow	-12.6 (9.3)	7.2 (45)	-31.1 (-24)	25.6 (78.1)	-48.9 (-56.0)	324

Sources: Brower et al. (1977)
Swift et al. (1974)

heaviest precipitation in July, August and September, averaging 5 to 10 centimeters (2 to 4 inches) each month (U.S. Coast and Geodetic Survey 1979). Snow can appear in any month and usually predominates beginning in September (Arctic Institute of North America 1974). Table 3-2 provides data on precipitation measurements at coastal stations.

The relative humidity is generally high with values averaging from 60 to 90 percent throughout the year. However, the absolute humidity is very low due to the low air temperatures, which prevent water vapor buildup in the atmosphere, and the ice cover, which limits evaporation. Other types of precipitation experienced include rime or granular ice, which occurs over most arctic coastal regions throughout the year, and hoarfrost, which occurs in winter (Arctic Institute of North America 1974).

Wind conditions tend to be fairly constant along the arctic coast year-round. The Arctic Institute of North America (1974) reports that a general yearly average for the coastal zone is 24 to 32 kilometers/hour (15 to 20 miles/hour) at relatively exposed locations. Table 3-3 summarizes surface wind data compiled by Swift et al. (1974) for coastal stations along the northern Chukchi Sea. Observational data summarized by Brower et al. (1977) indicate that 45 percent of all observations reported winds less than 19 kilometers/hour (12 miles/hour) and 5 percent of all observations reported winds less than 6 kilometers/hour (4 miles/hour).

High winds may occur at any time of the year although maximum velocities have historically occurred in the coldest months. Gales occur about 2 percent of the time in the northern Chukchi Sea (U.S. Coast and Geodetic Survey 1979).

Brower et al. (1977) estimates that the 100-year wind speed may exceed 179 kilometers/hour (111 miles/hour) in the northern Chukchi Sea. Sustained winds of 93 to 105 kilometers/hour (58 to 65 miles/hour) have been recorded with gusts going much higher (Swift et al. 1974). In addition to the design parameters affected by surface winds, ambient wind conditions during the summer occasionally drive the pack ice into nearshore areas. This

TABLE 3-2

PRECIPITATION AT ARCTIC COASTAL STATIONS

Station	Liquid Precipitation (cm) Annual Mean	Monthly Maximum	24-Hour Maximum	Snow (cm) Annual Mean	Monthly Maximum	24-Hour Maximum
Cape Lisburne	37.3	17.7 (Aug)	4.5 (Aug)	152.4	--	27.9 (Nov)
Point Lay	16.7	15.7	3.8	50.8	--	--
Wainwright	12.7	23.6 (Aug)	10.1 (Jul & Aug)	30.4	30.4 (Oct)	--
Barrow	10.9	7.1 (Aug)	2.5 (Oct)	73.6	66.0 (Apr)	38.1 (Oct)

Source: Swift et al. (1974)

TABLE 3-3

SURFACE WINDS AT ARCTIC COASTAL STATIONS

Station	Winter		Summer		Maximum Recorded	
	Prevailing Direction	Mean Speed (km/hour)	Prevailing Direction	Mean Speed (km/hour)	Prevailing Direction	Speed (km/hour)
Cape Lisburne	E, SE	21	E, NE, SW	19	--	>105
Wainwright	E	--	E, SW	--	--	--
Barrow	E, NE	18	E	19	W	93

Source: Swift et al. (1974)

relatively rapid shift in the pack ice can adversely affect vessel and barge movements or other offshore activity associated with oil and gas exploration and development.

Fog is the major restriction to visibility in the Arctic. Dense fog can be expected to occur from 30 to 100 days each year along the coast. Offshore and inland areas are much less prone to fog. Advection or sea fog is the primary restriction to visibility during the warmer months of the year. It is most prevalent from June through September, and is most dense during the morning hours. Areas along the coast may have advection fog for up to 15 to 20 days per month in summer (Arctic Institute of North America 1974). In July and August, visiblities drop below 3.2 kilometers (2 miles) 10 to 25 percent of the time (U.S. Coast and Geodetic Survey 1979). Advection fog, provided by relatively warm, moist air moving over a cold surface, tends to persist due to strong temperature inversions that prevent turbulent dissipation (Energy Interface Associates 1979).

During winter, radiation fog, ice fog and steam fog can all reduce visibility. Table 3-4 presents annual and monthly data on fog conditions at coastal stations. It is apparent from the data that there are wide variations in visibility limitations imposed by fog due to both season and location. In general, summer fog conditions tend to be about twice as bad as winter conditions at coastal stations. However, winter visibilities can be reduced to less than 0.8 kilometers (0.5 miles) by snow or blowing snow (U.S. Coast and Geodetic Survey 1979). Cloudiness is another prevalent condition along the entire arctic coast that tends to reduce visibility. Energy Interface Associates (1979) report that over 60 percent of the days are cloudy on an annual basis. During the summer and early fall, cloudiness occurs more than 70 percent of the time.

3.2.1.2 Bathymetry

The Chukchi Sea is shallow with a mean depth of about 40 meters (130 feet), having gentle knolls and several shallow troughs but with a relief that is a substantial fraction of the mean depth (Paquette and Bourke 1981).

TABLE 3-4

FOG CONDITIONS AT ARCTIC COASTAL STATIONS
(Percent Frequency of Occurrence Based on Hourly Observations)

Station	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cape Lisburne	12.3	8.1	10.5	11.7	13.5	16.6	22.8	18.6	18.8	11.3	5.2	4.4	6.1
Barrow	15.8	12.5	13.1	7.9	9.3	17.4	26.4	25.9	25.5	17.7	13.0	10.5	10.4

Source: Brower et al. (1977)

The central Chukchi shelf, which extends northwestward from the coastline between Cape Lisburne and Point Barrow to the 50-meter (165-foot) isobath, is a shelf of low relief. A broad north-south trending trough 50 meters (165 feet) deep lies between the mainland and Herald Shoal (McManus et al. 1964). In this area, nearshore depths along the coast are usually less than 20 meters (66 feet) and remain less than 60 meters (200 feet) throughout most of the shelf. The maximum recorded depth is 70 meters (230 feet).

The offshore area between Icy Cape and Cape Lisborne is shallow (less than 25 meters [80 feet]), very flat and featureless. Gradients are extremely gentle, averaging less than 3 meters/kilometer (10 feet/mile) across the shelf (Toimil 1979). The only relatively steep nearshore bottom topography occurs between Point Belcher and Point Franklin where depths reach 40 meters (130 feet) within 8 kilometers (5 miles) of shore. Nearshore depths in the Chukchi Sea are maintained by currents and altered by seasonal ice gouging. Storm actions shift sand spits and shoals considerably, but there is little evidence of storm waves affecting deeper areas (Alaska Department of Fish and Game 1982).

As shown on Figure 3-1, Hanna Shoal (30 to 40 meters [100 to 130 feet]) lies to the northeast and another 40-meter (130 foot) shoal lies approximately at 71° N, 165° E. To the east, the Barrow Canyon parallels the northwest coast of Alaska. The northern section of the Barrow Arch, which extends approximately to the 100-meter (330-foot) isobath, includes the Herald Canyon, a shallow trough that lies at about 175° W and is much less notable than the Barrow Canyon (Paquette and Bourke 1981).

3.2.1.3 Circulation

The circulation within the Chukchi Sea is known only in the most general fashion, having been inferred from water mass studies reinforced by infrequent, short-term current meter measurements with some support from the concept of bathymetric steering (Paquette and Bourke 1981).

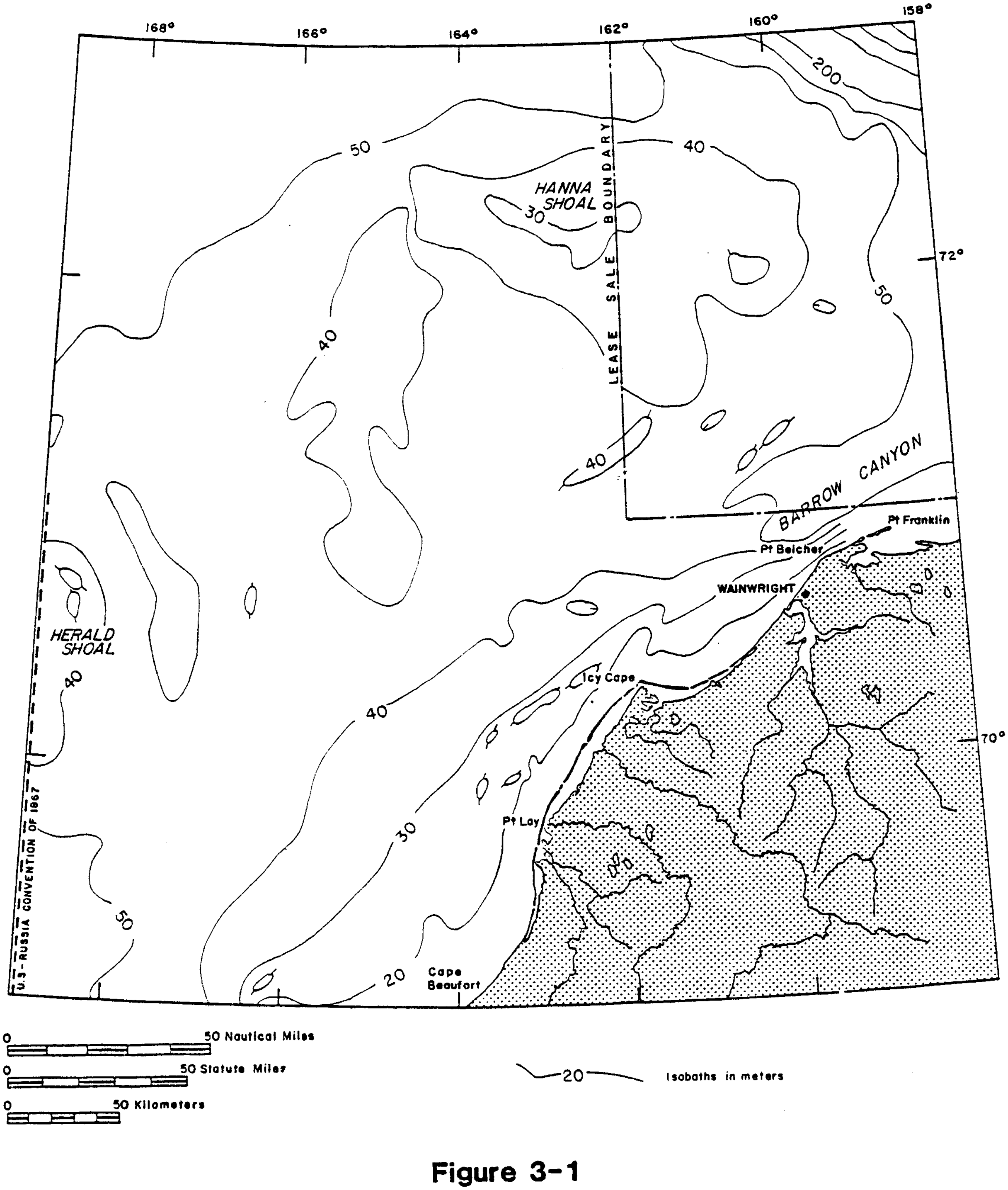


Figure 3-1

BATHYMETRY OF THE NORTHEAST CHUKCHI SEA

Source: Adapted by Dames & Moore from Schumacher (1976).

Although the Chukchi Sea is part of the Arctic Basin, its currents are dominated by the northward flow of water from the Bering Sea. Detailed measurements show that the flow is predominately barotropic, with speeds and directions uniform from top to bottom (Arctic Institute of North America 1974). A pressure-induced, north-sloping sea surface is thought to cause the northward flow of water from the Bering Sea to the Arctic Basin (Wilimovsky and Wolfe 1966). In 1945, Russian scientists reported average current speeds of 45 centimeters/second (1.5 feet/second) during summer and 10 centimeters/second (0.3 feet/second) in winter. The direction of the primary current is generally parallel to the coast, with eddies and reversals noted in nearshore areas. Winds have been observed to slow the current, occasionally reversing its direction through the Bering Strait (Arctic Institute of North America 1974).

Figure 3-2 illustrates patterns of flow in the Chukchi Sea. In general, Coachman et al. (1975) indicate that warm waters entering the Chukchi Sea through the eastern side of the Bering Strait at estimated flow speeds from 30 to 150 centimeters/second (1 to 5 feet/second) flow northward and turn west-northwest in a broad stream starting from south of Point Hope. Near shore, a northeasterly stream branches from this flow in the vicinity of Cape Lisburne. The westerly branch, moving at 15 centimeters/second (0.5 feet/second), enters the Arctic Ocean by way of Herald Canyon. The northeasterly branch narrows into a high-speed jet-like stream, moving from 25 to 30 centimeters/second (1 foot/second), approximately along the 40-meter (130-foot) isobath north of Cape Lisburne and then close to the Alaska coast between Wainwright and Point Barrow, where it flows eastward into the Beaufort Sea. Dubbed the Alaska Coastal Current by Paquette and Bourke (1974), currents on the outer shelf form a regime that is highly energetic over a broad band of sub-tidal frequencies, with a mean eastward flow affected by local bathymetry (Coachman et al. 1975).

Within this general picture of the circulation regime, significant uncertainties and variations exist. Ingham et al. (1972), in a set of observations in the fall of 1970, indicate that currents were strongly influenced by the northeasterly winds and showed the expected northeastward

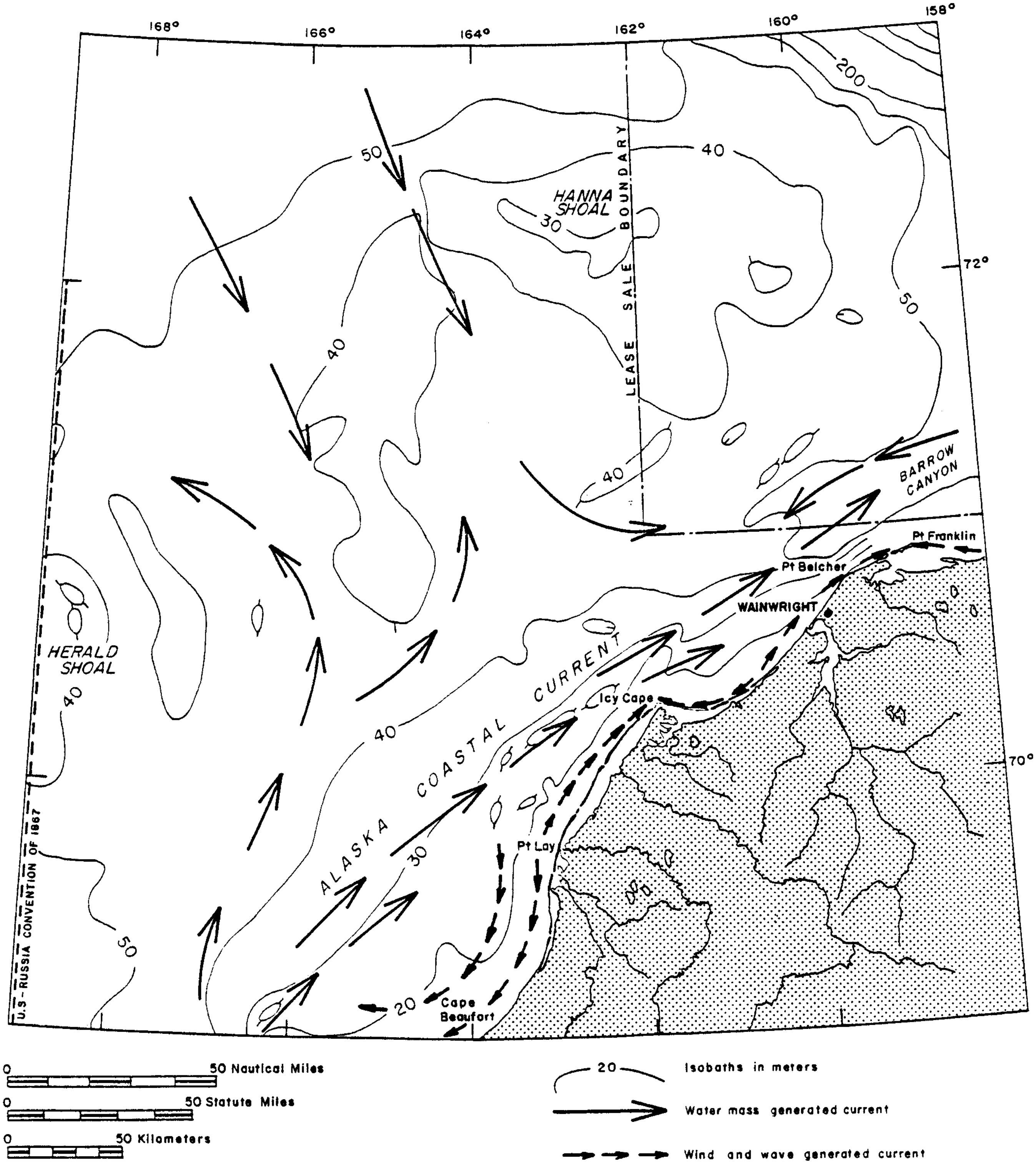


Figure 3-2

SURFACE CURRENTS IN THE NORTHEAST CHUKCHI SEA

Sources: Adapted by Dames & Moore from Coachman, Aagaard and Tripp (1976); Garrison (1976); Hufford (1977a); Paquette and Bourke (1974); Schumacher (1976); Searby and Hunter (1971).

set only when winds were weak and variable. Their observations also indicated that returning nearshore southwesterly currents between Cape Lisburne and Icy Cape were weak and variable. Hufford (1977) reports the existence of a significant offshore southwesterly current beyond the Alaska Coastal Current in the vicinity of Point Franklin. The U.S. Coast and Geodetic Survey (1979) reports that another current moves northwest out of Kotzebue Sound and joins the Alaska Coastal Current in the vicinity of Cape Krusenstern, producing a resultant velocity of 75 to 100 centimeters/second (2.5 to 3.3 feet/second) at Point Hope in July and August. They report that during summer months, the Alaska Coastal Current moves at 50 centimeters/second (1.7 feet/second) after rounding Point Hope. They also indicate that currents are influenced not only by the wind, but by moving pack ice, with currents stopped completely by landfast ice.

3.2.1.4 Tides and Storm Surges

Almost no work on the tides of the Alaska arctic coast has been published. Astronomic tides are very much smaller than meteorological tides (OCSEAP 1978). Along the northern Chukchi coast, astronomic tides are reported to be small, averaging approximately 30 centimeters (1 foot) (Arctic Institute of North America 1974). The mean tidal range at Wainwright is reported to be 15 centimeters (6 inches), according to Bechtel (1979), while tides at Kiwalik in Kotzebue Sound are reported at 80 centimeters (2.7 feet) by Stringer (1978a,b).

Deviations in sea level produced by meteorological forces are a significantly greater problem than tides in the Barrow Arch planning area. These deviations, known as storm surges or storm tides, are produced by wind stresses and barometric pressure gradients acting on the water surface (Energy Interface Associates 1979). The dominant storm track producing storm surges is to the northeast, from storm systems originating in the Aleutian chain and moving through the Bering Strait (U.S. Navy 1968). An occasional storm moving eastward from the Siberian Shelf may produce surges. The most severe surges, often accompanied by high waves, occur during September and October when storm frequencies are highest and open water exists (OCSEAP 1978).

Chukchi Sea is ice-covered. Since the pack ice retreats a relatively short distance offshore during most summers, the wave climate is characterized by low, short-period waves (except during storms) with winds that blow parallel to the coast (Energy Interface Associates 1979). Wave heights of 6 meters (20 feet) or more occur less than 1 percent of the time during the ice-free season (Brower et al. 1977).

The extreme wave conditions for the Chukchi Sea have been calculated (Brower et al. 1977). These data suggest that the 10-year storm (i.e., a storm with a long-term average recurrence interval of once every 10 years) will have sustained winds of 75 knots and extreme wave heights of 23.5 meters (77 feet). The 50-year storm will have corresponding values of 90 knots and 31 meters (102 feet). Calculated 100-year return period values are 97-knot winds generating significant wave heights of 19.5 meters (64 feet) with maximum waves 35 meters (115 feet) high. However, these extreme wave heights for the Chukchi Sea were calculated based on the work of Thom (1973a,b) and do not allow for the probability that the wind fetch and wave height are reduced by the presence of ice cover. In our judgment, extreme waves on the order of one-half of these values would be closer to realistic design parameters, for deepwater conditions.

Nearshore, where depths limit waves, the values will be even lower. Heideman (1979) calculates that for a 100-year return period at a 9-meter (30-foot) water depth inside a Beaufort Sea barrier island, a storm surge of 2 meters (6.6 feet) is accompanied by a maximum wave height of only 8.2 meters (27 feet). Heideman's analysis relied on two proprietary storm hindcast studies prepared by Joy (1978, 1979). For the Chukchi Sea, a conceptual design study of an arctic terminal for ice-breaking tankers (Bechtel 1979) arrived at wave oceanographic design data for 37-meter (120-foot) water depths off of Wainwright on the northern Chukchi Sea coast. Calculated wave parameters were a storm surge of 3.3 meters (11 feet), a significant wave height of

Along the Chukchi Sea coast and Kotzebue Sound coast, surges are possible from mid-June through November. The Chukchi Sea coast is most susceptible to storm surge damage from northward moving storms from the Bering Strait, while Kotzebue Sound is affected by storm surges and coastal flooding from westerly Siberian storms with winds in excess of 75 kilometers/hour (45 miles/hour; Brower et al. 1977). Storms causing the most extensive flood damage require a long fetch and little or no ice cover. Storm surges are also greater when the air temperature is colder than the water.

Negative surges, which are usually smaller than positive surges, also occur and appear to be more frequent in winter. Negative surges are potentially hazardous to vessel traffic in the Arctic due to the relatively shallow water depths that provide limited draft clearance in many areas. A few observations of negative surges indicate that they are smaller than positive surges, on the order of 1 meter (3 feet) or less (Energy Interface Associates 1979).

There are no direct measurements of storm surge elevations, but secondary observations of strandlines above the coastal beaches provide evidence of their general magnitude. The most severe recorded storm in 1963 produced a storm surge of 3 meters (10 feet) plus waves of the same height (Brower et al. 1977). The surge produced extensive coastal flooding, ice grounding and shoreline erosion in the vicinity of Barrow (Hunkins 1965).

Thirteen storm surges have been documented in the Chukchi Sea area since 1960. Although insufficient data exist to develop recurrence intervals for storm surges, Reimnitz and Barnes (1974) record that local Eskimos report such severe positive surges at around 25-year intervals.

3.2.1.5 Waves

Wave generation in the Chukchi Sea is limited to the summer open-water season. No significant wave activity exists from November to May when the

Chukchi Sea is ice-covered. Since the pack ice retreats a relatively short distance offshore during most summers, the wave climate is characterized by low, short-period waves (except during storms) with winds that blow parallel to the coast (Energy Interface Associates 1979). Wave heights of 6 meters (20 feet) or more occur less than 1 percent of the time during the ice-free season (Brower et al. 1977).

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5.4 meters (18 feet), and a maximum wave height of 10.3 meters (34 feet) based in part on oceanographic survey data near the proposed terminal site.

Seasonal wave activity is summarized in Table 3-5 based on Brower et al. (1977). Several observers, including Sellman et al. (1972) and Wiseman et al. (1973), confirm the mild wave climate that predominates during summer, ice-free periods. Much more severe waves can occur under certain conditions, particularly during periods of pack ice retreat. Energy Interface Associates (1979) reports that, during some summers, the pack ice has retreated as far as 190 to 260 kilometers (120 to 160 miles) off the coast. Under these conditions, severe and rapidly moving storms proceeding across the shelf can generate waves over a long fetch. They report a shipboard observation of average wave heights on the order of 4 to 5 meters (13 to 17 feet) during a storm in the vicinity of Point Barrow in 1951.

3.2.1.6 Sea Ice

Expected ice conditions in the Barrow Arch planning area are briefly described based on several public and proprietary sources. Ice data for this area remains very limited. Ice data from ongoing and future surveillance projects should be used directly when they become available. Typical ice conditions in the northern Chukchi Sea are characterized by:

- o Ice coverage of close to 100 percent for most of the year
- o Dynamic pack ice conditions exist relative to those in the Beaufort Sea
- o Multi-year ice floes transported to the region from the Arctic
- o Ice decay and growth patterns that show distinctive climatological patterns related to bottom topography, proximity to warm water sources and a semi-permament ice circulation feature (Webster 1982).

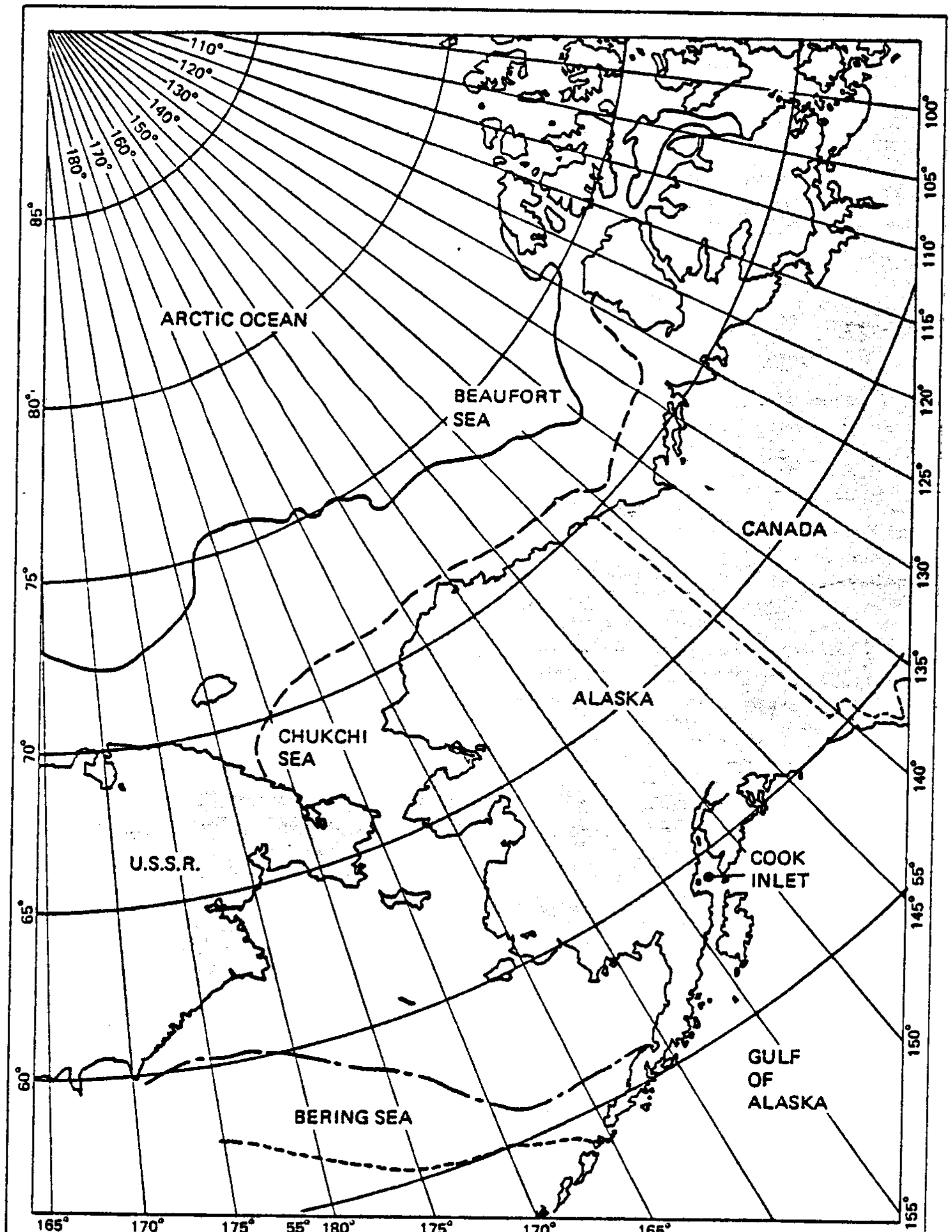
Arctic Sea ice has a complex variety of forms, properties, and behaviors. Figure 3-3 illustrates the general extent of sea ice in the

TABLE 3-5

SEASONAL WAVE ACTIVITY FOR BARROW ARCH PLANNING AREA
PERCENT FREQUENCY OF OBSERVED WAVE HEIGHT THRESHOLDS
(NON-HAZARDOUS SEA CONDITIONS) IN CHUKCHI SEA (NORTH OF 70°N LATITUDE)

		Wave Height					
Month	Meters Feet	0 - 0.5 0 - 2	1 - 1.5 3 - 6	2 - 2.5 7 - 9	3 - 3.5 10 - 12	4 - 5.5 13 - 19	6 - 7.5 20 - 25
July		76%	21%	2%			
August		76%	21%	3%	1%		
September		61%	32%	5%	1%	1%	
October		67%	25%	1%			

Source: Brower et al. 1977.



Sea Ice, Absolute Maximum Extent
Sea Ice, Average Maximum Extent
Sea Ice, Average Minimum Extent
Sea Ice, Absolute Minimum Extent

Figure 3-3

ALASKA ARCTIC SEAS & EXTENT OF SEA ICE

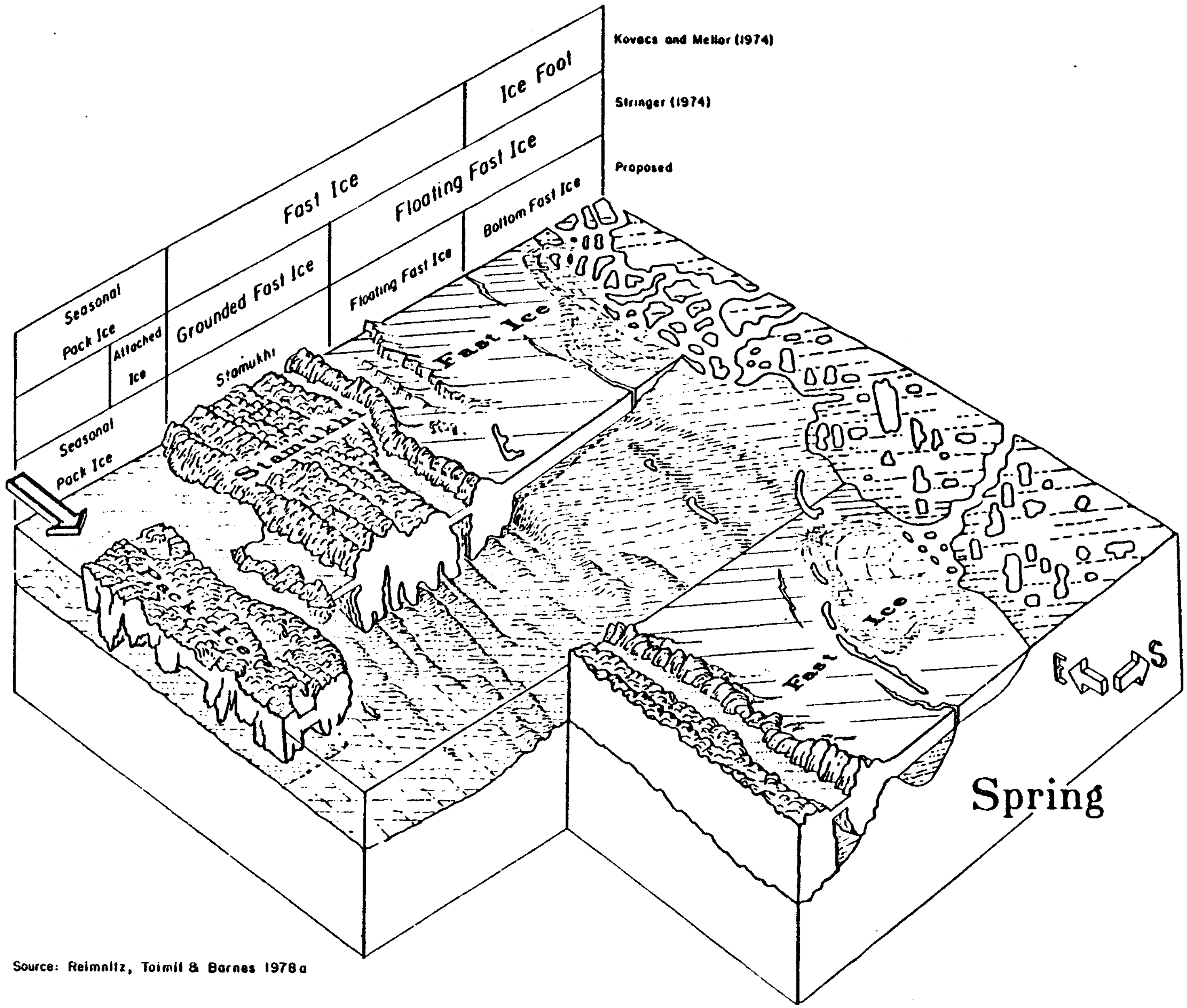
Source: National Academy of Sciences 1982

Alaskan arctic and Figures 3-4 and 3-5 illustrate the general patterns of spring and late winter ice zonation in the Arctic Ocean. In the Chukchi Sea, sea ice is year-round in waters north of 72°N and can be shifted at any time by winds and currents. The general ice movement is to the south through the Bering Strait under influences of wind and current (Ahlnas and Wender 1979; Reimer et al. 1981).

The Chukchi Sea remains virtually ice-covered for most of the year. From the beginning of December through May, 98 to 99 percent of the Chukchi Sea is covered with ice with the exception of a relatively wide shore lead that may develop seaward of the shore fast ice along the northwest coast (Webster 1982). From August to October ice coverage is least, but still averages 40 percent. First-year ice (fast ice and seasonal pack ice) forms 42 to 60 percent of the winter ice cover. Freeze-up generally begins by late September or early October and breakup occurs late the following June or early July. The first continuous fast-ice sheet is usually formed nearshore by mid to late October. This fast-ice sheet continues to extend and thicken throughout the winter. In general, stable land-fast ice is formed out to the 15-meter (50-foot) isobath by December, and out to the 30-meter (100-foot) isobath by March or April (Alaska Department of Fish and Game 1982).

North of Icy Cape, the fast ice freezes to thicknesses of 1.8 to 2.4 meters (6 to 8 feet). South of Icy Cape, the normal winter thickness is 0.6 to 1.2 meters (2 to 4 feet). The fast ice zone is generally most extensive between Cape Lisburne and Point Lay where shallow waters are extensive, and narrowest north of Icy Cape where bottom depth increases more rapidly and the shelf is vulnerable to pack ice incursion. The pack ice usually lies about 16 kilometers (10 miles) offshore from Icy Cape north toward Point Barrow. Beyond this point the edge of the pack ice swings northwest toward Wrangell Island. Pack ice intrusion is frequent along the coast as far south as Icy Cape (Alaska Department of Fish and Game 1982).

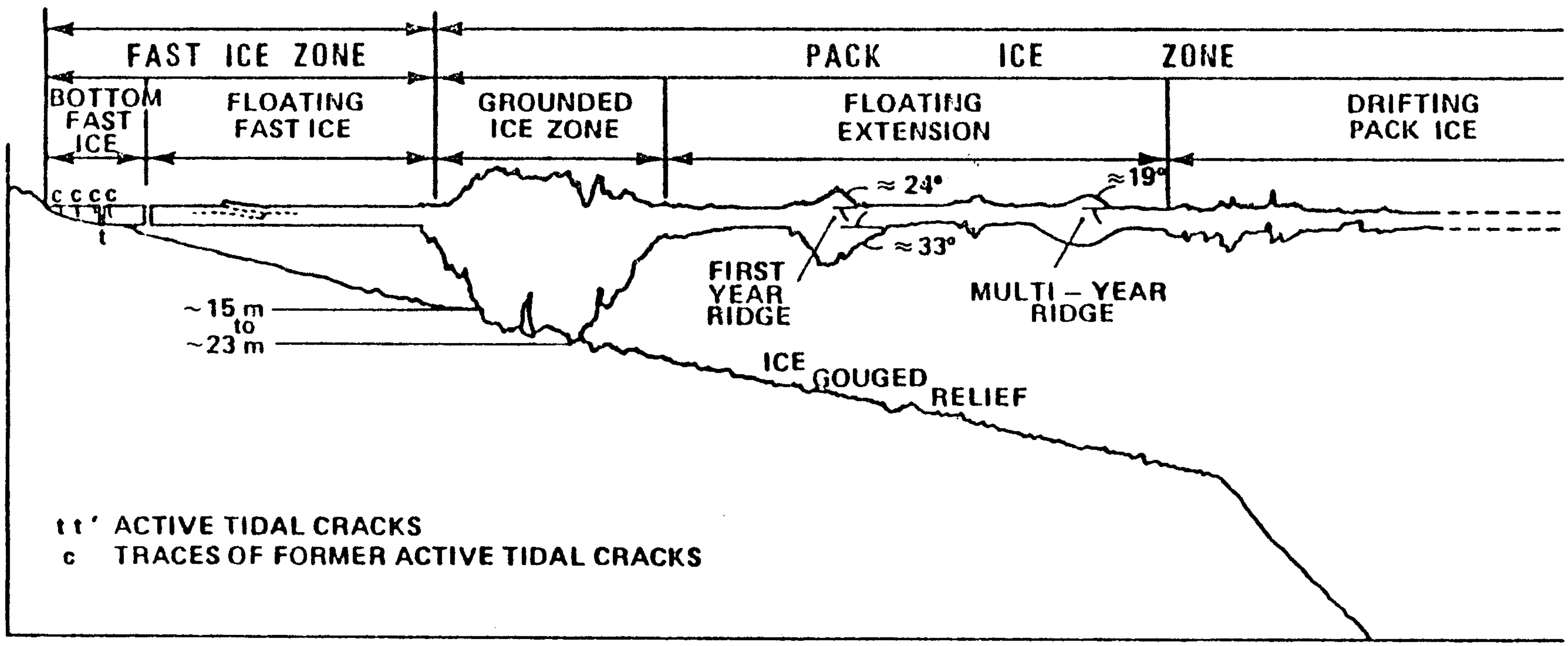
The multi-year pack ice lasts all year. Up to 40 percent of the ice cover between November and June may contain multi-year ice. Normally, polar pack ice is 3 to 4 meters (10 to 13 feet) thick at the end of winter and



Source: Reimnitz, Toimil & Barnes 1978a

Figure 3-4

SPRING ICE ZONATION OF THE ALASKA BEAUFORT SEA



Source: OCSEAP 1978

Figure 3-5

LATE WINTER ICE ZONATION OF THE ALASKA BEAUFORT SEA

decreases to 2 to 3 meters (6 to 10 feet) thick during the summer. In years of maximum ice retreat, the polar ice pack lies well north and west of the Chukchi Sea coast. The heavy pack ice begins to close in on the coast by October with new ice forming along its margin and in open-water areas between the pack ice and the shorefact ice. In heavy ice years, the pack ice lies close to the Chukchi coast and can unexpectedly be blown inshore even in midsummer. When it is blown ashore, ice keels, which can extend up to 20 meters (67 feet) deep, sometimes gouge into the sea floor (Alaska Department of Fish and Game). Ice islands with lateral dimensions of several kilometers are also known to occur (National Petroleum Council 1981).

During the winter and spring, the Chukchi Sea ice is more dynamic than Beaufort Sea ice. The Beaufort Sea has a large area of stable landfast ice often with an even larger area of immobile pack ice attached to it. Along the Chukchi coast there is an extremely active flaw zone lead system between the fast-ice and the moving pack ice. This lead system often extends from Point Barrow to Cape Lisburne and new ice in the flaw zone is continually being formed, detached, piled-up, and transported southward. In some years, the flaw zone may exceed 50 kilometers (30 miles) in width near its southern end (Burns, Shapiro and Fay 1981). The flaw zone becomes particularly pronounced from near Point Lay to Point Barrow during periods of strong easterly winds (Webster 1982).

Pack ice in the Chukchi Sea is continually in motion. Because of the southward converging Alaska and Siberian coastlines and the pressure exerted on the ice cover by the expanding polar ice pack, Chukchi Sea ice is heavily deformed. Another reason for this dynamic condition is the opportunity for ice in the Chukchi Sea to be transported southward out through the Bering Strait. Thicknesses of annual ice range from 100 to 120 centimeters (3 to 4 feet) with thicknesses of multi-year pack ice floes approaching 3 meters (10 feet; Webster 1982). Ridges can be several times this thickness.

Shear ridges or pressure ridges are formed where blocks of sea ice are slid, broken, pushed, and packed together. Pressure ridges are formed in the ice field due primarily to wind-induced stresses. There is at present very little data on the size, shape and distribution of ice ridges in the Chukchi Sea. The shear ridges generally have a sail height to keel depth ratio of 1:4.5, but this ratio can vary from 1:3 to as much as 1:9. Throughout the winter and early spring, ice movements create large and massive shear ridge systems. These shear ridges are most common along the shoals that extend seaward from capes and headlands. The ridging is particularly extensive in the nearshore area of the coast, north of Icy Cape and the offshore north of Cape Lisburne.

Pressure ridges are formed by compression of adjacent pack ice sheets when blocks of ice accumulate above and below the abutting ice floes. These pressure ridges may be free-floating or grounded if in shallow water. Both types of pressure ridges are frequent in the Chukchi Sea, and sail heights of 5 to 6 meters (18 to 20 feet) are found. In the northeastern Chukchi Sea, the frequency of pressure ridges is high, about 8 or 9 per kilometer (Kovacs and Weeks 1977). Average ridge thickness in February, including sail and keel is 9 meters (30 feet).

A probable range of ridge size and frequency has been extrapolated in Table 3-6 for the Barrow Arch planning area from some limited data assembled by the U.S. Army Corps of Engineers (1970), John J. McMullen Associates (1980), and Voelker et al. (1981). Pressure ridges can contain both first-year and multi-year ice. Based on a heat flow analysis, first-year ridges are estimated to have a consolidated zone thickness (i.e. with ice bonding) of less than 3.9 meters (13 feet). Multi-year pressure ridges probably can have a consolidated zone thickness exceeding 14 meters (45 feet) but the probability of encountering such a feature cannot yet be estimated.

Breakup in the Chukchi Sea occurs in late June or July. Commencing in late May or early June, river breakup causes estuarine flooding of the shorefast ice. Continued warming and summer insolation lead to melt pond formation on the ice by early June. The ice continues to decay and loosen its attachment to shore through June. Open water begins to form near river mouths and embayments. Eventually winds, storms, or water currents dislodge the fast ice, and breakup occurs usually in late June. This marks the

TABLE 3-6

EXTRAPOLATED PRESSURE RIDGE CHARACTERISTICS AND FREQUENCY

Sail Height (meters)	Sail Height (feet)	Keel Depth (meters)	Keel Depth (feet)	Number of Ridges per Kilometer
0.6 - 1.2	2 - 4	2.1 - 4.2	7 - 14	15
0.9 - 2.4	3 - 8	5.4 - 8.5	18 - 28	15
1.5 - 3.6	5 - 12	5.4 - 12.8	18 - 42	4
2.4 - 6.0	8 - 20	8.5 - 21.3	28 - 70	2
>6.0	>20	21.3	>70	2

Source: Brian Watt Associates

beginning of the "open-water season." Scattered leads open along the coast and the pack ice recedes offshore and begins its gradual disintegration.

It is not until the beginning of July that a significant reduction in probabilities of both the ice limit and 50 percent ice concentration boundary occurs in the southern Chukchi Sea (Webster 1982). As the ice decreases in concentration, it drifts north toward the Arctic Ocean. According to Webster (1982), the disintegrative influence on the ice cover is a tongue of warm water flowing northward through the Bering Strait. The probability of close pack ice falls to less than 50 percent south of Cape Lisburne and in a narrow corridor along the coast northeastward to Wainwright. This early lead formation is likely a result of a northeastward setting stream of warm water branching from a generally northward flow of water in the vicinity of Cape Lisburne referred to by Paquette and Bourke (1974) as the Alaska Coastal Current.

By the beginning of August, a narrow shore lead is likely to develop along the coast between Wainright and Barrow as the probabilities of encountering close pack ice fall to about 25 percent. However, there still remains a good chance that "heavy" ice concentrations will prevail in the area of Point Barrow and over the Chukchi Sea generally as far south as 71°N latitude. The lead increases in width through August. August and September are the months with least sea ice in the Chukchi Sea. These are the best months for navigation because the coastal area is generally free of fast ice to Point Barrow. The north-setting warm-water Alaska Coastal Current usually keeps the Chukchi coast free of ice through September. However, the presence of decaying ice fields still adhering to the shore along the Alaska northwest coast may complicate marine operations, including shore facilities. After September, freeze-up and the incursion of the pack ice prevent further vessel traffic, except for ice breakers.

A permanent circulation feature in the Arctic basin, which shunts ice westward north of the Alaska mainland and then northwestward between 155°W and 160°W longitude, maintains relatively high ice probabilities north of the mainland between Wainwright and Point Barrow throughout August and into

September. The withdrawal of the ice pack is greatest over the Chukchi Sea between 162° W and 175° W during this period. The persistence of sea ice west of 175° W seems largely due to the lack of any warm water inflow into the region to accelerate melting (Webster 1982).

The seasonal withdrawal of the ice pack from the Chukchi Sea exhibits, mainly in August, certain climatological configurations that have been related to current steering by bottom topography (Paquette and Bourke 1974). The literature associates these northward projections of lower ice probabilities with troughs in the sea floor that concentrate and direct the current into the marginal ice zone, thus creating bays of lower ice concentrations or open water. These features become less definable as the melt season progresses into September and the ice recedes farther northward over the continental shelf (Webster 1982).

The northward retreat of the ice pack peaks in mid-September when the median ice limit moves north of the Chukchi Sea to about 72° N latitude and the median edge of close pack ice recedes to near 73° N. The perennial polar pack in the Arctic Ocean begins its southward advance in late September. By mid-October, it is likely that sea ice will be found in the proximity of Barrow, but will likely be less than 50 percent concentrated, consisting mainly of new ice developing in situ. In extremely cold weather, new ice can develop in the coastal area as far south as Kotzebue Sound (Webster 1982).

After mid-October, sea ice forms more rapidly next to the cooling Alaska landmass than over the Chukchi Sea waters farther removed from the source of cold air. By November, sea ice will likely be extensive in the coastal waters from Cape Lisburne northward as well as in the interior of Kotzebue Sound. Farther westward the probabilities of the ice limit and 50 percent ice concentration boundary are lower with the contour pattern similar to that occurring during the ice melt-back period in August and September, presumably due to bathymetrically-induced current steering previously discussed. Freezeup is rapid during the first half of November and by the fifteenth it is likely that the waters north of the Bering Strait will be ice covered, becoming absolutely ice covered by December 1 (Webster 1982).

Ice conditions during the open-water season can vary considerably from year to year. Good ice years occur about 1 year in every 5. Exceptional ice years are less frequent (National Petroleum Council 1981). As mentioned earlier, the period of least ice cover is typically from mid-August to mid-October.

At most sites along the coast, the ice retreats some distance offshore during the summer. However, heavy pack ice and multi-year pack ice are never far away. Wind and currents can rapidly move the pack ice back onshore during summer months. Ice movements can be rapid. Pack ice is much more mobile than land-fast ice with movements of 10 to 20 kilometers (6 to 12 miles) per day being commonplace (Boone 1980). Shipboard observers passing through the Chukchi Sea have made anecdotal reports of ice movements estimated at up to 6 knots (Arctic Institute of North America, 1974).

In the Chukchi Sea, there is little data regarding ice movement except in the vicinity of Barrow. Several factors suggest that results of most Beaufort Sea ice studies are not directly applicable to the Chukchi. The Chukchi Sea has relatively few barrier islands to protect and stabilize the landfast ice sheet, except for the Kusegaluk Lagoon. Furthermore, the landfast ice zone is much narrower than in the Beaufort and is subject to considerably greater spring and winter pack ice movement (OCSEAP 1978). Other differences include a smaller inter-annual-fast ice variation along the Chukchi coast as well as a decrease in the intensity of ridging (OCSEAP 1978). However, the increasing activity in Beaufort Sea ice beyond the barrier islands will provide experience useful for Chukchi Sea development.

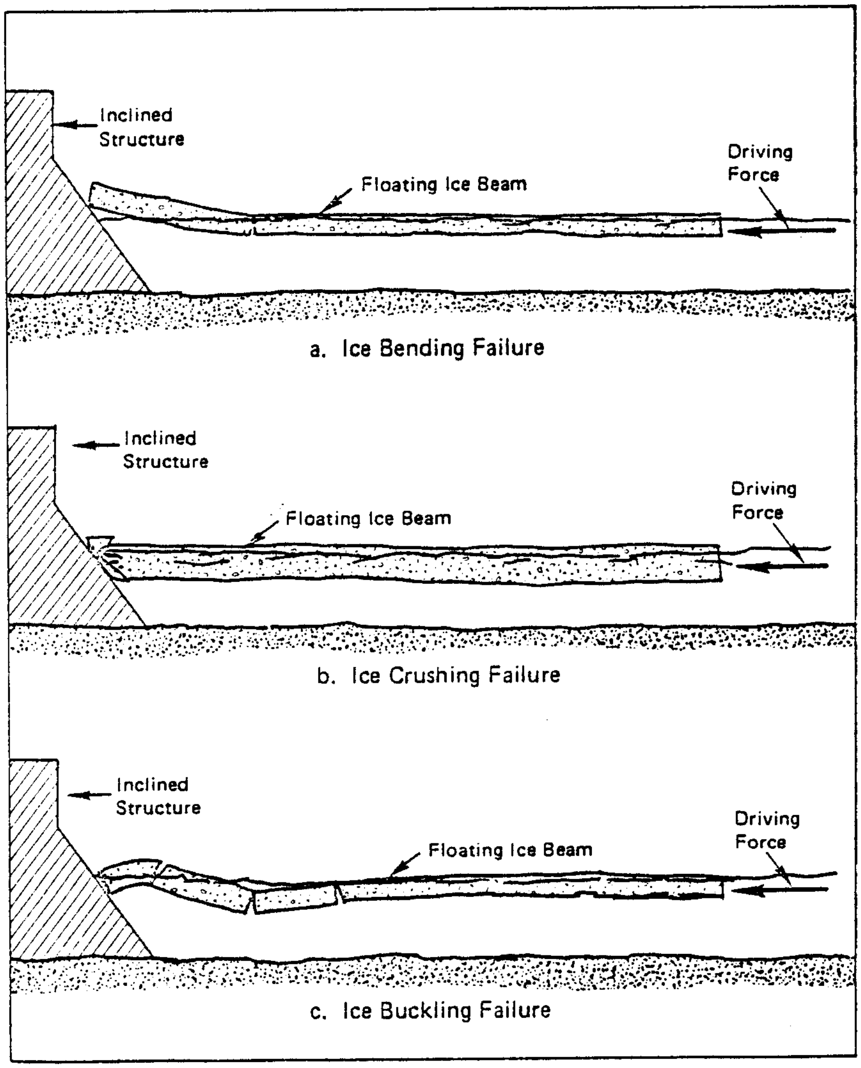
Stringer (1978), in addition to observing that the morphology of Chukchi Sea is considerably more dynamic than that in the Beaufort Sea, indicates that the two major ice features in the Chukchi Sea, the edge of contiguous pack ice and the location of large ridge systems, are relatively independent of each other. The former is controlled by season, being farther offshore during summer and advancing towards shore with advancing season, while the location of large ridge systems appears to be controlled mainly by bathymetric configurations.

In spite of those studies to measure ice movement, the statistical data base required for structural design is still limited. A larger data base consisting of measurements having both geographic and temporal continuity is required to estimate potential extremes. Any structure deployed in the open ice sheet for a period of years will be required to withstand many ice invasions. Continuing ice studies will be useful to provide adequate data for reliable prediction of expected ice forces, resulting in a safer design. By the time the first exploration structure is deployed in the Chukchi Sea, at least four more years of more detailed ice data will have been collected and analyzed. Prior to emplacing a production structure, at least eight years of more detailed ice data will be collected by industry operators.

Sea ice loads are a function of size and shape of the ice features, its strength and deformability and the mode of failure. Figure 3-6 illustrates three modes of ice failure. The strength of sea ice is a complex function of many factors including crystal type, strain rate, temperature, brine volume, and the direction of loading. The flexural strength of sea ice may be less than one-tenth of its compressive strength. This factor has a considerable influence on structure design (Watt 1982).

The design total ice forces will depend not only on the ice features but also on the structure configuration and contact surface characteristics. For the purposes of this planning study, Table 3-7 gives general ice loads suggested as examples for fixed structures to be located in the zone of large ice movement and where large multi-year ice features can be expected. In the (floating) landfast ice zone, ice movement will be significantly less and multi-year ice features will be less likely to be encountered. In this zone, a load of 350 kips per foot of waterline diameter for a vertical cylindrical structure or gravel island seems appropriate.

It is expected that engineering structures for the northern Chukchi Sea will have to be designed for very high and localized ice loads. Selecting appropriate design ice pressure criteria for these structures is a very



Source: National Academy of Sciences 1981

Figure 3-6

INTERACTION OF A FLOATING ICE BEAM WITH AN INCLINED STRUCTURE

TABLE 3-7

GENERALIZED ICE LOADS FOR REPRESENTATIVE DRILLING STRUCTURES IN DEEPER WATER[1]

Structure Type	Total Horizontal Load[2] (1000 kips)	Vertical Load (1000 kips)
Gravel Island	200[3]	0
Vertical Cylinder	140 - 200	0[4]
45° Cone	135 - 180	100 - 135
20° Cone	60 - 80	100 - 135

(1) See text for explanation.

(2) Total load includes both static (widely distributed) and impact (locally distributed) loads.

(3) For a 400-foot island, using 500 kips/foot of waterline diameter.

(4) Assumes no adfreeze plus tidal movement.

Source: Brian Watt Associates

difficult task due to the lack of data and industry experience. Bruen et al. (1981) discuss the complications involved in criteria selection and suggest a tentative relationship between the design ice pressure and the contact area under consideration. The suggested design ice pressure starts at 1600 psi for a 5 square foot area decreasing to 1200 psi for a 100 square foot area, and 500 psi for a 1000 square foot area.

3.2.2 Geology and Geologic Hazards

3.2.2.1 Major Data Sources and Reference Materials

The Chukchi Sea shelf, as a geographic and geologic unit, has received intermittent study from researchers over the last two decades, and a reasonable amount of knowledge has been accumulated about the structural, tectonic and environmental geology of the area. However, the Chukchi Sea has received considerably less attention than the Beaufort Sea, due to its remoteness from existing petroleum development and transportation infrastructure. Nevertheless, a limited amount of magnetic, gravity and seismic data is available, primarily from research conducted by the U.S. Geological Survey. At the time of this writing little of the available information had been synthesized, although a geohazards report is currently in preparation by the U.S. Geological Survey.

Further information and analysis of the geology of the Barrow Arch planning area are presented in Appendix A, emphasizing petroleum-related conditions.

3.2.2.2 Geologic Setting

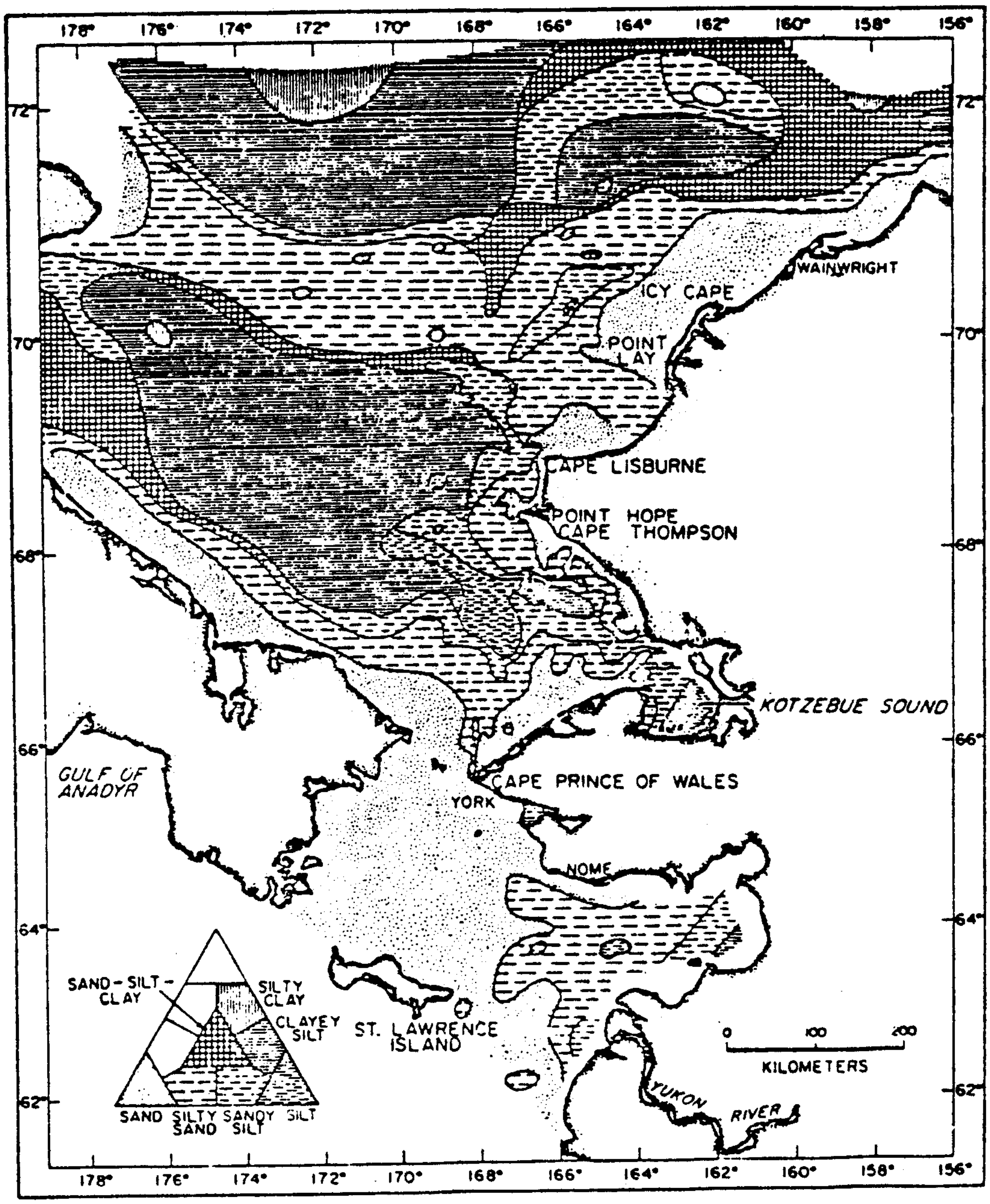
The Chukchi shelf is a peneplained, infolded sedimentary remnant. The extension of the Colville geosyncline beneath the Chukchi Sea shelf is comprised of lower Cretaceous and older sedimentary rocks with a presumed average thickness of 5 kilometers (3 miles) and a maximum thickness speculated at 8 kilometers (5 miles). It has been estimated that as much as

6,000 meters (20,000 feet) of Cretaceous sediments interbedded with volcanics may lie immediately offshore beneath the Chukchi Sea (Arctic Institute of North America 1974).

The thickness and stratigraphy of the pre-Cretaceous interval is in question. A great deal depends on the nature, age and extent of apparent basement highs indicated by gravity and magnetic surveys. Subottom reflections of the Tigara uplift area off Point Hope and Cape Lisburne indicate no stratification but suggest buried sedimentary rock. Basement rocks are generally believed to be complexly folded and faulted rocks of Devonian, Carboniferous, and early Mesozoic age (Moore 1964).

The sediment character of the Chukchi shelf is fairly well known, primarily from the work of Creager and McManus (1967). In general, the Chukchi shelf displays very low relief and is covered by thin relict and residual sediments with a minimal input of new fine sands, silt and clay from the Bering Strait and Kotzebue Sound (Ingham et al. 1972). Extreme diversity, even over short distances, is the most distinctive characteristic of arctic shelf sediments. The sediment cover rarely exceeds 10 meters (33 feet) and frequently is on the order of 3 to 5 meters (10 to 17 feet; Moore 1964). Sediments are predominantly overconsolidated Holocene silts and clays with widespread Pleistocene gravel sheets occurring at depths from 3 to 10 meters (10 to 33 feet; OCSEAP 1978). In water depths of 30 meters (100 feet) and more, bedrock is frequently exposed with only patches of sediment filling depressions (Moore 1964).

Bottom sediments in the area range from silt and clay through well-sorted sands to muddy or clean gravels. The bottom sediment characteristics of the Chukchi Sea, as described by Creager and McManus (1967), are illustrated in Figure 3-7. In general, grain size decreases away from the shore or downstream from the sediment source. Coarse gravel is almost always found near cliffs and headlands or with bedrock outcrops on the seafloor, except in the northeastern Chukchi Sea between Point Lay and Wainwright where gravel was noted offshore in relatively shallow water (Creager and McManus 1967).



Source Creager & McManus 1967

Figure 3-7

DISTRIBUTION OF BOTTOM SEDIMENTS, CHUKCHI SEA

In the nearshore waters of the Chukchi Sea and on the Chukchi shelf, sedimentary depositional structures are largely absent. A combination of ice bottom interaction and intensive bioturbation is considered the primary process, replacing older explanations that emphasized wave and current action (Barnes and Reimnitz 1974). Ice gouge phenomena are discussed in greater detail in Section 3.2.2.3.

Toimil and Grantz (1976) speculate that the anomalously coarse sediments reported on many shoals of the Chukchi shelf by Creager and McManus (1967) may in part result from seabed-sediment winnowing by processes related to repeated massive ice groundings or bergfields. They recognize, however, that the coarseness of sediments on some of the shoals can be more directly attributed to nearby outcrops or to wave and fluvial erosion and deposition during times of eustatically lowered sea level.

3.2.2.3 Geologic Hazards

Several types of potential geologic hazards to petroleum development exist in the proposed lease sale area. These include ice gouging, subsea permafrost, seismicity, and coastal erosion. Based on evidence reviewed for this report, volcanism and seafloor instability do not appear to be major risks in this region.

Sea ice reworks sediments and modifies bottom topography by impaction, plowing and gouging. Ice gouging or ice scour, as it is also called, may be caused by any type of ice with sufficient draft and momentum to penetrate the seafloor. Pressure ridges are probably the most common type of ice feature to produce major depressions in the seafloor although ice islands and their fragments are capable of scour as well. According to Barnes and Reimnitz (1974), ice processes appear to dominate the entire shelf of the Chukchi Sea, including the beach, during the winter season.

Reimnitz and Barnes' (1974) studies of the Beaufort Sea ice gouges indicate that ice-scoured relief tends to dominate the small-scale shelf morphology between depths of 8 to 10 meters (26 to 33 feet) and the greatest intensity of gouging corresponds to depths where the zone of grounded ridges (Stamukhi zone) is formed in 10 to 20 meters (33 to 66 feet) of water. Ice gouging is also especially intense on the seaward slopes of bathymetric highs. Figure 3-8 shows the location and density of see ice gouging in the Chukchi Sea (National Academy of Sciences 1982).

Toimil's (1979) reconnaissance study of ice scour in the eastern Chukchi Sea produced the following observations:

- o The density of ice scour increases with increasing latitude, increasing slope gradients and decreasing water depth.

- o Scour was observed to occur at least as far south as Cape Prince of Wales.

- o Densities of over 200 gouges per kilometer (320 per mile) were encountered in water depths less than 30 meters (100 feet).

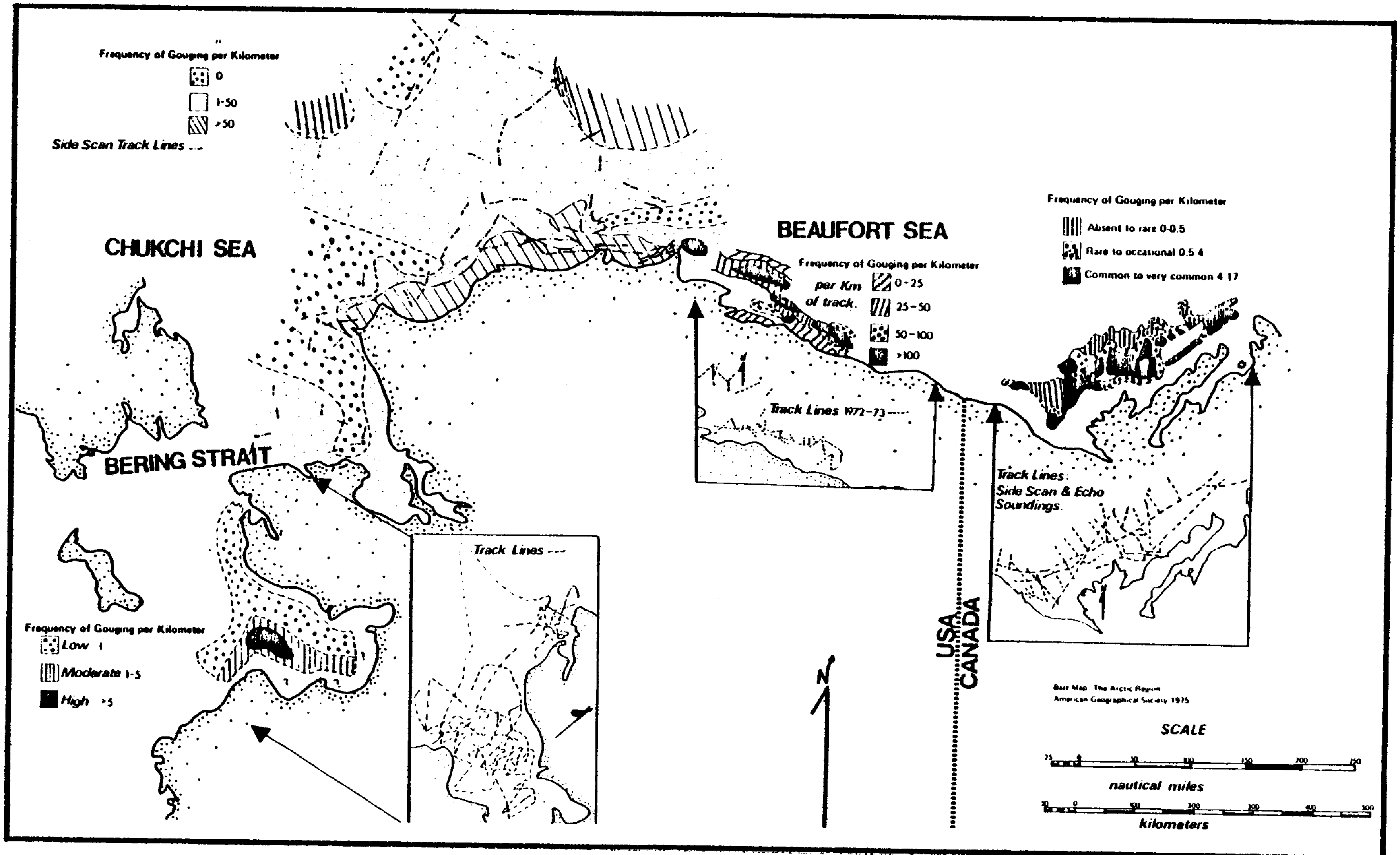
- o No values higher than 50 per kilometer (80 per mile) were found in water depths deeper than 50 meters (165 feet).

- o The maximum depth at which evidence of scour was observed was 58 meters (192 feet) and maximum incision (seafloor penetration) depths were found in water depths of 35 to 50 meters (115 to 165 feet).

- o An extreme incision depth of 4.5 meters (15 feet) was encountered at a depth of 35 to 40 meters (115 to 130 feet).

Toimil (1979) also noted several differences between gouging in the Beaufort and Chukchi Seas:

- o The maximum water depth of ice gouging occurrence appears to be shallower in the Chukchi Sea than the Beaufort Sea.



Source: National Academy of Sciences, 1982

Figure 3-8

DISTRIBUTION OF ICE GOUGES, OFFSHORE ALASKA

- In the Chukchi Sea, ice scour is associated with and may be modified by strong currents.

- Gouge trends in the Beaufort Sea are generally parallel to shore, reflecting the westward drift of pack ice, but this feature is poorly developed in the Chukchi Sea.

- In the Chukchi sea, gouge densities are variable and patchy under otherwise uniform conditions.

In spite of a fairly limited data base, several characteristics of the region's seismicity are known. In general most parts of the arctic coastal plain and the Chukchi Sea are characterized by low seismicity. The only reported seismic activity with a Richter magnitude greater than 6.0 occurred in the Hope Basin portion of the southern Chukchi Sea where four epicenters have been recorded in the last 30 years (Eittreim and Grantz 1977). According to the American Petroleum Institute (1982b), the Barrow Arch planning area falls into earthquake zone 1.

Although ice-bonded permafrost is known to be widely distributed on the Beaufort Sea shelf, little is known about conditions on the Chukchi shelf (Weeks et al. 1978). The Arctic Institute of North America (1974) indicates that while relict permafrost is known to occur beneath the coastal waters of the Chukchi Sea, little is known about its areal distribution, thickness, nature and equilibrium conditions.

According to Barnes and Hopkins (1978), subsea relict permafrost is most likely to be encountered in shallow, inshore areas where ice rests directly on the seabed. Relict permafrost may be encountered on any part of the shelf inshore of the 90-meter (300-foot) isobath. Larry Phillips (personal communication, 1982) of the U.S. Geological Survey in Menlo Park, California indicates that subsea permafrost is unlikely to be found extensively offshore due to the thickness of Holocene sediments. While several OCSEAP investigators continue to study the pattern of subsea permafrost occurrence on the Chukchi Sea shelf, no more recent data is available.

Frozen gas hydrates or clathrates are a geological feature often encountered in association with or below ice-bonded permafrost zones. They occur as a latticework of gas and water molecules with a typical ratio of one gas molecule to six water molecules (Energy Interface Associates 1979). When heated, clathrates may decompose, releasing gas with a much greater volume and/or pressure than it had in the frozen state. Because of the high pressures that may accompany thawing, frozen hydrates are of concern to offshore drilling operations in arctic waters.

Little is known about the distribution of clathrates on the Chukchi Sea shelf. Indirect evidence from seismic reflection records indicates that clathrates may be widespread in the Beaufort Sea (Weeks et al. 1978).

The coast along the Chukchi Sea is generally a narrow transition zone between the tundra surface and the sea (Arctic Institute of North America 1974). It ranges from steep, nearly continuous sea cliffs with gullies and narrow valleys to low, gentle slopes where the sea meets the plain with little discernible shoreline break. The nearshore regime is composed of both semi-enclosed lagoons and open embayments with common coastal landform features such as beaches, barrier islands, barrier bars, spits, dunes and river deltas. During the short summer when sea ice moves off the coast, thermal and wave erosion form steep sea cliffs, and a marked annual retreat of shorelines occurs.

Studies of coastal erosion in the Barrow region show that annual rates of cliff retreat east of Barrow in Elson Lagoon generally exceed 1 meter/year (3.5 feet/year) and occasionally exceed 10 meters/year (33 feet/year; Harper 1978). However, west of Barrow along the Chukchi Sea coast, cliff erosion rates have been measured at 0.3 to 3 meters/year (1 to 10 feet/year) with a long-term retreat rate of over 2 meters/year (7 feet/year; Harper 1978).

Harper (1978) speculates that temporal variations in erosion rates may result from variations in annual wave energy levels associated with storms, migratory bar-attachment points, and localized beach borrow activity.

An additional concern affecting not only coastal erosion rates but also the siting of onshore support facilities is ice pile-up or ride-up events. Described by Kovacs and Weeks (1981), shore ice pile-up and override are frequent events along arctic shorelines. Events generally occur between March and June in the Chukchi Sea. Ice override events can affect structures up to 25 meters (80 feet) from the waterline at elevations of 6 meters (20 feet), even within barrier islands. Shore ice pile-ups along the Chukchi Sea coast in 1981 were found to be massive, some reaching heights of 20 meters (66 feet) and extending continuously along several kilometers of shoreline. Ice override events of more than 30 years ago produced inland ice movements of at least 125 meters (410 feet) near Camden Bay in the Beaufort Sea (Kovacs and Kovacs 1982). Ice pile-up events can also produce extensive soil berms and tundra scars.

A final geologic hazard, overpressured shales possibly occurring in the northern Chukchi Sea basin, may pose drilling problems. These shales are associated with upthrusting shale diapirs areas and may cause well control problems when encountering fluid pockets. See Appendix A for further discussion.

3.2.3 Biology

The Barrow Arch planning area is characterized by significant seasonal and year-round populations of mammals, birds and fish. The area has year-round populations of marine mammals including ringed seals and bearded seals. Polar bears are also found on pack ice and occasionally den in the area from Point Hope to the Kuparuk River. Some barren-ground caribou overwinter in the Icy Cape to Point Lay area. Seasonal populations of bowhead whales, belukha whales, spotted seals, walruses and gray whales are common. Some 13 other species of marine mammals are occasional or rare inhabitants of the region. The endangered bowheads migrate in the ice leads in the northern Chukchi Sea in April and May, and return westward in the fall. Bowheads have been sighted off Barrow as late as November. Walruses use the pack ice edge of the northern Chukchi Sea as summer habitat, migrating in spring and fall within several miles of shore and feeding in mollusk beds (Arctic Institute of North America 1974).

Sea bird colonies are of minor importance in the area north of Cape Lisburne. The northernmost nesting sea bird colony in the Arctic is located at Cape Beaufort. Birds are transient in the northern Chukchi Sea. Sea birds are seasonally present from May through September. The largest concentrations are found in coastal areas between July and September. Large late summer concentrations are found at Peard Bay and on Solovik Island near Icy Cape. Nesting seabird colonies are found at Capes Thompson and Lisburne and in Kotzebue Sound. The endangered arctic peregrine falcon is found between Cape Lisburne and Point Lay (Arctic Institute of North America 1974).

In the Chukchi Sea, waterfowl make extensive use of shore leads in May. Significant year-to-year variations exist in habitat use by post-breeding migrants, making delineation of critical habitat difficult. Potential OCS development conflicts with birds include use of open ice leads by barge and tanker traffic, aircraft overflights and onshore support facilities. Major bird nesting colonies are located south of Cape Beaufort (OCSEAP 1978). Regulatory measures exist to mitigate potential OCS conflicts with birds according to their demonstrated significance and long term impact.

The majority of the fish found in the Chukchi Sea area fall into one of five species: arctic cod, arctic cisco, least cisco, arctic char, and fourhorn sculpin. The arctic cod is the major secondary consumer in the arctic marine food chain. A few small commercial salmon runs are present in Kotzebue Sound (Arctic Institute of North America 1974). The major potential conflict with fish concerns possible disturbance of fish overwintering areas under ice. This conflict is most likely to occur in connection with any winter gravel dredging from fresh water lakes or rivers in the area. In general, potential conflicts with fish are likely to be limited to the construction and operation of shore base and marine terminal facilities discussed in Chapter 4.0.

Arctic ecosystems display considerable resilience, effectively coping with extremes of temperature, light and salinity, and inconstancy in ice cover and length of the growing season. However, sensitivities to disturbance do exist. Arctic species are generally long-lived and slow to reproduce. Disturbed communities may repopulate, but over a relatively long time period as recruitment rates are generally low (OCSEAP 1978).

Considering the above the major biological concerns related to Chukchi Sea OCS development will b: the endangered species (principally the Bowhead whale) and native subsist nce issues (including the Bowhead, other marine mammals, polar bears anc food fishes). Future lease stipulations and mitigation measures may be expected to affect how the arctic oil development activities proceed, especially during the limited and intense open water season (see assumptions in this study regarding impact of regulations, discussed in sections 1.2, 4.5 and 6.3).

3.3 Field Development Components

The presence of sea ice in Chukchi Sea waters poses a serious challenge in the design of offshore field development components for the exploration and production of oil and gas. Water depth is also an important factor, but present technological capabilities for arctic areas are on a different scale from those for ice-free OCS areas. Water depths from 3 to 60 meters (10 to 200 feet) are found across the relatively shallow Chukchi Sea shelf. Due to industry's relatively limited experience in open-coast sea ice environments, the term "deep water" may be appropriate for arctic water depths beyond 30 meters (100 feet).

The progressively more severe ice conditions found as one moves north in the Chukchi Sea substantially limits the summer season during which conventional open-water drilling and construction techniques can be used. Ice-designed vessels and operations plans can somewhat extend the drilling/ construction season for floating equipment. This limitation is such that only bottom-founded, ice-resistant concepts have been seriously considered as first-generation technologies for year-round exploration drilling and oil field development in the Chukchi Sea.

Statistically, there is only a 35 percent chance of the working time in any year being as great as the mean open water period. Thus considerable potential for a short work season exists in planning and costing offshore operations in the Arctic; it is unreasonable to assume that something close to the mean open-water period will be available for summertime construction (Jahns 1980).

All structures emplaced in the multi-year pack ice zone will have to be capable of resisting the dynamic forces developed by moving ice. Beyond the landfast ice zone, multiple ridges form in the shear zone of transition between the stationary ice and the moving multi-year ice of the polar gyre. Exploration and production systems will have to deploy slope protection systems or employ passive design concepts to survive in the shear zone and the multi-year ice beyond. Bottom-founded systems must be flexible enough to absorb the initial concentrated loading from large irregular ice shapes while spreading the load over a large enough area to mobilize the concept's mass resistance and thus develop the forces required to cause failure of the largest ice features (Downie and Coulter 1980).

Weather will also play a role in affecting exploration programs. Limited visibility due to fog and snow can occur anytime, and is most prevalent in the open-water season. High wind and waves, particularly those associated with early fall storms may shorten exploration seasons or affect the construction period for exploration concepts such as artificial islands. Any year-round exploration operations may also be adversely affected by the severe cold of winter and the limited visibility due to fog and snow.

The remoteness of the Barrow Arch planning area from developed ports and industrial centers and its lack of in-place shore facilities capable of supporting an exploration program is another constraint. The great supply distances will make crew rotations and resupply more difficult and costly. Crew rotations and critical spares will be transported by air. An airstrip and forward base along the northern coast, probably in the vicinity of Wainwright seems probable although temporary facilities could just as easily be established in close proximity to the exploration effort. Resupply of bulky materials such as mud and water and any material required for construction or emplacement of exploration platforms will probably be barged from an expanded regional supply center such as Nome or Kotzebue. Desalination units might be installed for water supply.

It should be emphasized that any of the concepts to be employed for exploration of the Chukchi Sea will be considerably more expensive than similar equipment for sub-arctic or non-arctic OCS regions. Compounding this problem is the fact that at present, little purpose-built equipment for operation in arctic regions is available. While some conventional equipment can be employed on a seasonal basis, the requirement for ice-survivable platform concepts and supporting equipment implies considerable costs for design and construction of new equipment. Therefore, exploration programs will have to be carefully planned and executed with maximum opportunities for cost-savings realized. Also, due to the high costs of developing fields in offshore basins with severe ice conditions, more exploratory delineation drilling than is normal may be required to evaluate the production potential of a prospect.

3.3.1.1 Exploration Platforms Selected for Representative Water Depths

Based on a review of the Barrow Arch planning area's petroleum geology and bathymetry, two representative water depths were selected as the basis on which to select suitable exploration concepts. The selected water depths are 15 meters (50 feet) and 37 meters (120 feet). Two additional water depths, 27 meters (90 feet) and 60 meters (200 feet) were examined less rigorously.

The shallower depth occurs only over a limited area of the federal waters just beyond the State of Alaska (3-mile) jurisdiction zone. This coastal strip of seafloor is most likely to contain extensions of geologic structures characteristic of the prolific North Slope.

The 37-meter (120-foot) depth was selected because it is most typical for significant areas of the relatively level central Chukchi shelf. The other two depths were briefly examined for transitional (limited area) and extreme (deepest with any reasonable interest) cases.

The following are the exploration concepts appropriate to each selected water depth for the Chukchi Sea:

15 meters (50 feet)

- Artificial gravel fill drilling island -- "gravel island"(1)
- Caisson-retained gravel drilling island

27 meters (90 feet)

- Caisson-retained gravel drilling island
- Conical drilling unit

37 meters (120 feet)

- Caisson-retained gravel drilling island
- Mobile caisson rig
- Conical drilling unit, other ice-strengthened floating platform

60 meters (200 feet)

- Conical drilling unit/round drillship
- Ice-reinforced semi-submersible, drillship and turret-moored drillship
- Mobile caisson rig

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(1) The widely used term "gravel island" is used generally in this report to refer to any type of artificial island or underwater berm for structural foundation support constructed from fill materials that can have a wide range of grain sizes.

3.3.1.2 Construction, Transportation and Installation Techniques for Selected Exploration Concepts

At the selected shallow water depth of 15 meters (50 feet), several exploration concepts seem feasible. The most viable technologies for extending the exploration drilling period beyond the open-water season are artificial islands. Artificial islands are suitable for operations in water depths out to 18 meters (60 feet) and several Canadian operators are experimenting with island-building techniques for 20- to 60-meter (65- to 200-foot) water depths (Ocean Industry 1982).

The cost of constructing an artificial island is very sensitive to the availability of fill material, the type of fill material used, the location and depth of the fill material and the method of island construction. Experience has shown that only free-draining materials such as gravel or sands with an average grain size of 150 microns or greater and with less than 10 percent silt are acceptable as building materials (de Jong and Bruce 1978).

For the Barrow Arch planning area, two major types of artificial islands appear most likely for exploration purposes. They are:

- o Gravel islands
- o Caisson-retained gravel islands.

Man-made islands of gravel or other dredge fill offer the distinct advantage that drilling can be conducted in essentially the same manner as on land. They can be designed for year-round operations. Islands are gravity structures that resist lateral ice loads by their large weight. By adjusting the island size and freeboard, the sliding resistance on the sea floor or on any given shear plane through the island fill can be adjusted as necessary to assure a stable platform for the anticipated ice loading conditions (Jahns 1980). Thus, this type of structure can be easily adapted to site-specific design parameters. Also, temporary islands for exploration drilling can be enlarged and transformed into a permanent production platform if a discovery is made. Gravel islands have been found to have minimal impacts on the environment at their location, both during construction and after the islands have been completed (Wright 1977). Once abandoned, they disappear gradually due to natural erosion.

The design of artificial islands requires a consideration of ice forces, storm waves and tides, geotechnical and seismic properties of the seabed, and availability and engineering characteristics of the fill material. Three techniques are available for the construction of gravel or other fill-based artificial islands. They are:

- Dredging of gravel from on-site seabed sources during open-water season.
- Dredging of gravel from off-site seabed sources and barging on-site during open-water season.
- Dredging of gravel from onshore borrow sources and winter transport over ice roads to the offshore site and island construction through a hole in the ice.

Due to the ice conditions at the selected water depths in the Chukchi Sea, only the first two techniques are feasible. The technique of over-ice winter construction utilized in the Beaufort Sea will not be possible since island construction will take place beyond the boundary of the smooth and stationary land-fast ice zone over which ice roads can be constructed.

Since only open-water construction techniques can be used in the Chukchi Sea to emplace artificial islands, scheduling constraints, weather, and ice conditions all become critical elements in successful island completion. The availability of suitable gravel fill material is critical for selecting island sites. Gravel is the preferred fill material since it offers faster consolidation, steeper stable slopes, and better resistance to wave or ice erosion of the constructed island. For purposes of this study, we have assumed that sufficient gravel deposits to construct any artificial island concept are located within a reasonable distance of the site.

Exploratory Gravel Fill Drilling Island

Given a sufficient supply of granular borrow material in the vicinity of a proposed island site, a gravel island can be constructed for exploration drilling. Prior to initiating dredging, an extensive borrow research program is conducted employing coring, high resolution seismic data and dredge tests. Once suitable borrow pits are identified, dredge equipment can be employed. Table 3-8 shows an example construction spread for construction of an exploratory gravel island. Figure 3-9 shows an elevation of an arctic exploratory drilling island constructed entirely of fill materials. It depicts side slopes of 1:15, while the island designs developed by SF/Braun for use in the economic analysis have side slopes of 1:10. A representative island will be designed with a circular working surface of 100 meters (330 feet) across, large enough to accommodate an arctic drilling rig, drilling supplies and fuel tanks. Design geometry is selected to protect against wave and ice attack and is based on expected fill properties. Standard design practice is to establish freeboard height as a function of intended platform life coupled with the probability of encountering an extreme wave and storm tide height (Energy Interface Associates 1979).

The rapid rate of island construction (up to 2,000 cubic meters [2,200 cubic yards] per hour) required by the short open-water season and the magnitude of the fill requirements necessitates controlled distribution of material over the site to reduce the risk of slope failure (Boone 1980). It is not possible to accurately predict losses due to erosion during construction. This depends greatly on weather conditions. Enough experience has been obtained with all-fill islands constructed to date to indicate that this is a serious problem. A particular problem is the building up of the island through the wave zone.

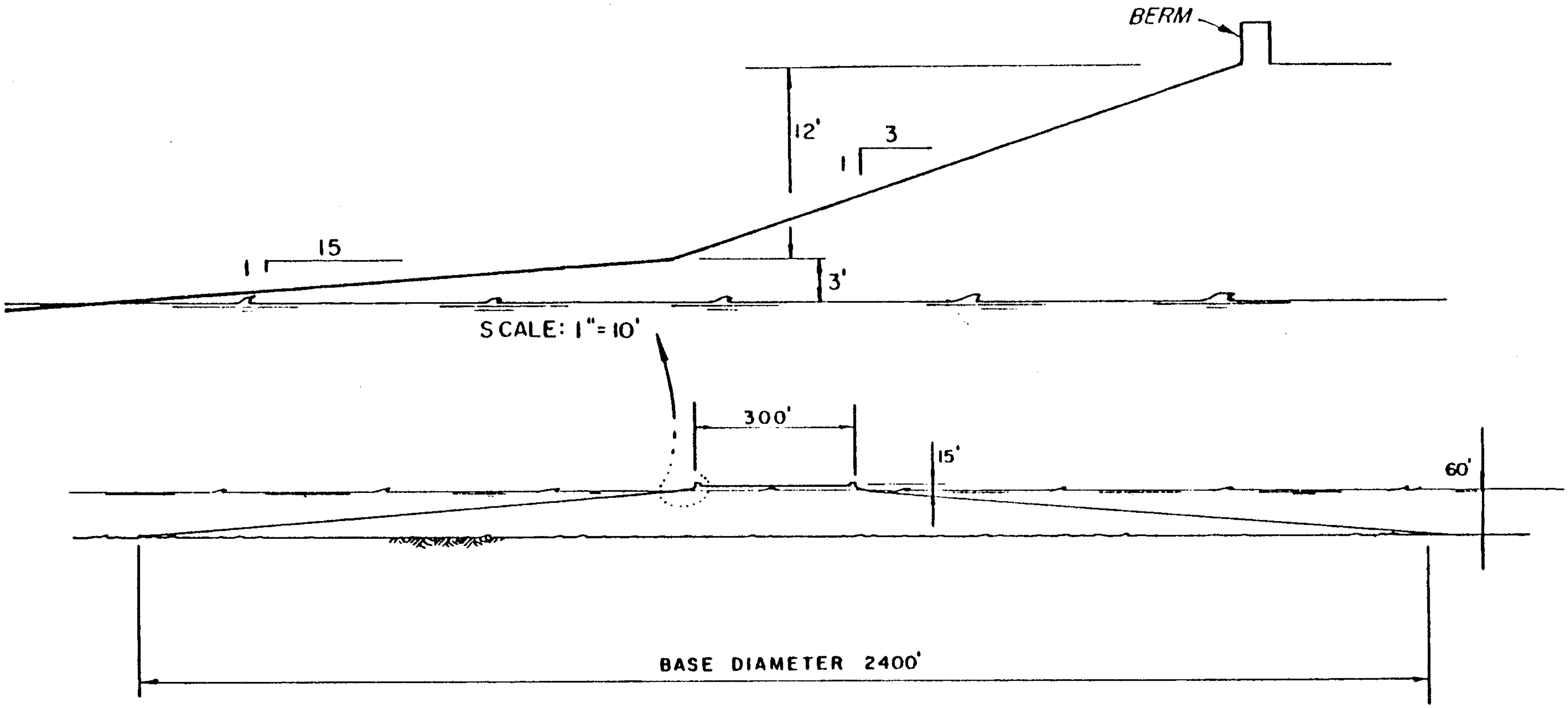
TABLE 3-8

EQUIPMENT SPREAD FOR CONSTRUCTION OF A GRAVEL ISLAND
IN 15-METER (50-FOOT) WATER DEPTH*

3 cutter head suction dredges
4 barges
2 derrick barges
12 work boats (tugs, survey vessels, etc.)
2 Icebreakers
2 Quarters Barges (worker accommodations)
2 Caterpillar tractors

* Assumes availability of gravel sources within direct dredge pumping distance -- on the order of one kilometer, and that the open-water construction season is short -- about 70 days.

Source: SF/Braun



Source: National Petroleum Council 1981

Figure 3-9

ELEVATION OF ARCTIC EXPLORATORY DRILLING ISLAND

A key consideration in successful island construction is availability on site of enough dredging power to produce the required fill material within the time allowed for construction. Trailer suction hopper dredges offer distinct advantages over stationary suction dredges because of their ability to work in sea states with up to 3-meter (10-foot) waves and 65-kilometer (40-mile) per hour winds along with rapid mobilization after a shutdown due to storms. In addition to several trailing suction hopper dredges of approximately 6,500-cubic meter (8,500-cubic yard) capacity, a stationary suction dredger/crane/work barge with a large crane mounted is preferred to build up the island or base berm from a stockpile deposited adjacent to the island site by the trailing suction hopper dredgers. If open-water season weather conditions permit, an alternative technique is use of a pontoon floating pipe to move the stockpile onto the island site. The same stationary suction dredger with mounted crane can be used to overbuild the sacrificial beach to provide for maintenance requirements. The same unit can also provide the lifting capacity for many miscellaneous tasks and the location of a floating construction camp at the island site (Downie and Coulter 1980).

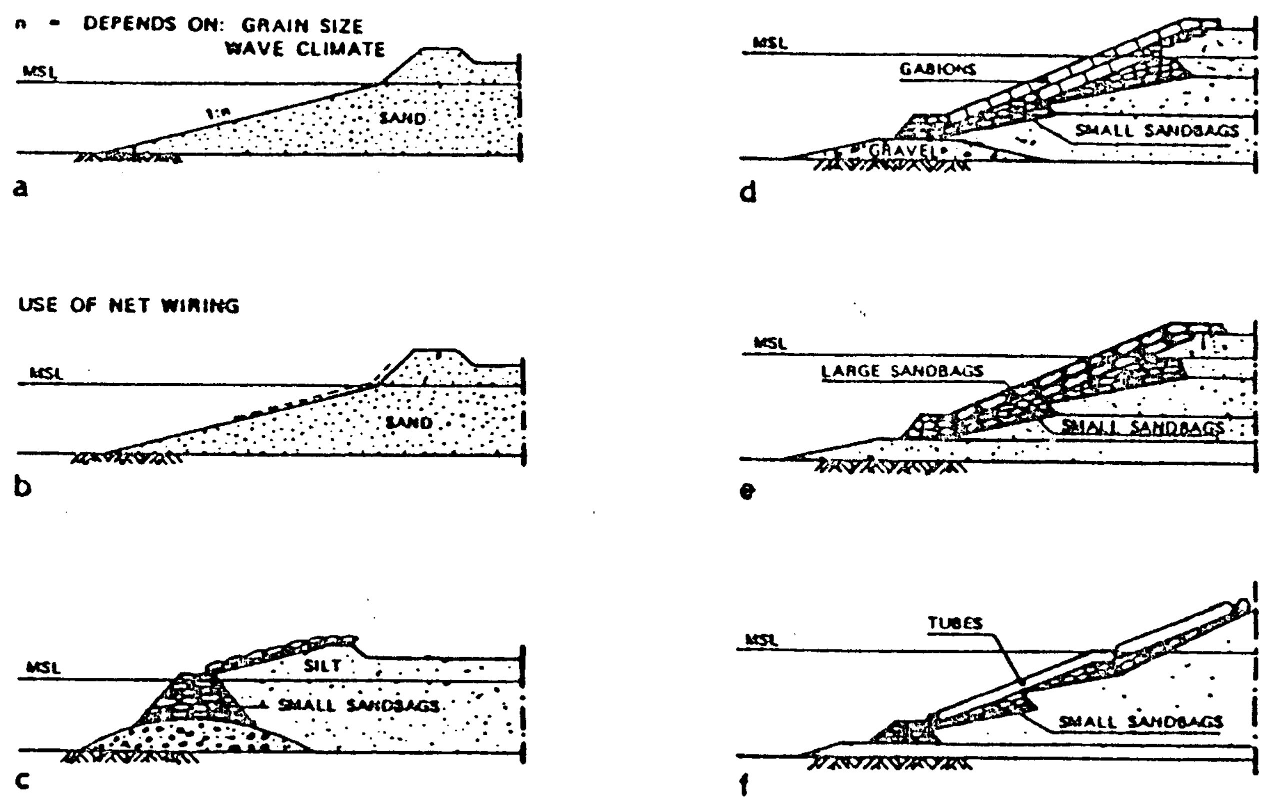
In its construction of the Issungnak sand island in 20 meters (66 feet) in 1978-1979 in the Canadian Beaufort Sea, Esso Resources Canada (formerly Imperial Oil Ltd.) used two stationary suction dredges to move fill from borrow pits on site. One dredge, the Beaver Mackenzie, provided the backbone of the fill movement with its 70,000-cubic meter (90,000-cubic yard) per day capacity. One smaller cutter suction dredge was employed to fill 1500-cubic meter [2,000-cubic yard) capacity split-bottom dump barges with sand from a remote borrow site. The dump barges stockpiled this material at the island site for use in completing the island. Floating pipelines with alternating rubber and steel pipe sections were used. Several pipeline breaks did take place without significantly disrupting operations. Average dredge production over a 69-day ice-free season was 23,400 cubic meters (30,600 cubic yards) per day (Boone 1980).

Marine support at the Issungnak construction site was enhanced by use of a 60-man camp onboard an ice-strengthened accomodation barge. This improved communication, allowed faster response time to potential problems and reduced dependence on weather. There is also a need for sheltered water in the vicinity of an island construction site. Dredging of a small harbor for tugs, supply barges and other vessels may be required. If more than one open-water construction season is required for island construction, ice-strengthened dredges and other vessels may be overwintered in harborage dredged behind nearshore barrier islands.

A critical point in island construction is reached at the end of the construction season where the island breaks the water surface and is topped off. According to Boone (1980), a period of relatively calm water at the end of the construction season is required for this final step. Imperial's Issungnak island nearly floundered at this point due to erosion caused by overtopping waves. In fact, the completed 4.1 million-cubic meter (5.3 million-cubic yard) island had a final freeboard of only 1.5 meters (5 feet) instead of the 5-meter (16-foot) design freeboard due to the erosion. Nevertheless, despite problems associated with moving equipment on and off the surface of islands, and preventing dredge pipe damage in breaking waves, the island was completed and a winter exploratory well successfully drilled.

Hydraulic fill exploratory islands are generally fortified with one of a number of slope protection features to provide short-term protection against wave and ice erosion of the island's sacrificial beach. These may be rocks, gabions, sand bags, wire netting, concrete mats, or some combination of these. Figure 3-10 illustrates several types of shore protection features. Slope protection devices will be installed by a derrick barge once an island's basic form is completed. It may also be necessary to add a dock by creating an arm or shoulder of fill on the island to provide berth space to land heavy equipment and to emplace the exploratory drilling rig.

Artificial islands at shallower water depths have significant advantages over conventional drilling platforms designed for arctic conditions. The key is use of equipment with sufficient dredging capacity to complete the island in the time allowed for construction. According to SF/Braun,



Source: de Jong 1975

Figure 3-10

GENERAL DESIGN OF SHORE PROTECTION FOR ARTIFICIAL ISLANDS

artificial islands out to 15-meter (50-foot) water depths can probably be constructed in one season, although annual variations in open-water seasons or equipment failures could force multi-year construction.

Exploratory Caisson-Retained Gravel Island

As exploration moves to deeper waters and to areas where sand or gravel is not available, simple dredge fill islands become very expensive. According to the Oil and Gas Journal (1981), as water depth doubles, the volume of fill needed to construct hydraulic fill islands quadruples. While industry is experimenting with construction of islands with steeper slopes to minimize fill requirements, other artificial island concepts offer significant advantages over all-fill concepts.

The caisson-retained concept was developed to reduce costs by reducing fill requirements, simplifying construction methods and eliminating the need for elaborate slope protection. It also offers several other advantages over all-gravel artificial islands. The steeper side slopes make it easier to maneuver barges or other vessels in close, facilitating lifts of equipment. Caisson-retained islands also offer a potential for reusability, since the caisson might be removed and floated onto another site. Table 3-9 illustrates the reduced fill requirements of a caisson retained island at several different water depths as compared to two types of all-fill artificial island construction. Figures 3-11, 3-12, and 3-13 illustrate a caisson-retained island in several aspects, including tow-out of the deballasted caissons.

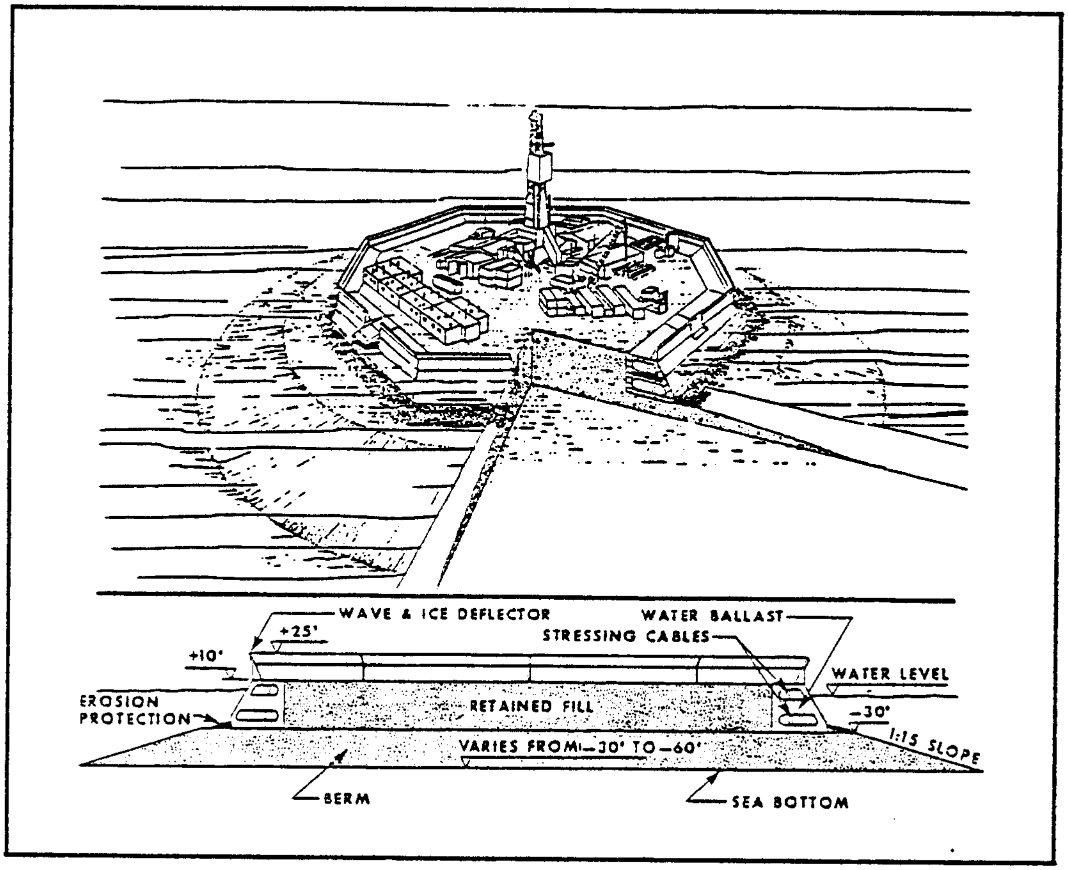
The design illustrated, proposed by Esso Resources Canada (formerly Imperial Oil Ltd.), consists of eight trapezoidally shaped steel caissons, each 43 meters (141 feet) long, 12 meters (40 feet) high with a base of 13 meters (43 feet). The caissons are designed for interlinking by flexible hinge joints and stressing cables. The structural design of the caissons is similar to that of ice-breakers. The caissons are designed for a freeboard of 3 meters (10 feet), which is increased to 7.6 meters (25 feet) by an ice and wave deflector (de Jong and Bruce 1978).

TABLE 3-9

ISLAND FILL REQUIREMENTS

Water Depth Feet	Sacrificial Beach Island Cubic Yards	Retained Fill Island (Sandbags) Cubic Yards	Caisson-Retained Island 30' Set-Down Depth Cubic Yards
20	800,000	250,000	150,000
30	1,700,000	500,000	150,000
40	2,500,000	900,000	300,000
60	5,000,000	2,500,000	900,000

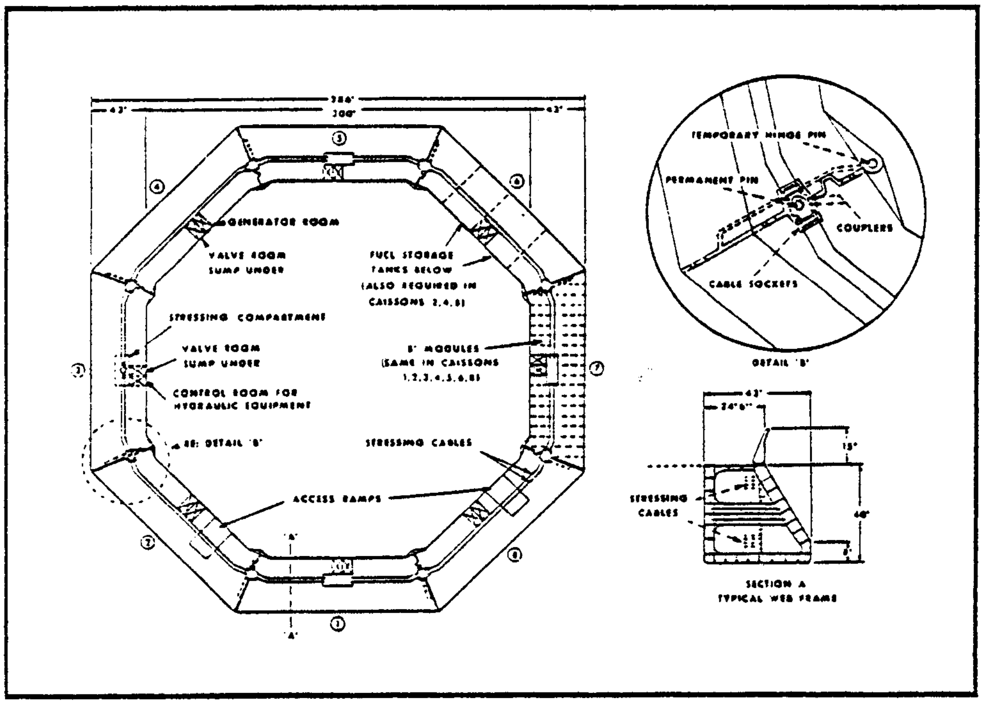
Source: deJong and Bruce 1978.



Source: deJong & Bruce 1978

Figure 3-11

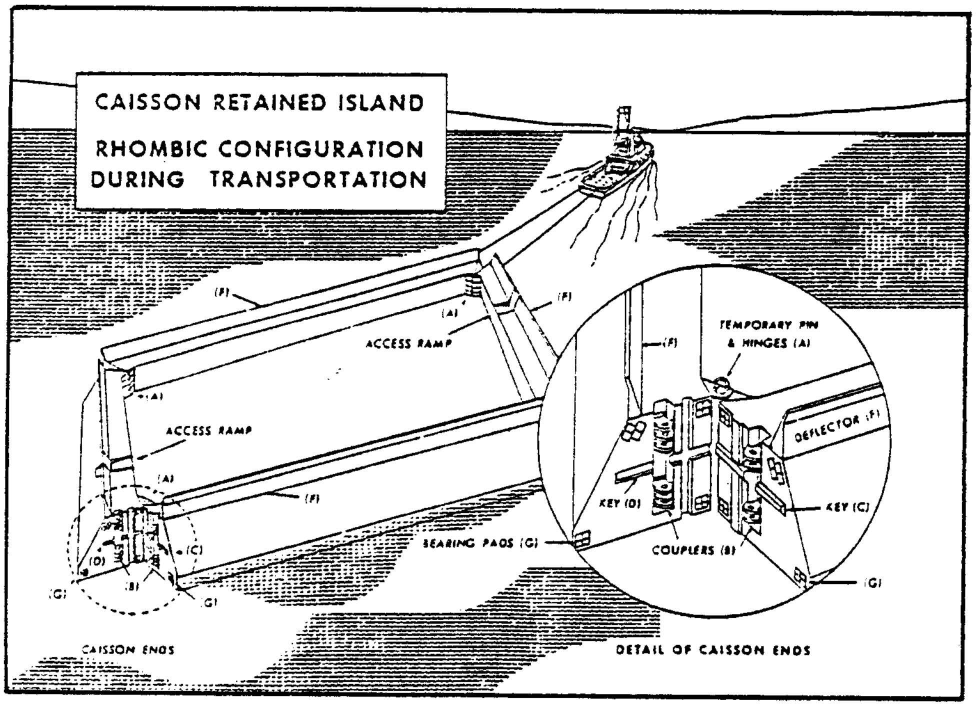
CAISSON-RETAINED ISLAND



Source: de Jong & Bruce 1978

Figure 3-12

CAISSON-RETAINED ISLAND SIMPLIFIED GENERAL ARRANGEMENT



Source: de Jong & Bruce 1978

Figure 3-13

CAISSON-RETAINED ISLAND
RHOMBIC CONFIGURATION DURING TRANSPORTATION

The caisson units will probably be constructed on the west coast and towed via the Bering Strait either singly or in a rhombic configuration in sets of four as illustrated. They could also be barge-mounted for transport to the Chukchi Sea. Once at the island site, the caissons will be set down on a previously prepared underwater berm built up from the sea floor to 9 meters (30 feet) below mean sea level. The berm will be constructed of dredged fill in a fashion similar to the gravel island previously described, although with steeper side slopes.

Once in position, they are secured with pins at corner couplers and stressing cables, then flooded with water to ballast. The center core of the ring is then filled with dredged gravel or sand fill to provide the base for the drilling equipment. The caisson units are equipped with hydraulic stressing jacks, generators, ice-melting heaters, miscellaneous electrical equipment, oil tankers in alternate units, winches, mooring facilities for supply vessels, loading and unloading ramps and a detachable helipad.

One of the intentions of the caisson design is reusability. The caisson ring can be raised and transferred to a new location for exploration drilling each summer after removal of the gravel fill. Once the caissons are deballasted and refloated, they can be disconnected, reassembled for transport and towed to a new site. The system was designed to allow transport of caissons between sites with as little effort and in as short a period as possible. The caissons have a constant set-down depth of 9 meters (30 feet) with the depth variation to the seabed being made up with dredged fill material built into a berm at the new site. However, the only prototype caisson-retained gravel island actually constructed to date, Dome's Tarsiut island, experienced difficulties in construction that may prevent it from being re-used (personal communication, SF/Braun 1982).

Another advantage of the caisson concept is that it eliminates erosion problems encountered in topping out all-fill artificial islands. As soon as the caisson ring is set down it provides sufficient wave protection to prevent erosion losses caused by wave overtopping while the central core is being built up through the wave zone. As a consequence of its reduced fill requirements and ease of assembly, the caisson ring concept reduces the construction time required to build an island and thereby reduces the risk of failing to complete an island during the short open-water season in arctic regions such as the Barrow Arch planning area.

SF/Braun estimates that a construction spread for a caisson-retained gravel island in 15 meters (50 feet) of water would be less than that for a gravel island since less fill has to be moved. The caissons in a caisson-retained island can be constructed of either concrete or steel. While the design discussed here is for a concept using steel caissons, Dome Petroleum Ltd. constructed its Tarsiut caisson-retained artificial island in 22 meters (72 feet) of water in two seasons of construction using four concrete caissons.

As a prototype artificial island, not only is Tarsiut the deepest arctic exploration island constructed to date, it is also the first to actually emplace any type of structure on its fill base. In contrast to Esso's Issungnak gravel island in 19 meters (62 feet) of water which was discussed earlier, Tarsiut's 1.8 million cubic meters (2.3 million cubic yards) of fill is under 40 percent of that used at Issungnak (Cottrell 1981). The two key reasons behind this success were accurate dredge placement techniques that allowed steep side slopes to minimize the fill volume required, and the emplacement of the caissons which avoided the erosion-prone wave zone.

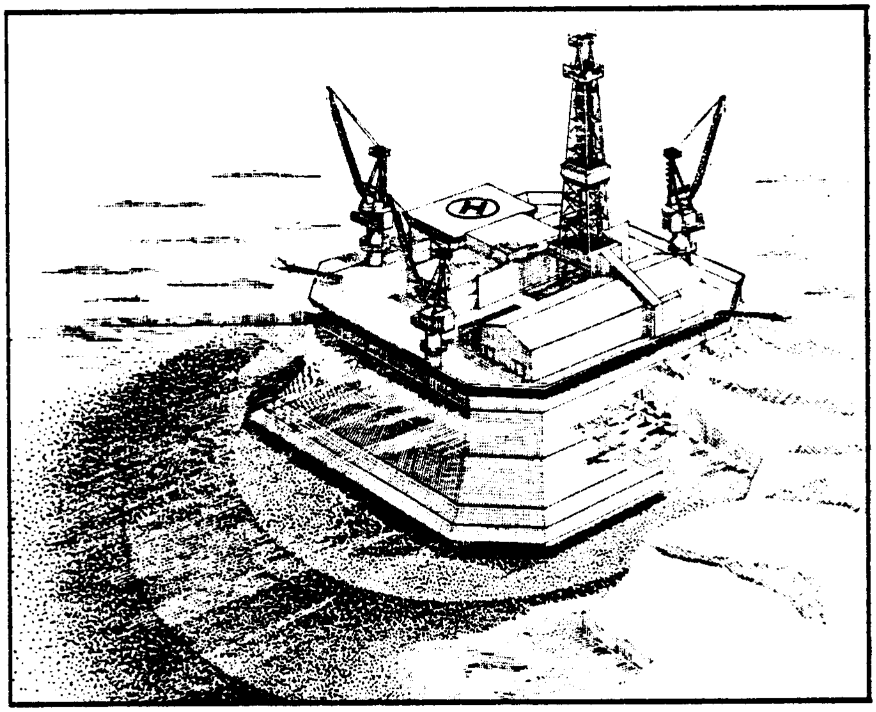
Tarsiut's concrete caissons are each 69 meters (226 feet) long, 15 meters (49 feet) wide and 11.5 meters (38 feet) high, with the gravel berm at 6.5 meters (21 feet) below mean water level, leaving a freeboard of 7.5 meters (25 feet) to the island's surface. The caissons are designed to fail ice by crushing rather than flexural failure so strain gauges and pressure cells have been built into the caissons to measure ice and soil loadings. The caissons were built by forming the bases in dry dock, then floating them out and slipforming to full height in the water. The caissons were constructed of high strength lightweight concrete using air entrainment and the expanded shale aggregate Herculite (Cottrill 1981).

As the water depths over the areas slated for exploration increase, the construction of artificial islands becomes increasingly difficult and costly. Due to the increasing fill requirements and more severe ice conditions, other types of drill platforms for exploration begin to look more attractive. While precise break points between technical concepts have not been delineated, gravel islands become uneconomic somewhere beyond 15 meters (50 feet) and caisson-retained gravel islands fall out beyond 37 meters (120 feet), leaving only one-piece caissons, concrete or steel monocones and ice-breaking drill ships or semi-submersibles as viable drilling concepts for waters out to 60 meters (200 feet) and beyond. According to Chevron, the breakeven depth for all-gravel islands is 18 to 19 meters (60 to 62 feet). Dome believes that its Tarsiut-type caisson-retained gravel islands are feasible for exploration out to 35-meter (115-foot) water depths (Cottrill 1981).

Mobile Caisson Rig

Hybridization of successful artificial island concepts with more traditional concrete and steel structures is evident as technical concepts to explore intermediate (27 meters [90 feet]) to deep (37 meters [120 feet]) water depths. A novel hybrid structure designed for Gulf Canada is a floating annular steel ring to be placed on an island of dredged material and then filled with sand. Weighing about 30,000 tons and constructed using shipmaking bulkhead techniques, the concept is designed to be used for water depths to about 35 meters (115 feet).

Designed to have the capability to operate year-round if necessary, Gulf's mobile caisson rig, pictured in Figure 3-14, is currently under construction in Japan for delivery in March 1984 for a total cost approximating $140 million (Cornitius 1981). The tapered floating steel cylinder will be placed on a sub-surface dredge berm before its center core is filled with sand to provide most of the resistance to the forces from the horizontal movement of ice. The rig is designed to be installed on a simple seafloor foundation, depending upon fill material available. The top of the submarine mound will be brought to 21 meters (69 feet) below sea level so



Source: Cornitius 1981

Figure 3-14

GULF CANADA BEAUFORT SEA MOBILE ARCTIC CAISSON

that the deck of the 29-meter (95-foot) high caisson will stand 8 meters (26 feet) above the water.

After the structure is towed to location and installed on its fill base by water ballasting, the space inside the annulus is filled with clean sand, which is then densified to help resist the ice force applied to the outer hull. The 86-by 86-meter (282 feet) eight-sided top will be the base for the drilling rig and support facilities. The insulated deck will retain heat pumped under the deck to keep the sand core in an unfrozen state. Core fill will be at or below water level with a volume of 115,000 cubic meters (125,000 cubic yards).

The hull configuration is similar to tanker construction with outer-plate, main frames and bulkheads with intermediate stiffeners (Watt 1982). The compartments in the external section of the mobile caisson system will be filled primarily with seawater for ballast. However, the upper sections will be used for storage of fuel and potable water.

After completion of drilling operations, the sand inside the annulus will be removed by suction heads to a level that will permit re-floating and removal of the caisson to a new location. Operations of the arctic mobile caisson rig are supported as necessary by one or more purpose-built Class IV ice breakers and supply vessels (Offshore 1981).

Floating Drilling Units

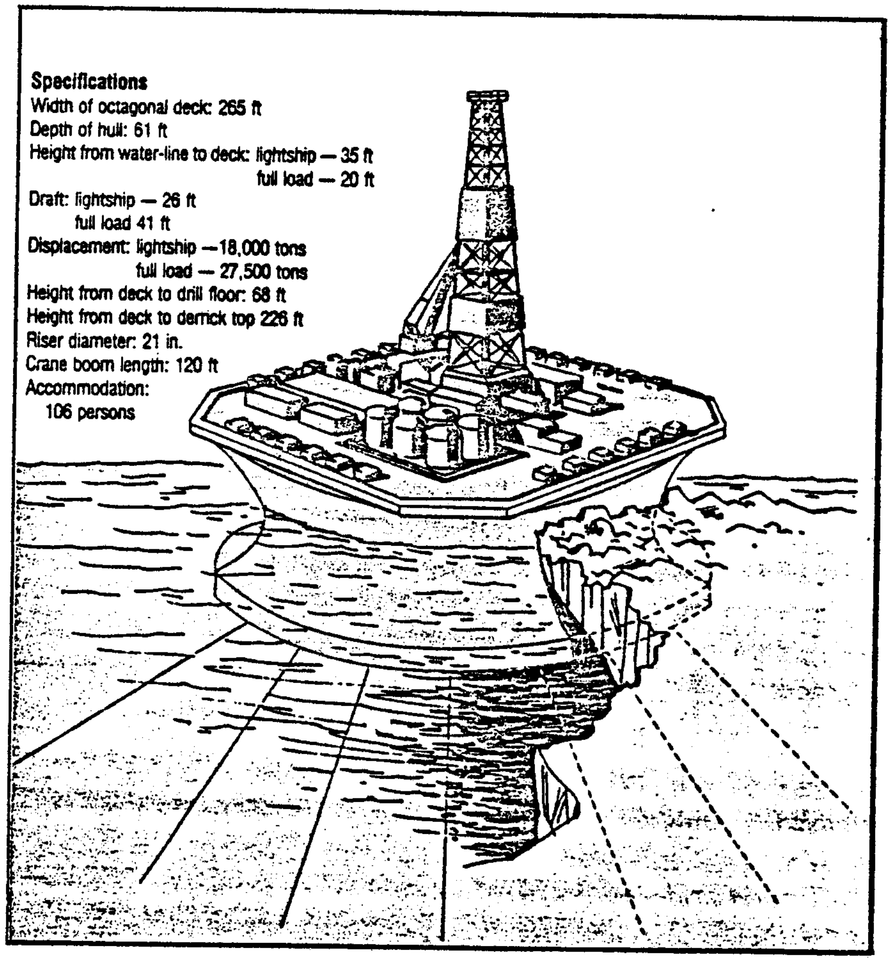
Despite the obvious difficulty inherent in operating floating platforms for arctic exploration drilling, two Canadian operators are proceeding with plans to construct conical floating drilling units for use in deeper arctic waters in the Beaufort Sea. The main purpose of moving to floating drilling platforms, other than ice-strengthened or ice-breaker drillships, is to extend the time period available for exploratory drilling in deeper more ice-infested areas. Dome Petroleum's round drillship and Gulf Canada's conical drilling unit will each be designed to withstand the forces of moving ice thereby extending the floaters' work period for the exploration and delineation phase of development. Such new configurations must also include mooring and riser designs to cope with the generally shallow waters of the Arctic (see Drillships, page 3-68).

Dome Petroleum has replaced its earlier proposals for a swivel drillship, which would have weathervaned into oncoming ice by swivelling around a central turret, with a proposal for a round drillship. The round drillship, intended for year-round drilling in the transition ice with ice-breaker support, is estimated to cost around $125 million. It is proposed as an arctic Class VI moored barge. Its 65-meter (213-foot) diameter hull will contain 10,000 tons of steel and will be shallow and saucer-shaped to offer the smallest possible resistance to ice approaching from any direction. Below the waterline it will draw into a central cone from which the anchor lines radiate outward well below the ice (Cottrill 1981). It will probably be in place by 1984, operating with support from Dome's arctic marine locomotive (AML) ice-breaker Kigoriak and the new AML X10.

Gulf Canada's conical drilling unit, designed for ice Class IV conditions, will be capable of operating from the beginning of June to the end of the following January, ice conditions permitting. The main hull angle slopes at 31° to deflect ice downward and break it. The downbreaking cone shape was selected because total horizontal forces on it are only 20 to 25 percent of what they would be on an upbreaking cone (Offshore 1981).

The unit is non-self-propelled and will be moored on location with 12 anchor cables as pictured in Figure 3-15. Transponders mounted in the seabed and hull will monitor the rig's position over the well location. The control console, which is under the captain's direction, will manage the position and line load using deck-mounted winches.

The hull is of double bottom design, conventional welded-steel ship construction. The ballasting system uses structural compartments for ballast chambers. The circular hull is topped by an eight-sided deck, 80 meters (262 feet) across on which standard drilling equipment is emplaced.



Source: Offshore 1981

Figure 3-15

GULF CANADA BEAUFORT SEA DRILLING BARGE

The conical drill unit will have a heliport capable of handling a Sikorsky S-61 helicopter as well as radar and radio links for communications with shore, marine traffic and aircraft. Instrumentation will record vessel movement and ice loading on the hull and mooring system. Class IV ice-breakers and supply vessels will be available to perform ice management duties, to protect the drilling system as it moves to new locations, to supply bulk materials and equipment to the barge, and to perform other operational functions such as anchor handling.

Ice-Resistant or Ice-Breaker Drillships

Although ice-breaker drillships or ice-reinforced drillships supported by ice-breakers can extend the open-water drilling season somewhat, there is a minimum water depth at which drillships can operate due to limitations on lateral motion or vessel excursion, which are dictated by the riser angle. This depth limitation lies between 15 meters (50 feet) and 20 meters (66 feet). Dome Petroleum has been successful in extending the open-water drilling season with its ice-reinforced Canmar fleet, and this Canadian approach may be applicable in the Chukchi Sea despite the more severe and dynamic ice conditions occurring in the deeper waters in which drillship operations appear desirable.

A second generation of arctic drillships incorporating special hull forms and mooring features to minimize hull forces in moving pack ice, including special features to reduce ice resistance between ice masses and the hull of the ship, once appeared likely. However, the decision of Gulf Canada and Dome Petroleum to order more ice-resistant, conservative designs, indicates the direction in which mobile exploratory drilling concepts are likely to move in years ahead.

Ice-Breaker Semi-Submersible and Jack-up Rigs

Recently, several arctic semi-submersible design concepts have surfaced. While no operators are known to be considering ordering such a system for exploratory drilling in the near future, it is significant that designs are being developed. Such rigs would appear to be particularly applicable in deeper waters of the Chukchi Sea, provided that such concepts were capable of being maintained on station in the dynamic ice conditions found in such waters.

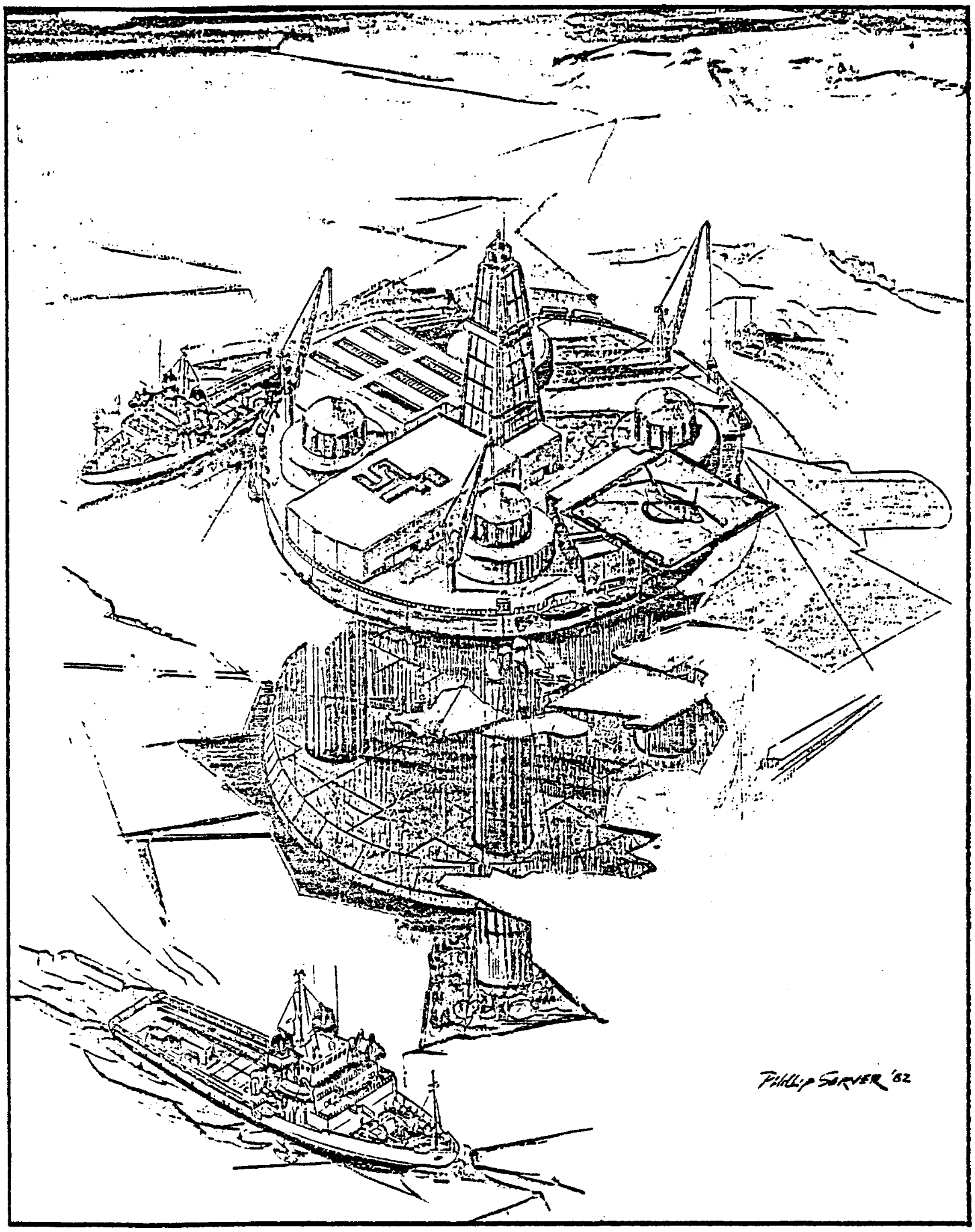
Figure 3-16 illustrates an "arctic drilling barge" concept developed by SF/Braun. The hull diameter is about 90 meters (300 feet) and each leg has a diameter of approximately 12 meters (40 feet). The jack-up will be designed to drill in ice-infested waters in up to 55-meter (180-foot) water depths with a variable deck load of 10,000 short tons.

3.3.2 Production Platforms

3.3.2.1 Background

Production platforms will be positioned over reservoirs to most efficiently develop hydrocarbon resources. The number of platforms needed to tap a reservoir depends on many factors including the area, shape and depth of the reservoir, and how much of it can be drained by a single platform using directionally drilled wells. Drilling and production systems will be concentrated into the fewest number of locations possible.

Selection of production platforms for Barrow Arch oil and gas fields will also depend on several factors. In order to resist the severe ice forces that characterize the Chukchi Sea over the 10- to 20-year life of an average field, bottom-founded platforms will be selected as permanent production systems. Artificial islands will predominate as production concepts, possibly out to water depths as great as 45 meters (150 feet; Harrison 1979). In deeper waters beginning at 37 meters (120 feet), stiff gravity-type structures of steel or concrete are the expected concepts. Such production platforms would include a cone-shaped form at and below the waterline to break advancing ice through flexural failure and to promote ridge clearing without ice pile-up (Harrison 1979).



Source SF/Braun 1982

Figure 3-16

MOBIL ARCTIC DRILL BARGE JACK-UP CONCEPT

Another production-related factor that may be of importance in later development of Chukchi Sea hydrocarbons will be establishing the feasibility of early production systems for arctic conditions. Early production systems have been used in other parts of the world to shorten the lead-time in bringing production on-stream and to allow extended reservoir evaluations prior to commitment of capital for permanent production systems. Such systems assume the existence of a suitable transportation infrastructure.

The production technologies selected in the Barrow Arch planning area will be influenced to a large extent by the exploratory technique used to discover the field when gravel islands or underwater berms are part of the discovery technique. At the present time, exploration technology for offshore arctic areas is significantly more advanced than production technology, reflecting the fact that it is easier to explore for oil than it is to produce it.

No production has at this writing yet occurred from an offshore arctic find anywhere in the world. Although several Canadian operators are currently designing production systems for oil and gas finds that may be produced by 1985 or 1986, there is not the reservoir of experience to draw upon as exists for arctic exploratory drilling technologies. The design concepts presented here are based on current knowledge and expertise. As more research, field data, and operational experience accumulates, design concepts will undoubtedly be modified as necessary by industry operators to improve the final installed technologies. Nevertheless, this report accurately reflects the current state-of-the-art and conceptual technologies for production platforms in the Arctic, and those concepts selected represent in our best judgement systems appropriate to the environmental conditions of the Chukchi Sea.

3.3.2.2 Platforms for the Barrow Arch Planning Area

Selection of production platforms for Barrow Arch reflects a combination of factors including: geographic location, field size, water depth, distance from shore, ice conditions, and transportation systems selected for moving produced oil or gas to market. Any production platform must provide adequate space not only for development drilling but also for processing facilities and crew accommodations.

The trade-offs between artificial island concepts and steel or concrete structures are not well understood for production as opposed to exploration concepts. While artificial islands appear much more favorable at shallow and intermediate water depths, the point at which the economics of steel or concrete structures begin to improve is not well-documented. While early designs for arctic production systems prominently featured monocones or monopods, even for water depths as shallow as 15 meters (50 feet) or less, these structure designs were shelved due to the success of artificial island concepts in the shallower waters. Consequently, monocone designs have only begun to reappear as economic structural configurations in water depths approaching 60 meters (200 feet; Jahns 1980). Economic trade-offs of artificial islands with other structure types depend on the physical location of suitable fill sources and on the operational requirements. Therefore, no definite water depth limit can be given for production platform types. In the Chukchi Sea, duration of the construction season will play a significant role in determining the economic water depth limit for island concepts (National Petroleum Council 1981). Offshore storage can be a major determinant in production structure selection; one arctic production technology (the ALPA, see page 3-10) has developable storage capacity of significant size, and the gravity-type structures also offer storage capability.

In addition, the comparative advantages of various production platforms over others in terms of offshore installation times are not well known. While the length of the open-water season is a critical construction and installation constraint, no experience in shifting from an exploration to production concept in arctic areas has been accumulated although several Canadian fields are on the verge of such choices. Concrete or steel structures have the advantage of being fabricated in an environment free of ice constraints, with tow-out and installation requiring good open-water conditions. No experience in expanding an artificial island from an exploration base into a production mode has yet been obtained. It is unclear in advance what advantage if any, hybrid production concepts emplaced on exploratory artificial islands may have. Such trade-offs will be site-, design- and operator-specific. Clearly, a successful exploration gravel island at a newly discovered producible reservior represents a valuable asset for oil recovery from at least a portion of the field.

As expected, ice loading forces on Barrow Arch production platforms are the controlling design factor. Structures must be able to survive in the shear zone between land-fast and moving pack ice and impacts of the multi-year pack ice itself. Natural ice floes or islands also present a potential hazard in the Chukchi Sea. Feasibility of different structural concepts is principally predicated on their ability to resist ice loads effectively.

The principal design criteria for a Barrow Arch structure are:

- o Ice loads
  - adfreeze*
  - multi-year ice
  - first year sheet ice
  - rubble piles
  - impact forces due to ice floes during open and partial open water
- o Water depth
- o Wave loads
- o Currents
- o Temperature
  - minimum air
  - maximum air
  - minimum water

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* Adfreeze is the adhesion or bonding of failed ice rubble to an offshore structure which is usually counteracted by heating or treatment with anti-bonding surfactants such as Zebron, which reduce the friction coefficient.

- Competency of seafloor soils
- Dredge fill availability (if dredge fill is required)
- Open-water season requirement
- Service life
- Installation and fabrication capabilities
- Number of conductors and spacing
- Seismic loading
- Topside facilities
- Transportation means (pipeline or tanker).

A constraint on the number of well slots exists for one type of Barrow Arch production platform but not the others. Due to the limited diameter of a steel or concrete monocone's vertical throat, space for a limited number of wells can be provided within the platform. Another constraint is the maximum number of wells that can be directionally drilled from one platform into the reservoir. We have assumed 60 wells, of which 15 to 20 wells are reserved for water and gas reinjection. Fewer than 15 service wells may suffice for gas reinjection only, and more than 20 may be needed for a complete waterflood program. Based on 60 wells, a monocone of 17 to 18-meter (55 to 60-foot) diameter would be needed. More wells would require a greater diameter at the waterline, increasing environmental forces that would increase the base width and thus platform design and fabrication costs.

Some alternatives for increasing the number of wells are:

- If more wells can be drilled into the reservoir from a single platform, the cone diameter might be increased. However, allowance must be made in this case for increased wave forces and ice loading on the structure.

- Subsea satellite wells can be drilled with flowlines back to the drilling/production platform. Maintenance for these wells might include TFL (through flowline) methods.

- o Independent drilling (only) platforms can be installed and the unprocessed crude flowed back to the production platform for processing.

The water depths considered for this study are relatively shallow and range from 15 to 60 meters (50 to 200 feet). This water depth range is very similar to the depth ranges of proposed Alaska Beaufort Sea platforms as well as some of the platforms presently being designed for Canada's Beaufort Sea finds. The following types of production platforms appear feasible for the Barrow Arch planning area at the following water depths:

<u>15 meters (50 feet)</u>

- o Gravel-fill production island
- o Caisson-retained gravel production island

<u>27 meters (90 feet)</u>

- o Caisson-retained gravel production island
- o Steel or concrete monocone/gravity island
- o Arctic production and loading atoll (APLA)

<u>37 meters (120 feet)</u>

- o Caisson-retained gravel production island
- o Mobile caisson production rig
- o Concrete gravity island
- o Steel or concrete monocone/gravity island
- o Arctic production and loading atoll (APLA)

<u>60 meters (200 feet)</u>

- o Steel or concrete monocone/gravity island
- o Arctic production and loading atoll (APLA)

3.3.2.3 Well Slot Limitations

One of the technical constraints of the monocone platform design with its conductors located within the vertical throat or shaft is a limitation on the number of well slots that can be housed on a production platform. In a conventional (e.g., Gulf of Mexico) platform, there are few constraints as to the number of well slots that can be incorporated into the design since the conductors are open and pass through conductor guides at horizontal bays in the jacket. However, in an area affected by sea ice, such as the Barrow Arch, open-well conductors cannot be considered. In the Cook Inlet designs, the larger the legs can be made, the greater the number of conductors that can be accommodated. However, as the diameter increases, so do the ice forces; therefore, additional internal stiffening is required, which reduces the number of conductors inside the legs. The same principle applies to monocone gravity-base structures.

For this analysis, the diameter of a monocone shaft is assumed to be on the order of 16 to 18 meters (55 to 65 feet). In this range, the total number of well slots would be limited to on the order of 48 to 60, depending on the size of the conductors and design criteria. Based on these ice-resistant design considerations, the maximum number of well conductors that we have assumed in a closed conductor platform design is 60. Anything over 60 could become a considerable design problem in order to resist very high ice loads.

3.3.2.4 Platform Construction, Transportation, and Installation Techniques

Techniques for installing these platforms in the Barrow Arch are a sensitive part of the project development.

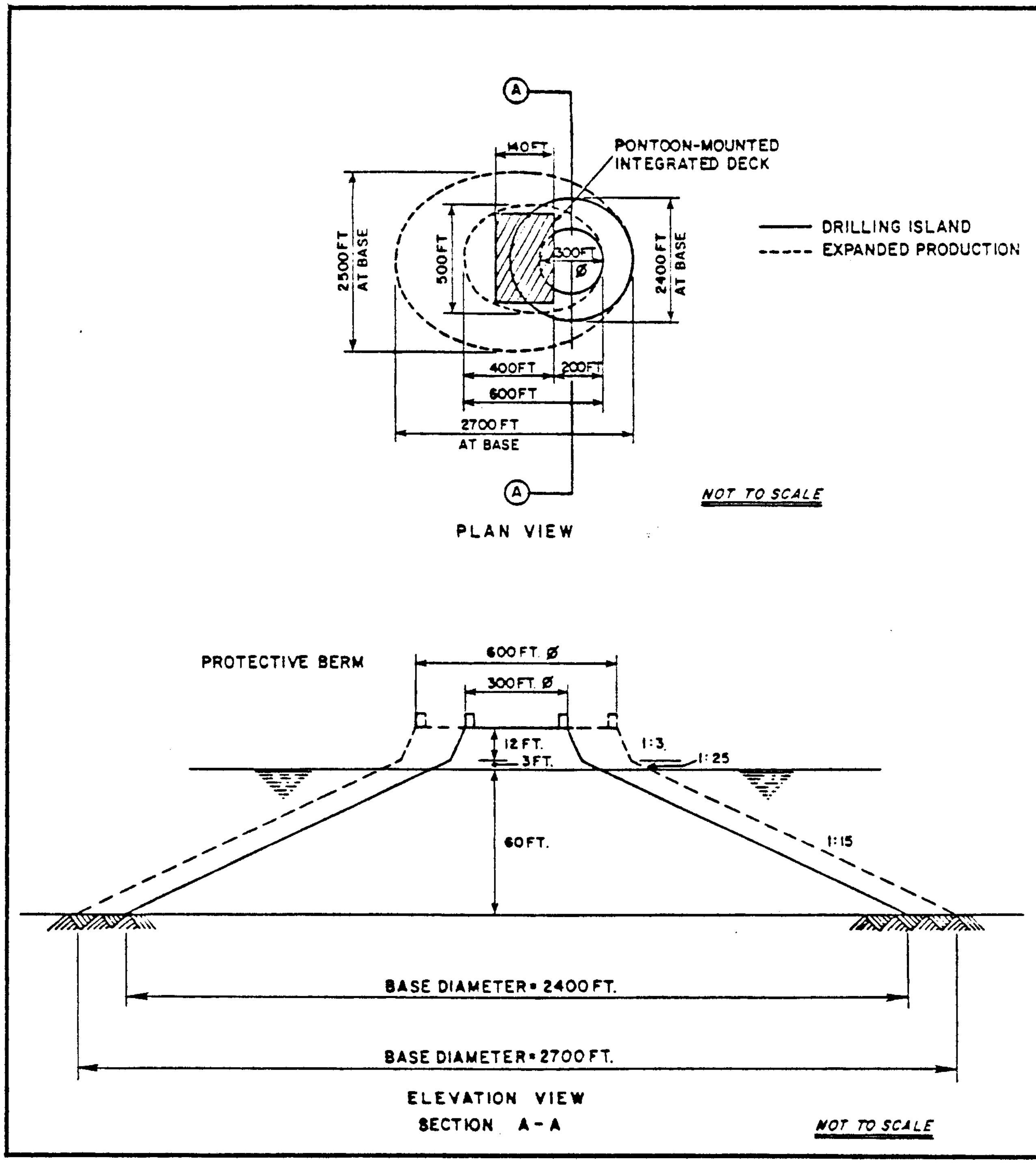
Artificial Island Concepts

Because of their larger size and permanent slope protection, production islands will be substantially more expensive than temporary islands for exploration drilling. The cost is a function of water depth, island size, soil conditions, underwater slope, freeboard, construction season, fill availability, distance from shore and the type of armor units used in slope protection. Finding the most cost-effective slope angle and construction method with locally available materials will be a major objective of site-specific design efforts (National Petroleum Council 1981).

For permanent production islands, a passive design against lateral ice loads will be required (Jahns 1980). Active defense measures, other than monitoring of ice conditions, will not be economically or operationally attractive for long-term, year-round production operations. Thus the design of production islands will have to accommodate more extreme ice events than is the case for temporary islands. This is accomplished by increasing the size and freeboard of the island.

- Gravel-fill Production Island - A construction procedure similar to that described for an exploration island will be required. Assuming that an exploration island is expanded into a production island, dredges are employed to expand the island's base and fill profile once open-water season arrives. The island's diameter above water might be expanded from 90 to 150 meters (300 to 500 feet). It is likely that drilling, production and processing equipment will be modularized, barge-mounted and floated in once the structure is complete. Expansion of an exploration island into a production island can be accomplished in one average open-water season, although if a larger production island is constructed from scratch, two seasons will be required. Figure 3-17 illustrates an expanded arctic production gravel island.

- Caisson-retained Gravel Production Island - Although only exploration designed caisson islands have been built to date, it is assumed that larger caissons and a larger fill berm are all that are required to expand this exploration concept for development. Construction procedure will be the same as for the exploration concept described earlier and production and drilling



Source: National Petroleum Council 1981

Figure 3-17

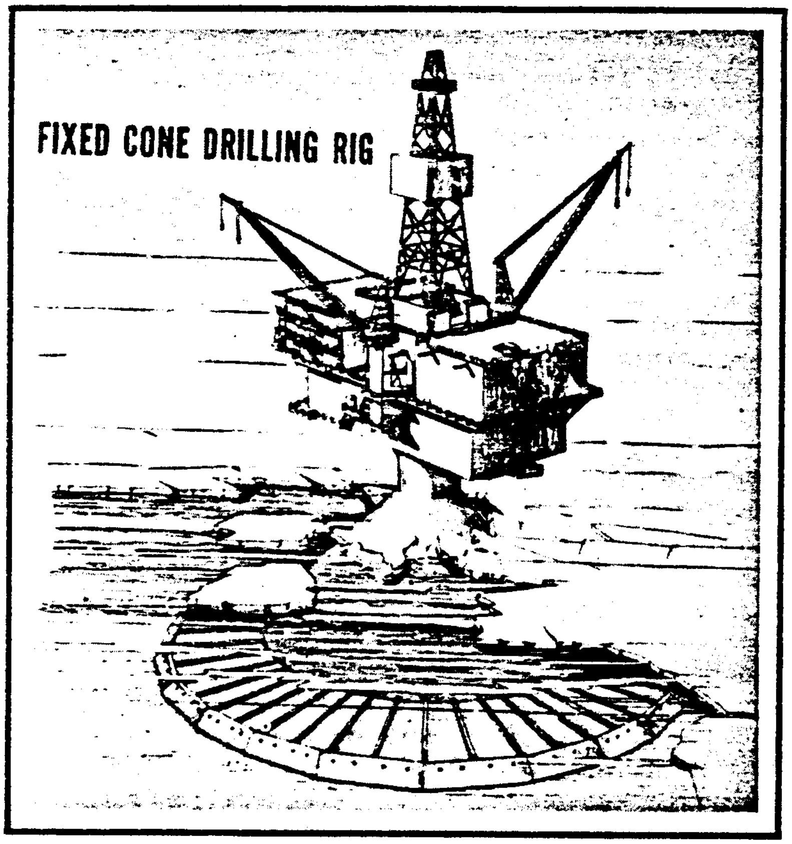
ARCTIC EXPLORATION DRILLING & EXPANDED PRODUCTION ISLAND

equipment is likely to be barge-mounted and modularized for easy installation.

- Mobile Caisson Production Rig - A larger caisson will have to be designed, constructed and floated out in order to develop this production configuration. Once the exploratory rig is de-ballasted and floated away, dredges can expand the fill berm to accept the production structure. It is not sure what deckload, if any, this concept could handle during tow-out.

- Steel or Concrete Monocone/Gravity Island - Monocone and other gravity island concepts have been studied by several operators, including Esso Resources Canada, Dome Petroleum and Exxon. The main principle of the concept is to expose a conical suface to invading ice so that it is broken up by flexure rather than by crushing, thus reducing ice forces. Both concrete and steel structures have been proposed. Steel offers the advantage of high strength and low weight, but in deeper waters a concrete structure's draft limitations are eased. A massive concrete gravity island offers potential for storage capacity, serving as an offshore loading structure.

Figure 3-18 illustrates a concept developed by Esso Resources Canada. The structure consists of a large diameter circular hull, a cone section with a 45° cone angle and a 12-meter (40-foot) diameter at the top, and a multistory deck section. The hull is designed for impact by deep-heeled ice features and serves two main functions. The first is to provide resistance against sliding and overturning when the structure rests on the bottom. The second is to provide buoyancy when deballasted so that the structure can be towed while floating on its hull in a stable configuration and with minimum draft. The particular structure illustrated, an exploratory concept, was designed for water depths from 20 to 40 meters (70 to 135 feet; Jahns 1980). Other designs developed by Esso Resources Canada are for water depths to 60 meters (200 feet).



Source: Jahns 1980

Figure 3-18

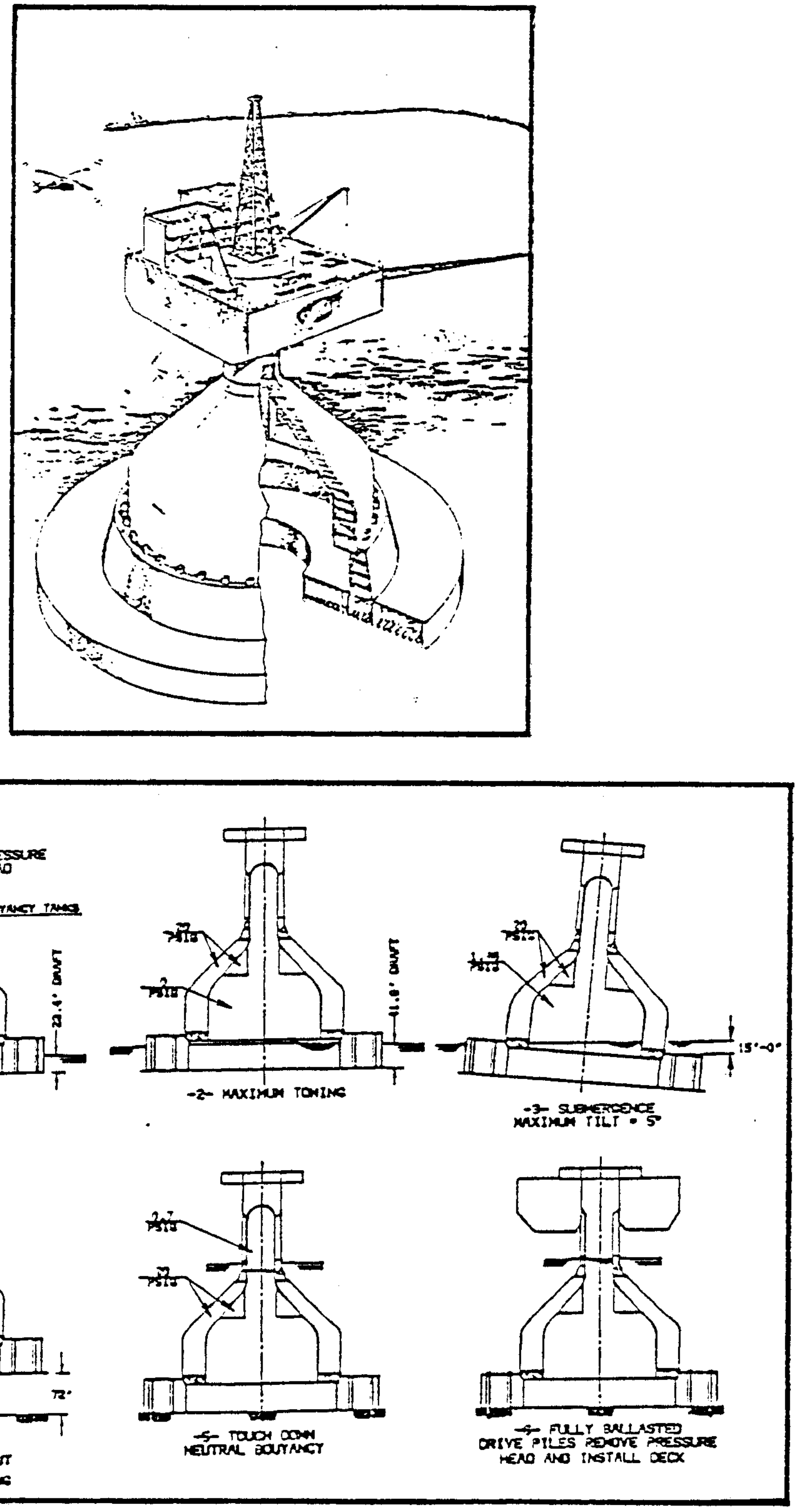
ESSO RESOURCES ARCTIC MONOCONE

Cone and monocone designs developed to date are designed to resist large multi-year ice pressure ridges up to 14 meters (45 feet) thick. If more severe ice loadings are anticipated, cone angles of less than 45° may be considered. Extensive model studies have been conducted to determine the ridge loads that are developed on cones with different slope angles. Other model tests have been conducted to determine wave loads and to observe the floating stability of cone structures during tow and installation. Lease sales held prior to the Barrow Arch sale will provide strong incentives for industry to further develop and field test such advanced development concepts for the Arctic.

Another monocone design developed for Dome Petroleum Ltd. is illustrated in Figure 3-19, which also shows its tow-out and installation. The structure is designed to cause failure and permit clearing of sheet and ridge formations and has a capability to disconnect at the cone-base interface in case of impending ice island collision. For design load resistance, the rotational inclined plane formed by the cone serves to fail ice ridges in flexure, while the slender throat minimizes ice sheet crushing failure and clearing forces. The impact of a small ice island of average draft and properties can also be absorbed (Bercha and Stenning 1979).

Although it is unlikely that a structure installed on the central Chukchi shelf would be endangered by an ice floe or island, the structure illustrated has the design capability to be disconnected from its base and floated out of the path of oncoming ice islands. The bottle mid-structure can be disconnected from the base by unlocking anchor pins, jacking down the deck and floating the assembly out of the ice island's way.

Different opinions exist regarding the selection of steel or concrete for a monocone design. SF/Braun selected concrete as the preferred construction material for monocone concepts to be installed in the Chukchi Sea. A concrete structure's heavier weight requires less ballast than a comparable steel concept. Concrete also possesses local strength superiority to resist buckling from local ice loads in comparison to steel. A concrete structure also has a superior insulation coefficient and a larger potential for storage capacity.



Source: Bercha & Stenning 1979

Figure 3-19

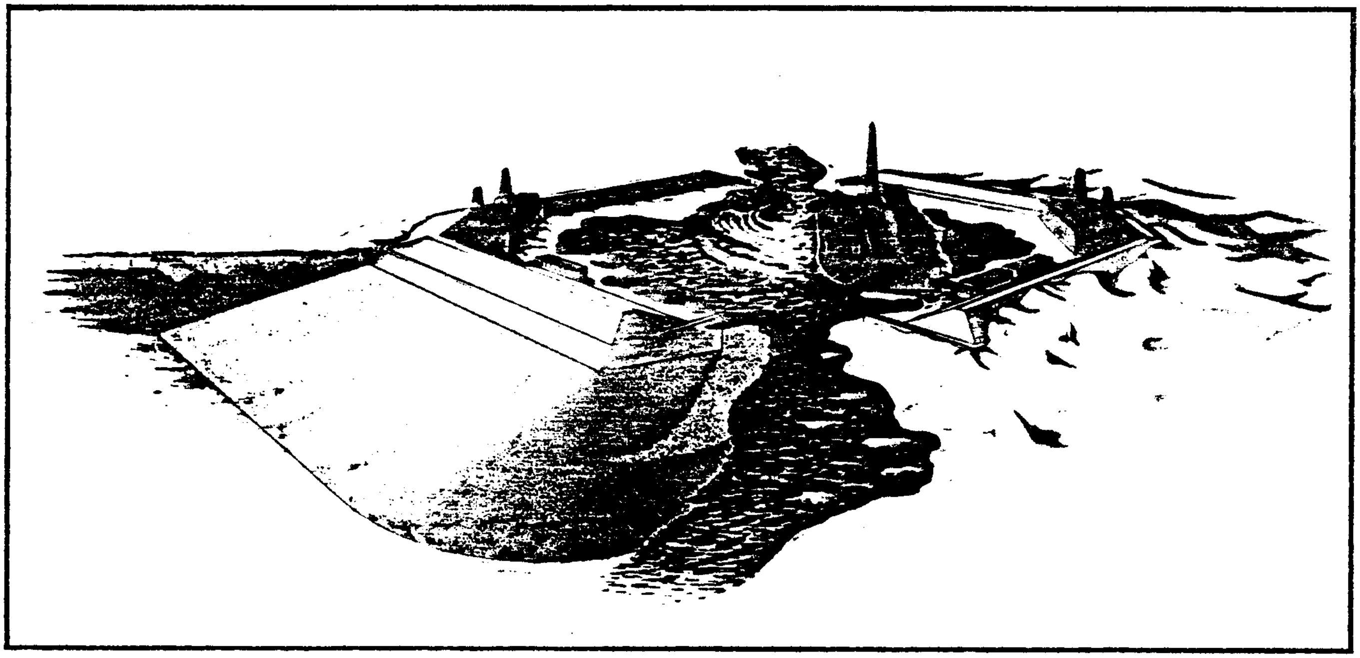
DOME PETROLEUM ARCTIC MONOCONE CONFIGURATION, TOWING & INSTALLATION

However, steel appears to be preferred by some operators over concrete as a construction material for monocones because of its superior abrasion resistance to sea ice. It can also be more easily treated with non-stick coatings such as Zebron to resist adfreeze or heated to achieve the same effect. Steels for arctic application must satisfy the usual criteria of strength, ductility, toughness and weldability. A number of steels are available for low temperature applications. This is important since the loads in an arctic structure caused by temperature differences can be severe.

It is assumed that steel or concrete monocone concepts will be constructed on the west coast and towed through Unimak Pass, the Bering Sea, through the Bering Strait into the Chukchi Sea. As soon as ice conditions permit, the structures will be towed to its final installation site, ballasted down, and either piled or grouted to the sea floor. Unless ice gouges on the sea bottom are present, it is expected that a minimum of site preparation will be required during installation. The floated-out monocone can also carry a substantial load of deck equipment in-place during tow-out with the remainder being barge-mounted and installed on deck by derricks.

Arctic/Artificial Production and Loading Atoll (APLA)

A novel production concept incorporating field production and offshore loading has been developed by Dome Petroleum Ltd. for use in its Mackenzie Delta reservoirs. Dome proposes to construct and operate offshore island terminals called arctic production and loading atolls (APLA) or artificial production and loading atolls (APLA) or arctic production and loading basins (APLB). Constructed from dredge fill in a manner similar to an artificial island, an APLA, pictured in Figure 3-20, would consist of two massive berms capped with concrete caissons. The atoll-like island will provide protection from ice in its "lagoon" basin for drilling and/or production barges and tanker loading facilities. An APLA-mounted terminal would provide docking and transfer facilities for ice-breaking tankers. The island's onshore area serves to support drilling and production facilities with



Source: Ocean Industry 1981

Figure 3-20

DOME PETROLEUM ARTIFICIAL PRODUCTION & LOADING ATOLL (APLA)*

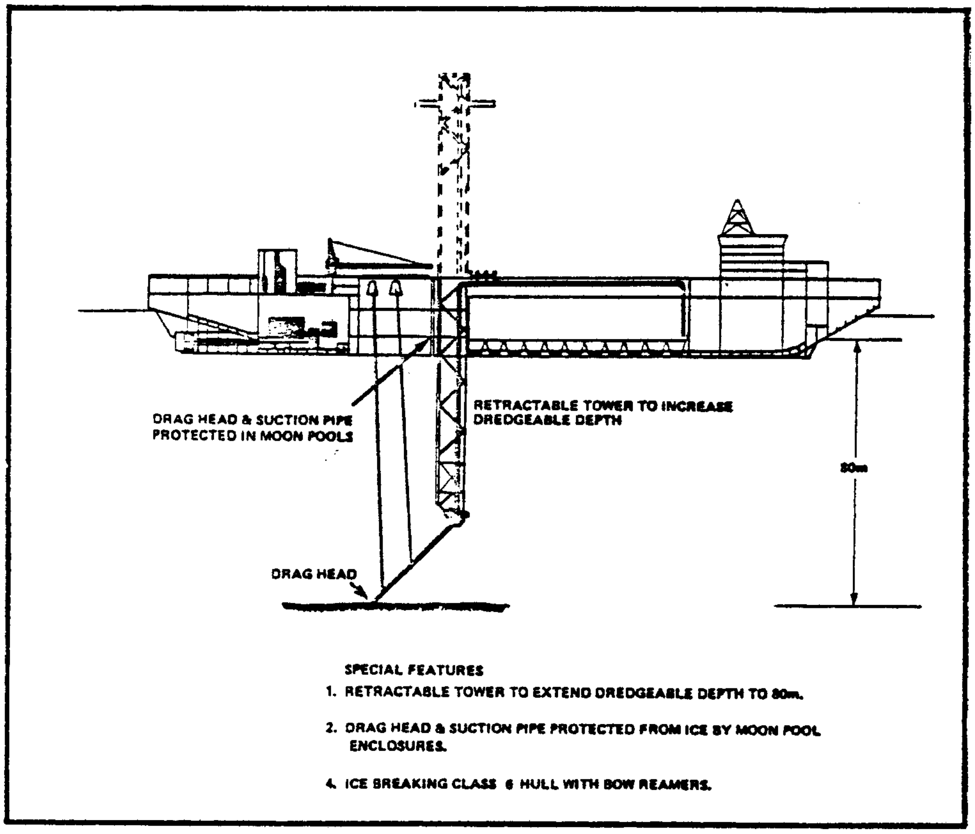
*ALSO "ARCTIC PRODUCTION & LOADING ATOLL" storage capabilities. Storage or production facilities could be increased through the use of slave tankers moored within the APLA.

Dome is examining the use of APLA's as a deepwater development concept in waters of 60-meter (200-foot) depth. Depending upon reservoir shape and size, an APLA may service a field entirely from directionally drilled wells, or be supplied by pipeline from smaller artificial islands equipped with drilling and production facilities to accommodate development of the extremities of the larger fields.

An integral part of an APLA's feasibility is its construction by so-called "super dredges" which will have far greater capacity than the largest currently available conventional dredges. Dome estimates that an APLA in 60 meters (200 feet) of water will require between 80 and 120 million cubic meters (100 and 160 million cubic yards) of dredged materials. Dome plans on using three or four "super dredges" to construct each deepwater APLA, with each "super dredge" available to do the work of three large conventional dredges.

Dome has calculated that it can reduce the cost of an APLA's or artificial island's construction by a factor of 24 through a combination of developments it is pursuing (Cottrill 1981). New "super dredges" should reduce unit costs by a factor of three through their greater capacity and extended season of operation, while steep slopes reduce the volume of fill required to about one-eighth of that previously needed. Dome estimates that an APLA in 60 meters (200 feet) of water would cost between \$3 and \$4 billion, not including the costs of the ice-breaking tankers.

Dome has placed an order for delivery of its first "super dredger" by May of 1983. It is estimated to cost \$100 million. The dredge is designed to have 2.5 times the capacity of the largest existing hopper suction dredger, the Geopotes 10. Dome's planned "super dredge," pictured in Figure 3-21 has the following special features:



Source: Ocean Industry 1982

Figure 3-21

DOME PETROLEUM ARCTIC SUPER DREDGE

- Year-round operation in transition ice without ice-breaker support, through an arctic Class VI hull, bow reamers and extreme ice-breaking devices.

- Hopper capacity of at least 25,000 cubic meters (33,000 cubic yards).

- Dredgable depth that can be extended to 80 meters (260 feet) using a retractable tower amidships, allowing high accuracy for subsidiary tasks like trenching and removal of clay overburden.

- Power plant of 60,000 horsepower allowing 25,000 cubic meters (33,000 cubic yards) to be loaded in two hours and 16 knots of sailing speed.

- Drag head and suction pipe in a moon pool, protected from ice (Cottrill 1981).

"Deepwater" Arctic Production Technology

While "deepwater" for the purposes of this study was defined as those water depths beyond 30 meters (100 feet), which reflects industry's current experience to date with exploration concepts in the Arctic, several production concepts for water depths beyond the 37-meter (120-foot) water depth selected as the representative deep water depth in the Barrow Arch planning area were also examined.

According to SF/Braun, two technical approaches seem feasible for development of oil and gas finds in areas of the Chukchi Sea with water depths of 60 meters (200 feet). The most economic approach would be emplacement of a monocone structure designed for shallower water depths, say 37 meters (120 feet), onto a base built up by dredged gravel fill to a height of 24 meters (80 feet) above the seafloor.

A second approach would be emplacement of a monocone specifically designed for 60-meter (200-foot) water depths. However, the costs of such a structure could be significantly greater than the first option, depending on gravel availability.

Dome Petroleum proposes to construct its APLA's in water depths up to 60 meters (200 feet). For such a concept to be viable in the Chukchi Sea, U.S. operators would have to commission "super dredges" similar to those planned by Dome.

3.3.3 Wells

Most production wells will be drilled directionally from the production platforms. The production concepts suggested for the Barrow Arch planning area have constraints on the maximum number of wells. Artificial island production concepts might each accommodate a total of about 100 wells, which can be slant drilled if required, but the total number of wells possible is a direct function of the amount of area constructed. Monocone production concepts can only accommodate a maximum of around 60 wells per structure, due to the limitation on throat diameter, and slant drilling will not be possible (see discussion in Section 3.3.2.3).

There are also technical limitations (as well as cost premiums) on directional drilling for angles of over 50°. A graph showing a typical rate of increase in drift for the generally adopted maximum slant angle of 60° is shown on Figure 3-22. Depending on seabottom soil conditions, a typical kick-off point(1) would be about 150 to 300 meters (500 to 1,000 feet). With conductors located within the legs of the structure, directional drilling is a part of the constraints to total number of wells and the subsurface area the platform can drain.

Development well drilling will begin as soon as feasible after platform installation. If regulations permit, the operator may elect to begin

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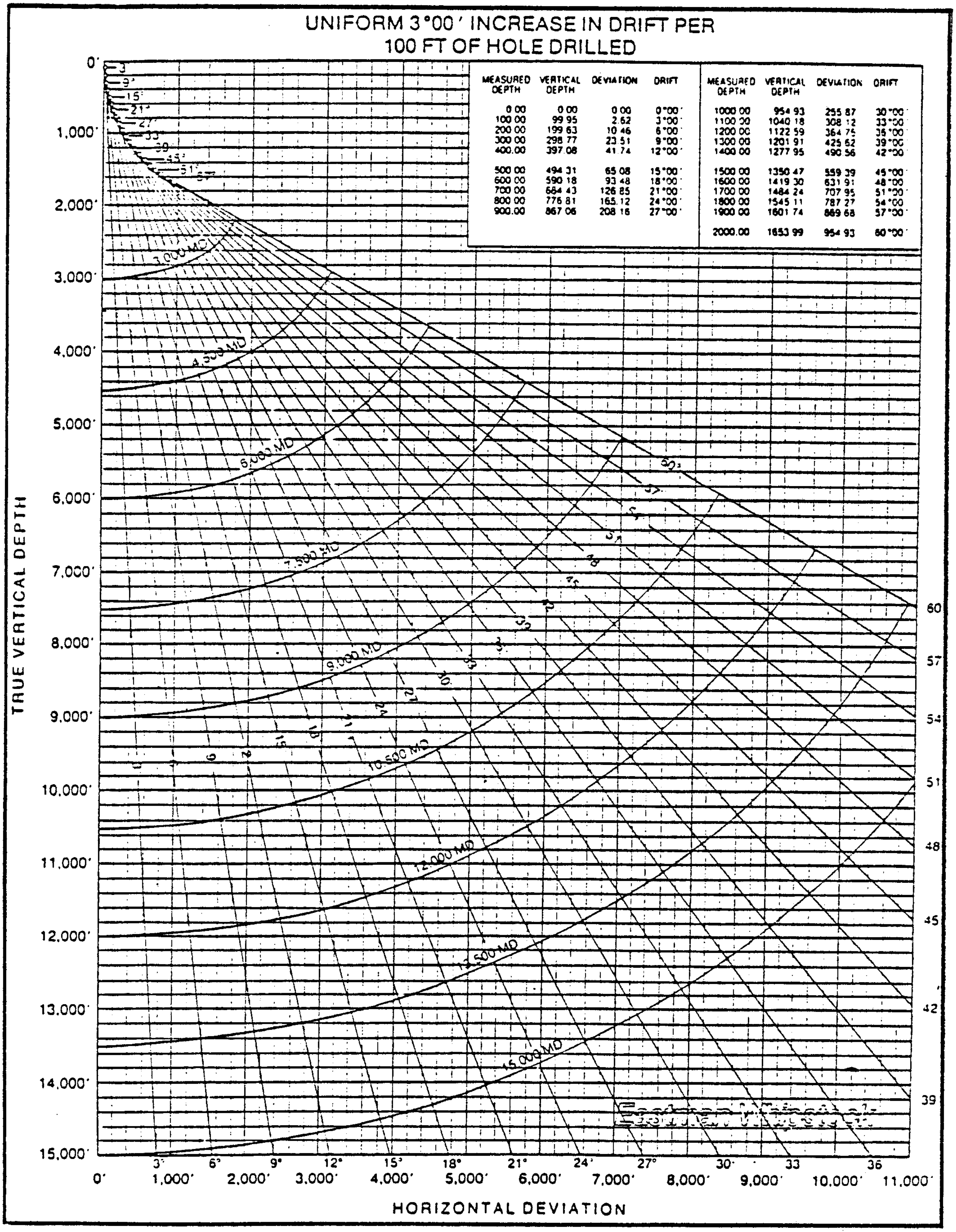
(1) Kick-off point = the depth where the traverse departs from the vertical in the direction of the target.



MEASURED DEPTH	VERTICAL DEPTH	DEVIATION	DRIFT	MEASURED DEPTH	VERTICAL DEPTH	DEVIATION	DRIFT
0 00	0 00	0 00	0°00'	1000 00	954 93	255 87	30°00'
100 00	99 95	2.62	3°00'	1100 00	1040 18	308 12	33°00'
200 00	199 63	10 46	6°00'	1200 00	1122 59	364 75	35°00'
300 00	298 77	23.51	9°00'	1300 00	1201 91	425 62	39°00'
400.00	397.08	41.74	12°00'	1400 00	1277 95	490.56	42°00'
500 00	494 31	65 08	15°00'	1500 00	1350 47	559 39	45°00'
600 00	590 18	93 48	18°00'	1600 00	1419 30	631 91	48°00'
700 00	684 43	126 85	21°00'	1700 00	1484 24	707 95	51°00'
800 00	776 81	165.12	24°00'	1800 00	1545 11	787 27	54°00'
900.00	867 06	208 16	27°00'	1900 00	1601 74	869 68	57°00'
				2000.00	1653 99	954 93	60°00'

Source: Eastman Whipstock, Inc.

Figure 3-22
DIRECTIONAL DRILLING CHART

drilling while offshore construction is still underway, accepting some interference between the two activities. The operator has to weigh the economic advantages of early production versus delays and inefficiencies in platform commissioning. Development drilling could commence about 10 months after the selected development concept is installed on site[(1)]. Development wells may be drilled in a "batch" where a group of wells are drilled first to the surface casing depths, then drilled to the next smaller casing depth, etc. (Kennedy 1976). The batch approach not only improves drilling efficiency but also improves material-supply scheduling. However, this does not provide timely geological information for planning the later wells.

On artificial island concepts and monocones, 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 performing well maintenance.

Permafrost could be encountered in parts of the Barrow Arch planning area. Therefore, wells will be completed with casing programs, cementing techniques and tubing strings similar to those used on the North Slope (National Petroleum Council 1981). Figure 3-23 illustrates a typical permafrost casing program.

3.3.4 Pipelines

Marine pipelines will be required to transport oil and gas from the Barrow Arch fields to shore terminals for further processing and tanker transport to market or to shore for pipelining to TAPS and on to market. Several pipelay techniques have been devised for use in arctic conditions.

The most important engineering design considerations for pipelines in the Barrow Arch planning area are:

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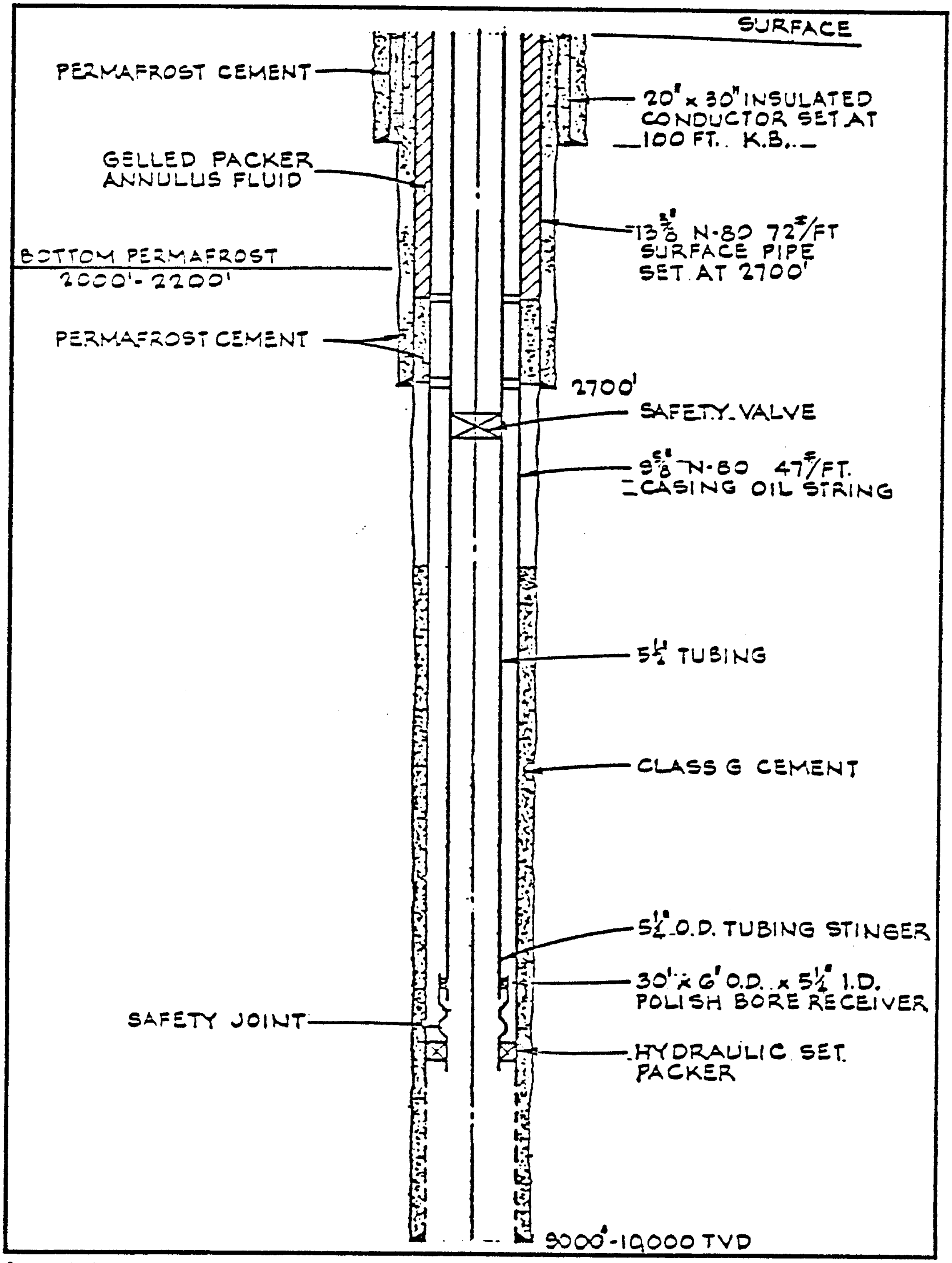
(1) See Sections 6.2.3 and 7.2 for detailed discussions of the timing assumptions made in our analysis.



Source: National Petroleum Council 1981

Figure 3-23

TYPICAL PERMAFROST CASING PROGRAM

- Depth of ice scour
- Subsea permafrost
- Ice override events in the coastal zone
- Low pressure water jets from strudel scour
- Geotechnical problems related to seabed soils
- Coastal erosion
- Limited open-water construction season
- Water, crude, and gas temperatures.

In pipelaying technology there are five areas requiring careful analyses and solution:

- Prediction of pipe stress during installation
- Control and knowledge of exact pipe location during lay operations
- Joining with an offshore riser
- Protection of applied coatings
- Design and implementation of the shoreline crossing.

Although arctic offshore pipelay technololgy is in its infancy, the strong technical base acquired from offshore operations in other areas gives a reasonable assurance that pipelaying can be successfully accomplished in the Chukchi Sea.

Only one pipeline has actually been laid in arctic conditions, a proof-of-concept demonstration held in the Canadian Arctic to lay a natural gas pipeline from an offshore wellhead to Melville Island for Panarctic Ltd. This demonstration employed what is called the Ice Hole Bottom Pull Method. A trench was cut through the ice and on-ice winches were used, first to pull an underwater plow to trench the seabed and then to deploy the pipeline. A remotely controlled connection module was used to connect the pipeline to the wellhead. However, this winter construction technique cannot be used in the Chukchi Sea since it requires a smooth landfast ice surface on which to operate.

Therefore, open-water pipelay techniques seem most feasible for laying marine trunk and feeder pipelines to service Barrow Arch oil and gas fields. Four different methods of pipe-laying developed for non-arctic operations may be adapted for use during the short open-water season in arctic areas. These are:

- Bottom-pull or bottom-tow method
- Flotation method
- Reeled pipe method
- Lay barge method.

Of these, the bottom-pull method has been touted as most feasible for arctic operations (Timmermans 1982). In this method, lengths of pipe section are welded onshore and then pulled along the sea bottom. A winch firmly anchored on a barge is used as the pulling force. The method requires construction of a mile-long gravel pad onshore that is used as a staging area to pre-weld pipe sections.

However, the National Petroleum Council (1981) believes that conventional pipelay systems will not be practical in the Chukchi Sea for a number of reasons. They prefer the bottom-tow method and believe that the sizable onshore pipe assembly site can be used later as part of the oil storage facilities. They also believe that ice conditions will make it difficult to time the arrival and exit of the pipeline spread to get the job done in one season. If the spread happens to be iced in and remains inactive for 10 months, costs could run as high as $150 million per year.

The length of the pipeline pulled is limited to relatively short offshore distances because of rapid increase of pulling force with distance (Energy Interface Associates 1980). Because of this, and the brief working season for the longer Barrow Arch pipelines, SF/Braun assumes conventional ship-type lay vessels for this cost analysis (Appendix B, Table B-5).

Assuming a 70-day open-water season in the Chukchi Sea, SF/Braun believes that a conventional lay vessel could lay close to 80 kilometers (50 miles) of pipe per season. This assumes downtime of 10 percent due to weather and an average lay rate of 1.2 kilometers (3/4 mile) per day assuming a pipe diameter of 22 to 30 inches.

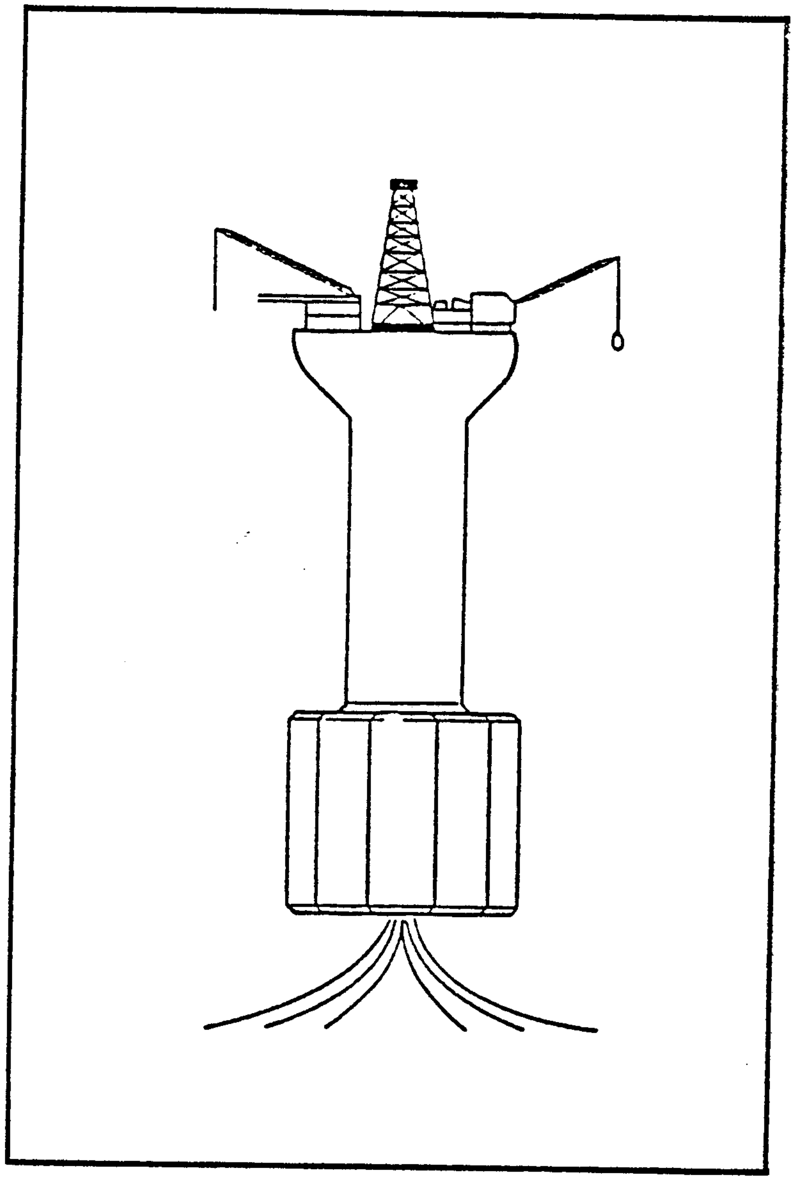
In order to avoid problems of bottom scour and gouging from ice, the pipe will be buried to a depth of 2 meters (7 feet) out to 25 meters of water depth (80 feet) and buried to a depth of 1 meter (3 feet) in the deeper water beyond that. SF/Braun is not planning to pre-trench the line but to trench after pipe laying is completed. Conventional plows or jetting techniques are feasible for this trenching to these burial depths (Timmermans 1982). These depths are assumed based on reasonable tradeoffs of ice gouge risk (Figure 3-8) and costs of trenching in view of the available techniques for burying marine pipelines.

Regardless of the method selected, pipe-laying in arctic offshore regions will require innovations and modifications of existing pipelay techniques. Lay barges with ice-reinforced hulls may be constructed to extend the open-water season somewhat (this will provide only limited extension, say to 10 or 20 percent ice cover, because of the exposed stringer, pipeline and mooring anchor array). Trenching may be completed in the season before the pipe is laid. Pipeline strings may be stored in a trench from previous seasons over winter. A variety of methods will be employed to bring pipes onshore due to the ice scour, ice override, erosion, and permafrost problems at the land-water interface. For example, shallow water approaches and shore approaches will need to be insulated to protect thaw unstable permafrost from the effects of a hot oil line. Gravel causeways may be used for this purpose.

Techniques for construction of land pipelines in arctic areas are well-established and will present no special problems in the Barrow Arch planning area, either for construction of laid pipeline sections to the marine terminal or to an inter-tie with TAPS.

3.3.5 Offshore Loading and Storage

While the extreme remoteness of some Bering Sea and Aleutian OCS areas suggests the use of offshore loading and storage terminals as a feasible



Source: National Petroleum Council 1981

Figure 3-24

ARCTIC FLOATING CAISSON

alternative to the use of pipelines for transporting hydrocarbons to market, present techniques do not appear feasible for fields in the Barrow Arch planning area. Offshore loading systems are not a proven technology for ice-infested areas such as the Chukchi Sea. Offshore loading systems operate best in good to moderate environmental conditions. Systems that have been installed to date in more severe environmental areas such as the North Sea have experienced considerable downtime due to maintenance repairs and severe sea states.

Conventional designs for fixed or floating storage, tanker loading-single point moorings (SPM), and combined storage and tanker loading schemes will not be applicable in arctic conditions. Brian Watt Associates have developed a design for an offshore marine terminal in Norton Sound that incorporates 3 to 5 million barrels of storage and is conically shaped to resist ice forces and allows loading tankers to weathervane as required.

The severity of the sea ice conditions in the Chukchi Sea will require loading and storage conceptual designs capable of resisting multi-year pack ice movements. Conical gravity structures or monocones are both capable of providing the required oil storage and ice resistance features that are required. Figure 3-24 illustrates a floating ice-breaking moored caisson vessel proposed as a production platform in water depths beyond 300 meters (1,000 feet). It incorporates an hour-glass shape at the waterline with downward breaking cone surfaces to fail ice. The structure was sized for a production rate of 100,000 barrels per day and 500,000 barrels of oil storage (Knecht et al. 1979). Such a structure would not be applicable to the Chukchi Sea, without adaptation of the general concept to bottom-founded support in shallow water.

Fixed pile or gravity base loading/storage towers have also been presented as options for less severe ice environments than those found in the Chukchi Sea. Designs of such structures for the Barrow Arch area would have to be greatly increased in size and weight to resist moving ice. Concrete structures would be more desirable due to their greatly increased weight to resist sliding and overturning. Modification of tower designs will be required to protect mooring and hose handling equipment. The height of the tower above the ice surface should be sufficient to avoid rubble pile interference with equipment.

Articulated column or tower designs have also been examined for their applicability in ice environments. Again, significant modifications of conventional designs would be required. Also, as discussed in early production systems, several designs for arctic moored ice-breaking tanker or barge loading designs have been developed.

In the Barrow Arch planning area, large reserves plus sustained high production rate will be needed to justify the large cost of development. A fleet of ice-breaking shuttle tankers would also be required. A large amount of offshore storage will be required in the form of storage vessel facilities. In order for the system to be economic, the throughput (e.g., 300,000 barrels per day loaded into shuttle tankers) would have to be dependable and substantial. This is a challenging operation due to ice movement and severe winter weather conditions.

Although the costs of conventional offshore loading systems appear to be much less than the cost of long pipelines, there are additional costs to consider. These costs include extra storage, a fleet of shuttle tankers, work boats, and possibly ice breakers, hiring of crews, and the construction and maintenance of shore facilities. In Alaska, offshore loading does not necessarily eliminate the costs of a shore terminal since purpose-built arctic icebreaker shuttle tankers would likely offload their cargoes at an Aleutian transshipment facility where the crude would be transferred to large tankers destined for markets to the south.

Arctic offshore storage and loading systems have not been developed, but general concepts have been proposed. For year-round operation, whatever designs prove out for the future, the facilities must be very large to accommodate storage volumes, ice-breaking tanker operations, and the resultant massive ice forces. The APLA concept (described in Section 3.3.2.4) includes these characteristics and so appears potentially feasible technically, assuming availablity of construction material sources and the "super dredges" described. We have used this concept for our economic analysis because it is the best-described arctic offshore storage and loading scheme available at this writing. Other concepts for arctic offshore storage/loading that could be applicable to the Chukchi conditions and timing can be expected in the near future.

3.3.6 Subsea Completions

Subsea technology has evolved in response to the increasing water depths and cost of fixed platform production systems. Theoretically, a subsea production system can either be an adjunct in a field development strategy involving fixed platforms or a complete production system. As a complete system, subsea trees, gathering manifolds, control systems and flowlines are used in conjunction with a floating processing and storage facility. Subsea gas-oil separation and storage is technically feasible but is less likely to be implemented because of cost and complexities.

The principal design problems in subsea production systems are maintenance and operation. In the design of subsea wells, two principal concepts have been employed -- "wet" Christmas trees and "dry" Christmas trees. The wet Christmas tree exposes all the components and requires divers for installation and maintenance. Typically, the wet Christmas tree is completely assembled and tested before installation on the sea floor from a drilling rig. The dry Christmas tree is totally enclosed in a chamber and can be serviced by men working in an atmospheric environment on the sea floor. A number of subsea production systems have been developed including those by Exxon, Lockheed, Deep Oil Technology, Subsea Equipment Associates Ltd. (SEAL), Cameron Iron Works, Regan Offshore International and Vetco. These systems variously employ single wellhead completions, multiple well templates, and combinations of "wet" and "dry" subsea equipment.

The advantages of subsea production systems include (Ocean Industry 1978):

- Early production can be established. Fabrication, installation of a fixed platform, and development drilling can take 5 years or more, whereas subsea equipment can be fabricated and installed in 1 to 2 years. This not only enables an early cash flow, but also permits evaluation of the reservoir prior to investment in permanent structures and equipment.

- Exploratory and delineation wells, which are normally plugged and abandoned, can be turned into satellite subsea producers.

- Subsea production equipment, in contrast to platforms, can be inexpensively salvaged after production diminishes below economic limits.

- Fields with insufficient reserves to justify investment in fixed platforms can be developed relatively inexpensively (especially if exploration/delineation wells can be utilized) by a subsea system with a temporary floating rig or jackup platform.

- In the case of shallow or complex reservoirs, subsea wells can drain those parts of the reservoir that cannot be reached by directional drilling from a fixed platform. Also, subsea wells can be used as injection wells for secondary recovery operations.

- Subsea systems extend production into water depths beyond the limits of platforms.

- Subsea systems can be used in arctic regions (below ice gouging) where surface structures are exposed to the potentially damaging forces of sea ice.

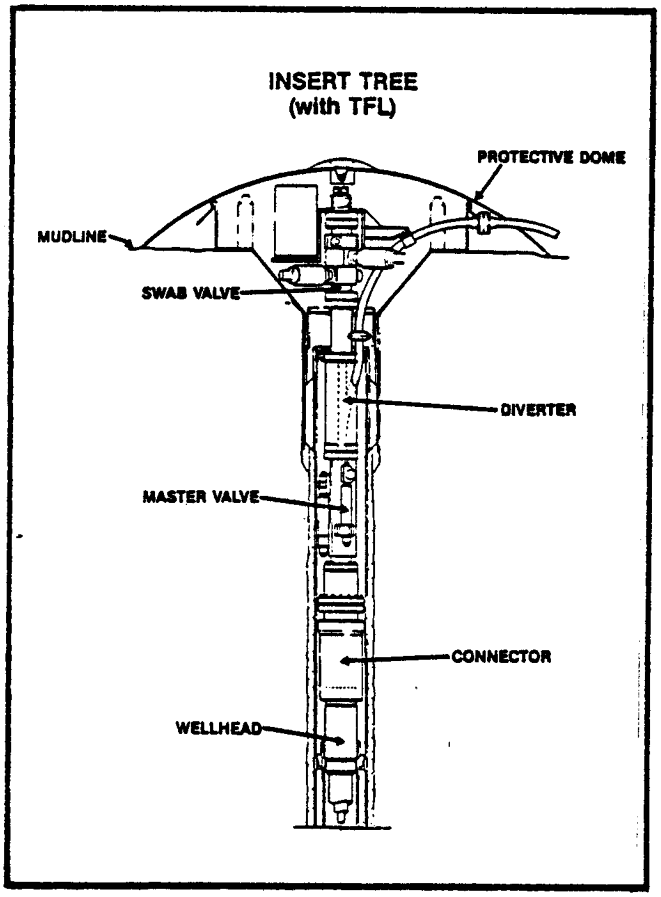
- In areas of incompetent sea floors unable to support bottom founded structures, subsea systems may provide a solution.

Complete subsea production systems are not yet considered state-of-the-art. However, subsea satellite wellheads, with pipelines to a mother platform, do appear to be feasible with shallow/low production reservoirs. Increasingly, operators are developing experience with and relying on sea floor wells. However, the evolution of sea floor well technology has been a slow process and most industry attention is currently focused on subsea production systems for deep water as opposed to arctic or sub-arctic installations (Mason 1980).

Clearly, subsea production systems offer substantial benefits in hostile environments such as the Chukchi Sea. Their cost is a fraction of what full-scale arctic-designed platforms would cost. The only subsea system installed in arctic waters to date is a subsea blow-out preventor (BOP) and production Christmas tree developed for Panarctic Oils Ltd. for gas drilling in the Drake Point Field of the Canadian arctic islands (Energy Interface Associates 1979). Cost was approximately $5 million. However, ice conditions at this deepwater site within the Canadian arctic islands are considerably less severe than those in the shallow Chukchi Sea.

To avoid the hazard of ice scouring, which is common in the Chukchi Sea into water depths of approximately 60 meters (200 feet), a BOP or Christmas tree has to be placed below the mudline and either protected within a caisson or buried in a "glory hole" at a depth dictated by the size of observed scour (Energy Interface Associates 1979). Figure 3-25 shows a recently developed subsea tree installed below the mudline. Only the swab valves, tree cap and flowline connector extend above the seafloor. In arctic offshore applications, the top of the protective dome would be placed below the scour depth and the flowlines would also be buried.

Before subsea production systems or subsea components for oil or gas wells receive widespread usage in arctic environments, high reliability and diverless maintenance will have to be proven under actual operating conditions. In addition, the presence of year-round ice cover in the northern pack ice-covered areas of the Chukchi Sea may limit applicability of subsea components.



Source: National Academy of Sciences 1980

Figure 3-25

**SUBSEA TREE
WITH THROUGH FLOW LINE (TFL) CONTROL**

The use of subsea completions in the Barrow Arch planning area will probably be single satellite wells installed below the mudline. These wells would produce through buried flowlines to fixed structures, artificial islands or to shore (Natural Petroleum Council 1981). Economics, not technology, will be the governing factor regarding the applicability of subsea installations.

3.3.7 Arctic Early Production Systems

While existing early production systems have been designed for non-ice environments, several designs for seasonal use in arctic conditions have been suggested. Conceivably, such systems could be used for producing oil during the 5- to 6-month period while permanent production systems are being constructed or installed.

One early production system for arctic summers designed by Swedish shipbuilders Gotaverken Arendal, is based on an ice-strengthened tanker of about 200,000 DWT acting as a storage and production vessel at a submerged single point mooring and subsea well. It would be served by a number of ice-strengthened shuttle tankers using bow loading from the storage ship. Both riser and moorings would be designed for instant release to avoid contact with severe ice.

3.3.8 Marginal Field Development

With the high costs of facilities and equipment (see Appendix B) required to develop oil and gas resources in a remote arctic area such as the Barrow Arch planning area, some significant discoveries will remain undeveloped because they cannot economically justify production. Such "marginal fields" will remain shut-in pending higher oil prices, cost-saving technological advances, or further discoveries close-by with which pipelines and other facilities can be shared. Delayed development of marginal fields has occurred in the North Sea. As noted in a series of articles on marginal fields in Offshore (April, 1978, p. 76):

"The factors which determine whether a field is marginal include the obvious producing characteristics such as reservoir size, shape, and depth below the ground, well producing rates, oil and/or gas quality, and the existence of production problems such as H_2S or CO_2 and sand productions. The status of technology required for development, availability of competent and efficient construction facilities in the area, nearness to market, accessibility for supplies and transport of production to market, plus environmental problems such as earthquakes and hurricanes must also be taken into account."

While the search for more cost-effective engineering solutions to develop marginal fields has been focused on the extension of offshore petroleum development into deeper waters where the cost of fixed platforms rises exponentially with water depth, many of the same principles will eventually be applied to arctic oil and gas development. Some possible solutions and trends in petroleum technology for marginal field development are listed below. While not all of these will be directly applicable to producing marginal fields in the Chukchi Sea, the underlying concepts such as using cheaper, faster and less material-intensive production techniques will be used. The trends and solutions include:

- Use of subsea production systems either as an adjunct to fixed platforms or as part of floating production systems (see Section 3.3.6).

- Two-stage development programs using an early (temporary) production system while further reservoir evaluation assesses the viability of a development plan employing fixed platforms, pipelines and major shore facilities.

- Employment of offshore loading in conjunction with a floating system, subsea system, or fixed platform with storage when long pipelines cannot be economically justified or shared.

3.3.9 Alternative Dredging Approach For Island Construction in the Chukchi Sea

The conditions on the Chukchi Sea suggest use of sea-going hopper dredges or tug/self-loading hopper barge combinations for island building. The exposed nature of the potential sites and the distance to protected areas precludes use of conventional cutterhead pipeline dredges. As used in this report, "hopper dredge" refers to a sea-going, self-contained ship equipped with capabilities to load material through hydraulic pumps to hoppers and to discharge this material by bottom dumping or by pumping ashore to fixed pipeline systems. A tug/self-loading hopper barge has similar capabilities but consists of a tug pushing a hopper barge that has the capability to load through hydraulic pump(s) and drag arms. These dredges are self-powered and have the capability of working in sea heights up to 2 meters (7 feet), riding out storms and transferring material over some distance from borrow area to island construction site. There are approximately 10 sea-going hopper dredges in private ownership in the United States and a limited number of self-loading hopper barges. However, conventional hopper barges can be converted to self-loading barges by addition of "off-the-shelf" equipment.

In order to prepare a comparative cost estimate, the following assumptions were made:

- o Size of an Exploration Island: 1.7 million cubic meters (2.2 million cubic yards) of which 1.3 million cubic meters (1.7 million cubic yards) is below 23 meters (75 feet) and 382,300 cubic meters (0.5 million cubic yards) above.
- o Dredging Depth for Borrow: maximum 15 meters (50 feet).
- o Average Haul Distance from Borrow Area to Island: less than 16 kilometers (10 miles), greater than 8 kilometers (5 miles).
- o Material: Sand with some gravel less than 0.6 centimeters (1/4 inch).
- o Working Season: 75 working days, more or less.

The hopper dredges would mobilize to the site at the start of the working season. Both dredges would begin hauling material from the borrow site and bottom dump at the island location, bringing the center of the island up to about 7 meters (23 feet) of depth. After one month, a self-elevating platform and mooring barge would be mobilized and put in place on the lee side of the island in approximately 9 meters (30 feet) of water. The platform would be used to secure the mooring barge and provide the stable connections for the underwater pipe leading from it to the center of the island. A smaller end barge would be used to secure the island end of the pipe and bring it to the surface for discharging and eventually landing the pipe to the island.

One dredge would begin to haul material and pump out to the island via the pipeline after being secured to the mooring barge. The other dredge would continue to bottom dump, building up the submerged periphery of the island.

When the center of the island breaks the water surface, both dredges would pump ashore until the island was well established. They could then pump ashore or bottom dump, depending on the quantity distribution to complete the island.

Based on the above operation concept, the following equipment spread is suggested based on fuel arriving by contract fuel barging service.

- o Two sea-going hopper dredges with minimum hopper capacity of 2,300 cubic meters (3,000 cubic yards) of sand and capable of pumping material from the hopper ashore.
- o One Delong-type self-elevating platform suitable for mooring in up to 15 meters (50 feet) of water and equipped with workshops, quarters and storage areas.
- o One mooring barge approximately 76 meters (250 feet) long equipped with anchors and winches suitable for independent moorage or moorage along side the platform.

- One derrick barge and two tugs.
- Two caterpillar tractors.
- Pipeline, connections and end barge all in duplicate for pump ashore operation.

While it is believed the tug-barge combination would be suitable for this work, sea-going hopper dredges have been used as the basis for cost estimating purposes.

This approach to dredging and filling an artificial island shows potential for significant cost savings, as well as greater operational flexibility, compared to the cutter-head dredges assumed for our economic analysis and described in Section 3.3.1. It appears that the fill placement costs with this approach could be less than half the costs assumed in our analysis. This savings would apply to the major cost of fill island construction -- dredging -- but would not necessarily result in savings for slope protection and equipment installation, although the latter operations may prove less expensive too with this dredging approach.

3.4 Production Conditions and Field Development Strategies for the Barrow Arch Planning Area

This section briefly reviews some of the principal criteria influencing an operator's selection of a field development plan in the Chukchi Sea and discusses our selection of the production systems and development issues evaluated in the economic analysis.

A number of factors influence an operator's decision on the production and transportation strategies to be used in field development. These include: field size, reservoir and production characteristics, physical properties and quality of oil or gas, location of the field, distance to shore, distance to other fields, oceanographic conditions, destination of production, availability of existing terminals, and economics.

3.4.1 Field Size

The economic analysis (see Section 6.0) suggests the necessary reserve size thresholds to justify production under alternative production systems including piping production to onshore terminals for transfer to ice-breaking tankers, pipelining production east to TAPS, and offshore loading directly into tankers from an arctic production and loading atoll (APLA). It is assumed that a giant field must be discovered in the Chukchi Sea to initiate petroleum development.

3.4.2 Reservoir and Production Characteristics

Reservoir and production characteristics are major determinants of transportation (pipeline capacity, storage) and platform equipment requirements. A field development plan will identify the optimal platform requirements, and identify and schedule the development well program, gas and water reinjection wells and rates, and platform equipment processing requirements that are, in part, determined by the transportation option selected. For Barrow Arch planning area, a relatively high production rate has been assumed because of the need for favorable economics to initiate development; this rate was selected based upon our review of the petroleum geology as being optimistic but entirely possible.

3.4.3 Quality and Physical Properties of Oil and Gas

The characteristics of oil produced from Barrow Arch will have a significant influence on the feasibility and economics of the selected transportation system. Important crude properties to be considered in the design of a transportation system (pipeline and/or tanker) include:

- Viscosity -- This dictates how well the oil will flow at a given temperature. Variations in viscosity will influence the pumping power required in pipeline transport. Cooling of oil in pipeline transport may lead to wax build-up in the pipeline and reduce effective pipeline diameter. For a waxy crude, direct loading to a tanker may be favored over pipeline transport.

- Salt water -- A small percentage of water is still present in the crude oil after primary separation on the platform. It is costly to separate the water from the oil, and it is even more costly to separate residual oil from water so that it can be discharged offshore. It is also economically unattractive to transport salt water with the crude because of pipe corrosion and reduced oil capacity, although removal of the water onshore may be less expensive than offshore.

- Sulphur -- Sulphur or hydrogen sulphide is a contaminant that, if left in the crude, can cause rapid deterioration to steel pipelines.

These and other factors influence pipeline and processing equipment design. There are trade-offs between the cost advantages of onshore crude stabilization and processing, and the upgrading requirements for offshore platform processing equipment for pipeline transport to shore.

Gas produced in association with the oil can either be transported to shore by pipeline or reinjected into the reservoir. If the crude is produced directly to tankers, associated gas could be reinjected or flared. Some will be used as platform fuel. Gas reinjection equipment is a major cost component. Reinjected gas can be marketed later as economic circumstances change. Associated gas may be reinjected into the reservoir to maintain pressure and to prolong the life of the field. Further, reinjection of associated gas is the only viable solution to the flaring ban imposed upon producing fields if natural gas production is not economically feasible.

As the gas-oil ratio increases, the size of the pressure or production vessels and pipelines increases. Large and more sophisticated equipment is required to handle the gas. At some point, depending on the amount of gas and entrained liquids handled, and on costs, the natural gas liquids will be stabilized and injected into the oil pipeline.

On offshore platforms, space requirements for larger process vessels, pipelines, and the increased equipment requirements for gas processing are usually not great enough to significantly affect the platform costs. Natural gas pipelines are usually trunklines as large quantities of gas reserves are required to produce sufficient revenue to pay back the capital investment (even without a return on the capital).

According to the assessments of the National Petroleum Council (1981), the Barrow Arch planning area shows potential for large gas fields. LNG technology will probably have to play a role in bringing Barrow Arch gas to market. The question of what and where the markets are for LNG will influence the economics of gas trunk pipelines to shore and onshore LNG production. The feasibility of arctic LNG production will be established by the Arctic Pilot Project, an undertaking of Petro-Canada, Dome Petroleum and others to bring gas from the Drake Point Field off Melville Island in the Canadian Beaufort Sea 160 kilometers (100 miles) by pipeline to a bargemounted LNG plant and storage tanks for shipment by ice-breaking LNG tankers. If regulatory approval for the project is received by early 1983, delivery of arctic gas could begin as early as 1986 or early 1987 (personal communication, Sandy Hunter, Petro-Canada, 1982).

3.4.4 Distance to Shore

Other factors being equal, the closer a field is to shore the more likely that production will be transported to shore by pipeline than by tanker. The unit transportation costs for oil increase with greater pipe length, whereas the transportation cost per barrel in an offshore loading system is relatively insensitive to modest increases in water depth. However, the ultimate destination of the crude and the number of terminal handlings are also important considerations.

It is also important to note that the feasibility of offshore loading concepts in arctic regions have not been proven and that longer pipelines may be more economic in the Arctic due to the high cost of arctic offshore loading concepts.

3.4.5 Meteorological and Environmental Conditions

Because information on sea ice in the Chukchi Sea is very limited, the ice forces estimated and platform designs postulated are tentative. Nevertheless, sea ice will be the most significant factor in selecting production systems, from platforms to transportation concepts. It will also be a major factor to overcome in establishing the feasibility of year-round exploration operations and resupply logistics. Ice-breaker support will be required for all marine activities.

Platforms will have to be installed or constructed during brief open-water seasons and all concepts must be capable of surviving the movement of multi-year pack ice. Artificial islands, in addition to passive defense measures, may need to maintain active defense activities when severe ice events occur. All mobile exploration vessels or platforms used on a year-round basis must be capable of surviving in multi-year pack ice conditions and should be able to rapidly disconnect and move off-station to avoid ice islands if necessary.

The onshore terminal for crude oil must be capable of operating year-round, regardless of the weather and of the ice conditions. This requires that the offshore single-point mooring (SPM) or tower must be capable of withstanding the impact of pack ice, and of breaking that ice to protect moored tankers. It must also be capable of monitoring, directing and controlling the movement of tankers in the vicinity of the terminal to permit safe mooring and departure in adverse weather. Means for attaching mooring lines and cargo piping in periods of sub-zero weather, high winds and low visibility must be provided.

Ice-breaking tankers, ice-breaking supply vessels and other craft intended for other than seasonal open-water operations must have hull designs capable of resisting ice impact with minimum chance of holing. Double-hull features, segregated ballast tanks and advanced satellite-based navigation aids will all be required.

The presence of seasonal ice cover and ice scour will require that all pipelines be trenched below ice scour depth and installed during open-water season. All pipeline construction and most installation activities will also take place during the short open-water season.

The Barrow Arch planning area's meteorology will also impose operational problems. While superstructure icing will not be a major problem, extremely low air temperatures will be. Severe cold reduces worker productivity, constrains many operational activities and requires use of special cold-resistant metals and materials. Low visibility due to darkness, fog and storms will also pose a significant constraint to operations. Storm winds may be intense, and although waves will only be a problem during the open-water season, the concentration of operations during this time period leaves little leeway for rescheduling.

Offshore loading systems are untested in arctic regions, and while weather and maintenance/repair downtime ratios have been established for such systems in the North Sea, design and operation of systems for ice-infested areas of the Arctic present more severe constraints. Design of offshore storage facilities has to match production rates, frequency and size of tankers, and expected weather and SPM maintenance downtime. Furthermore, the storage and loading system must allow for very high pumping rates when a tanker is available to load. Lack of operational experience with such systems in the Arctic also limits our ability to predict repair and maintenance requirements, which are likely to be high due to ice forces and severe cold. Provision of adequate storage for unexpected tanker delays will be required to ensure continuous field production with technical and cost constraints on the maximum amount of storage that could be provided on an APLA or other ice-designed storage structure; there may still be times when production will have to be curtailed.

3.4.6 Location of Terminals

Virtually all Barrow Arch crude will be exported to the Lower 48. A very small amount may be refined in Alaska at Kenai Peninsula plants. One or more onshore pipeline terminals will serve as transshipment facilities. The terminal(s) will stabilize the crude, recover liquid petroleum gas (LPG), treat tanker ballast, and provide storage for about 10 to 15 days' production. The most logical location for a terminal to serve oil fields in the northern part of the Barrow Arch planning area would be in the vicinity of Point Belcher near Wainwright where deep water approaches relatively close to shore. In fact, a terminal at Point Belcher may already be in existence by the time Barrow Arch fields are developed. A terminal located at Point Belcher could also serve finds in the western section of the Diapir Field planning area that may be leased before Barrow Arch development takes place. Similarly, production from finds located in the western portions of the National Petroleum Reserve-Alaska (NPR-A) may be shipped via tankers from Point Belcher.

For finds in the southern part of the Barrow Arch planning area, the lack of good deep water anchorages in Ledyard Bay might make location of a terminal south of the Lisburne Peninsula in the vicinity of Cape Thompson a possibility. Oil would be shipped south from a terminal at either Point Belcher or Cape Thompson in ice-breaking tankers to an Aleutian Island transshipment terminal that could also serve fields in other Bering Sea lease sale areas, such as the St. George Basin, North Aleutian Shelf, and Norton Sound areas. In fact, the Aleutian Islands and southwestern tip of the Alaska Peninsula are strategically placed for support and transshipment functions for most of the Bering Sea and Chukchi Sea basins. Crude oil from Barrow Arch offshore fields will be transferred to larger tankers destined for the U.S. westcoast at the terminal in the Aleutians.

3.4.7 Barrow Arch Production Strategies Selected for Economic Analysis -- Summary

The geography and environment of the Barrow Arch planning area offer few options in development strategies. Further, these same factors imply that only the find of a major field would provide a viable economic investment. The petroleum geology does in fact hold out prospects for giant fields (see Appendix A-II). We have assumed that the initial development of the Chukchi Sea, like the North Slope, will require a major find to justify the risks of starting the petroleum technology infrastructure needed to bring Barrow Arch hydrocarbons to market.

The major alternative strategies for Barrow Arch petroleum development are four:

- o Relatively short marine pipelines or combination marine-land pipelines from producing platforms to shore; construction of an onshore crude oil terminal with storage and facilities for loading a fleet of ice-breaker tankers; an Aleutian transshipment terminal for very large crude carriers (VLCC's) carrying crude to market.

- o Relatively short marine pipelines to shore; construction of an overland pipeline approximately 500 kilometers (300 miles) east across the North Slope for transfer to the trans-Alaska pipeline system (TAPS); transfer of crude into VLCC's to market at Valdez.

- o Offshore treatment and storage of field production at a facility such as an APLA; loading into a fleet of ice-breaker tankers; an Aleutian transshipment terminal for VLCC's carrying crude to market.

- o Pipeline production southward to a new loading terminal on the west coast of Alaska.

Strategies 1 and 3 may require a lower threshold of reserves to begin production since oil movement by tanker is considerably more flexible than by pipeline. However, the capital costs associated with construction of an ice-breaking tanker fleet are high and year-round operation of a high-arctic marine terminal will present many difficulties due to sea ice and weather. Although this strategy will require an Aleutian transshipment terminal, a reasonable presumption is that such a facility might already exist to service Bering Sea production. This could help offset the capital and operating costs for this strategy's second terminal.

Strategy 2 has the advantage of tying into the already proven TAPS, but oil pumped through the line will have to bear the TAPS tariff, which is considerable. Also, the costs of the new connecting pipeline will be high. However, this strategy eliminates the expense of constructing and operating an ice-breaking tanker fleet and two terminals.

For strategy 4, we examined a scenario including pipelining oil or gas from a southern Barrow Arch field to a new terminal on the south side of the Lisburne peninsula. This and related strategies, such as land pipelines to Nome, require trading off long onshore pipelines to gain some reduction in the environment for a loading terminal and ship operations.

4.0 PETROLEUM FACILITIES ONSHORE SITING

4.1 Overview of Onshore Facilities

Siting of onshore facilities is an important element in oil and gas development in the Barrow Arch planning area. Oil and gas development always requires a suitable complement of onshore facilities, and development of such facilities along the northwest coast of Alaska will be a challenge, not only due to the severe weather and ice conditions prevailing during most of the year, but also because the existing physical infrastructure in the area is so limited. The effort required will be analogous to establishment of the Prudhoe Bay facilities.

Transportation distances to habitable living areas and supply base sites are much greater in northwest Alaska than in comparable offshore fields in other parts of Alaska with the exception of the Navarin Basin. Long distances and severe weather will make ready transport difficult. Personnel will be required to live on location for longer periods, requiring recreation and medical facilities. Critical supplies and spare parts must be stored on-site.

At present the northwest coast of Alaska in the Barrow Arch planning area offers only limited potential to support the marine and onshore activities necessary for oil and gas exploration and development. With the exception of Barrow, which has a population of nearly 3,000, the other established communities, Umiat and Nuiqsut, are extremely small and poorly equipped to support oil and gas industry operations. All are isolated by lack of overland transportation and lack of marine transportation in the winter. While a few small airstrips exist along the coast, any would require expansion or modernization to handle anticipated air activities associated with oil and gas development. Ship transport is limited by the absence of adequate port facilities and the shallow water depths throughout the area. Barge unloading sites presently exist only at Barrow and Peard Bay.

The actual onshore facilities required to support oil and gas development will depend greatly on the magnitude of offshore fields, their location, whether oil and gas or only oil is actually produced, and the transportation systems selected to service field production. For the purposes of this report, a representative range of required onshore support facilities is presented. As exploration and development actually proceeds in the Barrow Arch planning area, more detailed studies of possible support bases, terminal sites, and pipeline routes will need to be conducted.

4.2 Physical Environment of the Region

The arctic coastal plain is a smooth surface rising gently from the shore of the Chukchi Sea to a maximum height of 180 meters (600 feet) at its southern end. Due to the extensive flat terrain and the continuous occurrence of permafrost under a shallow active layer, drainage on the coastal plain is very poor, and marshes occur in low places. Rivers that cross the plain originate in the hills or mountains to the south.

In the western part of the region, the plain is covered by thaw lakes that have their long axes aligned north-northwest and cover 50 percent of the land. The lakes range from several meters to over 30 kilometers (20 miles) in length and are seldom deeper than about 3 meters (10 feet). The lakes form, enlarge, and drain continually.

The entire land area is underlain by continuous permafrost extending from a few centimeters below land surface to depths ranging from 200 to 600 meters (600 to 2,000 feet).

The Chukchi Sea coast is fronted at most places by narrow gravel beaches below low coastal banks and bluffs. From Cape Lisburne to Cape Thompson, high rocky sea cliffs drop abruptly into the sea for several hundred meters.

Chains of barrier islands extend for many kilometers parallel to the coastline, enclosing shallow lagoons with numerous shoals. This occurs from

Point Lay to Wainwright where the enclosed Kasegaluk Lagoon provides a protected waterway for well over 160 kilometers (100 miles), reaching past Icy Cape almost to Wainwright. This section of coast ends at Peard Bay and from that place to Barrow the coast has been undercut to form prominent cliffs.

4.2.1 Sand and Gravel Resources

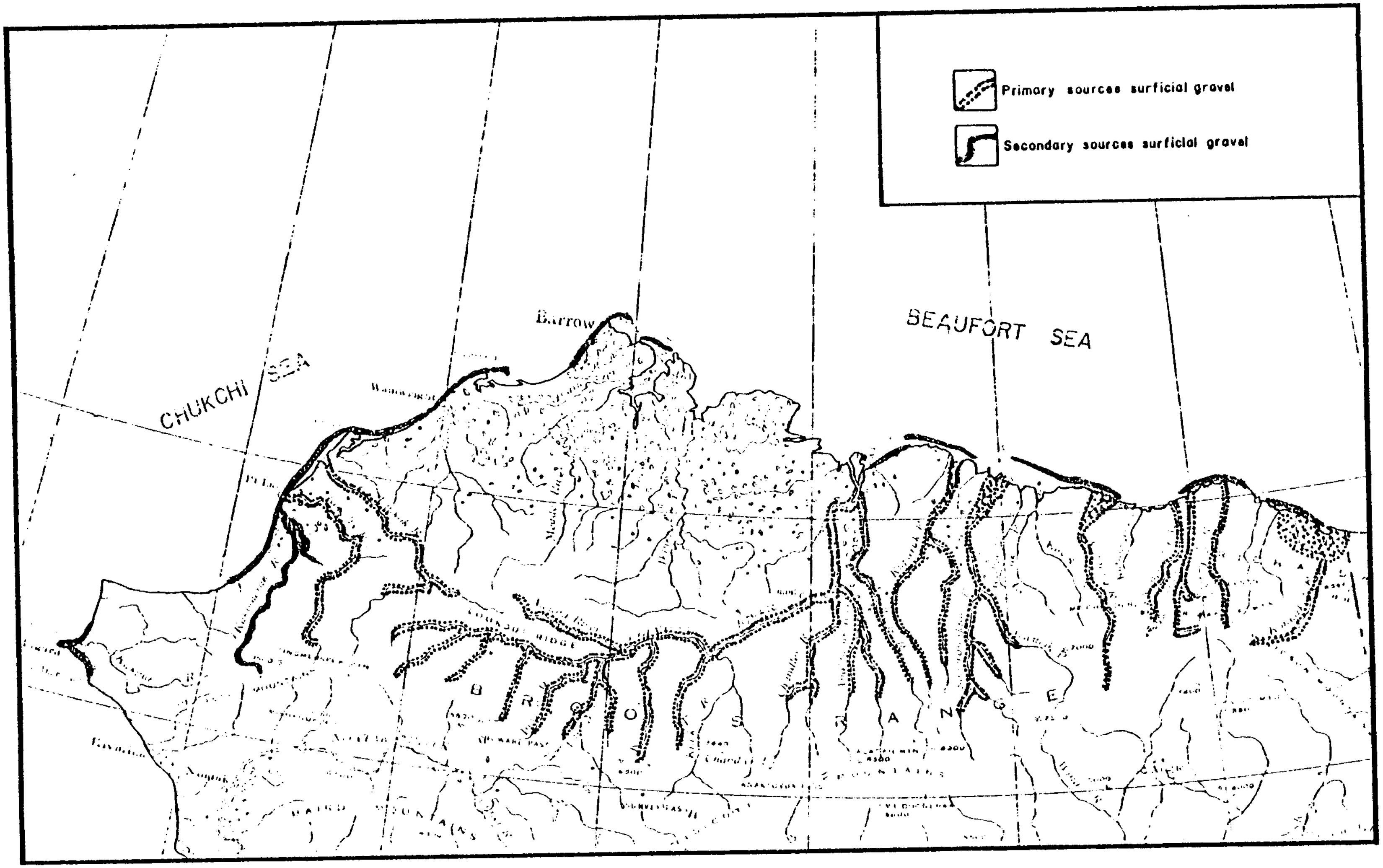
Sand and gravel sources will be critical to construction of onshore facilities in the Barrow Arch planning area. Figure 4-1 illustrates the distribution of surficial gravel deposits in the Barrow Arch planning area and Figure 4-2 shows bottom sediment types in the vicinity of the southern portion of the Barrow Arch planning area.

4.2.2 Freshwater Sources

Supplies of fresh water to service onshore facilities in the Barrow Arch planning area are not well delineated. Little data is available on the extent of surface water available during winter months. According to Rick Smith of Alaska's Department of Natural Resources, Land and Water Management Division, water for onshore oil and gas support operations will probably come from sources similar to those used at Prudhoe Bay. The most likely sources for fresh water will be the deep lakes that do not freeze completely to the bottom during winter. It is also likely that some water reservoirs will be created as gravel is extracted from onshore borrow pits. Winter water withdrawals from rivers will probably be restricted to protect fish overwintering habitat.

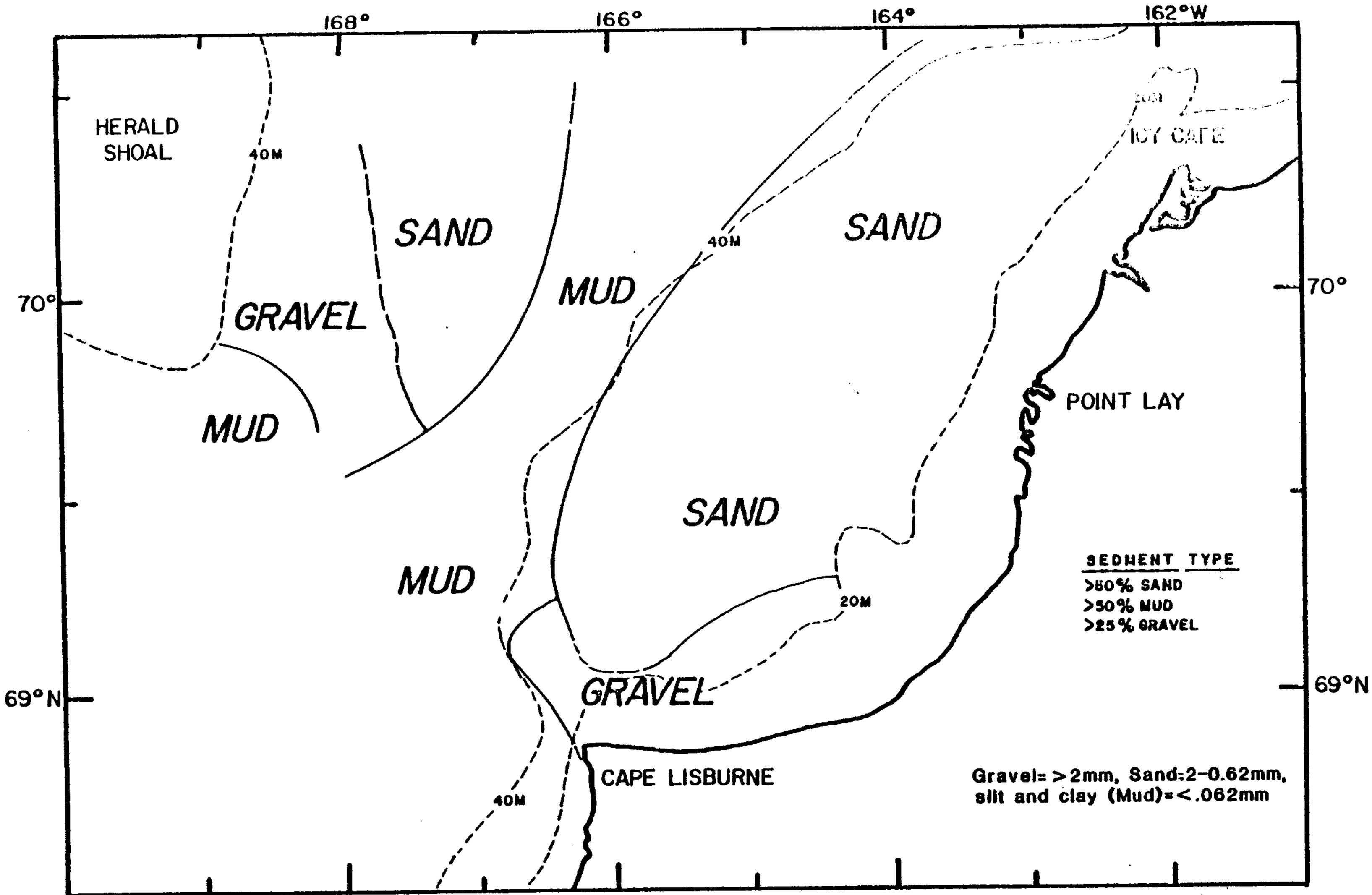
4.3 Types of Onshore Facilities Required

Onshore support facilities will be required at several stages of oil and gas development in the Barrow Arch planning area. The main requirements that must be accommodated in nearshore areas of the Barrow Arch planning area are:



Source: Arctic Institute of North America 1974

Figure 4-1
DISTRIBUTION OF SURFICIAL GRAVEL DEPOSITS



Source: Arctic Institute of North America (1974)

Figure 4-2

CHUKCHI SEA BOTTOM SEDIMENT TYPES

- A basic shore base facility to service exploration, development and long-term production.

- Temporary shore facilities to handle peak construction activities associated with artificial island construction, terminal construction and pipeline construction.

- Appropriate airport or airstrips and heliport facilities to service exploration and development activities.

- A basic port facility to accommodate:
  - service vessels and tugs
  - supply barges
  - construction vessels (dredges, pipelay barges, etc.)
  - ice-breakers for winter port and terminal ice management.

- A marine terminal to receive produced crude oil for treatment, storage and off-loading via a single-point mooring (SPM) to ice-breaking tankers.

- A terminal to liquefy natural gas and transship LNG by ice-breaking tankers.

4.3.1 Marine Service Bases

Marine service bases are an integral part of any offshore development program. Their construction will involve staging areas, operating around the clock to provide drilling materials and support equipment from the coast to the offshore oil fields. Size and function will vary considerably with offshore activity. However, the marine service base will be the longest-lived activity related to offshore development. Marine service bases need to be carefully conceived and efficiently planned so as to aid the stability and economic diversification of northwestern Alaska.

Service bases are required from the time crude oil or natural gas exploration is initiated to the point where production ceases and the equipment is dismantled. The entire range of activities offshore in the exploration and the production of oil and gas resources requires support from onshore facilities.

The marine service base operations must be premised upon taking optimum advantage of suitable weather conditions. Operations should be designed to accommodate peak demands created by adverse weather conditions. The National Petroleum Council (1981) suggests that, in areas like the Chukchi Sea, serious economic studies should be conducted of the possible need for additional capacity in terms of conventional ice-breaking supply boats, work boats, tugs and barges, dock spaces, and other factors to take maximum advantage of favorable weather. Work stoppages that result from not supplying an island-mounted drilling rig or production concept or a pipe-laying barge must be weighed against the increased cost of having a fully manned support base available for use.

4.3.1.1 Exploration-Related Facilities

Depending upon the magnitude of the exploration program and the types of rigs used, base camps could approach the size of a development/production camp, or could be very modest. High investment costs would normally favor a minimal level of development or the use of existing facilities.

Seismic survey or other early exploration efforts will most probably be conducted from self-sufficient vessels with no need for onshore facilities in the area. Onshore support needs will commence with the exploratory drilling phase.

Prior to the start of exploratory drilling, an onshore camp and an operating port must be constructed to house workers and provide storage space and fabrication areas for materials and equipment. If floating rigs are used for exploration drilling, onshore support requirements will be reduced and may not be initially located in the immediate vicinity of the Barrow Arch area. Surveys of gravel and water resources are required prior to construction of facilities and excavation of gravel borrow areas. Transportation facilities to be constructed will include an adequate boat harbor, runways to land fixed-wing supply aircraft and a helipad for cargo and crew helicopters. Appropriate docks and roads will also be constructed to service the harbor and support base complex.

If exploratory drilling in the area is conducted from artificial islands, adequate onshore construction of support base facilities will require a sophisticated planning and mobilization effort to ensure material delivery prior to the short summer construction season. Although as much work as possible will be conducted off-site to avoid the high costs of labor, low productivity, and weather delays that are inherent in the Arctic, a considerable amount of onshore construction will be required. Onsite activities are likely to include: mining and transporting gravel; filling and grading; construction of roads, workpads, foundations and causeways; and installation of utility distribution systems, prefabricated modules and interconnecting pipework. Care must be taken in all construction activities to minimize the impacts on tundra, waterbodies and wildlife.

Since exploratory drilling in the area is likely to be conducted from artificial islands, adequate space must be incorporated into the base camp to accommodate peak manpower and material loads associated with island construction. Also, because of the severe weather prevailing during most of the year and the criticality of maintaining schedules to complete exploration efforts, ample spares will need to be stockpiled to prevent delays.

Harbor facilities will be required at the outset of the exploratory drilling program. In addition to the need to receive construction loads for shore base fabrication, harbor facilities will be required to service the large amount of marine activity associated with artificial island construction, re-supply and maintenance. Use of floating drilling platforms will greatly reduce this requirement. Although an enclosed barrier island/lagoon system occurs along much of the lease area's coastline, all of these protected waters are extremely shallow and the entrances are normally not navigable for anything but small boats (Parker 1975). Therefore, due to the lack of suitable natural harbor facilities, a dredged harbor may have to be created.

Because of the need to provide maximum ice protection for over-wintering vessels, a harbor location within an enclosed lagoon appears preferable. However, the amount of dredging required presents several difficulties. Intensive dredging of harbors and harbor entrances could cause major erosion of both onshore and offshore permafrost. There are no currently accepted methods of stabilizing underwater permafrost and the costs of stabilizing even small areas where the permafrost must be penetrated (as in drilling oil wells) has proven to be quite high. The accepted method of insulation used in building roads and airstrips is to put a blanket of gravel or other material over the permafrost. If this method is used in constructing harbors, it means that very large amounts of material will have to be used to extend the landmass into deeper water rather than dredging into the land. There may be sites where this is possible along the northwest coast of Alaska but they have not been identified as yet (Parker 1975). Also, many waters of the Chukchi Sea are poorly charted and intensive bathymetric survey work will be required prior to harbor construction.

If an enclosed lagoon cannot be utilized for a harbor site, a dredged harbor may be created some distance from shore, due to the shallow water depths found in the Chukchi Sea. The offshore harbor would be dredged one to several kilometers offshore, surrounded with a protective berm, and connected to the shore by a gravel causeway.

Since promising areas of the Barrow Arch planning area are more than 500 nautical miles from a major deepwater port, supplies and equipment will be most economically moved by barge. Although barge operations are presently confined to the open-water season, the construction of ice-breaker barges could make year-round resupply possible. Even prior to harbor dredging, landing craft-type barges could deliver supplies directly to a beach or a temporary cargo pier.

At a minimum, the harbor should have the physical dimensions to allow maneuvering, anchoring and berthing of a large enough number of supply boats, barges and other vessels supplying the base. A minimum of 10 to 12 hectares (25 to 30 acres) dredged to 10 meters (30 feet) would be required. Ideally, it should have the dimensions to accommodate a number of vessels that may be forced to call to port for emergency repairs or seek refuge from storms.

The harbor must be deep enough at dockside to accommodate supply boats and barges to load or unload all various items of cargo necessary to support an offshore operation. The supply boats must operate around the clock throughout the year taking into account the range of possible ocean and ice conditions. During the exploration and construction phases, they may also be used to haul anchors in support of pipelaying, and operate other support missions from towed rigs or platforms.

Berthing space is an important parameter to harbor capacity. It is essential to be able to load many supply vessels in a relatively short period of time and space must be available to carry out this function.

The siting of the supply base within the harbor is also important. Since service base operations are predicated upon taking optimum advantage of suitable weather conditions, their efficiency is measured in terms of turn-around time. To do this, vessels must be able to move to and from the service base with as little impediment as possible.

4.3.1.2 Production-Related Facilities

Facilities required in support of field development and production operations will be significantly greater and more permanent than those required for exploration. The exploration base camp could be expanded to accommodate development and production, or a new marine production support base could be constructed in closer proximity to the actual offshore development fields. The major activities to be serviced by the marine service base in the post-exploration period are:

- Construction
- Development
- Production
- Post-Production

Construction

The construction stage involves constructing production islands or expanding exploration islands into production islands, installing towed production concepts, building oil collection stations or gas processing plants and tanker terminals, and laying of trunk and feeder marine pipelines to shore and land pipelines to a terminal or pump stations. A marine service base plays an active role in support of installation of production concepts through its support of tugs, barges and other vessels required to install the platforms, pipelines, and production equipment. This generally does not involve a large tonnage or volume of material except in support of pipelaying operations where a large volume of pipe may have to be stored and distributed.

Development

The development stage consists of drilling numerous deviated wells from the production platforms. Generally this phase represents the height of service base activity in terms of tonnages and volumes supplied offshore.

Production

Production commences with the flow of oil or gas and continues through the life of the field. The volume and tonnage supplied offshore are substantially reduced. Also, operations and manpower requirements are reduced at the shore station.

Post-Production

After the fields are exhausted, the service base may support the dismantling of production platforms and other offshore facilities.

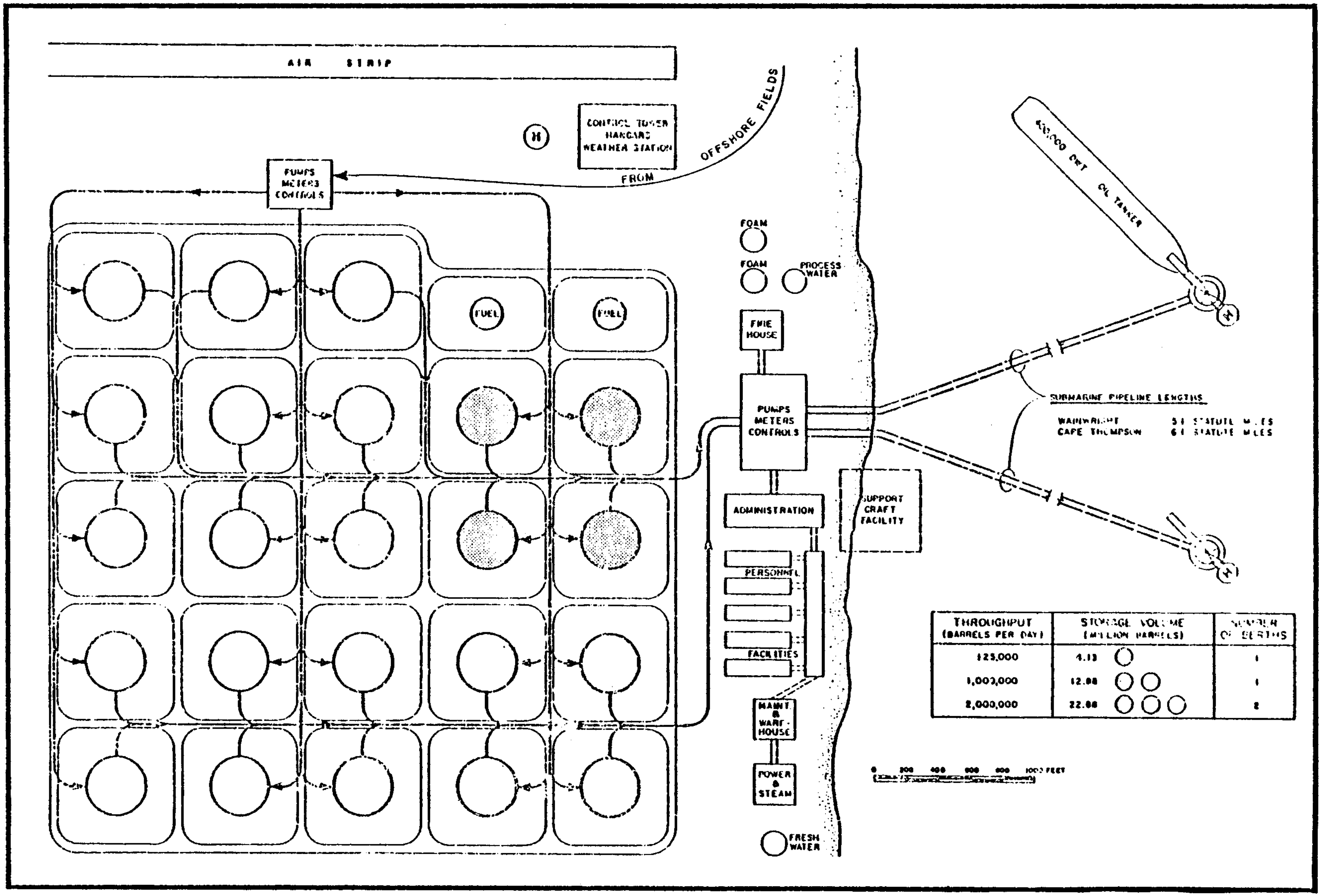
Incorporated as part of the marine service base should be several types of facilities in addition to the harbor and crew quarters and mess. The physical plant is likely to include: a pipe marshalling or terminal yard; warehousing for tubular drilling goods and drilling muds and cements; storage tanks for chemicals, fuel and water; fabrication yards; communications facilities; office accommodations; mud and cement make-up facilities; vehicle and machinery maintenance and repair shops; power plant; sewage facilities; and oil spill response and clean-up equipment.

4.3.2 Marine Terminal

In addition to the marine service base, a marine terminal to receive, treat, store, and transfer crude oil to ice-breaking tankers may be constructed. Conceptual designs for such arctic facilities have been developed by Global Marine (1978), Bechtel (1979), and McMullen (1980). In addition, several proprietary studies of arctic marine terminals have been prepared for industry operators.

The onshore facilities associated with a marine terminal include storage tanks, a topping plant, a power plant, a tubular and equipment yard, a warehouse, and storage areas and shops. Figure 4-3 illustrates the layout of such a facility. The terminal will be connected to the offshore fields by marine pipelines and to two SPM structures, each located in deep water at the end of a several kilometer marine pipelines and capable of off-loading into ice-breaking tankers.

To achieve maximum efficiency in utilization of harbor facilities, labor, equipment and onshore facilities, the marine terminal will probably be located in close proximity to the marine service base, except in the event that oil is found in the southern end of the Barrow Arch planning area. In such a case, marine service base facilities would be located in Ledyard Bay while oil would be transported ashore via pipeline and transported overland across the Lisburne Peninsula by pipeline to a marine terminal in the vicinity of Cape Thompson.



Source: McMullen 1980

Figure 4-3
CRUDE OIL MARINE TERMINAL

4.3.3 Pipeline Service Requirements

In the event that oil or natural gas is transported east via pipeline to the Kuparuk pump station instead of being transported to a marine terminal for transfer to ice-breaking tankers, some additional onshore facilities will be required. Pump stations or compressor stations would have to be constructed to boost the flow of produced hydrocarbons.

4.3.4 Natural Gas Liquefaction Plants and Terminals

In the event that a pipeline is not constructed to transport natural gas, a liquefaction plant and marine terminal would be constructed to liquefy natural gas, store the produced LNG and transfer it to ice-breaking LNG tankers at an SPM. The Arctic Pilot Project being undertaken by PetroCanada to produce Mackenzie Delta natural gas is one such project. Figure 4-4 illustrates the likely layout of such a facility.

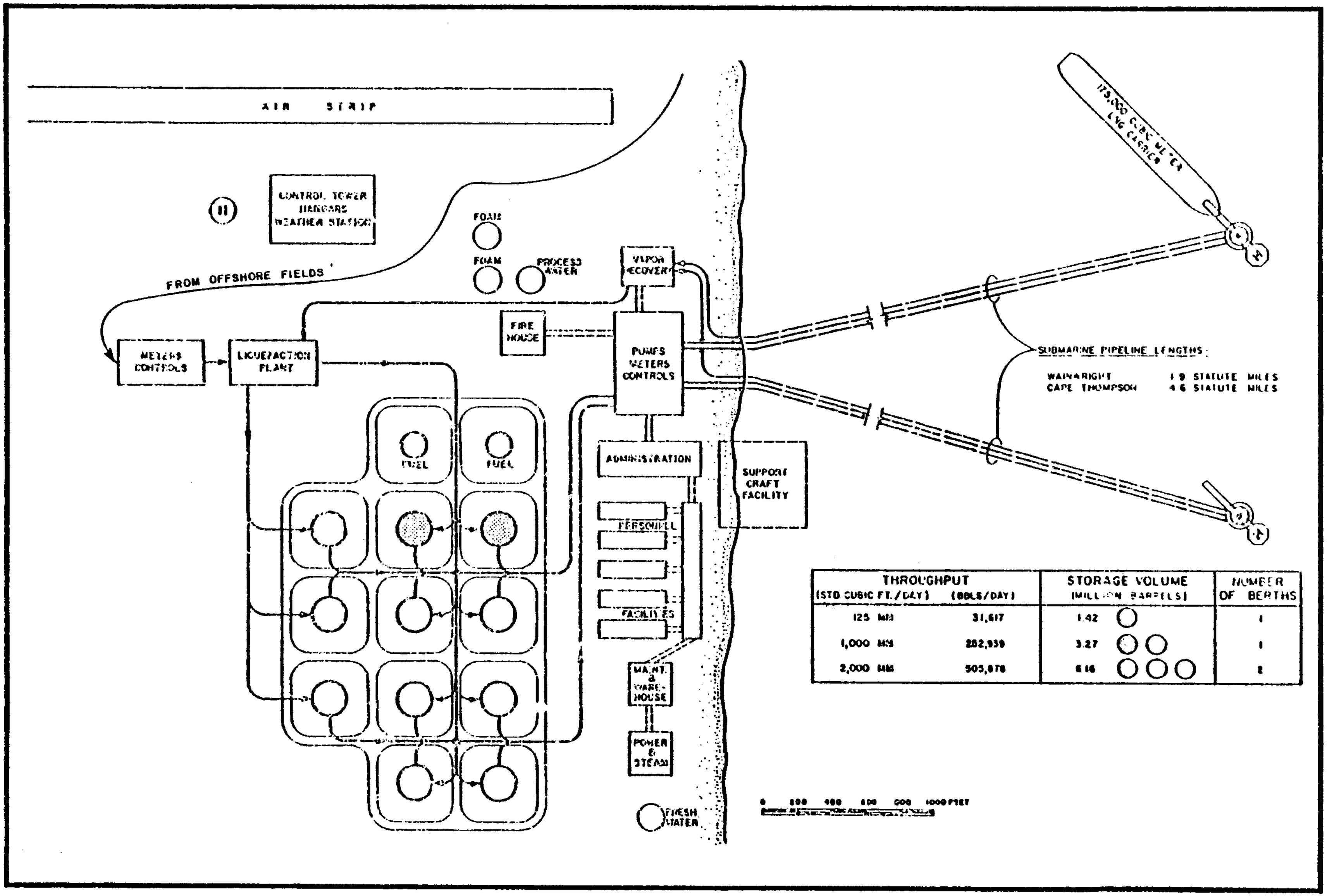
4.3.5 Summary of Petroleum Facility Siting Requirements

Table 4-1 illustrates some representative siting requirements for the major onshore facilities required to develop the oil and gas resources of the Chukchi Sea. Figure 4-5 illustrates how such representative facilities might be arranged.

4.4 Onshore Facilities Siting Constraints and Criteria

A variety of technical and environmental constraints and criteria must be taken into account selecting sites for onshore oil and gas facilities. Among the constraints to be considered in selecting onshore sites for support facilities are the following:

- o Landfast ice
- o High rates of coastal erosion
- o Nearshore permafrost



THROUGHPUT (STD CUBIC FT./DAY)	THROUGHPUT (BBLS/DAY)	STORAGE VOLUME (MILLION BARRELS)	NUMBER OF BERTHS
125 MM	31,617	1.42	1
1,000 MM	252,939	3.27	1
2,000 MM	505,878	6.16	2

Source: McMullen 1980

Figure 4-4

LIQUEFACTION PLANT & LNG MARINE TERMINAL

TABLE 4-1

SUMMARY OF PETROLEUM FACILITY SITING REQUIREMENTS

Facility	Land Hectares (Acres)	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									
Small-Medium (<250,000 B/D)	30 (75)	15-23 (50-75)	14-20 (46-66)	13-19 (42-61)	12-18 (40-58)	1	457 (1500)	1220 (4000)	Required space in turning basin can be reduced substantially should tug-assisted docking and departures be required
Large (500,000 B/D)	138 (340)					2-3	914-1371 (3000-4500)	1220 (4000)	
Very Large (<1,000,000 B/D)	300 (740)					3-4	1371-1829 (4500-6000)	1220 (4000)	
LNG Plant									In addition to thoroughput, size of plant will also depend on amount of reconditioning 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	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

Source: Dames & Moore 1980c.

B/D = barrels per day

MMCFD = million cubic feet per day

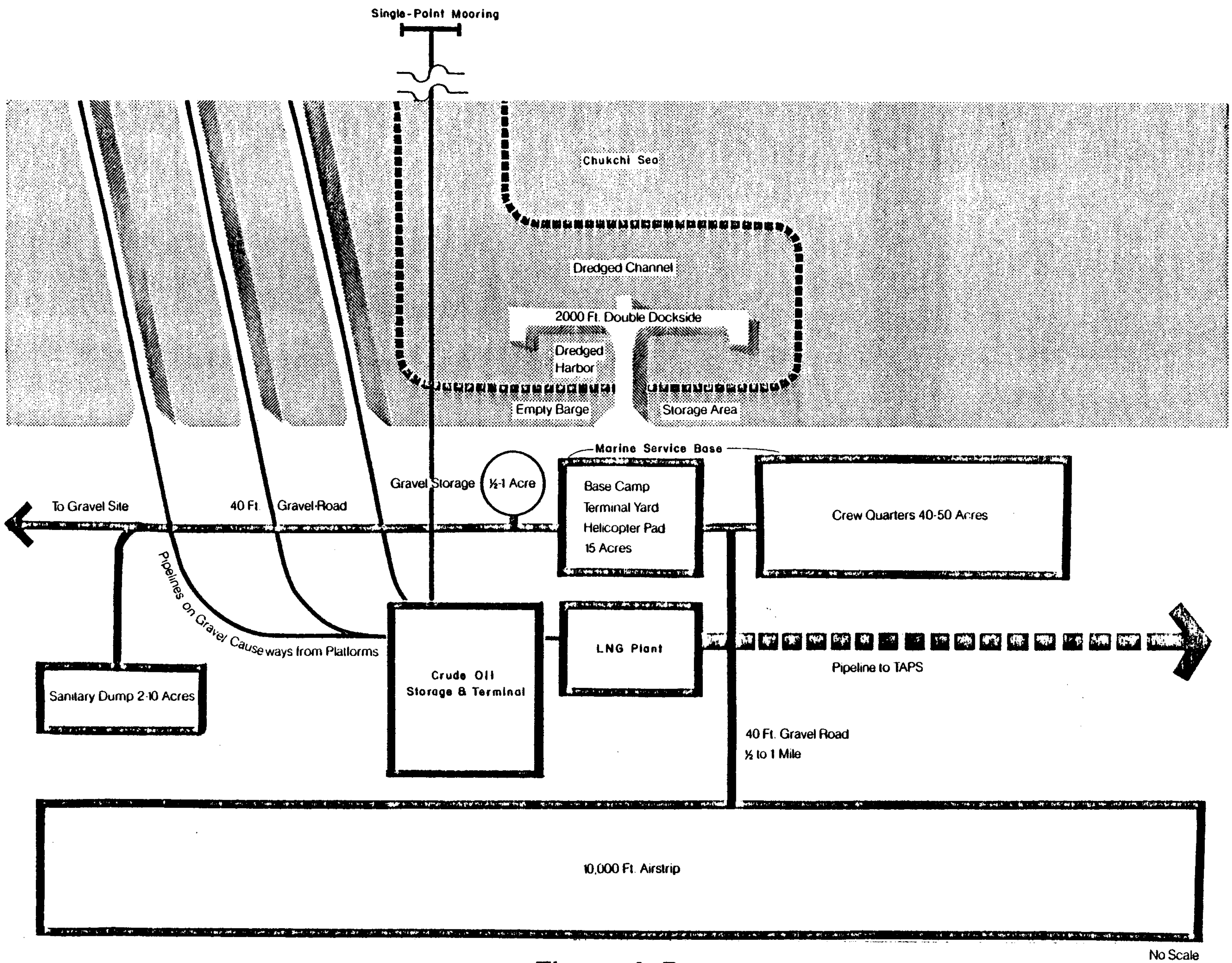


Figure 4-5
REPRESENTATIVE OIL & GAS DEVELOPMENT ONSHORE FACILITIES

- o Gravel deposits
- o Sediment dynamics (littoral drift)
- o Freshwater supplies

While the principal oceanographic, geologic and geomorphic characterization of the Barrow Arch planning area's coastlines have been discussed, both earlier in this chapter and in Chapter 3.0, more detailed studies of possible sites for onshore facilities will have to be conducted once a lease sale has been held. Nevertheless, the technical and environmental criteria for such a composite site ranking can be identified. They include:

- o Flat terrain and sufficient acreage
- o Proximity to known faults
- o Shelf width/water depth
- o Absence of navigation hazards
- o Sufficient elevation to avoid flooding and ice override events
- o Slope stability
- o Site physiography
- o Surficial deposits
- o Wave exposure
- o Ice conditions
- o Berth orientation to prevailing winds and current
- o Current speeds
- o Nearshore processes
- o Proximity to existing harbor and airport facilities
- o Proximity to marine mammal concentrations

4.5 Socioeconomic Setting and Regulatory Constraints

Coastal communities in the Barrow Arch planning area, notably Wainwright and Barrow, as well as a number of smaller native villages, are likely to be affected by oil and gas development. Coastal Zone Management regulations require advanced area planning to accommodate any sizable onshore energy-related installations relative to the communities affected by oil and gas development. This required planning addresses housing of personnel, appropriate land on which to site facilities, and existing services and utilities that may be impacted. To the extent desirable, the energy facilities can be made to be self-sufficient.

The administration of lands in the Barrow Arch planning area is split among several major holders. The North Slope Borough is responsible for taxation, development, and land infrastructure planning. The federal government also controls much of the land in the area as part of the National Petroleum Reserve - Alaska (NPR-A), and the State has some land holdings and controls the seafloor out to a 3-mile (4.8-kilometer) line beyond the coast.

A coastal management program for the North Slope Borough, pursuant to the federal Coastal Zone Management Act (CZMA) and partially funded by the Coastal Energy Impact Program (CEIP), is currently in the process of being developed. A coastal inventory and assessment is currently being prepared. The North Slope Borough and its constituent local communities will undoubtedly play a large role in responding to and directing the siting of energy facilities along Alaska's northwest coast.

The predominantly native population of the area is involved in a transitional economy featuring aspects of both a cash, wage-based economy and a traditional, subsistence economy. Much of the wage employment that exists is seasonal and a significant portion of the cash that enters the area comes through State and federal transfer payments.

Subsistence fishing and hunting activities are a significant economic contributor to Inupiat Eskimo villages and natives from the regional communities of Wainwright and Barrow. Care will have to be taken in siting and constructing any oil and gas-related onshore and coastal facilities to avoid adverse impacts on these activities.

4.6 Representative Onshore Facility Sites in the Barrow Arch Planning Area

Several studies have been conducted during the last 5 years to examine the feasibility of siting and developing major oil and gas-related onshore facilities, particularly for ports and marine terminals. Engineering Computer Optecnomics (1977) conducted an assessment of 29 potential port sites in Alaska including Point Lay, Point Hope, Kivalina and Kotzebue. Global Marine (1978), in its preliminary feasibility study of a tanker transportation system serving the northwest coast of Alaska, examined the siting of an oil terminal and storage facility near Cape Thompson. Bechtel (1979) prepared a conceptual design of an arctic marine terminal for transferring crude oil to ice-breaking tankers. They studied siting such a facility in the vicinity of Wainwright at Point Belcher on the basis of serving potential oil fields in the Chukchi Sea, NPR-A, or other onshore fields in northwest Alaska. McMullen Associates (1980) conducted an analysis of a marine transportation system for NPR-A that evaluated potential marine terminals sited at either Wainwright or Cape Thompson.

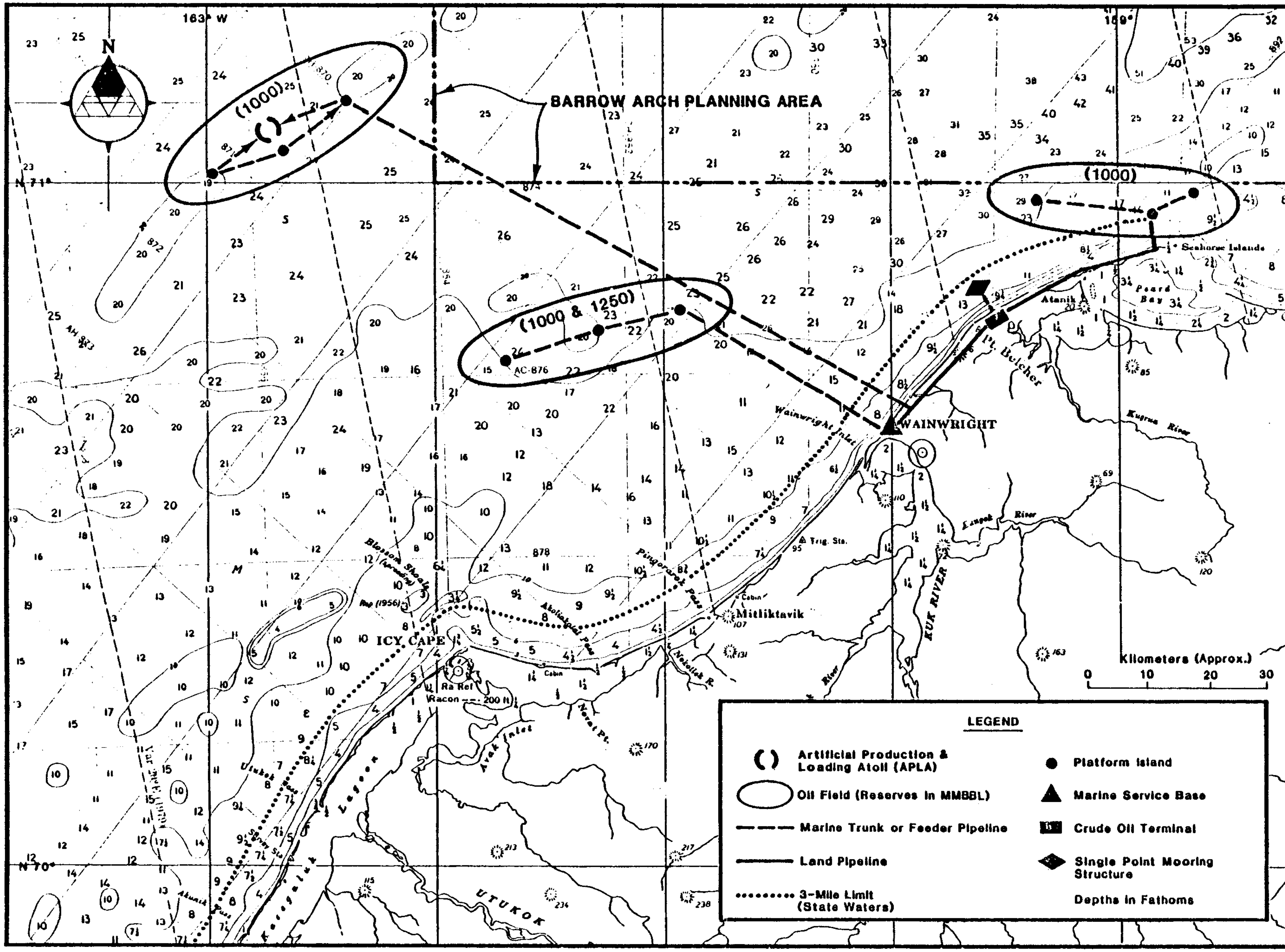
For the purposes of this study, two representative sets of offshore oil fields were established along with marine terminal sites to guide the economic analysis contained in Chapter 6.0. The most likely location of oil and gas reserves is in the northern part of the Barrow Arch lease area south of 71° N latitude. A terminal is likely to be located at Point Belcher near Wainwright due to the close approach of deep water to shore (relatively unusual in comparison to the rest of lease sale planning area). A pipeline to an SPM, 3 to 8 kilometers (1.4 to 4.4 nautical miles) in length, would be required to reach water depths sufficient to avoid tanker grounding, depending upon the size of the tankers selected to transport produced oil or gas (McMullen 1980).

Marine service base and harbor facilities are likely to be constructed in one of several places. To the northeast of Wainwright is Peard Bay. Just below Wainwright is Wainwright Inlet and the mouth of the Kuk River. Several passes into Kasegaluk Lagoon may be expanded and harbor facilities dredged out within the lagoon. Pingorarok Pass, north of the Nokotlek River, is one possible site. Further south, below Icy Cape, Icy Cape Pass or Utukok Pass enter Kasegaluk Lagoon near the Utukok River, which contains large gravel resources. In the vicinity of Point Lay, Kukpowruk Pass enters the lagoon between the Kokolik and Kukpowruk Rivers, both of which furnish gravel sources.

The second representative site of oil and gas fields is at the southern end of the proposed lease sale area. In the event of sizable finds of oil or gas, produced hydrocarbons might be moved south via marine and land pipelines to a marine terminal site near Cape Thompson, where deep water approaches close to shore and ice conditions are less severe. A site at either Kisimilok Creek or Ogotoruk Creek seems feasible. Depending on the actual terminal site and the size of the tankers used, pipeline lengths to a SPM in deep water would be between 5 and 10 kilometers (2.5 and 5.3 nautical miles; McMullen 1980).

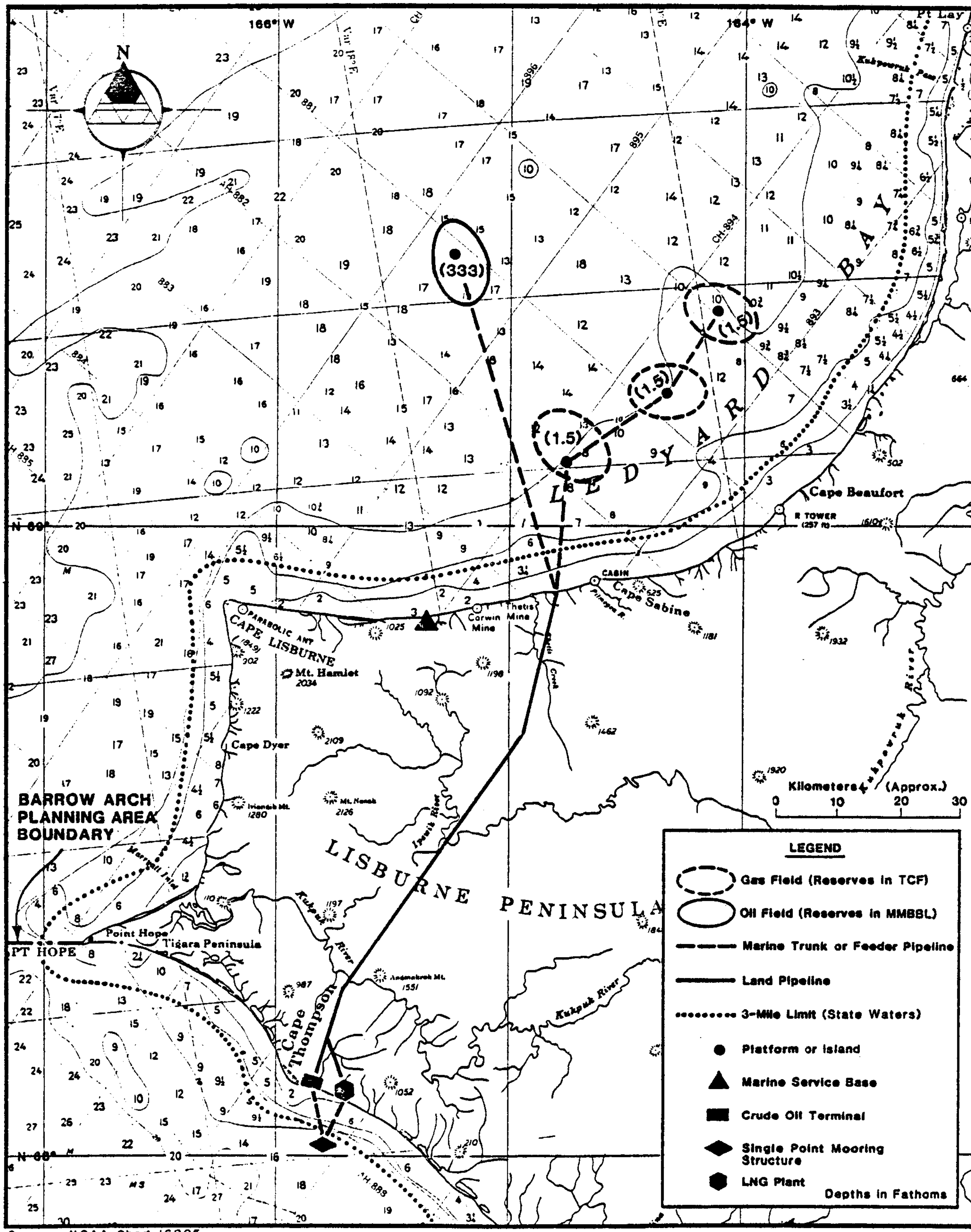
Marine service base facilities are likely to be put in place at one of several locations for a southern field. Ayuyatak Lagoon, east of Cape Lisburne, might be dredged out and a pass through the barrier beach established. Noakok Pass into the southern-most end of Kasegaluk Lagoon might be expanded into harbor facilities or the passes in the vicinity of Point Lay might be utilized.

Figure 4-6 illustrates the location of representative offshore oil fields, platforms, offshore and onshore pipeline corridors, marine terminal sites, LNG plant sites, and marine support base sites in the northern part of the Barrow Arch planning area. Figure 4-7 illustrates the same type of facilities for fields in the southern portion of the lease sale area. (These are described in detail in Section 6.2.)



Source: NOAA Chart 16005, Cape Prince of Wales to Point Barrow

Figure 4-6
REPRESENTATIVE FIELD & SHORE FACILITY LOCATIONS - NORTHERN PORTION



Source: NOAA Chart 16005,
Cape Prince of Wales
to Point Barrow

Figure 4-7

REPRESENTATIVE FIELD & SHORE FACILITY LOCATIONS SOUTHERN PORTION

5.0 MANPOWER REQUIREMENTS

5.1 Introduction

The purpose of this chapter is to provide estimates of manpower requirements for each of several major tasks involved with the exploration, development, and production of petroleum for the Barrow Arch planning area. The estimates are presented here in a format similar to that used in the Navarin Basin Petroleum Technology Assessment (Dames & Moore 1982a). Manpower estimates for Barrow Arch for each major exploration, development, and production task are presented in Table 5-1. Table 5-2 presents transportation support services associated with these major offshore operations.

Our estimates reflect previous research on manpower requirements for offshore petroleum development, for example "Beaufort Sea Petroleum Development Scenarios" (Dames & Moore 1978a), which discusses background on arctic labor considerations and specifically covers Prudhoe Bay experience with opening an arctic frontier area. Also see St. George Petroleum Technology Assessment (Dames & Moore 1980c) for general factors affecting offshore labor force size and productivity (Sections 4.2 and 5.3 of that report). Our manpower estimates for this study also benefited from consultation with engineers from SF/Braun about specialized arctic structures and operations that will be used in the development of resources in the Barrow Arch planning area. The reader is referred to Appendix E of Technical Report 49 (Dames & Moore 1980a) for a full definition of the manpower and employment terms used in this report.

5.2 General: Three Phases of Petroleum Resource Labor Activities

Exploitation of a petroleum reservoir 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

TABLE 5-1

ESTIMATES OF LABOR REQUIREMENTS FOR SPECIFIC TASKS OF PETROLEUM DEVELOPMENT IN THE BARROW ARCH PLANNING AREA

Activity	Onsite Labor (Number of Jobs)	Duration of Onsite Employment
Exploration Drilling	60/cone or island	4 months/well
Geophysical Survey	30/year of exploratory drilling	during exploration phase
Shorebase Construction		
Exploration Phase	200/mo. (peak) 50/mo. (average)	8 months
Development Phase[1]	200/mo. (peak) 50/mo. (average)	36 months
Oil Terminal Construction		
Arctic Site[2]	1300/mo. (peak) 400/mo. (average)	60 months
Aleutian Site	1000/mo. (peak) 550/mo. (average)	24 months
Artificial Production and Loading Atoll (APLA)	600/mo. (peak) 150/mo. (average)	90 months
Early Production System (temporary)	200/mo. (average)	9 months
LNG Plant Construction (barge-mounted)	200/mo. (peak) 50/mo. (average)	24 months
Offshore Fill Construction[3]		
Gravel Island (50' depth)		
Exploration	430/mo.	3 months
Production (add-on)	450/mo.	3 months
Production (new)	620/mo.	3 months
Caisson-retained (50' depth)		
Exploration	400/mo.	3 months
Production (add-on)	445/mo.	3 months
Production (new)	575/mo.	3 months
Production Monocone	350/mo.	3 months
Production Equipment Installation and Hook-up		
Monocone	400/mo. (peak) 300/mo. (average)	10 months
Gravel/Caisson Island	400/mo. (peak) 300/mo. (average)	10 months

TABLE 5-1 (Continued)

Activity	Onsite Labor (Number of Jobs)	Duration of Onsite Employment
Development Drilling		
Production Wells(4)		
Monocone	112/mo.	60 months
Gravel/Caisson Island	112/mo.	75 months
Submarine Pipeline Construction(5)		
Trunk	350/spread/mo.	0.75 mi/day
Feeder	150/spread/mo.	1.25 mi/day
On-Shore Pipeline Construction(6)		
Cross-Country	350/mo.	0.5 mi/day
Short-Distance	150/mo.	0.25 mi/day
Shorebase Operation		
Exploration Phase	40/mo.	exploration phase
Development Phase	200/mo.	development phase
Production Phase		
Year-round	50/mo.	12 months
Seasonal	100/mo.	3 months
Production Platform Operation, Cone and Island	80/mo.	12 months
Production Island Maintenance		
Gravel	55/mo.	3 months
Caisson	20/mo.	3 months
Production Equipment, Pipeline Maintenance; Cone and Island	30/mo.	3 months
Oil Terminal Operations		
Arctic Site(7)	65/mo.	12 months
Aleutian Site	50/mo.	12 months
LNG Plant Operation	60/mo.	12 months

Source: Dames & Moore and G. Harrison

NOTES TO TABLE 5-1

(1) It is assumed that the development shorebase will be located at the terminal site near Point Belcher. It is assumed that the shorebase will be incorporated into the terminal site. Therefore, shorebase construction has been phased with terminal construction. Shorebase construction could be completed much more quickly if done on a separate basis. A separate shorebase would need to be built in the vicinity of the Cape Sabine pipeline landfall if a terminal were located at Cape Thompson (Case 5). For this case, double this labor requirement.

(2) Arctic terminal construction duration has been estimated by SF/Braun and by Bechtel (1979). The long total construction period to completion is predicated on the assumption that year-round construction would not be utilized due to the high inefficiency of outdoor winter construction in arctic regions. Therefore, the bulk of construction must be accomplished during the open-water season of several successive years.

(3) An existing exploration island could be expanded for use as a production island. The estimates shown for production islands "add-on" represent the incremental labor required for expansion. Caisson island assumes a Gulf-IHI-type steel structure. Monocone requires gravel ballasting.

(4) Two rigs, 60 wells, 2 months/well on monocone; 2 rigs, 100 wells, 23 days/well on islands (SF/Braun 1982).

(5) Oil or gas pipeline. Duration of employment for pipeline construction can be estimated for each scenario based on average rates of progress.

(6) Estimate for cross-country pipeline includes pump station; one spread is required (Case 5). Short-distance pipeline construction would use smaller crew to avoid the high cost of mobilizing a large crew for a very short period.

(7) Includes pipeline operation.

TABLE 5-2

ESTIMATES OF HELICOPTER AND SUPPORT VESSEL
UNITS AND CREWS FOR OFFSHORE ACTIVITY IN THE BARROW ARCH PLANNING AREA

		BOATS(1)		HELICOPTERS(2)
Activity	Platform Type(s)	Type	Number	Number
Exploration	All	Supply	2/exploration concept(3)	2/exploration concept
Production Concept Tow-out	All except gravel islands - caisson-retained gravel island	Tug-tow (conventional)	6/set of caissons(4)	________
	- mobile caisson rig	Tug-tow (conventional)	5/structure	________
	- monocone	Tug-tow (conventional)	5/structure	________
Production System Towout	All except monocone(5)	Tug-tow (conventional)	10/production concept(6)	________
Production System Installation and Hookup	All	Supply	3/production concept	2/production concept
Pipelaying	All	Tug-tow/anchor-handling	2/spread(7)	2/spread
		Supply	2/spread	
Production System Operation & Maintenance	All except gravel islands	Supply	2-3/production concept	2/production concept
	Gravel islands(8)	Supply	3-4/gravel island	2/gravel island
Marine Oil Terminal Operation	All	Tug (ice-breaking)	2/terminal single-point mooring	________
		Icebreakers	2/terminal	
LNG Plant and Terminal Operation	All	Tug (ice-breaking)	2/terminal single-point mooring	________
		Icebreakers	2/terminal	

(1) Assume an average crew of 10 for supply boats, tow boats and tugs. Unless otherwise indicated, all support vessels may be either of a conventional, ice-reinforced/ice-resistant, or ice-breaking design. Selection of ice capability will be determined by season of operation, concept type and location, vessel cost and operator preference. For example, conventional supply vessels may service open-water pipelay operations, while ice-breaking supply vessels may be selected for assuring year-round resupply capabilities to offshore production systems.

(2) Assume crew of 3 for Boeing Vertol Chinook with 44-passenger capability or cargo capability; 2 for other helicopter types.

(3) Resupply of year-round exploration operations in the Chukchi Sea presents several technical and logistical problems for which one of several operational solutions may be selected. Operators of artificial island concepts may stockpile material seasonally to minimize winter resupply requirements. In any event, all winter resupply operations will be slow due to reduced headways for ice-breaking vessels (3 to 4 knots while moving through multi-year ice). To assure redundancy and emergency evacuation capability, 2 vessels are preferred.

(4) It is assumed that caisson tow-out will be more easily accomplished if caissons are barge-mounted. A total of 3 barges will be required to transport the caisson concept. Six vessels are needed for towing and for on-site handling of the 8 units.

(5) It is assumed that all production concepts will utilize barge-mounted production models towed to site except the monocone, which can handle a substantial deckload during tow-out.

(6) It is assumed that approximately ten 500-ton barges will be required to transport each production system's modularized deck equipment with one conventional tug per barge. This assumes use of common West Coast USA equipment; the alternative of fewer large lifts is possible.

(7) Due to the short open-water season during which pipelay operations must be conducted and the difficulty of conducting a shore-staged bottom-pull pipelay, anchor-handling vessels will be critical.

(8) The additional supply vessel required for production gravel islands reflects this concept's need for annual maintenance of slope protection during open-water season.

Source: Dames & Moore, SF/Braun and G. Harrison a large field) and construction of the equipment and pipelines necessary to process the crude oil and transport it to a refinery or to 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.

Figure 5-1 depicts a very general and hypothetical temporal relationship of the fieldwork for exploration, development, and production phases and the relative magnitude of onsite employment created by each. Particular oil fields differ in their own development schedule and requirements for production and transportation facilities.

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

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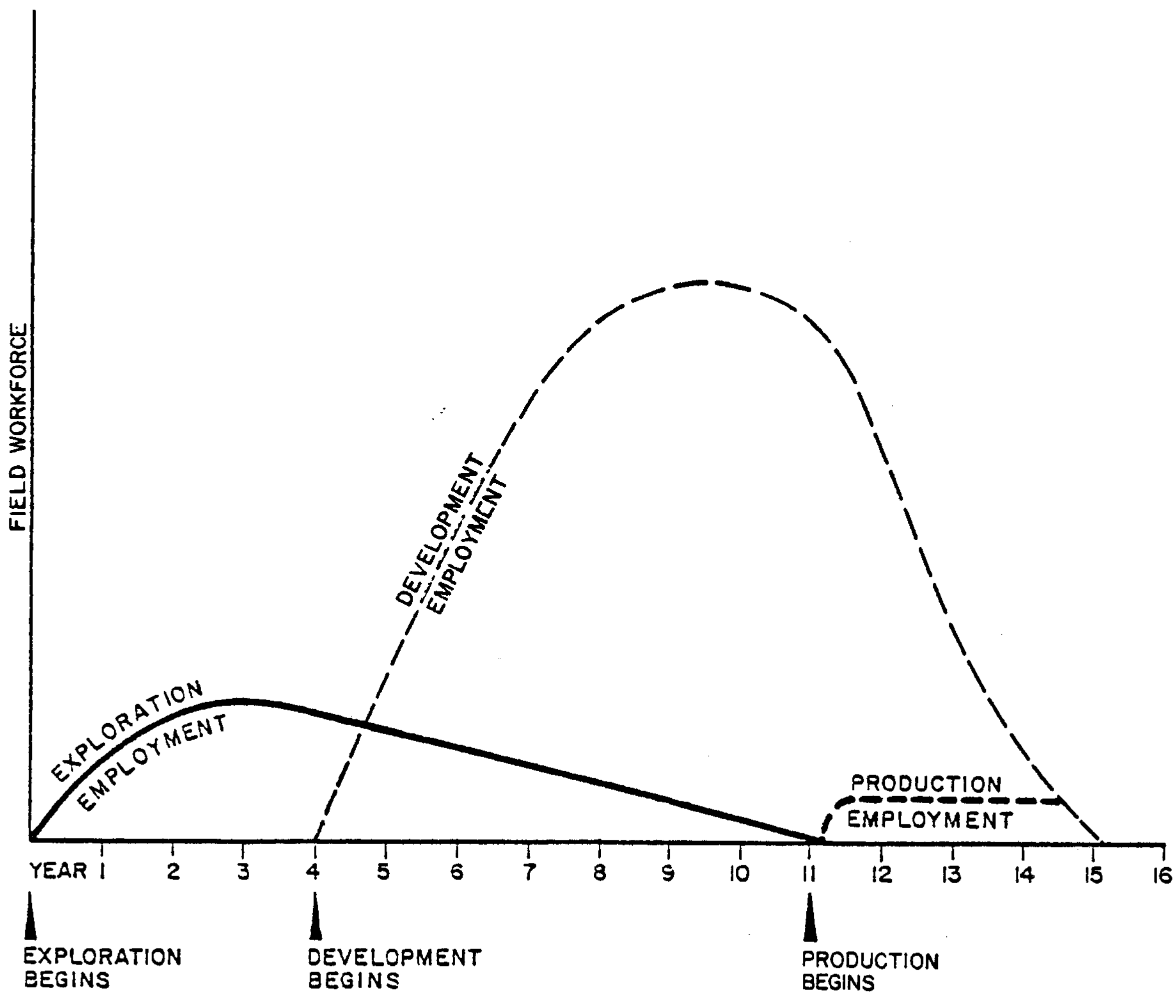
(1) "Local employment" in the oil industry generally refers to employment at or near the petroleum reservoir. It does not include the manufacturing and construction employment created away from the site, such as that involved with the building of process equipment and offshore platforms, nor does it 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). "Local employment" in Alaska usually carries an additional implication referring to jobs specifically for nearby villages. In this case we mean the former, i.e., on-site work force regardless of origin.



SOURCE: DAMES & MOORE 1980a

Figure 5-1

ON-SITE EMPLOYMENT LEVELS OF THE THREE PHASES OF PETROLEUM EXPLORATION, A HYPOTHETICAL CASE

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.

5.3 Background: Manpower Utilization in an Arctic Environment

5.3.1 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 geatly 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 outdoor work, does not, of course, suffer the massive inefficiencies of outdoor 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 cites the Canadian 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 contrast to $0.50 per pound by airlift (while these costs are no longer applicable, the magnitude of the differential is still representative).

5.3.2 Labor Savings Techniques

In discussions with industry representatives about the likely technology and construction methods to be used in Barrow Arch, they have made it clear the 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.

Initially developed for small-scale applications, the modular approach to construction has not 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 3 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 Barrow Arch, 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 construction of a LNG plant.

5.3.3 Prefabricated, Barge-Mounted LNG Plant

It seems likely that if an LNG plant is required for gas production in Barrow Arch, it would be built on a series of barges that 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 tidal slips. A concrete-barge-mounted LNG facility 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 x 135 x 58 feet), and had a capacity of 65,000 tons. The barge-mounted facility 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 Barrow Arch. This assumption considerably lowers 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 infrastructure might be shared with other facilities). This construction would probably require two seasons 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, 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.

5.3.4 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. 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 buried only in thaw 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 inefficiency 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 (where conventional tankers are used), and site preparation are unavoidably 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.

5.3.5 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, especially in shallow water. 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
- Down-time caused by weather and equipment failure
- Construction technique used (reinforced sandbag, artificial beach, etc.)

5.3.6 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 the tundra surface, to prevent 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 Barrow Arch could vary significantly from these estimates.

5.4 Barrow Arch Labor Force Considerations

To be commercially feasible, petroleum production in the Barrow Arch planning area must occur from large fields. Thus, the general scale of development will be large, comparable in size to current Beaufort Sea development in Alaska and Canada, and comparable to development foreseen in other remote and hostile Alaska OCS frontier areas such as the Navarin Basin. In general, seasonal factors will be very important in the utilization of manpower because outdoor work in the Arctic during the winter is very difficult and inefficient. The "weather window" here may be shorter than 70 days. Construction of major facilities will take longer than elsewhere to complete and involve higher seasonal fluctuation of personnel (higher peaks, lower annual monthly averages).

5.4.1 Longer Crew Rotations

A typical crew rotation at Prudhoe Bay is 7 days on and 7 days off. A typical North Sea crew rotation is 14 days on and 7 days off. Operators in the Barrow Arch area will consider long rotations, particularly during the winter when flying may be especially more hazardous. Rotations of 4 weeks on duty may be feasible. Long rotations will reduce flying requirements and thereby lessen the danger of accidents. They will also reduce the cost of changing crews from Anchorage, which in the remote Chukchi Sea will be a significant operational expense (however, crews will have to be compensated for longer rotations with higher pay). This cost consideration could be especially relevant if Chukchi Sea developments of marginal size are implimented, where a large efficient transportation system (such as Prudhoe Bay) is not justifiable. Then, the alternative of longer crew rotations will be especially considered.

5.4.2 Major Shore Facilities Required

Development of oil and gas resources of the Chukchi Sea will require the construction and operation of major shore installations. These are a shore base with an all-weather runway of at least 1,800 meters (6,000 feet) for Lockheed Hercules and Boeing 737 aircraft, a crude oil marine terminal on the coast (e.g., Point Belcher), and a transshipment terminal in the Aleutian Islands. These facilities will make Barrow Arch a labor-intensive frontier area to develop and operate in contrast to other, less remote offshore fields.

Oil terminal construction at Point Belcher or Cape Thompson, for example, is expected to last about 5 years. Although the transshipment facility in the Aleutian Islands and the arctic terminal will be functionally similar and have the same basic components (tank farms, pumping, and metering facilities, power generation, crew quarters, administration and control buildings, shops, airport, and barge docks), the arctic terminal may require up to 80 percent greater manpower. This is largely due to the reduced productivity of labor in the Arctic, as well as to the large, complex offshore loading and mooring structure required in the waters of the Arctic Ocean.

In its study of an arctic terminal for icebreaking tankers, Bechtel (1979) wrote: "Construction offsite in the contiguous 48 states and elsewhere will be done as much as practicable to avoid the high labor costs and schedule disruptions that attend construction in the Arctic. Accordingly, maximum use will be made of modular, prefabricated structures, machinery, and equipment that can be transported by barge to the site in finished form . . . Even with a maximum amount of prefabrication, there will remain a great amount of work to be done at the site. Over a five-year construction period, it is estimated that a peak work force of 1,200 to 1,300 will be required onsite, engaged in site improvement, utility distribution, and installation work, onshore and offshore."

A shorebase to service offshore production islands, gravity platforms, and pipelines in the study area would be at the terminal site (except in the case of a terminal built at the end of a pipeline outside of the planning area). Therefore, construction of the base for the field development and production phases would enjoy many economies in contrast to a free-standing remote service base. A number of facilities could be shared, such as power generation, utilities, housing, shops, communications, and airport. Our labor estimate for building a permanent shorebase reflects these economies.

5.4.3 Offshore Construction

The APLA concept is still exotic, and estimates of the manpower requirements to construct one are very rough indeed. Our estimate is that a structure of this type would require up to 8 years to build, assuming use of current dredges, and it would require an average monthly workforce of about 150 people during that period (a peak workforce of approximately 600 people). Operational manpower requirements of the structure would be similar to a shore-based oil terminal and a production island.

Construction of artificial islands will also create substantial demand for labor during the development phase. Because of their larger fill requirements, gravel islands are more labor intensive than caisson-retained islands. The labor requirements of constructing these structures are very sensitive to the depth of water, quantities of fill materials, and the proximity to suitable fill. Islands of similar design with the same surface area above the waterline might vary in their construction effort by a factor of five or six because of differing water depth, fill quality, and distance to source.

For estimating purposes of this study, we have assumed the following equipment spread (influenced by Canadian approaches) for building an artificial island:

3 conventional cutterhead suction dredges
4 barges
2 derrick barges
12 boats (survey, workboats, tugs and crew transports)
2 ice-breakers
2 crew quarters barges
2 large caterpillar tractors for work above waterline

We have assumed an intense period of work activity over a total field season of 90 days, with a peak crew of up to 400 people for an exploration gravel island. (Also, the ballasting of a large production monocone is assumed to involve a crew of up to 300 for a 3-month period.) Expanding an exploration island to a production island requires more fill, and the labor estimate for providing this incremental fill is a directly proportional increase added to the exploration estimate.

Artificial islands require annual maintenance to repair damage caused by the action of waves and ice. Our estimate of this manpower requirement is 55 people for 3 months for a gravel island and 20 people for 3 months for a caisson island.

6.0 THE ECONOMICS OF PETROLEUM DEVELOPMENT

6.1 Introduction and Modeling Approach

This chapter presents the results of an economic analysis of OCS oil and gas development in the Barrow Arch planning area. These results indicate how alternative transportation and production systems affect the economic feasibility of petroleum reserve development. The distribution of costs between onshore and offshore facilities is analyzed in terms of both total costs and their contribution to cost per unit of product.

The economic viability of OCS oil and gas is strongly influenced by reservoir and environmental conditions. Reservoir conditions include reservoir size, target depth, initial well productivity, viscosity and pour point (oil) and hydrate formation (gas), porosity, permeability, percent fill-up, and gas-oil ratio. Since no production has taken place in the Chukchi Sea, and exploration has been limited to seismic and geophysical reconnaissance, these reservoir parameters must be estimated. Our analysis of the petroleum geology of the Barrow Arch planning area in Appendix A presents the data, assumptions and rationale to arrive at reasonable values for these parameters.

Environmental conditions of concern include geography, water depth, wind, wave and ice conditions, depth of permafrost and ice-gouging, and open-water season length. Ice conditions pose the most serious technologic and economic challenge in the Barrow Arch planning area. When coupled with the very short (estimated 70 working days) open-water season, emplacement of offshore structures and laying of marine pipeline are rendered technologically difficult and very costly. Because of the high cost and state-of-the-art technology necessary for even the relatively nearshore central Chukchi shelf portion of the lease sale area, the economic assessment will focus on only this portion. While this emphasis does not mean that the remainder of the lease sale is not technologically developable, it is clear that further offshore areas will be even more costly to develop. Since we shall demonstrate that even the more favorable central Chukchi shelf resources are marginal to submarginal economically, it follows that the remaining portions of the Barrow Arch planning area are less economically attractive given the assumed constraints and parameter values of this analysis.

The economic analysis highlights two major strategy considerations: selection of offshore production system and choice of transportation path. Several offshore production systems have been proposed that are designed to withstand the forces of moving sea ice. These alternatives imply major differences in timing of production and initial cost. Thus, the economic analysis focuses on a comparison of production systems, rather than on assumed differences in reservoir characteristics. Reservoir conditions are held constant based on a set of reasonable geologic assumptions (see Section 6.2.2 and Appendix A).

In addition, the economics of the two major transportation modes -- tankers to an Aleutian terminal or pipeline to TAPS -- are compared. Capital investments and operating costs for dedicated transportation facilities are included within the boundaries of the analysis. Thus, the analysis includes all expenditures incurred in producing the oil or gas and delivering it to a common carrier. For oil development, this includes the cost of a dedicated ice-breaking tanker fleet and an Aleutian Islands transshipment terminal, or a pipeline across the North Slope of the Brooks Range to TAPS. At either of these "boundaries," the remainder of the trip to market can be accomplished via existing infrastructure (conventional tankers or TAPS plus conventional tankers).

Since dedicated ice-breaking LNG tankers are needed for delivery of Chukchi Sea gas, these tankers are included within the boundaries of analysis. A common receiving and regassification terminal, servicing other LNG sources is presumed to exist in southern California by the late 1990's when Chukchi Sea gas would come on line[1]. Therefore, the cost of

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(1) There is no clear market indication to suggest that there will be a demand for LNG imported at such a terminal, or that such a terminal will, indeed, be built.

building this receiving terminal is not included in the analysis. Revenues received for oil reflect the value of oil F.O.B. an Aleutian terminal ($31.50 per barrel), or F.O.B. a pipeline at Pump Station 2 of TAPS ($26.00 per barrel)(2), or C.I.F. an LNG tanker in southern California ($6.75 per thousand cubic feet). The basis for these prices appears in Appendix B.

Note that the economic scenarios and analysis are restricted to the development phase only; these are investments subsequent to the decision to develop. Bonus bids and exploration costs are external to the analysis.

The oil development scenarios analyzed are described in Section 6.2. The results of the economic analysis of the oil scenarios are presented in Section 6.3. In Section 6.4, the equivalent amortized costs (EAC) for the components of oil development are allocated among the capital expenditures. Section 6.5 discusses the conclusions regarding the economic viability of Barrow Arch oil. Section 6.6 presents the results of the Barrow Arch gas development scenario. Finally, Section 6.7 presents the relationship of Barrow Arch oil production to the U.S. energy balance. Economic and modeling assumptions and facilities costs and scheduling estimates are discussed in Appendix B.

The reader's attention is particularly directed to the discussion in Section 6.3 regarding the degree of "optimism" in significant assumptions used in this analysis.

6.2 Development Scenarios Used for Economic Analysis

6.2.1 Comparison of Five Scenarios

As noted in the previous section, the economic analysis focuses on alternative offshore oil production systems and on transportation systems

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(2) Assuming a $6.50 tarriff on the existing TAPS and Kuparuk pipelines yields an oil price in Valdez of $32.50. Differential VLCC rates from Valdez and the Aleutian terminal imply oil lays into the West Coast at $34.00 per barrel, consistent with the West Coast price of the other scenarios.

for the central Chukchi shelf. Five analytical scenarios were defined for modeling to represent the specific characteristics of the central Chukchi shelf. These are listed below, shown in Figures 4-6 and 4-7, and described more fully in the following pages.

Scenario 1 compares production systems: gravel islands (Scenario 1B) versus caisson-retained gravel islands (Scenario 1A) for nearshore (Point Belcher/Wainwright vicinity) in shallower water (15 meters [50 feet]). In this scenario, oil is transported south to the Aleutian terminal via ice-breaking tankers from an offshore terminal at Point Belcher.

Scenario 2 introduces the pipeline to TAPS. This scenario is otherwise identical to Scenario 1B -- the offshore production system is a caisson-retained gravel island in 15 meters (50 feet) of water nearshore.

Scenario 3 analyzes deeper water (37 meters [120 feet]) production systems, 43 kilometers (27 miles) offshore. Deeper water is found further offshore; hence, longer pipelines and bigger platforms are implied. A concrete monocone platform (Scenario 3A) and a caisson-retained gravel island (Scenario 3B) are compared. In addition, a higher productivity larger field (Scenario 3C) is modeled to show the sensitivity of the economics to geologic assumptions by using the same systems as Scenario 3B.

Scenario 4 describes far offshore (87 kilometers [54 miles]) systems in 37 meters (120 feet) of water. An APLA concept developed by Dome Petroleum Ltd. (Scenario 4A) is compared to a caisson-retained production system with a pipeline to a shore terminal near Wainwright (Scenario 4B). The APLA precludes onshore infrastructure.

Scenario 5 analyzes southern Chukchi gas and oil development, presumed to be located in Ledyard Bay and produced by a concrete monocone in 27-meter (90-foot) waters and transported southward by overland pipeline to a new marine terminal at Cape Thompson. This scenario is designed to model development in that nearshore part of the Barrow Arch planning area less likely to contain the super-giant fields assumed in the more northerly scenarios, and to model this alternative transportation route.

The above scenarios and their required facilities are summarized in Table 6-1, which shows system components and capital investment costs.

6.2.2. Analytical Assumptions for Oil Reservoirs

In order to facilitate comparisons among the scenarios, a number of reservoir conditions and reservoir engineering assumptions were held constant. These conditions include:

o Recoverable reserves per field	1 billion barrels (Scenarios 1, 2a, 2b, 3, and 4) 1.25 billion barrels (Scenario 3c) 333 million barrels (Scenario 5)
o Number of offshore production units per field	3 (except for Scenario 5, which has 1)
o Recoverable reserves per offshore production unit	333 million barrels
o Recoverable reserves per acre	60,000 barrels
o Gas/oil ratio (GOR)	500:1 (reinjected)
o Reservoir (target) depth	3,000 meters (10,000 feet)
o Initial productivity per well	2,000 barrels per day (except for Scenario 3C: 2,500 barrels per day)
o Number of producing wells per production unit	50 wells
o Number of injection wells per production unit (water and gas)	14 wells
o Peak daily production per platform production unit	100,000 barrels per day
o Ratio of peak year production to reservoirs	1:10
o Percent of reserves recovered before decline	45 percent
o Overall production efficiency	96 percent

TABLE 6-1

EQUIPMENT AND CAPITAL INVESTMENTS FOR BARROW ARCH OIL DEVELOPMENT
($ Million 1982)

SCENARIO	1A Caisson-Retained (also 1C)	Cost	1B Gravel Island	Cost	2 Pipeline to TAPS	Cost
Daily Throughput (B/D) Reserves (MMBBL)	300,000 1,000		300,000 1,000		300,000 1,000	
Production Facilities						
Platform	3 caisson-retained gravel islands (15 m water)	390	3 gravel islands (15 m water depth)	495	3 caisson-retained gravel islands (15 m water)	390
Wells	192 wells @ 3000 m	1152	192 wells @ 3000 m	1152	192 wells @ 3000 m	1152
Deck Equipment	3 @ 100,000 B/D capacity	900	3 @ 100,000 B/D capacity	900	3 @ 100,000 B/D capacity	900
Pipelines: Marine	Trunk: 7 km @ 22" Feeders: 19 km @ 12"	43 74	Trunk: 7 km @ 22" Feeders: 19 km @ 12"	43 74	Trunk: 7 km @ 22" Feeders: 19 km @ 12"	43 74
Onshore	34 km @ 22"	113	34 km @ 22"	113	34 km @ 22"	113
Subtotal		2672		2777	(Same as 1A)	2672
Terminals						
Pipeline/Marine/ Storage	Point Belcher	950	Point Belcher	950	Point Belcher (Pipeline only)	500
Transshipment	Aleutians	1300	Aleutians	1300	None	0
Subtotal		2250		2250		550
Transport						
Pipeline to TAPS	None	0	None	0	500 km @ 26" + 3 pump stations	2100
Tankers	4.1 Class 7 ice-breaking tankers 200,000 DWT 1.5 MMBBL	1558	4.1 Class 7 ice-breakers 200,000 DWT 1.5 MMBBL	1558	None	0
Workboats	2 ice-breaking tugs 1 ice-breaking work-boat	120 75	2 ice-breaking tugs 1 ice-breaking work-boat	120 75	1 ice-breaking tug 1 ice-breaking workboat	60 75
Subtotal		1753		1753		2235
Contingency (10%)		668		678		561
TOTAL		7343		7458		6018

TABLE 6-1 (continued)

EQUIPMENT AND CAPITAL INVESTMENTS FOR BARROW ARCH OIL DEVELOPMENT
($ Million 1982)

Scenario	3A Monocone		3B Caisson-Retained		3C Geologic Sensitivity	
Daily Throughput (B/D) Reserves (MMBBL)	300,000 1,000		300,000 1,000		375,000 1,250	
Production Facilities		Cost		Cost		Cost
Platform	3 monocone @ 37 m water	1440	3 caisson-retained @ 37 m water	1020	3 caisson-retained @ 37 m water	1020
Wells	192 wells	1152	192 wells @ 3000 m	1152	192 wells @ 3000 m	1152
Deck Equipment	3 @ 100,000 B/D capacity	900	3 @ 100,000 B/D capacity	900	3 @ 125,000 B/D capacity	900
Pipelines: Marine	Trunk: 43 km @ 22"	138	Trunk: 43 km @ 22"	138	Trunk: 43 km @ 26"	158
	Feeders: 19 km @ 12"	74	Feeders: 19 km @ 12"	74	Feeder: 19 km @ 12"	74
Onshore	27 km @ 26"	93	27 km @ 26"	93	27 km @ 28"	121
Subtotal		3797		3377		3425
Terminals						
Pipeline/Marine/ Storage	Point Belcher	950	Point Belcher	950	Point Belcher	950
Transshipment	Aleutians	1300	Aleutians	1300	Aleutians	1300
Subtotal		2250		2250		2250
Transport						
Tankers	4.1 tankers(1.5 MMBBL)	1558	4.1 tankers (1.5 MMBBL)	1558	5.1 tankers (1.5 MMBBL)	1948
Workboats	2 ice-breaking tugs	120	2 ice-breaking tugs	120	2 ice-breaking tugs	120
	2 ice-breaking work-boats	150	2 ice-breaking workboats	150	2 ice-breaking workboats	150
Subtotal		1828		1828		2218
Contingency (10%)		788		746		750
TOTAL		8663		8201		8682

TABLE 6-1 (continued)

EQUIPMENT AND CAPITAL INVESTMENTS FOR BARROW ARCH OIL DEVELOPMENT
($ Million 1982)

Scenario	4A APLA		4B Far Offshore Monocones		5	
Daily Throughput (B/D) Reserves (MMBBL)	300,000 1,000		300,000 1,000		100,000 333	
Production Facilities		Cost		Cost		Cost
Platform	APLA + 2 monocones @ 37 m water	3680	3 monocones @ 37 m water	1448	1 caisson-retained @ 27 m water	216
Wells	192 wells	1152	192 wells	1152	64 wells	384
Deck Equipment	3 @ 100,000 B/D capacity	900	3 @ 100,000 B/D capacity	900	@ 100,000 B/D capacity	330
Pipelines: Marine	Trunk = None	0	Trunk = 84 km @ 24"	350	Trunk = 51 km @ 16"	168
	Feeders: 19 km @ 22"	74	Feeders = 19 km @ 22"	74	Feeders = 0	0
Onshore	None	0	27 km @ 26"	93	Cape Sabine to Cape Thompson 96 km @ 16"	350
Subtotal		5806		4017		1448
Terminals						
Pipeline/Marine/Storage	(Marine/Storage in APLA)	0	Point Belcher	950	Cape Sabine (pipeline) Cape Thompson (storage/marine)	500
Transshipment	Aleutians	1300	Aleutians	1300	Aleutians	600
		1300		2250		1100
Ships						
Tankers Workboats	4.1 tankers (1.5 MMBBL)	1558	4.1 tankers (1.5 MMBBL)	1558	1.1 tankers (1.5 MMBBL)	418
	2 ice-breaking tugs	120	2 ice-breaking tugs	120	2 ice-breaking tugs	120
	2 ice-breaking workboats	150	2 ice-breaking workboats	150	1 ice-breaking workboat	75
		1828		1828		613
Contingency (10%)		893		810		316
TOTAL		9827		8905		3477

These parameters were selected, in consultation with the study team's consulting petroleum geologist (Tom Marshall, personal communications, June 1982), to be representative of expected conditions, should commercial reserves be present. The field sizes are optimistic rather than representative, but are possible based on seismically-inferred structures and sedimentary conditions. These parameters imply that a 1-billion-barrel field will be produced in about 20 years. The production rate is also economically optimistic; lower values would be more realistic to avoid reservoir abuse.

Waterflood is presumed to be initiated as soon as necessary following completion of all production wells. Timely inception of waterflood is important to sustain high productivity and to permit recovery of the indicated reserves.

6.2.3 Descriptions of Scenarios

The following paragraphs describe the unique elements of each scenario.

Scenario 1: Shallow water nearshore production systems

Scenario 1 illustrates the most favorable location for an oil field in the Chukchi OCS: a large nearshore shallow water discovery. This scenario assumes a water depth of 15 meters (50 feet) with the field located 7 kilometers (4 miles) offshore (although most water this shallow occurs in State of Alaska waters, within the 3-mile jurisdiction zone). The area offshore in the vicinity of Peard Bay offers these conditions in an area that could conceivably be an extension of the geologically favorable Barrow Arch formation.

Two production systems are modeled: caisson-retained gravel islands (Scenario 1A) and artificial gravel islands (Scenario 1B). For each scenario, three such islands are required to develop a hypothetical billion-barrel field. These islands are located within 10 kilometers (6 miles) of each other and pipe their production to a control island via 12-inch feeder lines. The control island pipes the combined production via a 7-kilometer (4-mile) 22-inch diameter trunk line to a landfall near Peard Bay. From there, an onshore 22-inch pipeline carries the crude to a marine terminal at Point Belcher.

SF/Braun believes that a 15-meter (50-foot) gravel or caisson-retained gravel island at a 15-meter (50-foot) water depth could be constructed in a single 70-day open-water season, using state-of-the-art high capacity dredges, and assuming all logistic support was in place. However, such large dredges are highly specialized and of limited availability so that it is reasonable to assume that only enough capacity would be mobilized for building one island per season. Thus, the scenario assumes that the islands are constructed in consecutive seasons, with deck equipment installation, drilling, and production step-up similarly sequenced over 3 to 4 years.

Construction of the first island takes place in the third year following the decision to develop. Drilling equipment is delivered in the third year. Some production equipment is also installed in that year. In the fourth year (fifth and sixth years for the outlying islands), the remainder of the production equipment is installed and drilling begins.

Drilling is accomplished by two rigs per island, each capable of completing a well to 3,000 meters (10,000 feet) in 46 days. Thus, 16 wells can be completed in a year on each island. The marine trunkline and onshore pipelines are completed during the fourth and fifth years. Production begins in the sixth year from wells completed during the previous two years. From the sixth year, production steps up at the rate of 16 wells per year (nominally 32,000 barrels per day) to a peak of 100,000 barrels per day when all production and gas injection wells are completed. Drilling then continues for an additional year until the water injection wells are completed.

The field reaches its peak production in the eleventh year following decision to develop. Production continues at peak for one more year, at which time 45 percent of the reserves are produced and field production begins to decline exponentially at a rate of about 16 percent per year.

The terminal at Point Belcher has capacity for storing 10 days production (1 million barrels). In addition, the terminal serves as a logistics and support facility for the offshore facilities. An ice-breaking workboat serves the logistical and safety needs of the offshore facilities. One ice-breaking tug is assigned to shore duty to keep the harbor open and assist in docking manuevers, while a second tug accompanies the ice-breaking tankers through difficult ice conditions. Berthing facilities are provided for two 1.5-million-barrel (200,000 dead weight ton [DWT]) tankers shuttling to a terminal in the Aleutians.

The class 7 ice-breaking shuttle tankers require 60 hours to load and unload crude and 187 hours of steaming time round-trip (at 14 knots). Thus, each round trip takes 10.3 days. Allowing a carrying capacity factor of 50 percent for slow downs due to ice, scheduled maintenance, and repairs, tanker are assumed to meet about a 20-day turn-around.

The shuttle tankers offload at an Aleutian Island transshipment terminal. In addition to providing 10 days storage (1 million barrels), this terminal treats tanker ballast, stores tanker fuel and services the shuttle fleet. At this terminal, berthing and loading facilities are provided for conventional VLCC tankers.

Because of the unique requirements for pipelines in the Barrow Arch planning area, costs for each pipe spread have been estimated on a scenario-specific basis by SF/Braun. These costs include costs of mobilization and demobilization of lay barges, pipe and coating, trenching (and where needed, burial), shore approach, and hook-ups. Pipe specifications and costs are given in Appendix B, Table B-5 for each scenario.

Total capital investment for the gravel island system is $7,458 million; $7,343 million for the caisson island system.

An additional scenario, 1C, is identical to Scenario 1A in all respects except oil price, which is assumed to be $34.15 -- $2.65 higher than Scenario 1A's $31.50 per barrel.

Scenario 2: Pipeline to TAPS

Scenario 2 is constructed to permit comparison of the two options for transporting Chukchi Sea crude to its presumed West Coast destination. The first option, shipment by ice-breaking tanker to an Aleutian Island transshipment terminal, is treated in Scenario 1A. Scenario 2 is identical to Scenario 1A with respect to the offshore production equipment and marine and onshore pipeline. The difference begins with the pipeline terminal. The terminal in Scenario 2 serves only as a pipeline terminal with some storage. Rather than providing tanker berths and loading facilities, the terminal pumps the crude into a pipeline to TAPS. This terminal is about $250 million less costly than that required under Scenario 1A.

The connecting pipeline to TAPS follows along the northern boundary of the Brooks Range, in a generally easterly direction for approximately 500 kilometers (300 miles), intersecting TAPS at Pump Station 2. The connecting pipeline is 26 inches in diameter and requires three intermediate pump stations, spaced roughly equally over its length.

The pipeline obviates the need for the ice-breaking tanker fleet, its attendant support vessels, and the Aleutian transshipment terminal. The cost for the pipeline and its pump stations is $2.1 billion.

The construction of the connecting pipeline would ideally not delay the production schedule described under Scenario 1A. Pipeline construction could be completed in time for a production start-up in the sixth year following the decision to develop, barring permitting delays, admittedly a heroic assumption for such a major project (see discussion of optimistic biases in Section 6.3).

Total cost for the system is $6,018 million -- $1,325 million less than comparable Scenario 1A. Scenario 2, however, relies on TAPS (at an assumed $6.50 per barrel tariff) to complete its transportation system.

Scenario 3: Deeper Water Offshore Production System

Scenario 3 provides a direct comparison of Scenario 1 with the deeper water, further offshore conditions more typical of the central Chukchi shelf. In Scenario 3, a discovery is assumed in 37 meters (120 feet) of water, at a distance of 43 kilometers (27 miles) offshore.

Reservoir conditions for Scenarios 3A and 3B are identical with those in Scenario 1. The difference between Scenarios 3A and 3B and Scenario 1 is their greater cost for deeper water production systems and longer pipelines. Reservoir conditions for Scenario 3C differ from the above with regard to both initial productivity and reserves due to increased reservior thickness. Scenario 3C is assumed to have an initial well productivity of 2,500 barrels per day; 25 percent higher than all other scenarios. The reserves are also assumed to be 25 percent greater. Thus, with the same number of wells, production throughput will be 25 percent higher.

In Scenario 3, two deeper water offshore production systems are compared. Scenario 3A assumes a concrete monocone production platform; Scenarios 3B and 3C assume caisson-retained gravel islands. (Scenario 3C is the same as Scenario 3B except for its greater productivity and the attendant larger sizing.) The two systems differ with regard to installed cost (the monocone platforms being 42 percent more expensive) and with regard to production scheduling.

The caisson-retained gravel island requires a minimum of two open-water seasons (2 years) to construct. Thus, the production schedule for Scenario 3B is 1 year behind that described for Scenario 1, with a production start-up 7 years from the decision to develop. By contrast, the production schedule for the monocone system is the same as that of the Scenario 1 shallower water gravel island with production start-up in year 6.

Apart from higher offshore production structure costs due to deeper water (and the production schedule delay in Scenario 3B), Scenarios 3A and 3B make the same transportation assumptions as does Scenario 1. Scenario 3C differs from these scenarios in that slightly larger pipelines are required and the terminal and tanker fleet are sized for the higher throughput.

Total capital investments required for Scenarios 3A, 3B, and 3C are $8,663, $8,201, and $8,682 million, respectively.

Scenario 4: APLA Concept

Scenario 4 is designed to compare two production concepts from discoveries that are remote from shore: offshore loading from an APLA versus the more conventional concept of production through a pipeline to a shore terminal. In both cases, the fields are assumed to be located 86 kilometers (52 miles) northwest of Wainwright (twice the distance assumed in Scenario 3) but in the same water depth of 37 meters (120 feet).

Under Scenario 4A, an APLA is constructed in the third and fourth years following a decision to develop. (It could take twice this time -- this optimistic schedule is discussed in Section 6.3.). Monocones are placed within 10 kilometers (6 miles) of the APLA. These platforms produce through 12-inch diameter lines to the APLA. The ice-breaking shuttle tanker would be loaded directly from the APLA's storage facilities, obviating the need for a marine trunkline, an onshore pipeline, and shore terminal at Point Belcher. The production schedule would follow that described for Scenario 3B with production beginning in year 7 and peaking in year 12.

Under Scenario 4B, oil is produced from three monocone platforms. A central platform produces to a 24-inch pipeline to shore. Feeder lines from two peripheral platforms feed into the central platform.

The schedule for construction of facilities and production is identical with that described for Scenario 3A. Production begins in year 6 and peaks in year 11. Note that this is one year sooner than is the case for the APLA scenario due to APLA's longer construction time.

Capital investments totaling $9,827 million are required under Scenario 4A compared with $8,905 million for its all monocone counterpart (4B). Thus, despite the lack of the pipelines and onshore terminal, the APLA scenario is 10 percent more capital intensive.

Scenario 5: Southern Chukchi --- Smaller Reserves and Another Route

Scenario 5 models conditions that might be representative of a discovery in the southern Chukchi Sea in the Herald Arch formation. According to the study team's consulting geologist (Tom Marshall, personal communication, June 1982), Herald Arch structures are unlikely to contain any fields greater than 300 million barrels. For analytical simplicity, a field size of 333 million barrels is assumed, which corresponds to the amount of reserves produced from a single platform or island in the other scenarios.

A discovery is assumed in Ledyard Bay, 51 kilometers (32 miles) offshore of Cape Sabine, in 27-meter (90-foot) water depth. Production takes place from a caisson-retained gravel island, which is constructed in the third and fourth years following the decision to develop. Production begins in the seventh year and peaks in the tenth year at 100,000 barrels per day. Capital investments total $3,477 million in Scenario 5.

The oil is moved through a 16-inch diameter marine pipeline to near Cape Sabine, where it enters a 96-kilometer (60-mile), 16-inch diameter overland pipeline across the Lisburne Peninsula to Cape Thompson. One pump station will be required on the Lisburne Peninsula. At Cape Thompson, a storage and loading terminal (similar in design but smaller than at Point Belcher) loads the crude into ice-breaking tankers for transport to an Aleutian transshipment terminal.

The capital requirements under Scenario 5 immediately suggest distinct diseconomies when compared with the other scenarios. Although the assumed reserves are only one-third of the other scenarios, capital requirements are $3,477 million or almost one-half of the requirement under Scenario 1A.

This is due to the need to support two terminals as well as a long onshore pipeline with a smaller field.

6.3 Results of the Economic Analysis

The Dames & Moore Equivalent Amortized Cost (EAC) computer model (on the Scientific Software GUESS System) was used to simulate the economic rates of return for each of the oil development scenarios described in Section 6.2. The results of these simulations are summarized in Table 6-2. These results provide the following for comparison:

- The economics of alternative offshore production systems.
- The economics of alternative transportation systems.
- The economics of alternative field sizes.
- The price sensitivity of the analysis.

These comparisons are discussed in Sections 6.3.1, 6.3.2, 6.3.3 and 6.3.4, respectively. In addition, the EAC model permits the amortized cost of capital to be apportioned among various facilities required. Those results are analyzed in Section 6.4.

In interpreting the results, the reader should bear in mind three underlying assumptions that lend an optimistic bias to the analysis: one geologic, one stochastic and one institutional in nature.

From a geologic standpoint, all scenarios except Scenario 5 assume that reserves of a billion barrels or more occur in a single field (or at least within a 20-kilometer [12-mile] radius). This is fairly optimistic, given that there is only an estimated 1.7 billion barrels in the central Chukchi shelf (T. Marshall, personal communication, 1982). That most of the resources should exist in a single field is not unlikely, but it is by no means assured. If the resources are distributed in several widely separated fields, development would be considerably more costly.

TABLE 6-2

RESULTS OF ECONOMIC ANALYSIS OF BARROW ARCH AREA PETROLEUM DEVELOPMENT

Scenario	Recoverable Reserves (MMBBL)	Number of Platforms (Units)	Net Present Value at 12 Percent (MM$)	After-Tax DCF Rate of Return (Percent)	Equivalent Amortized Total Cost ($/BBL)	Equivalent Amortized Capital Investment Cost ($/BBL)	Equivalent Amortized Operating Cost[2] ($/BBL)	Total Capital Investment (MM$)
1. Shallow Water (15 m, nearshore)								
1A Caisson-Retained	1000	3	(336)[1]	10.0	32.69	18.69	6.53	7343
1B Gravel Island	1000	3	(394)	9.8	32.90	19.01	6.53	7458
1C Caisson-Retained (Higher Price)	1000	3	(3)	11.3	34.24	18.69	6.53	7343
2. Pipeline to TAPS								
	1000	3	(328)	9.7	26.89	15.63	5.20	6013
3. Deep Water (36 m, 43 km offshore)								
3A Monocone	1000	3	(1029)	7.7	35.14	22.29	6.77	8663
3B Caisson	1000	3	(785)	8.2	34.61	21.29	6.93	8201
3C Caisson (Higher Productivity)	1250	3	(377)	10.2	32.56	19.21	5.58	8682
4. APLA Concept (86 km, deep water [36 m])								
4A APLA	1000	3	(1681)	5.9	38.18	26.87	6.61	9827
4B Monocone	1000	3	(1147)	7.4	35.56	22.93	6.77	8905
5. Southern Field (Ledyard Bay)	333	1	(932)	2.1	41.90	29.14	11.21	3477

Source: Dames & Moore

Notes:
(1) Parentheses indicate negative values.
(2) Includes general and administrative costs.

From a stochastic standpoint, several variable factors are assumed at their mean value. The most critical of these factors is weather. A 70-day open-water season is assumed based on the limited historic record. Of these 70 days, 63 days are assumed to be working days; the remaining 7 days are assumed to be non-working due to weather. In reality, a shorter or longer season is quite possible. A longer season is, of course, no problem, but with fewer working days during a critical year (such as the year of monocone installation or gravel island construction), the entire project could be set back a year. This would have serious consequences on economic viability. In a similar vein, any random occurrence, such as failure of a critical piece of construction equipment (e.g., as a dredge), could also have serious consequences. Although such occurrences are not unlikely in a hostile frontier area, no allowance has been made for them in the results reported on Table 6-2.

A third optimistic bias is that legal or regulatory matters will not materially delay development, once the decision to develop has been reached. While careful planning and close agency coordination make this condition possible, political and institutional factors make delays a distinct possibility. Judicial challenges such as those that held up TAPS are an example (some of the scenarios require long onshore pipelines). None of these unpredictable delays have been assumed for this analysis.

6.3.1 Economic Comparison of Alternative Offshore Production Systems

The results of the economic modeling indicate that no single offshore production system is clearly more cost effective under all conditions; rather, the comparative advantage of alternative systems depends primarily upon water depth and to a lesser extent upon distance from shore.

Comparing caisson-retained gravel islands with conventional gravel islands (see Scenarios 1A and 1B on Table 6-2), the caisson-retained gravel island appears to have a slight cost advantage at the 15-meter (50-foot) water depth. Under identical conditions and production schedules, the caisson-retained concept for the required three islands costs $115 million less. This results in an Equivalent Amortized Cost (EAC) of $0.21 per barrel lower and a rate of return 0.2 percent higher for production from the caisson system. This difference, however, is within the range of estimation error. Considering the greater weather vulnerability of the conventional gravel island, which has higher dredging and filling requirements, perhaps the caisson-retained concept will ultimately prove even more cost effective. Sitespecific precision would be required to determine which system is superior.

At greater water depths, such as 37 meters (120 feet; see Scenarios 3A and 3B on Table 6-2), the choice is between caisson-retained gravel islands and concrete monocone platforms. The conventional gravel island concept is not as competitive at these depths because of the massive fill volumes required.

At this greater depth, the caisson system has the apparent cost advantage over concrete monocones. Despite the additional year to bring such a system into production, the caisson-retained island showed a 0.5 percent higher rate of return and about a dollar per barrel cost advantage over the monocone. Again, however, the difference between the two systems is small and could be offset by risk considerations. The monocone would be built in an ice-free, protected harbor and towed to the site for enplacement, while the caisson-retained island would be pre-fabricated off-site, towed and assembled on-site and thus be more subject to environmental conditions. At the 37-meter (120-foot) depth, the caisson island would take two seasons to construct. Some wave damage can be expected between the first and second years. If this damage were extensive enough, or if the weather or ice conditions were unusually poor in either year, the project could be set back an additional year, which would wipe out the advantage of the caisson system. Of course, a construction project of the magnitude of the monocone fabrication and tow-out is also subject to a variety of delays.

Comparing the caisson-retained concepts at different water depths (Scenarios 1A and 3B), we note that the real after-tax rate of return (ROR) declines from 10.0 to 8.2 percent due primarily to the greater cost of deeper islands. Since greater water depths occur further offshore, part of this difference is due to the greater cost of marine pipelines to shore. The pipeline, however, accounts for only 13 percent of the $854 million difference in capital investment between the two caisson scenarios. The major difference (shown on Table 6-1) is the $630 million additional cost for platforms.

For deeper water discoveries further offshore (i.e., 84 kilometers [52 miles] offshore versus the 42 kilometers [26 miles] assumed in Scenario 3), the two offshore production systems compared were monocones with pipeline to a shore terminal (Scenario 4B) and APLA's (Scenario 4A). Here, choice seems to strongly favor the monocone system, at a real after-tax ROR of 7.4 percent versus the 5.9 percent ROR for the APLA. APLA's are much more capital intensive at an estimated cost of $3.0 billion compared with $1.8 billion for monocones plus the required pipeline and shore terminal. The cost difference is further increased by the additional year that it would take to bring the APLA system into production. Even with our very optimistic APLA construction schedule (only one more year -- it could be 3 or 4 years), this concept does not look economically attractive.

The economic disadvantage of the APLA system is further exaggerated by its dependence on favorable conditions during construction and its fill source requirements. The APLA cost estimate presumes that adequate fill is available from near-site bottom sediments. If haul distances were great, both the construction cost and production schedule would suffer.

6.3.2 Economic Comparison of Alternative Transportation Systems

Transporting Barrow Arch area oil production to market via ice-breaking tankers is a costly endeavor. According to our analysis, a connecting pipeline to TAPS appears to be competitive with tanker transportation despite the high cost of the connecting pipeline and the estimated $6.50 per barrel tariff for TAPS.

Although any of the offshore production systems, except offshore loading from an APLA, is compatible with delivery to TAPS for comparison purposes, we have modeled Scenario 2 using the nearshore caisson-retained gravel island system of Scenario 1A. The TAPS scenario produces a real after-tax ROR of 9.7 percent versus a 10.0 percent ROR in Scenario 1A. This difference is small compared at the level of precision of our cost estimates.

Direct comparison of the EAC cost per barrel between Scenarios 1A and 2 is misleading due to the differences in the value of the crude at the boundary of analysis. Whereas crude tankered to the Aleutians has a value of $31.50 per barrel, the value at Pump Station 2 of TAPS is $26.00 per barrel. Hence the similarity between the rates of return under the two scenarios. Each of these boundary prices nets back from $34.00 per barrel oil laid-in to the West Coast. Alternative offshore production systems were not modeled, but since offshore cost differences will affect TAPS and tanker scenarios equally, the close economic comparability would be unaffected.

6.3.3 Economic Comparison of Alternative Field Sizes

Although three different field sizes (333, 1000, and 1250 million barrels) were analyzed, only two of three scenarios are directly comparable. Under Scenario 3B, three caisson-retained gravel platforms produce 1 billion barrels, while the larger reserves and higher initial productivity allow Scenario 3C to produce 25 percent more oil in the same time period at only a 6 percent greater capital investment. The higher investment is due entirely to higher capacity pipeline, terminal, and tanker requirements. It is significant that while the real after-tax ROR improves from 7.7 to 10.2 percent with the greater reserves, even this giant field does not reach the presumed 12 percent hurdle rate necessary to induce development of a risky frontier prospect. Extrapolating this result, the estimated minimum field size to reach the hurdle ROR would be roughly 1.4 to 1.5 billion barrels, producing at a proportionately higher peak than the assumed 2500 barrels per day per well assumed for the 1.25 billion barrel field.

Given a minimum economic field size in the 1.5 billion barrel range, it is not surprising that the 333 million barrel field modeled in Scenario 5 is grossly uneconomic with an after-tax ROR of 2.1 percent. The scenario suffers from the need to transport the crude across the Lisburne Peninsula to a suitable terminal or tanker loading site. But even if a suitable facility could be constructed at the landfall at Cape Sabine, it is highly unlikely that this area can be developed unless much larger fields are discovered or oil prices rise markedly.

6.3.4 Price Sensitivity of the Analysis

The shallow water nearshore caisson-retained system in Scenario 1A was modeled with both \$31.50 and \$34.15 oil prices assumed. The higher price assumes 1.5 percent real growth in oil prices by 1992 on the West Coast compared to \$29.50 during July, 1982. This is shown as Scenario 1C on Table 6-2.

This increase in oil price results in an 11.3 percent ROR--still marginally uneconomic. This scenario does indicate, however, that real oil prices must be in the \$35.00 range (F.O.B. the Aleutians) to justify development, given the assumptions of the analysis.

6.4 Equivalent Amortized Costs of Oil Development

The GUESS system, as modified by Dames & Moore's Equivalent Amortized Cost (EAC) model, is capable of disaggregating the distinct components of capital investment in facilities on a per barrel, discounted, after-tax basis. Although this information is available for each run, display of the EAC disaggregated cost is confined to selected cases shown on Table 6-3.

Development costs shown on Table 6-3 range from \$27.29 to \$41.90 per barrel. These development costs are the total of capital charge, general and administrative expenses, operating cost, royalties and federal taxes. Capital charge (interest at 12 percent real plus capital recovery) is by far the largest development cost component. Capital charge is lowest for Scenario 2 since the use of TAPS substitutes for the capital expenditures for the shuttle tanker fleet plus the transshipment terminal. The TAPS tariff brings the laid-in West Coast cost under this scenario into the

TABLE 6-3

EQUIVALENT AMORTIZED COSTS OF SELECTED BARROW ARCH AREA OIL DEVELOPMENT SCENARIOS

	Scenarios ($ Per Barrel - 1982)						
	1A	2	3A	3B	3C	4A	5
	15m Caisson	Pipeline To TAPS	37m Monocone	37m Caisson	37m Monocone (High IP)	APLA	Ledyard Bay
Field Size (MMBBL)	1000	1000	1000	1000	1250	1000	330
Present Barrel Equivalent (1982 MMBBL)	282	282	282	253	355	253	90
Capital Charge*	18.69	15.63	22.29	21.28	19.21	26.87	29.14
(Cost of Capital @ 12% Real)	(12.95)	(10.42)	(14.16)	(13.55)	(12.65)	(17.36)	(16.92)
Operating Cost	5.40	4.30	5.56	5.56	4.60	5.31	8.92
General/Administrative Expenses	1.13	0.87	1.21	1.37	0.98	1.30	2.29
Royalty @ 16.67%	5.25	4.33	5.25	5.25	5.25	5.25	5.25
Federal Taxes (Net of Tax Credits)	2.22	1.76	0.84	1.15	2.53	- 0.55(1)	- 3.70(1)
SUBTOTAL - Development Costs	32.69	27.29	35.14	34.61	32.56	38.18	41.90
Transport to West Coast	2.65	1.65	2.65	2.65	2.65	2.65	2.65
TAPS Tariff	.00	6.50	.00	.00	.00	.00	.00
TOTAL - Laid-In Cost	35.34	35.44	37.79	37.26	35.21	41.53	44.54
*Allocation of Capital Charge							
Offshore Production	6.83	6.83	9.92	8.76	7.92	17.46	8.57
Pipelines (Marine)	0.33	0.33	0.60	0.61	0.57	0.23	1.55
Pipelines (Onshore)	0.32	6.05	0.26	0.27	0.21	0.00	3.23
Terminals	6.30	2.03	6.31	6.42	5.65	3.96	10.14
Ships	4.91	0.39	5.20	5.22	4.86	5.22	5.65
TOTAL	18.69	15.63	22.29	21.28	19.21	26.87	29.14

Source: Dames & Moore

Notes: (1) The negative federal tax indicates the discounted EAC value of the tax shelter provided by this unprofitable development.

same mid-$30 per barrel range typical of all other scenarios with the exception of Scenarios 4A and 5.

The latter two scenarios result in laid-in costs in the $40-plus per barrel range. These high cost scenarios reflect their very high EAC capital charges. In Scenario 4A, the high capital charge reflects the huge investment cost for the APLA system. The $17.32 per barrel share of capital charges for the offshore production system is $8 to $10 per barrel higher than the other scenarios shown on Table 6-3. For Scenario 5, the high cost is due primarily to the high cost of terminals, since the terminal offers significant diseconomies of scale at the lower throughput assumed for that case.

Operating costs and general and administrative expenses are significantly lower for the TAPS scenario because of the absence of the shuttle tanker fleet and for Scenario 3C because of its higher utilization of offshore facilities and terminals. Scenario 5 has a high operating cost per barrel, again due to diseconomies of lower throughput.

Federal taxes vary as a function of the profitability of the scenario. Scenarios 4A and 5 have negative federal taxes when expensed against other operations because of their low rates of return. The royalty, which is calculated at 16.67 percent of revenue reserves, is uniformly $5.25 per barrel, except for Scenario 2. Under that scenario, the lower value of the crude at the TAPS terminal is reflected in lower royalties.

6.5 Conclusions Regarding the Economic Viability of Developing Barrow Arch Area Oil Resources

Assuming the facilities' cost estimates used in this study are reasonable, Chukchi Sea oil development appears to be uneconomic at current prices. However, should any of several conditions differ from those modeled, development could become economic. These critical conditions include:

- A rise in real oil price
- Discovery of fields with reserves larger than one billion barrels
- Cost reducing improvements to development technologies

A rise in real oil prices would obviously improve the development prospects for Barrow Arch area oil. However, the price rise would have to exceed the difference between the computed equivalent amortized cost (see Table 6-2) and $31.50 due to the buffering effect of taxes and royalties.

For example, Scenario 1A shows an after-tax ROR of 10 percent and an EAC cost of $32.69. However, simply raising the received price $1.19 per barrel from the assumed $31.50 (all other factors held constant) would not result in a ROR of 12 percent (the assumed hurdle rate). Rather, royalties would rise by 16.67 percent and federal taxes would consume about 46 percent of the remaining revenue difference. Thus, the EAC price would rise above $32.69 per barrel and still exceed revenues. Scenario 1C illustrates that raising the oil price to $34.15 also raised the EAC to $34.24. For revenues to equal costs, thus achieving the 12 percent hurdle rate, the oil price must rise about $4.00.

The minimum field size necessary for economic development in the Chukchi Sea depends significantly on water depth, and (to a lesser extent) on distance to the shore terminal. As noted in Section 6.3.3, at a 37-meter (120-foot) water depth, the minimum field size is about 1.4 to 1.5 billion barrels. At shallower water depths nearer to shore (e.g., Scenario 1), the minimum field size would be only slightly larger than the billion barrel field assumed. Current knowledge of the resources in the southern area of the Chukchi Sea suggests that area will not be economic to develop under current prices and technologies, unless resource estimates are too low.

The caisson-retained gravel islands and monocone structures appear to be the most advantageous offshore production systems for the Chukchi Sea. Unretained gravel islands are more suitable for the shallower water depths (less than 15 meters [50 feet]). There are few areas within the federal lease sale with water this shallow.

The APLA system in our scenario is decidedly uneconomic.(1) A technology more cost-effective than the APLA system will have to be utilized. Concepts with features similar to the APLA are in principle still favorable for the Barrow Arch planning area. Much of this area is at about the same 37-meter (120-foot) water depth, so this type of concept does not become unrealistic far offshore due to steeply increasing depths (although ice impacts increase greatly). Since the coastline is not favorable for onshore marine terminal sites, some manner of offshore production-with-loading concept would still be attractive, especially in view of the very high cost for marine pipelines and landfalls under arctic conditions. The APLA concept might prove economically viable in shallower sites. It will be interesting to follow any application of the APLA concept in the Canadian Beaufort Sea.

6.6 Development of Barrow Arch Area Gas Resources

6.6.1 Gas Development Considerations

Should gas be found in the Barrow Arch Planning Area, there are two primary factors to be considered to assess its commercial development. First, how can the gas best be made available to the marketplace? The transportation options include pipeline, liquefied natural gas (LNG), or conversion to methanol or fertilizer. Second, is the gas associated with oil, or is it in large gas fields ("non-associated")?

Addressing the first issue, the pipeline, methanol and fertilizer options do not seem feasible. Even if the Chukchi Sea reserves were much

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(1) The reader must keep in mind the interaction of assumptions regarding geology, engineering, prices and costs that drive a complex analysis. Any conclusion regarding what is "economic" is only valid for the assumptions used in the analysis.

greater than estimated, they would not support a gas pipeline project to the Lower 48, and the question of where that market would be is also problematical. Even the substantially greater proven gas reserves of Prudhoe Bay have not yet been able to support a gas pipeline. The methanol and/or fertilizer conversion/transport options were also examined this year for Prudhoe Bay gas and were found to be unattractive (ICF Inc. 1982).

Given that arctic transport to market would be more feasible by conversion to LNG, we performed our analysis for a large, centralized non-associated gas field, as discussed in the following two Sections 6.6.2 and 6.6.3. This case allows for maximum economies of scale with respect to both the production and LNG transportation systems. Based on these results, we have made correlative conclusions regarding the economies of production of gas associated with oil, given in Section 6.6.4.

6.6.2 Description of Non-Associated Gas Development Scenarios

Based on Dames & Moore's technology assessments of Bering Sea gas reserves and the doubtful commerciality of the vast Prudhoe Bay gas reserves, we did not anticipate that Chukchi Sea gas resources would be economic. In order to test this hypothesis, the Chukchi Sea non-associated gas development scenario assumptions were selected to reflect the most favorable conditions that could reasonably obtain in the area. These conditions include:

o Recoverable reserves -- total of fields	4.5 TCF
o Recoverable reserves per offshore production unit	1.5 TCF
o Number of production units per field	3
o Offshore production technology	Caisson-retained gravel island
o Water depth	37 meters
o Reservoir (target) depth	3,000 meters (10,000 feet)

o Recoverable reserves per acre	200 MMCF
o Initial productivity per well	15 MMCF/D
o Amount of recovery before decline	65 percent
o Production efficiency	96 percent
o Laid-in price (regassified)	$6.75 C.I.F. (Point Conception)

Timing of facilities installation, capital expenditures and production timing assumptions are identical to those used in oil development Scenario 3A. However, consistent with our discussions of petroleum geology (Appendix A), these gas fields are most likely to be located in the southern portion of the lease sale area in Ledyard Bay.

Two monocone platforms produce to a third monocone offshore of Wainwright. Altogether, these fields have the entire mean non-associated gas resources estimated to be present in the central Chukchi shelf -- 4.5 trillion cubic feet.

The production is piped to a landfall near Cape Sabine in a 36-inch diameter line, then through an overland pipeline for 100 kilometers (60 miles) across the Lisburne Peninsula to a Cape Thompson LNG terminal. Here, the gas is liquefied and loaded onto ice-breaking LNG tankers for shipment directly to a hypothetical Point Conception, California regassification plant.

The tanker fleet consists of vessels rated Ice Class 8, each with a capacity of 140,000 cubic meters (3 billion cubic feet). The distance from Cape Thompson to southern California is about 6,000 kilometers (3,300 nautical miles). At a speed of 16 knots, and allowing 60 hours loading and unloading, the round trip will take about 20 days.

Assuming a 75 percent tanker capacity factor for maintenance, repairs and slow-downs due to weather, 27.3 days are actually allowed in the analysis. This capacity factor is one-and-one-half that assumed for the oil tankers; since so much of the distance is in ice-free waters, ice slowdowns are not as significant.

Two gas development scenarios were modeled, each with a different recovery rate. Scenario 6A assumes that 51 wells on three islands produce 740 million cubic feet per day at peak. This amounts to 6 percent of reserves produced during a peak year for a 22-year recovery period. Scenario 6B assumes 990 million cubic feet per day peak production resulting in 8 percent of reserves being produced during a peak year. This results in a 15-year production period, which is very short by industry standards, but as our results indicate, produces a markedly improved profitability.

Under the rapid production scenario (6B), the peak daily production is 990 million cubic feet per day. Thus, nine tankers are needed. The standard production scenario (6A) requires only 6.7 tankers for its 740 million cubic feet per day production. Each tanker is estimated to cost $310 million. In addition to the tankers, two tugs and two ice-breaking work boats are required in each scenario. One of the tugs assists in port maintenance and docking while the second serves as ice-breaking support for the tankers. The workboats service the platforms and the port, and also assist tankers when needed.

The total capital investment for Scenario 6A is $7,634 million, while Scenario 6B requires $8,496 million. Annual costs (operating plus general and administrative expenses) total $373 million and $451 million for Scenarios 6A and 6B, respectively.

6.6.3 Economic Results of Barrow Arch Area Gas Field Development Scenarios

The results for the two gas development scenarios are shown on Table 6-4. Neither scenario approaches the 12 percent (real) hurdle ROR believed to be necessary to induce development in a frontier area. Indeed, it may be argued that 12 percent is too low a hurdle rate for gas in an area like the Chukchi Sea, which has a risk factor associated with the severe weather and

TABLE 6-4

RESULTS OF ECONOMIC ANALYSIS FOR BARROW ARCH AREA GAS FIELD DEVELOPMENT

Scenario	Recoverable Reserves[1] (TCF)	Number of Platforms (Units)	Net Present Value at 12 Percent (MM$)	After tax DCF Rate of Return[2] (Percent)	Equivalent Amortized Total Cost ($/MCF)	Equivalent Amortization Capital Investment Cost ($/MCF)	Equivalent Amortized Operating Cost ($/MCF)	Total Capital Investment (MM$)
6A	4.5	3	(1741)[3]	5.2	8.49	5.34	1.86	7634
6B	4.5	3	(1192)	7.5	7.72	4.79	1.35	8496

Source: Dames & Moore

Notes:

(1) Recoverable reserves are assumed to be 1.5 TCF per platform and 4.5 TCF for the field. This is optimistic both with regard to total resources and reserves producible by each platform. Thus, results represent upper limit estimates.

(2) Gas price assumed to be $6.75/MCF regassified in California.

(3) Parentheses indicate negative values.

ice environment in addition to the economic risks related to marketability in any LNG project. However, this debate is moot since the scenarios produce far lower ROR's of 5.2 and 7.5 percent, respectively.

The faster recovery rate in Scenario 6B increases the ROR 2.3 percent above that of Scenario 6A. The EAC cost correspondingly falls from $8.49 to $7.72 per thousand cubic feet. However, the even lower cost is about one dollar per thousand cubic feet higher than the landed value. As with oil, it is important to note that as landed value rises so does EAC cost, due to the increased royalty and federal tax costs. Thus, for even the optimistic Scenario 6B to be economic, gas value would have to rise about $3.50 per thousand cubic feet or almost 50 percent above the current BTU equivalency value of diesel oil.

Note that the faster recovery in Scenario 6B results in a 15-year field life versus 22 years for the standard recovery rate scenario. This is faster recovery than normal practice. Potential problems, such as well interference and reduction of ultimate recovery, at this high recovery rate were not assumed.

According to the breakdown of EAC components in Table 6-5, the major reason for gas being uneconomic is the high cost for LNG shipping facilities.

Another optimistic bias is built into the analysis because part of the product is lost in liquefaction, tanker transport and regassification. This loss was not included in this analysis. According to estimates compiled for Petro Canada's Arctic Pilot Project, these losses include:

Boiloff in liquefaction	6.8%
Consumed in transit	6.9%
Boiloff during regassification	2.0 to 2.5%
Total Loss	15.7 to 16.2%

The fact that acceptable rates of return are not obtained for gas development, despite the consistent optimistic biases built into this analysis, leads inevitably to the conclusion that Chukchi Sea gas resources are far from commercial under present technologic and economic conditions. To become economic would require a signficant increase in the value of gas, to about $10.50 per thousand cubic feet.

6.6.4 Economics of Associated Gas from Barrow Arch Area

Associated gas production was not specifically modeled because of the markedly uneconomic results obtained for non-associated gas cases. However, by using the EAC results for oil and gas from Tables 6-3 and 6-5, respectively, it can be demonstrated that production of gas in association with oil is less economically attractive than producing the oil and reinjecting the gas.

If gas were produced associated with oil rather than on a stand-alone basis, the major cost savings are related to shared production facilities -- platforms and deck equipment. Some terminal costs would be saved; but not much. Most of the gas terminal facility investment would be related to LNG processing and transport. General and administrative (G&A) costs would mostly be saved, but operating costs would not be significantly reduced.

We assumed all the production and G&A and 25 percent of the terminal costs for gas are borne by oil production. Based on this assumption the EAC for Scenario 6A of Table 6-5 would drop from $9.19 to $7.00.

Scenario 6A EAC	$9.19
Less:	
Offshore production	1.30
Terminal (25%)	.47
G&A	.42
Non-associated gas EAC	$7.00

Incremental gas associated with oil production only saves about 25 percent of the total cost of gas production and delivery to market. The

TABLE 6-5

EQUIVALENT AMORTIZED COSTS OF
BARROW ARCH AREA GAS FIELD DEVELOPMENT SCENARIOS
($1982/MCF)

	SCENARIO 6A	SCENARIO 6B
Field Size (TCF)	4.5	4.5
Present Equivalent (1982 TCF)	0.99	1.23
Capital Charge*	5.34	4.79
(Cost of Capital @ 12%)	(3.78)	(3.01)
Operating Cost	1.87	1.35
General & Administrative	0.42	0.33
Royalty @ 16.67%	1.13	1.13
Federal Taxes	-0.27 (1)	0.13
(Net of Tax Credits)		
SUBTOTAL - Development Costs	8.49	7.72
Regassification	0.70	0.70
TOTAL - Laid-In Costs	9.19	8.42
*Allocation of Capital Charge		
Offshore Production	1.30	1.10
Pipeline (Marine)	0.23	0.18
Pipeline (Onshore)	0.10	0.08
Terminals	1.89	1.53
Ships	1.82	1.90
TOTAL	5.34	4.79

Source: Dames & Moore

Notes:

(1) The negative value represents the discounted EAC value of the tax shelter of this unprofitable investment. Taxes are assumed to be written off or credited against other investments.

processing and transporting of gas as LNG is three-quarters of the cost. Thus, producing associated gas incurs these costs, and they are substantial.

On an energy equivalent basis, $7.00 per thousand cubic feet of gas is equal to oil at $39.76 per barrel. Thus, producing associated gas and incurring LNG facility and transport costs raises the average cost (on a barrel-equivalent basis) of combined oil and gas development compared to oil development alone. The EAC for oil cases 1A to 3C on Table 6-3 range from $35.21 to $37.79 delivered to the West Cost. These oil development cases had rates of return in the 8 to 10 percent (real) range. Since the estimated EAC of associated gas on a barrel-equivalent basis is higher than that for oil on a stand-alone basis, it follows that producing associated gas would tend to lower the return on a combined gas-oil project -- given the various assumptions built into our analysis.

On this basis we conclude that associated gas production does not improve the economics of oil production.

6.7 Relationship of Barrow Arch Area Oil Production to the U.S. Energy Balance

Potential oil and gas supplies from the Chukchi Sea could be developed and supplied to the United States no sooner than 1996, given the February 1985 lease sale date specified in the latest U.S. OCS lease schedule. Production estimates are based on oil reserves of 1.7 billion barrels of oil. Oil could flow from the Barrow Arch planning area at nearly 500,000 barrels per day at the turn of the century. Development in the Chukchi Sea will entail large onshore developments in the Aleutians and near Wainwright or both. Alternatively, the oil production could be piped to TAPS, helping to keep the TAPS operating at capacity as the Prudhoe Bay Field enters decline. This action would preclude the Aleutian terminal.

6.7.1 Consensus Energy Forecasts

Forecasts of total United States energy use and petroleum's share continue to drop in response to the OPEC price increases of 1979-1980.

Observers of U.S. energy trends now believe U.S. petroleum consumption, peaked in 1978 at 18.9 million barrels per day, will range between 15 and 17 million barrels per day throughout the remainder of the century. There is uniform agreement that the U.S. will place greater reliance on coal in meeting its increased requirements for energy. Coal is expected to supply two-thirds of <u>increased</u> U.S. energy requirements.

Table 6-6 shows six prominent recent U.S. energy and oil use forecasts through 2000. A remarkable degree of consensus exists among four of these forecasts. Dames & Moore believes lower energy growth is more likely than Chevron's and Chase's forecasts.

The table illustrates four essential aspects of the U.S. energy situation.

1. The long-term rate of growth of total energy use is estimated to be 1.0 percent 1980 to 1990 and 1.1. percent 1980 to 2000. Excluding Chevron's and Chase's forecasts from the group (for reasons to be explained below), there is a very narrow range to the U.S. energy forecast. The six forecasts shown yield an average 2.7 percent real growth rate in the U.S. economy.

2. U.S. oil consumption, which dipped to 15.9 million barrels per day during 1981, is estimated to range between 15 and 17 million barrels per day throughout the century. The price increases of 1979 and 1980 together with the Fuels Use Act have reined in the U.S. propensity to consume oil. Oil's share of total energy will drop from 44 percent in 1980 to about 38 percent by 1990 and 34 percent by 2000.

3. The U.S. will remain dependent on OPEC imports throughout the century. Imports in 1990 are expected to range between 5 and 7.5 million barrels per day excluding Shell's and Exxon's import forecasts. Their forecasts do not appear to reflect the impact of the U.S. drilling boom of 1980 and 1981 on expected U.S. production throughout the 1980's.

TABLE 6-6

U.S. ENERGY FORECASTS
(Million Barrels Oil Equivalent)

Forecast	Date	GNP Growth %	Total Energy 1980	Total Energy 1990	Total Energy 2000	Oil 1980	Oil 1990	Oil 2000	Oil Imports 1980	Oil Imports 1990	Oil Imports 2000	% Coal 1980	% Coal 2000
Conoco	January , 1982	3.0	38.2	42.2	49.0	17	15.5	16.3	6.2	4.9	5.8	20	32
Chase	September, 1981	2.8	38.2	44.9	NA	17	16.9	NA	6.2	7.6	NA	20	NA
Texaco	February, 1982	2.5	38.2	43.0	48.3	17	16.6	16.1	6.2	7.4	7.2	20	33
Chevron	May, 1981	2.8	38.2	45.0	55.0	17	16.5	16.4	6.2	6.5	6.6	20	35
Shell	August, 1980	2.5	38.2	42.0	NA	17	17.2	NA	6.2	8.2	NA	20	NA
Exxon	October, 1980	2.5	38.2	41.5	45.0	17	16.0	15.0	6.2	9.0	7.5	20	33
Consensus Ex Chevron & Chase		2.6		42.2	47.4								
Consensus Rate of Growth (%)		2.7		1.0	1.1								

Sources: Conoco (1982)
Chase Manhattan Bank (1981)
Chevron (1982)
Texaco (1981a)
Exxon (1980)
Shell (1980)

4. Coal's share of total energy consumed will rise to one-third by the end of the century. By 2000, coal's share will about equal oil's share of total consumption. This will entail more than doubling production from about 850 million tons in 1980 to 2 billion tons by 2000.

Since the U.S. will continue to use between 15 and 17 million barrels per day of oil throughout the century, it is extremely important for the U.S. to develop its own domestic oil supply. Every barrel of domestic crude produced in the U.S. backs out a barrel of foreign crude. U.S. domestic oil production is forecast to range between 10 and 11 million barrels per day through 2000. This represents a radical change. Domestic oil supplies, such as those in the Chukchi Sea, are important to the U.S. in terms of a dependable and secure source of energy.

6.7.2 Oil Price Growth Through 2000

Real oil prices have declined significantly over the past 2 years in sharp contrast to the five-fold price increases from 1973 to 1980. Several factors contributed to the late 1981 - early 1982 price weakness. These factors include increased energy conservation in response to earlier oil price shocks, recessions in industrialized countries, reduction of inventories due to high interest rates, attempts by some OPEC members to increase market shares, and excess world production capacity of 7 to 8 million barrels per day.

We believe oil prices will remain flat through 1985 primarily due to OPEC pricing policies, the lingering worldwide recession, conservation, and substitution effects. Although the oil market is currently soft and may remain so for several years, most energy analysts agree that real oil prices will increase by the end of the decade and trend upward through 2000. This trend is expected because the growth in oil supplies is projected to be slower than the growth in oil demand brought on by world economic expansion.

Forecasts of real annual oil price growth rates vary between 1 and 4 percent as shown in Table 6-7. Although some analysts believe rates will

TABLE 6-7

ARAB LIGHT CRUDE OIL PRICE FORECASTS - ANNUAL REAL RATE OF GROWTH

FORECAST	DATE OF FORECAST	PERIOD	ANNUAL REAL RATE OF GROWTH (%)
Data Resources, Inc.	Spring 1982	1983-2000	3.7
Energy Modeling Forum	February 1982	1980-2000	4.0
Texaco	July 1981	1980-2000	1.0-2.0
Chevron	May 1981	1982-2000	3.0

Sources: Data Resources, Inc. (1982)
Energy Modeling Forum (EMF) (1982)
Texaco (1981b)
Chevron (1981)

be in the lower range, the most recent forecasts suggest higher growth rates are more likely. We support forecasts in the upper range for the following reasons.

First, recent oil price declines combined with forecasted short-term price declines will increase long-run demand. Lower oil prices in the short term will improve the world economy by lowering inflation and interest rates, thus bolstering demand, especially in energy industries.

Second, in response to lower oil prices, conservation efforts have been slowed due to the perception among buyers that oil supplies are plentiful. Substituting oil with alternative sources of energy has also become less attractive due to relatively cheap oil. Although conservation and substitution effects resulting from earlier price increases are still being felt, the recent oil glut and low oil prices have already reversed this trend. Many projects that started in the 1970's were backed by the belief that oil prices would continue to rise. Recently, some of these projects, such as the Exxon-Tosco Colony oil shale venture, have been abandoned due to high costs. The Alaska gas pipeline has been delayed for years and in Europe coal imports have been reduced. With fewer alternative sources of energy, the U.S. and other countries will have to look to imported oil as demand increases.

Third, the quantity of imported oil in the U.S. can be expected to pick up soon as oil inventories are reduced and the rate of domestic production slows. Data Resources, Inc. (1982) assumes in their forecast that the lower real price of energy we are experiencing now will have a significant negative impact on domestic production and result in higher oil prices in the long term.

A final consideration in assessing long-term oil prices is the political situation in the Middle East. It is highly possible that geopolitical instabilities could lead to supply interruptions during the coming decade. There is actually a greater chance of oil supply cutoffs resulting from internal political changes than from intervention by major countries such as the Soviet Union. Recent developments in the Middle East have underscored the instability of that area and have increased the chance of oil supply disruptions.

The overall effect of these factors on oil prices will probably be a relatively sharp upturn in prices after 1985 followed by a milder rate of price increase from 1990 to 2000. The base case of the Energy Modeling Forum (1982) forecasts real price increases of 6 percent annually from 1985 to 1990 and 4 percent annually for the rest of the century.

On balance, Dames & Moore believes that annual real oil price increases will average about 3 percent over the next two decades with major increases occurring between 1985 and 1995. After that time prices will begin to stabilize barring any major Middle East disturbances. In the long run, the demand for OPEC oil will decline as alternative sources of energy are developed, incentives to conserve are restored, and non-OPEC oil reserves are developed.

6.7.3 The Relationship of Barrow Arch Planning Area Production to PAD V Supply and Demand

6.7.3.1 PAD V Supply/Demand Balance: 1978-1981

Table 6-8 shows the District V 1978 through 1981 supply/demand balance for crude oil and petroleum products. PAD V consumption has dropped a total of 454 barrels per day since 1979. In the same 2-year period, PAD V crude production has increased by almost 300,000 barrels per day.

Table 6-8 shows that for 1981:

- o Although California and Alaska are among the top four oil and gas producing states, PAD V had to import foreign oil products to cover part of its product demand.

- o California crude production equalled 46 percent of PAD V consumption.

TABLE 6-8

U.S. DISTRICT V SUPPLY/DEMAND BALANCE: 1978-1981
(Thousand B/D)

DEMAND	1978	1979	1980	1981
District V Consumption	2624	2754	2570	2300
Interdistrict and Foreign Product Shipments	136	115	100	150
Total Demand	2760	2839	2670	2450
SUPPLY				
Production				
California Crude & NGL	951	995	980	1060
Alyeska Pipeline Throughput	1065	1250	1520	1520
Cook Inlet Production	137	121	95	85
Subtotal PAD V Production	2153	2366	2595	2665
Foreign Imports				
Crude Oil	571	560	420	300
Products	120	150	95	80
Subtotal	691	710	515	380
Interdistrict Products Receipts	167	155	95	90
Refinery Process Gain	112	115	115	100
Subtotal	279	270	210	190
TOTAL SUPPLY	3123	3346	3320	3235
Non-Refinery Consumption	-	-	(90)	(120)
INTERDISTRICT AND EXPORT CRUDE SHIPMENTS	363	507	560	665
Refinery Utilization Data:				
Refinery Capacity	2889	2868	2959	3056
Crude Runs	2361	2419	2388	2250
Percent Utilization	82	84	80	71

Source: Department of Energy, Monthly Petroleum Statement

- PAD V imported approximately 380,000 barrels per day of foreign crude and products in 1981 at the same time it exported or trans-shipped to Districts I-IV 665,000 barrels per day of California offshore and Alaska crude oil.

6.7.3.2 PAD V Petroleum Product Demand Forecast: 1990

The essential elements of PAD V's demand forecast can be highlighted with the estimated growth rates shown on Table 6-9. Notice that these are 1978 to 1990 growth rates. The 1979-1980 price increases, together with the on-going recession, have already radically reduced PAD V petroleum demand. Hence, 1981 to 1990 product growth rates would be flatter than 1978 to 1990 growth rates. Table 6-9 shows:

- Total PAD V consumption will decline to 1990 at 1.3 percent per year from the 1978 base year.

- The decline in fuel oil is much greater than the decline in light products consumed.

- The increase in distillate fuel consumption is more than offset by the decline in mogas consumption.

- Light products consumed decline at 0.8 percent per year to 1990.

Most of the reduction in residual demand is for low sulfur fuel oil. Hence, the need to import high volumes of Sumatran-type crude to make LSFO has been reduced. Utilities are switching to gas near term and look to more use of coal and nuclear long term. So long as utilities are granted exemptions to use gas, it looks as if gas will be available on the West Coast for their use.

TABLE 6-9

PAD V 1990 PRODUCT DEMAND FORECAST
(Thousand B/D)

	Actual 1978	1990 Low NPC[1]	1990 Dames & Moore	Growth Rate[2] (1978-1990)
Mogas	1129	975	832	(2.5)
Distillates				
Jet	301	390	341	1.1
Diesel	345	419	444	2.1
Subtotal	646	809	785	1.6
Subtotal - Light Products	1775	1784	1617	(0.8)
% of Demand	67%	70%	72%	
Residual Fuel Oil				
LSFO	265	186	70	(10.5)
HSFO	223	148	190	(1.3)
Subtotal	488	334	260	(5.1)
All Other	368	428	373	(0.1)
TOTAL PAD V Consumption	2631	2546	2250	(1.3)

1 National Petroleum Council (1980) (This is their low case demand forecast; their base case called for 2,715,000 barrels per day in 1990.)

2 Growth Rate based on Dames & Moore 1990 forecast value.

6.7.3.3 West Coast Supply/Demand Forecast with Reference to Barrow Arch Planning Area

The whole West Coast supply/demand picture is presented in Table 6-10 and shown in Figure 6-1. Demand consists of Pad V consumption, which is tied to products demand on Table 6-9, plus interdistrict and foreign product shipments. The California crude production forecast is based on Dames & Moore's most likely forecast. The Alaska production forecast consists of most recent projections for Prudhoe Bay, Kuparuk River, and Cook Inlet, and a conservative forecast for other North Slope production. West Coast crude supplies available for shipment to Districts I-IV peak in 1985 at over 800,000 barrels per day and decline to a deficit in 2005.

The California crude oil production forecast on Table 6-11 indicates that California heavy crude production will dramatically increase and California light crude production will decline. California's largest light crude field--Elk Hills--peaked during the third quarter of 1981 at 179,000 barrels per day and is in decline. Kern River and the Santa Barbara Channel (namely the Santa Ynez Unit) will be producing an increasing amount of heavy crude through 1990. Federal OCS production will increase dramatically through 1990 especially in the Santa Ynez Unit where production will account for 10 percent of the heavy oil produced in California in 1990. As a result, the mix of California crude supply will increase from 56 percent heavy in 1981 to about 70 percent heavy by 1990. One result of the decline in product demand is that the existing and planned refinery capacity in PAD V appears to have sufficient residuum reduction capacity to process this mix of crude supplies.

Other supply sources, shown on Table 6-10, consisting of foreign imports (crude oil and products), interdistrict product receipts, and refinery process gain, are forecast to gradually decline through 2010. Foreign imports, especially Sumatran crude, are declining due to high natural gas avails and imported light products will be reduced due to refinery modifications and reduced demand. Interdistrict product receipts will continue but decline slightly over the period, while refining process gain will remain flat.

TABLE 6-10

IMPACT OF POTENTIAL BARROW ARCH AREA PRODUCTION ON PAD V
Supply/Demand Balance
(1000 Barrels per Day)

	1980	1985	1990	1995	2000	2005	2010
DEMAND	2670	2350	2325	2350	2350	2400	2400
California Production and NGL[1]	980	1156	1150	1250	1250	1250	1250
Alaska Production[2]	1615	1790	1690	1630	1060	900	600
Other Supply[3]	725	370	310	305	150	100	100
Enhanced Recovery Field Use[4]	(90)	(155)	(170)	(180)	(185)	(185)	(185)
SUPPLY SUBTOTAL	3230	3161	2980	3005	2275	2065	1765
Projected Chukchi Sea Production[5]	-	-	-	71	300	350	140
TOTAL SUPPLY	3230	3161	2980	3076	2575	2415	1905
West Coast Crude Supplies available for shipment to Districts I-IV	560	811	655	726	225	-15	-495

Source: Dames & Moore (1982c)

(1)California crude production forecast is based on Dames & Moore's assessment of a wide range of potential heavy crude forecasts. Geologic potential would justify higher liftings. Economic and environmental constraints suggest the liftings shown are the most likely.

(2)Alaska production is based on published information and our conservative forecast for Milne Point, Sag Delta, Duck Island and Point Thompson announced discoveries.

(3)Includes foreign imports (crude oil and products), interdistrict product receipts and refinery process gain.

(4)Enhanced oil recovery use amounts to crude consumed directly as fuel oil and crude burned in production of California heavy crudes.

(5)Production shown in year 1995 actually beings in 1998.

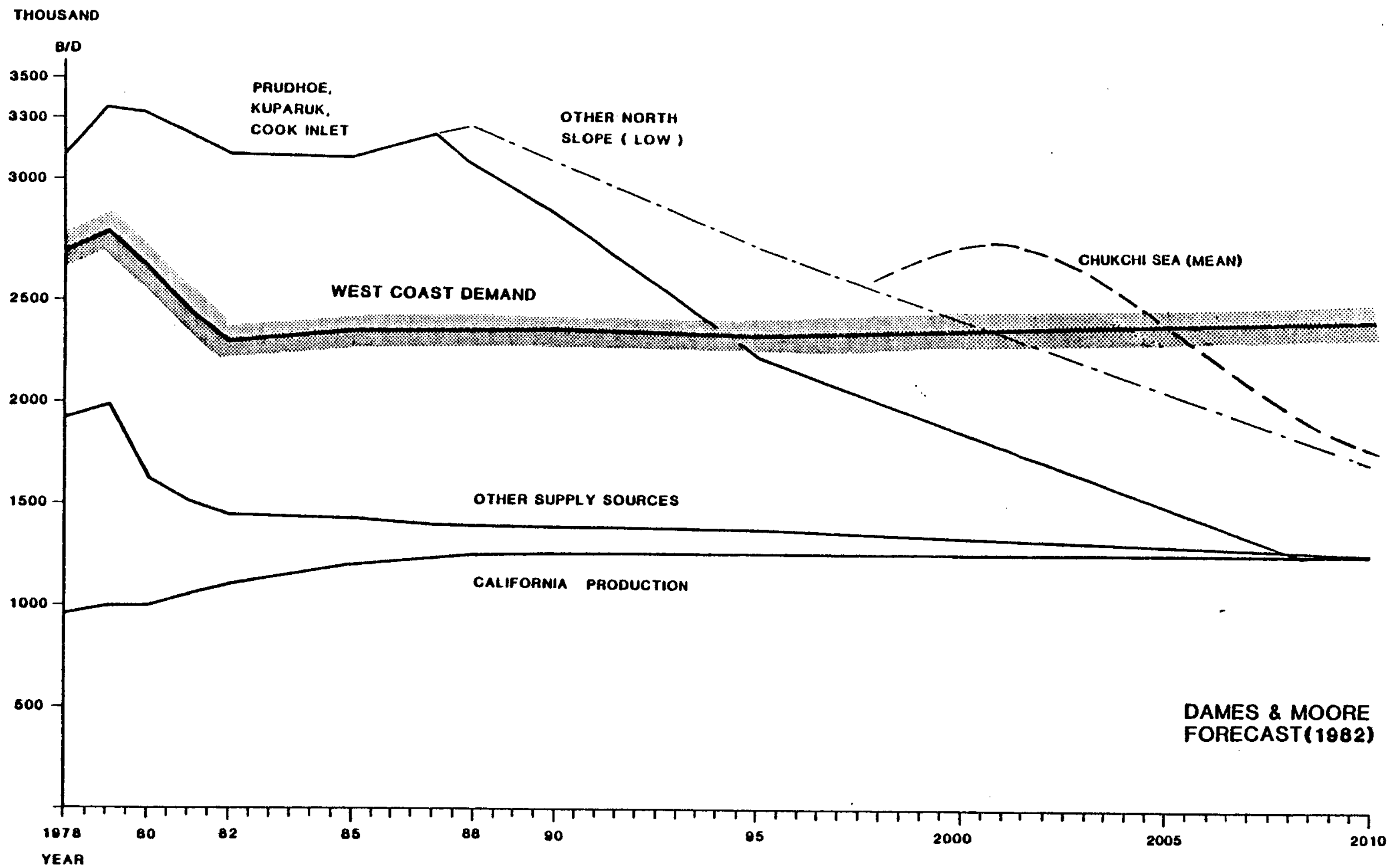

Figure 6-1

WEST COAST / DEMAND FORECAST

WITH REFERENCE TO CHUKCHI SEA
BARROW ARCH PLANNING AREA

TABLE 6-11

CALIFORNIA CRUDE OIL PRODUCTION FORECAST
(Thousand B/D)

Most Likely Forecast	1970	1975	1980	1981	1985	1990	2000
Light (>20 ° API)	524	375	439	462	429	391	326
Heavy (<20 ° API)	514	504	508	598	771	859	924
TOTAL	1038	879	937	1060	1200	1250	1250
% Heavy	50	57	54	56	64	69	74
High Forecast							
Heavy				598	821	1009	1074
TOTAL				1060	1250	1400	1400
% Heavy				56	66	72	77

Note: These forecasts are derivative of three research documents, but represent a range of other points of view. Production includes crude burned in the field for enhanced oil recovery; 20 percent of heavy production is assumed to be burned.

Source: California Energy Commission (1980)

California Energy Commission (1981)

California Division of Oil and Gas (1982)

Total existing Alaska production will decline from a peak of 1,790,000 barrels per day in 1985 to 500,000 barrels per day in 2000. Prudhoe Bay production will decline from 1,540,000 barrels per day to only 400,000 barrels per day in 2000. Kuparuk will decline from 250,000 barrels per day in 1985 to 100,000 barrels per day in 2000. Cook Inlet will continue its gradual decline from 85,000 barrels per day in 1981, and cease production about 1995. As Figure 6-1 shows, this downward trend for existing North Slope crude will continue through 2010.

As these Alaska fields enter decline in the late 1980s, potential new field crude supplies in the Beaufort and Bering Sea will start production as shown in Figure 6-1. New Alaska production, however, will probably not offset the decline of Prudhoe Bay. To partially offset this PAD V supply decline, Chukchi Sea production will start up in 1998 at 71,000 barrels per day, peak at over 400,000 barrels per day in 2003, and gradully decline thereafter. As shown in Figure 6-1, Chukchi Sea production could make a timely impact on PAD V crude supplies.

7.0 HYPOTHETICAL PETROLEUM SCENARIOS FOR THE ESTIMATED MEAN OIL AND GAS RESOURCES OF THE CENTRAL CHUKCHI SHELF

7.1 Introduction

This chapter presents a hypothetical oil and gas development case for the central Chukchi shelf portion of the Barrow Arch planning area. Mean resource estimates of recoverable oil and gas in this basin are estimated to be 1.7 billion barrels of oil and 4.5 trillion cubic feet of non-associated gas (Tom Marshall, personal communications, June 1982). Associated gas is assumed to be be reinjected.

The hypothetical development scenario focuses on only central Chukchi shelf resources rather than the larger resources estimated to exist in the entire lease sale area. It is our opinion, based on the economic analysis reported in Chapter 6.0, that only the central shelf resources are commercially recoverable by conventional means. (Indeed, even these more favorably located resources may not be commercial.) USGS resources estimates for the planning area have not yet been released.

The development case hypothesized here assumes a relatively rapid exploration and development schedule. The schedule is characterized by a high level of exploratory activity with a commensurate rate of discovery that results in two commercial oil fields and one gas field discovered within 7 years of the lease sale. Many factors, such as the availability of drill rigs following the lease sale or environmental restrictions on drilling, could alter the speed and course of events. The schedule of development follows Scenario 3B of Section 6.2.3.

7.2 Development Strategy and Production Facilities

The development scenario is summarized in Table 7-1, assuming a February 1985 lease sale date. Except where noted, field conditions follow those described in Chapter 6.0.

TABLE 7-1

CENTRAL CHUKCHI SHELF HYPOTHETICAL PETROLEUM DEVELOPMENT CASE:
(for Mean Estimate of Resources)

Calendar Year	Years After Lease Sale	Expl'n & Delineation: Rigs Operating	Expl'n & Delineation: Wells Drilled	Commercial Field Discovered: Oil	Commercial Field Discovered: Gas	Commence Installation of Offshore Production Units: Oil (Gravel Islands)	Commence Installation of Offshore Production Units: Gas (Mono-cones)	Development Wells: Oil	Development Wells: Gas	Pipeline Construction (km): Oil (1)	Pipeline Construction (km): Oil (2)	Pipeline Construction (km): Gas (1)	Pipeline Construction (km): Gas (2)	Production: Oil (MMB/YR)	Production: Gas (BCF/YR)
1985	1														
1986	2	2	3												
1987	3	3	6												
1988	4	3	6	1											
1989	5	4	8	1	1										
1990	6	4	8												
1991	7	2	4	D											
1992	8	1	2	D	D										
1993	9														
1994	10					1									
1995	11					2	1								
1996	12					1	1								
1997	13					1	1	16	8	43	27	43	19		
1998	14							48	16	62	5				
1999	15							84	17					26	126
2000	16							72	9					70	216
2001	17							56	1					109	263
2002	18							24						140	268
2003	19							8						153	268
2004	20													158	268
2005	21													145	268
2006	22													128	268
2007	23													103	268
2008	24													86	268
2009	25													73	268
2010	26													61	268
2011	27													51	268
2012	28													43	246
2013	29													36	207
2014	30													31	175
2015	31													26	147
2016	32													22	124
2017	33													18	104
2018	34													15	88
2019	35														74
TOTALS		37	19	2	1	5	3	288	51	105	31	43	19	1488	4450

Source: Dames & Moore

Notes:

(1) Offshore
(2) Onshore
D = Decision to develoo is 3 years after discovery

Oil is assumed to be discovered in two fields. The first field is located 50 kilometers (30 miles) offshore of Wainwright and contains 1.0 billion barrels of reserves. A second 0.5-billion-barrel field is located slightly to the north about 50 kilometers offshore of Point Belcher. Production from the 1.0-billion-barrel field takes place from three caisson-retained gravel islands and follows the development and production schedule of Scenario 3B. Production from the second field takes place from two caisson-retained islands.

The gas resources are contained within a single discovery and are produced from three monocone platforms. Production and developmental schedules follow those described for Scenario 6A. Although the gas discovery is assumed to occur in the same vicinity as the 1.0-billion-barrel oil discovery, the facilities are assumed to be entirely separate.

Development Assumptions and Sequence:

1. The lease sale occurs in February 1985. Exploration begins in the spring of the following year (1986) and continues for 7 years.

2. The 1.0-billion-barrel oil field is discovered in 1988 and the gas field is discovered in 1989, as is the second (0.5-billion-barrel) oil field.

3. Delineation takes 2 additional years. The decision to develop is thus reached in the third year after discovery (i.e., 1991 for the larger oil field and 1992 for the smaller oil field and the gas field).

4. Caisson-retained island construction begins in the third (1994), fourth and fifth years after decision to develop for the gas field and the larger oil field, and in the third and fifth years after decision to develop the smaller oil field. Thus, construction begins in 1994, 1995 and 1996 for the larger oil field; 1995 and 1997 for the smaller oil field; and 1995, 1996 and 1997 for the gas field.

5. Construction of the caisson-retained gravel islands (for oil production) requires 2 years each. Therefore, the first oil production island is completed in the fourth year following the decision to develop (1995). The monocone platforms (for gas production) take 1 year to construct. Thus, they are completed in the third, fourth and fifth years following decision to develop gas (1995, 1996 and 1997).

6. Drilling begins in the year that each island or platform is completed.

7. Production starts in the third year of drilling (1998 for both oil and gas) and produces from the wells drilled during the previous 2 years. In subsequent years, production takes place from the wells completed during the preceding year.

8. Gas production peaks in year 2001 and oil peaks in year 2003.

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APPENDIX A

PETROLEUM GEOLOGY, RESERVOIR AND TECHNICAL ASSUMPTIONS

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APPENDIX A

PETROLEUM GEOLOGY, RESERVOIR AND TECHNICAL ASSUMPTIONS

I. INTRODUCTION

This appendix describes the reservoir, production, and technical assumptions that are the essential parameters for the economic analysis. The role of these assumptions and the overall study methodology are described in more detail in Appendix A of our final report entitled "St. George Basin Petroleum Technology Assessment OCS Lease Sale No. 70" (Dames & Moore 1980c). Many of the assumptions of this study are unique to the Barrow Arch planning area. This appendix is devoted to a description of the petroleum geology of the Barrow Arch lease sale area and related reservoir engineering assumptions, and technical assumptions that are specific to the analysis.

II. PETROLEUM GEOLOGY, RESERVOIR, AND PRODUCTION ASSUMPTIONS

II.1 Introduction

Section II.2 reviews the petroleum geology of the Barrow Arch OCS planning area to provide the geologic specifications for the reservoir and production assumptions that are essential parameters for the economic analysis. The assumptions are presented in Section II.3.

Geology from the western part of Alaska's North Slope, known principally from wells drilled along the northwest coast, can be correlated into parts of this planning area but no COST wells or other wells have been drilled anywhere in the planning area. In the north Chukchi Basin portion of the planning area, the geology is believed to be much different than typical North Slope geology and, due to pack ice cover in this area about 80 percent of the year, marine seismic exploration has been very limited and compromised as to location. Although the amount and quality of geological information varies greatly, there is insufficient geologic and geophysical data to make predictions with a high degree of certainty on reservoir characteristics in the Barrow Arch planning area. Our approach in this study was to explore the economic and engineering impacts of diverse geologic and reservoir characteristics. That diversity, however, should fall within the range of conditions indicated by the available data and data from producing basins with similar geologic settings.

II.2 Summary of Barrow Arch Planning Area Petroleum Geology

II.2.1 Regional Framework

Geologically, the Barrow Arch planning area contains a variety of geological features, making it much more complex than the Bering Sea planning areas which essentially contained one basin or a series of closely associated basins. The Barrow Arch planning area extends northward from an east-west line touching the Alaska coast at Point Hope.

From south to north the following geological features are included:

1. Northern one-fifth of Hope Basin, occasionally referred to as part of the south Chukchi Basin, consisting of inferred Tertiary sedimentary rocks.

2. The Herald Arch, a broad positive feature exposing rocks as old as Mississippian quartzites in its core.

3. The central Chukchi shelf, which includes a very thick sedimentary section and many northwest trending anticlines in the offshore extension of the Colville trough from the North Slope oil and gas province.

4. The north Chukchi Basin which is filled with great thicknesses of inferred Cretaceous and Tertiary rocks containing shale diapirs.

Because of the difficulties of conducting seismic exploration in seas most often covered with pack ice, and the fact that seismic line spacing has been 80 kilometers (50 miles), geological information in the north Chukchi is certainly not based on ideal seismic data. A break occurs in the continental shelf in the northeastern portion of the north Chukchi Basin where the bathymetry plunges into the Chukchi borderland but the remainder of the Barrow Arch planning area, including the other features described in this section, lie on the remarkably large and flat Chukchi continental shelf.

Crustal plate tectonics is demonstrated by continental rifting and continental break up on the Chukchi shelf portion of the Barrow Arch planning area and has divided the shelf into two distinct structural and stratigraphic domains separated by subsidence hinge lines. Seafloor spreading or crustal thinning formed the north Chukchi Basin probably during early Cretaceous time and it now contains more than 16 kilometers (52,500 feet) of younger (mostly Tertiary) sediments. The domain that lies south of the hinge line is dominated by the arctic platform, which extends all across northern Alaska north of the Brooks Range.

Whereas the physiography is simple, the geological features range from quartzite arches to shale diapirs and the age of rocks perspective for oil and gas range from Mississippian through Tertiary. Based on seismic interpretations, it is quite possible that sedimentary rocks representing all systems from pre-cambrian to Quaternary are present. In this study we will consider mainly rock units known to be capable of oil or gas production on the North Slope or thought to have good reservoir possibilities based on lithologic characteristics.

In considering the regional geology, it is important to relate the Barrow Arch planning area to the oil province commonly known as the North Slope, the habitat of the giant Prudhoe Bay and Kuparuk oil fields and many other oil and gas occurrences. North Slope geology extends well into Area 1 and is especially relevant to the attractive nearshore exploration targets.

The North Slope encompasses all the land north of the Brooks Range drainage divide. It is subdivided into three physiographic provinces, from south to north: the Brooks Range, the Foothills (generally subdivided into northern and southern foothills), and the Coastal Plain. Trending in a sub-parallel easterly direction, these provinces reflect underlying geologic trends. The North Slope is composed of three main structural elements: the Brooks Range orogen (a belt of very deformed rocks), the Colville trough, and the Barrow Arch. These structural elements correspond generally to the respective physiographic provinces. In the context of the entire North Slope, the Barrow Arch is certainly best known as the Barrow-Canning River Arch, which is the locus of current oil and gas exploration along the arctic coast from the western boundary of the Arctic Wildlife Range to Point Barrow. At Point Barrow, the arch brings older rocks fairly near to the surface and then rises even higher to bring basement rocks to the surface in the western Chukchi Sea.

This arch is a broad regional basement high that separates the Colville trough on the south from the Arctic Ocean Basin. Very dense Devonian rocks, forming the economic "basement" found at relatively shallow depths along the Barrow Arch, slope gently southwesterly into the Colville trough which, in the Barrow arch planning area, is marked by the axis of the Hanna trough. (The Hanna trough intersects the coast near Point Lay.) Here the Colville-Hanna trough may be as deep as 10,600 meters (34,779 feet) and contains many slump anticlines closely resembling those of the Foothills physiographic province, which occupies the major part of the Colville trough on the North Slope. Geophysical evidence (Steve May, U.S. Geological Survey, personal communication) strongly suggests that this multitude of southwest trending offshore anticlines terminate abruptly about 150 kilometers (93 miles) offshore.

The surface outcrops, the subsurface well data, crude oil characteristics, and oil and gas field performance histories on the North Slope provide very useful information to transfer to a study of the North Slope related areas of the Chukchi shelf. However, there is geophysical evidence that the western half of the Barrow Arch planning area has been strongly influenced and possibly radically changed by one or more plate tectonic episodes that could greatly effect the stratigraphy, structure and the reservoir qualities.

Water bottoms lying within 5 kilometers (3 miles) of Alaska coastline are owned by the State of Alaska. Approximately 700 kilometers (378 nautical miles) of Alaska coastline adjoin the southeastern Chukchi shelf.

II.2.2 Structure

The U.S. Geological Survey ran 24 channel seismic-reflection surveys on the Chukchi shelf using a reconnaissance grid spacing of about 80 kilometers (50 miles) in 1977, 1978 and 1980 using the survey ship S.P. Lee. This data augmented and in several ways changed the original structural interpretations made using single channel data run from ice breaking Coast Guard cutters since 1969 using sparker and air-gun energy sources. Sonobuoy refraction lines, total magnetic measurements and limited gravity measurements were also obtained in the surveys run from Coast Guard cutters. Gravity data has not been very useful for geological interpretations on the Chukchi shelf (Steve May, U.S. Geological Survey, personal communication).

II.2.2.1 Area 1 - Central Chukchi Shelf

It is inferred that the Herald fault zone is an extension of the thrust belt of exposed Ellesmerian (includes Lisburne limestone) rocks in the Lisburne Hills near Cape Lisburne. North of Cape Lisburne the Herald fault zone crosscuts the east-west trending thrust folds that trend offshore from the arctic foothills of the Brooks Range and are related to the up.ift and thrusting of the Brooks Range mountain building activity.

The Herald fault zone thus appears to postdate the thrust faults, thrustfolds and detachment folds of the extension of the arctic foothills into the Chukchi shelf. The amount of northward thrusting on the Herald Arch is unknown but would be of considerable magnitude. The portion of the Barrow Arch planning area lying in the north part of the Hope Basin and in the Herald Arch area is included geologically in Area 1, the central Chukchi shelf, because there is a possibility that the oil and gas traps, which would be exploration objectives, could be located below the overthrust plates of the Herald Arch or under part of the northeastern portion of the Hope Basin. These sub-thrust plate objectives would be more closely related to the Foothills province geology of Area 1 than to the Hope Basin.

The thick sections of middle Cretaceous beds north of Cape Lisburne are deformed by large northwest trending folds that die out near longitude 167° W. These anticlinal folds are a continuation of the folds of the northern Foothills physiographic province of the southern North Slope. They are strongest and have faulted cores near the Herald Arch; they decrease in amplitude northward and die out into a gentle monocline near the latitude of Icy Cape 450 kilometers (280 miles) southwest of Barrow. The folds are detached from the structure of the rocks below and conform to the structural style known as decollement often associated with thrust faulting. In the Ellesmerian rocks underlying the detachment surface, structural closures and truncation surfaces could provide exploration targets.

The Barrow Arch dominates the northern half of Area 1 (central Chukchi Basin) and brings Franklinian rocks considered to be economic basement to within 230 meters (750 feet) of the seabed. From the crest, the basement rocks slope southwestward to the axis of the Hanna trough where these same Franklinian rocks lie at 10.6 kilometers (34,779 feet). Overlying the basement is the Ellesmerian series, including the Lisburne limestone and Jurassic sandstones known to produce oil and gas near the crest of the Barrow Arch at Prudhoe Bay where the reservoir rocks are truncated by impermeable younger rocks. Broad anticlines, normal faults, updip pinchouts, onlap, as well as erosional truncation traps could possibly occur on this broad inclined shelf. The reconnaissance type seismic surveys run in this area, however, do not provide specific interval information on which to determine where structural closure exists. Based on geophysical data, Grantz (1982) speculates on the northern limit of the Ellesmerian rocks (see Figure A-1). This line probably represents the disappearance of the Kingak shale and the Jurassic sandstones that it may contain. Subsurface well data onshore at Peard Bay indicates that the Lisburne Formation has already been completely truncated against the Barrow Arch rising to the north but almost 1000 meters (3281 feet) of Lisburne were cut in the Tunalik well 161 kilometers (100 miles) south of Peard Bay.

II.2.2.2 Area 2 - North Chukchi Basin

This basin is structurally and stratigraphically quite different from the Chukchi shelf lying to the south. It is dominated by thick Cretaceous and Tertiary sedimentary prisms that rapidly filled the basin formed by a seafloor spreading episode related to the formation of the huge Canada Basin lying almost 160 kilometers (100 miles) north of Point Barrow. The north Chukchi Basin contains more than 16 kilometers (52,000 feet) of sediments above the economic basement. A notable feature is the occurrence of shale diapirs. Its Cretaceous beds have been broken into many rotated slump blocks bounded by normal faults. These Cretaceous age beds are approximately the same age as the Nanushuk Group of rocks from which the Umiat oil field is capable of producing oil.

Strata in the southern part of the north Chukchi Basin dip as much as 15° northerly. Farther to the north dips decrease to less than 1° northerly.

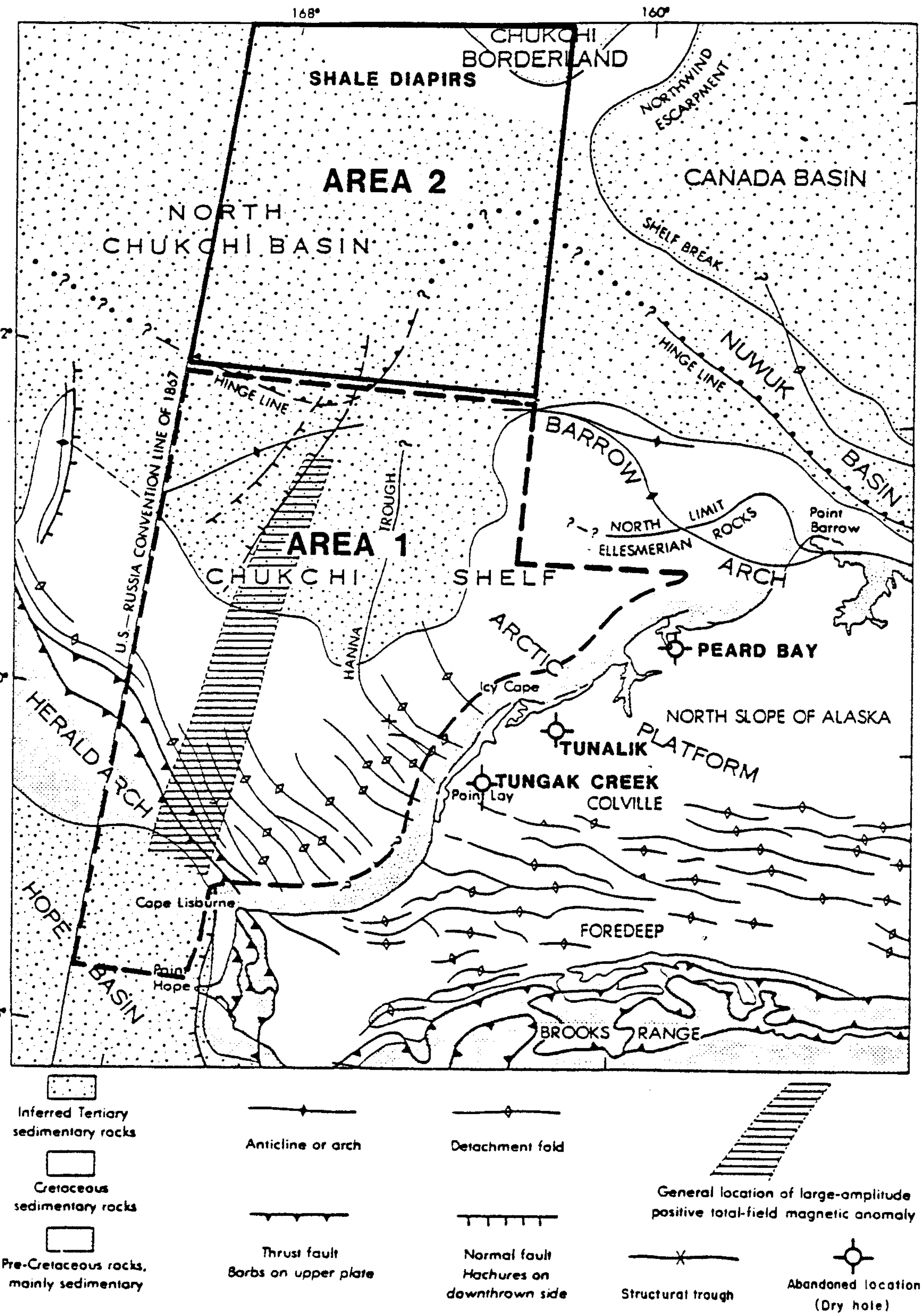

Figure A-1

PRELIMINARY TECTONIC MAP OF CHUKCHI SHELF & PETROLEUM GEOLOGY STUDY AREAS

Source: Adapted by Dames & Moore from Grantz A. and S.D. May. (1982).

II.2.3 Stratigraphy

The depositional axis of the North Slope (Colville Basin) is close to the southern edge. The basin is very assymetrical with the deepest portion being only 80 kilometers (50 miles) north of the Brooks Range. The Colville Basin is filled mostly with Mesozic and Tertiary rocks shed into the basin from a southern source area that lay in approximately the same position now occupied by the Brooks Range onshore and the Herald Arch offshore. Prior to the development of the Colville Basin, a geologic high existed in approximately the position of the present Canada Basin. Sediments of mid-Paleozoic to early Cretaceous age were shed to the south from this northern high and carbonate rocks of Paleozoic age were laid down on its flanks, forming the Ellesmerian sequence. These rocks were partially eroded during a period of uplift (prior to deposition of the younger sediments from the southern source areas), resulting in an unconformity that truncates the older rocks in several areas along the Barrow Arch. This unconformity forms part of the trapping mechanism of the Prudhoe Bay oil field and also would be operative on the southern flanks of the Barrow Arch in its offshore extension in the Chukchi Sea.

On the basis of limited seismic surveys and no well data or measured surface sections, the north Chukchi Basin is thought to contain a thick sequence of clastic sedimentary rocks of Cretaceous and Tertiary age consisting of mainly shallow marine clastic beds from a southerly source.

II.2.4 Reservoir Rocks and Traps

In Area 1 (central Chukchi area), there are four main rock units known to have reservoir potential. These include the Sadlerochit Formation of Permo-Triassic age, the Lisburne Group of Mississippian-Pennsylvanian age, the Kuparuk River Sands of Jurassic or earliest Cretaceous age, and the Sag River Sandstone of Jurassic age. Numerous younger sediments of Cretaceous or Tertiary age, which occur in the Kuparuk oil field (Ugnu-Cretaceous) or within the Nanushuk group in small oil fields in the NPRA, could be reservoir rocks but generally tend to be thinner and less porous than the older known reservoir rocks.

The Sadlerochit Formation has considerable lateral variation in reservoir characteristics, probably due to differences in source area geography and the relative position of a depositional area to the source of the sediments.

The variation in the amount of sand in the formation is caused by these depositional differences. Prudhoe Bay oil field is actually a fortunate coincidence of a large trap in conjunction with a center of sand deposition from the Sadlerochit Formation. The amount of sand in this formation decreases to the northwest of Prudhoe Bay in the direction of the Barrow Arch planning area. However, the possibility of other depositional centers along the lateral extent of the Sadlerochit Formation makes it a drilling target within the central Chukchi shelf where it has not been removed by erosion from the Barrow Arch or buried too deeply in the Hanna trough. Traps could be combinations of structure and stratigraphy, such as at Prudhoe Bay, or due to trunactation and sealing by a Cretaceous unconformity on the Barrow Arch.

Shelf-type carbonate rocks of the Lisburne group deposited along the flanks of a northern high land area are reservoirs in the Prudhoe Bay oil field and contain shows of oil and gas over a wide area of northwestern Alaska. An exploratory well operated by Union Oil Company spudded in 1982 at Tungak Creek about 35 kilometers (22 miles) northeast of Point Lay on the northwest coast and bordering the central Chukchi area (Area 1). This well may have been an attempt to find the updip truncated edge of the Lisburne Formation on the rise of the Barrow Arch. The Lisburne is found over a wide area of the North Slope but is noteably absent on and near the crests of positive areas such as: the Meade Arch, which runs north-south through NPRA; at Smith Bay, about 160 km (100 miles) southeast of Point Barrow; and east of the Prudhoe Bay oil field. Being low in the Ellesmerian series of rocks, the Lisburne is severely truncated off on the south flank of the Barrow Arch but it remains an attractive exploration target. Some control as to its zero thickness is provided by the Husky Peard Bay well, which found the Lisburne missing, and the Tunalik well (see Figure A-1), which encountered a thick Lisburne section but curiously the Lisburne was cut by nearly 305 meters (1000 feet) of volcanic rocks. It is believed that good reservoir rocks could develop in the Lisburne in Area 1 (central Chukchi Basin) due to dolomitization, reefing and other mechanisms that develop porosity in carbonate rocks.

The Kuparuk River sandstones are now producing oil from the Kuparuk River oil field about 68 kilometers (40 miles) west of the Prudhoe Bay oil field and form a separate oil pool in the Prudhoe Bay oil field. These sands were deposited in a shallow marine environment from a northern source and usually occur as multiple reservoirs aggregating 15 to 21 meters (50 to 70 feet) thick. Reservoirs are generally lenticular but large and could be present in a broad band in the northern part of the central Chukchi Basin with stratigraphic traps being favored because of the lenticular nature of the sands.

Stratigraphic equivalent sands to the Sagavanirktok River sandstone of Jurassic age in the Prudhoe Bay oil field may also be an important and wide spread exploration target south of the line on Figure A-1 indicating the northern limit of Ellesmerian rocks. This sandstone would probably be less than 30 meters (100 feet) in net thickness but would exhibit fairly good lateral uniformity. Traps would be structural or truncation on the rise of the Barrow Arch.

Sandstones of lower Cretaceous age derived from a southern source equivalent to reservoirs found at the Umiat oil field in the Nanushuk Group could be widespread in Area 1 (central Chukchi) in both structural and stratigraphic traps. Gas reservoirs would also certainly be expected because this thick clastic wedge is coal bearing. In terms of total hydrocarbons, these rocks have a high potential.

Sketchy geophysical data and the absence of any well data or outcropping rocks requires that comments about the reservoir rocks and traps of the north Chukchi Basin (Area 2) be stated in very general terms. Single channel reflection profiles indicate a north dip of 15° in the rocks on the south rim of the Chukchi Basin and less than 1° northerly dips basinward to the north. North Chukchi sediments are thought to be deposited on oceanic crust or very thin continental crust and possibly could form oil and gas traps by differential compaction over remnant high standing blocks or on upthrown fault blocks. The rather steeply dipping marine rocks on the southern rim of the north Chukchi Basin could provide the locus for traps associated with various types of offshore sand lenses but it must be emphasized that there is no reliable data on the presence or absence of reservoir rocks in this area. Rotated slump blocks bounded down to the basin normal faults also seen on seismic profiles could provide traps if reservoir quality rocks exist.

It seems likely that many (perhaps 50) diapirs will be found in the Chukchi based on the fact that five have already been identified on the basis of the almost random seismic surveys. Exploring for diapers is something like exploring for pinnacle reefs in that both are non-linear structures and a considerable amount of luck is helpful in locating them.

II.2.5 Source Rocks

Until recently it has been generally accepted that the source of Prudhoe Bay oil is marine shale of Cretaceous age (Morgridge and Smith 1972). Recently, Magoon and Claypool (1982) suggest that medium gravity, high sulfur oils found along the Barrow Arch at Prudhoe and Point Barrow are derived from a carbonate or other iron deficient source rock and that the higher gravity, low sulfur oils of the Umiat, Cape Simpson and Skull Cliff are derived from a silica rich clastic source rock. Work by Siefert et al. (1979) comparing biologic marker compounds in the oils and shale extracts concluded that major sources of the principal oil accumulations were the Triassic Shublik Formation, a phosphatic-calcareous shale; the Jurassic Kingak Shale; and deeply buried (3,480 meters [11,418 feet]) upper Cretaceous shales. In addition, they determined that the encasing shale was the unique source for the oil recovered from the Kuparuk River sandstones within the Kingak Shale.

Source rocks are widespread and abundant in the central Chukchi Basin especially south of the line on the Barrow Arch where the Shublik Formation and other carbonate rocks have not been removed by erosion. With abundant source rocks, it is expected that traps will be filled to the spill point in the central Chukchi Basin except in areas of intense deformation.

Based on the tremendous thickness (16 kilometers [52,500 feet]) of probable marine shales thought to exist in the north Chukchi Basin (Area 2) and high heat flow expected because of the thin or absent continental crust, the north Chukchi is expected to contain excellent oil and gas source rocks.

II.2.6 Comparison to Other Arctic Margin Basins

Since the central Chukchi Basin is actually an extension of North Slope geology, comparisons to the North Slope have been drawn under all subheadings of the petroleum geology section. However, as stated earlier, the geologic origin, stratigraphy and structure of the North Chukchi Basin appear to be quite different than the North Slope Basin and the amount and quality of the information available is very much less. The Barter Island area of the eastern Beaufort Basin near the Alaska-Canada border resembles the north Chukchi in that they are the deepest basins along the present northern Alaska continental margin and both contain the thick shales and dynamics to produce shale diapirs. The eastern Beaufort Basin is productive of oil and gas in the McKenzie River Delta area.

II.3 Assumptions

II.3.1 Initial Production Rate

II.3.1.1 Oil

Initial well production rate is used in the economic analysis as an index of reservoir performance in the absence of specific data about reservoir characteristics (pay thickness, porosity, permeability, drive mechanism, etc.). Initial production rate refers to the sustained average productivity of a well over the first 45 percent of its total production, after which exponential decline occurs. The initial productivity per well influences the number of wells that have to be drilled to efficiently drain a reservoir. Assuming standard well spacing (65 hectares [160 acres]) and the maximum number of wells that can be drilled from a single platform (dictated by the reservoir depth and well spacing limitations), the peak throughput of a producing system can be estimated using the initial well productivity assumption.

Initial production rate for wells on anticlines in the Barrow Arch planning area is assumed to average 2,000 barrels per day in Area 1 and 1,000 barrels per day in Area 2. The estimated depth of wells in Area 1 should range between 1,524 and 7,620 meters (5,000 and 25,000 feet). An overall average of 3,048 meters (10,000) feet is used as a base case in Area 1 and 2,286 meters (7,500 feet) is used in Area 2. At this depth, the most favorable ratio of porosity, permeability, and pressure is anticipated to occur.

The initial productivity assumed for wells producing from stratigraphic traps will vary widely as depths of these traps range from very shallow to very deep. Considering that some of the productive potential in Area 1 may orginate from clean clastics in truncation traps, an initial well productivity of 2,000 barrels of oil per day is also assumed for stratigraphic and combination structural and stratigraphic traps. In Area 2, reservoirs are thought to have less favorable reservoir characteristics due to the relatively rapid filling of the north Chukchi Basin. Consequently, initial productivity is placed at 1,000 barrels of oil per day in stratigraphic traps.

Within certain technical and economic constraints, the number of wells and their spacing can be varied, depending upon the initial well productivity, to optimize the recovery or take-off rate. These are trade-offs between the investment in additional wells, and the increased revenue streams from a higher offtake rate. (Increasing the number of wells will decrease the well spacing.) In general, the deeper the reservoir the more expensive are the development wells and the longer the drilling time. Thus, it is more advantageous to increase the number of wells in shallow reservoirs (1,500 meters (4,500 feet) or less) to overcome low initial well productivities than it is for deeper reservoirs.

In this study, we have fixed the number of wells to obtain a recovery rate that produces about 10 percent of total assumed reserves in the peak years of production. Our production profile, which assumes secondary recovery, produces approximately 45 percent of reserves during peak production prior to the onset of decline. (See also discussion of recoverable reserves, Section II.3.3, and production profile, Section II.3.4.).

II.3.1.2 Non-Associated Gas

In Area 1, thick coal beds in the Lower Cretaceous deltas favor a high gas potential. Total reserves may be large but they are likely to be spread in numerous small fields. Initial productivity per well for non-associated gas is essentially unknown at this time. Geochemical data on shale well cuttings are needed to determine the ability of a given potential source rock unit to generate oil and/or gas in Area 2. This critical information is not available to us at this time. For economic analysis, we will assume a gas well productivity of 15 million cubic feet per day.

II.3.2 Reservoir Depth

The geophysical records indicate reservoir depths may range from very shallow (600 to 3,000 meters [2,000 to 10,000 feet]), to very deep (1,500 to 7,600 meters [5,000 to 25,000 feet]). We assumed reservoir depths in Area 1 of 3,000 meters (10,000 feet), and in Area 2 of 2,286 meters (7,500 feet). Analysis of the USGS seismic data provides limited control for the reservoir depth assumptions. The economic analysis reflected only one target depth -- 3,000 meters (10,000 feet) in Area 1 -- which is weighted toward the deeper Lisburne play. In Area 2, the shelf edge anticlines, fault traps and diapirs objectives appear to average about 2,286 meters (7,500 feet) deep.

Reservoir depth in this analysis defines the number of producing systems required to efficiently produce a given field size and, in combination with optimal well spacing, the maximum number of production wells that can be housed in a single producing system whether it be a platform, gravity structure or sub-sea system. All other factors being equal, a shallow field with a thin pay reservoir covering many square kilometers and requiring several systems to produce is less economic than a field of equal reserves with a deep, thick pay zone that can be reached from a single producing system. In the economic and manpower analyses, reservoir depth dictates the rate of development well completion that, in turn, affects 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.

II.3.3 Recoverable Reserves

II.3.3.1 Technical Introduction

An assessment of recoverable reserves in virgin basins, such as these, is very speculative. Recoverable oil from a reservoir is controlled by a combination of the following parameters:

- Oil gravity
- Oil viscosity
- Gas solubility in the oil
- Relative permeability
- Reservoir pressure
- Connate water saturation
- Presence of 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.

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 formation volume factor
- Permability
- 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 areal extent is needed.

Probably the most difficult question to answer in estimating recovery factors is the effect of production rates. The answer to this is based on complex relative permeability effects. Arps' (1967, 1968) studies do not take this into account because of the lack of data on relative permeability.

II.3.3.2 Estimate for Barrow Arch Planning Area

A great difference exists in the recovery rates for North Slope oil fields. On the low end of the scale for reservoir recoveries, information is available to indicate that the Kuparuk River oil field will yield about 31 barrels per acre-foot on primary and 62 barrels per acre-foot on secondary for a total of 93 barrels per acre-foot. At the high end, the Sadlerochit sands will probably yield 350 barrels per acre-foot on primary and an additional 250 barrels per acre-foot on secondary for a total of 600 barrels per acre-foot.

Assuming a recovery factor of 200 barrels per-acre foot and net pay thicknesses of 200 feet, recoverable reserves per acre approximate 40,000 barrels for primary recovery. Secondary recovery would add an additional 50 percent to the primary recovery amount. These figures are used for both Area 1 and Area 2 in this study.

Table A-1 shows maximum recovery per producing system for various reservoir depths for these recoverable reserves. We emphasized 60,000 barrels per acre in the economic analysis. To optimize recovery, we have also assumed that a secondary recovery program (e.g., water injection) is initiated early in the development schedule. The field development plan would incorporate secondary recovery in the producing system and process equipment design since retrofitting for a secondary recovery program could be exceedingly expensive.

An assumption on a range of recoverable reserves per acre is required for this study as a general indication of the potential areal extent of a field for a given (assumed) reserve or field size, assuming simple reservoir geometry. This assumption, in combination with reservoir depth and well productivity, allows an estimate of the number of producing systems and wells required to drain a given field. A "best case" producing system (i.e., fewest producing systems) insofar as reservoir geometry would probably occur in the case of a simple anticline. Obviously, a complex faulted reservoir with the same reserves would necessitate a different producing system configuration, more systems, or even subsea wells. If the incremental recovery could not economically justify investment in an additional system, subsea wells may be required in a complex reservoir to drain isolated portions that could not be reached from directionally-drilled wells.

II.3.4 Production Profiles

II.3.4.1 Oil

The three basic production profile assumptions are: (1) about 40 to 45 percent of the reserves are captured during peak production prior to the

TABLE A-1
MAXIMUM AREA REACHED WITH
DIRECTIONAL WELLS FROM A PLATFORM

DEPTH OF RESERVOIR		MAXIMUM AREA PRODUCED[1,2]			MAXIMUM RECOVERY PER PLATFORM (million barrels)[3]		
METERS	FEET	SQUARE MILES	ACRES	HECTARES	30,000 bbl/acre	60,000 bbl/acre	90,000 bbl/acre
763[4]	2,500	0.25	162	66	4.9	9.7	14.6
1,525	5,000	3.9	2,510	1,016	75.3	150.6	225.9
2,286	7,500	11.7	7,503	3,036	225.1	450.2	675.3
3,000	10,000*	20	13,000	5,000	390	730	1,190

Notes:

1. Maximum angle of deviation assumed to be 60 degrees with a kick-off point at a depth of 150 meters (500 feet); this point is not likely to be more shallow than this.

2. See directional drilling chart Figure 3-21 for geometry below kick-off point.

3. Assumes secondary recovery.

4. For shallow reservoirs, the area of coverage is very sensitive to the depth of the kick-off point.

* Reservoir depth evaluated in this study. This is near the limit of horizontal reach for directional drilling; the area and recovery maximums are therefore only approximate and will not change with further increases in depth.

Source: Dames & Moore

onset of decline; (2) no more than 10 percent of total reserves are captured each year of peak production; and (3) decline is exponential at approximately 10 to 15 percent per year.

The timing of production start-up and build-up to peak is governed by the number of development wells, the reservoir depth (rate of well completion), and numbers of rigs (one or two) operating in the platform. For the Barrow Arch analysis, production is assumed to commence in the sixth or seventh year after the decision to develop, and steps up to peak as a function of well completion rate, numbers of wells, and field size by about the twelfth year after decision to develop. Offshore loading platforms take an extra year to complete and delay production for one year.

II.3.4.2 Associated Gas

While recognizing the complex reservoir dynamics related to the production of associated gas, the economic model requires the analytical simplification of a constant ratio of associated gas to oil production at the assumed gas-oil ratio (GOR). Thus, an initial GOR of 500 standard cubic feet of gas per barrel of oil in Area 1 and 600 standard cubic feet per barrel of oil in Area 2, for example, is maintained throughout the life of the oil-producing field.

II.3.4.3 Non-Associated Gas

The principal production assumptions concerning non-associated gas production are: (1) about 75 percent of the reserves are captured during peak production*; and (2) decline is exponential and rapid thereafter. The factors affecting production time are essentially the same as those for oil; the main difference is that peak gas production generally occurs earlier because fewer wells are required. Typically, gas field production commences in the sixth year after the decision to develop and peak commences in the ninth year.

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* Note this is essentially a plateau in the production profile where gas is produced at constant rate for a number of years (i.e., production at "peak" is essentially "flat").

II.3.5 Field Size and Distribution

Three types of traps of economic importance may be present in each planning area. These are:

Area 1

1. Relatively shallow, closed anticlines resulting from thrusting or slumping.
2. Relatively deep, closed anticlines probably due to compressional forces.
3. Updip pinchouts, onlap and erosional truncation traps on the rise of the Barrow Arch.

Area 2

1. Small-scale doming resulting from upward pressure from shale diapirs and small circumferential traps formed by upwarping of reservoir rocks by piercement diapirs.
2. Closed anticlines parallel to the edge of the continental shelf caused in part by differential compaction over the edge.
3. Updip pinchout, onlap and truncation traps mainly near south margin of north Chukchi Basin.

Indications of all potential traps are visible on the USGS seismic lines in the Barrow Arch planning area but detailed seismic surveys would be necessary to provide an indication of structural closure. Only drilling will actually confirm closure.

Assuming that traps will be hydrocarbon bearing, and assuming seismic data were available to identify structures and estimate the areas of closure, etc., the all important economic problem would be the prediction of percent fill-up. The approach used to predict fill-up would be an analogy based on statistical comparisons with known productive basins. It should be emphasized, however, that any analogical approach to prediction of petroleum resources is extremely speculative. Each basin is unique. One critical difference in geologic parameters can completely negate the effect of many similarities.

Factors affecting percent fill-up are the richness of the source rock and quality of reservoir rock. 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 and 15 percent full, respectively. On the less deformed Coastal Plain province of the North Slope, fill-up is thought to be nearly 100 percent in the Kuparuk oil field.

Unfortunately, there is no reliable way to estimate percent fill-up. We assume that fill-up of 50 percent would be a proper compromise between the extremes that are likely to be encountered.

The field sizes selected for economic screening were consistent with, or reflect, the following factors:

- o Anticipated economic conditions and the requirement to examine a reasonable range of economic sensitivities.

- o Geology (discussed above), which indicates that "giant" fields (billion barrels or more) are a possibility; and

- o National Petroleum Council and U.S. Geological Survey resources estimates;

The field sizes evaluated in this study, therefore, ranged from 300 million barrels to 1.25 billion barrels for oil and 1.5 trillion cubic feet for non-associated gas. It should be noted that once a number of field sizes (with a certain reservoir characteristic and matched engineering) have been evaluated, minimum economic field sizes can be calculated by the model. Therefore, a reasonable range of field sizes to be screened is important rather than the actual field size distribution.

III. TECHNOLOGY AND TECHNICAL ASSUMPTIONS

III.1 Introduction

This section outlines the technical and technology assumptions behind the economic analysis, the principal aim of which was to evaluate the relationships among the engineering strategies that may be adopted to develop Barrow Arch oil and gas resources, and the minimum field sizes required to justify each technology as a function of geologic conditions in the sale area.

III.2 Production Systems Selected for Economic Evaluation

Based upon the results of the petroleum technology assessment (Chapter 3.0), the following production systems were selected for economic screening:

- Caisson-retained gravel islands or gravel islands in 15 meters (50 feet) of water with marine and land pipelines to a marine terminal at Point Belcher and transport via ice-breaking shuttle tankers to an Aleutian transshipment terminal.

- Caisson-retained gravel islands in 15 meters of water with a marine pipeline to shore and an overland pipeline to TAPS.

- Monocones or caisson-retained gravel islands in 37 (121 feet) meters of water with marine and land pipelines to a marine terminal at Point Belcher and transport via ice-breaking shuttle tankers to an Aleutian transshipment terminal.

- An APLA and monocones in 37 meters of water with APLA storage and off-loading for transport via ice-breaking shuttle tankers to an Aleutian transshipment terminal.

- Monocones in 37 meters of water with marine and land pipelines to a marine terminal at Point Belcher and transport via ice-breaking shuttle tankers to an Aleutian transshipment terminal.

- Caisson-retained gravel island in 37 meters of water with marine pipelines to shore and an overland pipeline across the Lisburne Peninsula to a marine terminal at Cape Thompson with transport via ice-breaking tankers to a transshipment terminal in the Aleutians.

III.3 Pipeline Distances and Transportation Options

Distances from potential discovery sites to the potential shore terminal sites are described and illustrated in Chapter 4.0. The following pipeline distances were selected for economic evaluation:

- 60 kilometers (37 miles) of marine trunk and feeder pipelines and onshore pipelines to a marine terminal;

- 60 kilometers of marine trunk and feeder pipelines and onshore pipelines to a 500-kilometer (311-mile) overland pipeline to TAPS;

- 89 kilometers (55 miles) of marine trunk and feeder pipelines and onshore pipelines to a marine terminal;

- 19 kilometers (12 miles) of marine feeder pipeline to an APLA terminal;

- 130 kilometers (81 miles) of marine trunk and feeder pipelines to a marine terminal; and

- 147 kilometers (91 miles) of marine trunk pipelines and onshore pipelines to a marine terminal.

III.4 Other Technical Assumptions

III.4.1 Well Spacing

III.4.1.1 General Considerations for Oil

Based on reservoir depths, initial well productivity, and recoverable reserves per hectare, there will have to be enough wells to meet these production criteria:

- Produce about 10 percent of reserves each year for peak production at a spacing generally between 32 and 65 hectares (80 and 160 acres).

- Allow exhaustion of recoverable reserves within 20 to 25 years.

Well spacings consistent with industry practice, reflecting maximum efficiency rates, and varying as a function of initial well productivity, recoverable reserves per acre, reservoir depth and numbers of wells are implicit in Table A-1. Table A-1 indicates the maximum number of production wells that can be housed on platform for well spacings of 32 and 65 hectares (80 and 160 acres). Based on industry practices in the upper Cook Inlet, well spacing for the Barrow Arch oil fields could range between 16 and 65 hectares (40 and 160 acres) per well. In shallow reservoirs with low IP, wells spacing may be as low as 16 hectares (40 acres). The oil wells in McArthur River field in upper Cook Inlet, for example, are now completed with 32-hectare (80-acre) spacing. Although the original spacing was 65 hectares (160 acres), this was reduced by in-filling as field development proceeded.

At Prudhoe Bay, high production is currently coming from wells on moderate spacing in this unitized field. Ultimate well spacing at Prudhoe Bay may be less, although the actual reservoir management strategy will depend upon reservoir performance. A reasonable assumption, therefore, is that standard industry well spacing of between 32 and 65 hectares (80 and

160 acres) will be adopted for Barrow Arch oil fields; oil fields may be developed initially on a 65-hectare spacing but, subsequently reduced by in-filling to 32-hectare spacing.

III.4.1.2 Non-Associated Gas

As noted in previous scenario studies, well spacing in Alaska frontier areas is likely to be set by the market demand for gas, or frontier constraints on the ability to convert gas to LNG, rather than by industry desire to maximize recovery. Consistent with reservoir engineering and petroleum geology, well spacing up to 486 hectares (1,200 acres) may allow sufficient gas production to run potential LNG capacity. Well spacing in the usual U.S. range of 65 to 130 hectares (160 to 320 acres) may have little relevance to gas producers in the Barrow Arch planning area if there is a limited market for gas.

Given a 60-meter (200-foot) pay section, 20 percent porosity, 60°F temperature correction, 14 psi atmospheric pressure, a 108 billion cubic foot reservoir would produce 65 billion cubic feet at a 130-hectare (320-acre) well spacing assuming a recovery factor of 60 percent.

III.4.1.3 Well Allowances

A certain number of wells in a field are non-producing wells. These wells may be (1) water injection wells required as part of a secondary recovery program, (2) abandoned wells, and (3) gas injection wells drilled either as part of a pressure maintenance program or because there was no market for associated gas. We have assumed that well allowances will be up to one in three wells since water flooding is likely. This is consistent with experience in producing fields although the ratio will be much less for gas reinjection programs. In our analysis we have assumed early initiation of a secondary recovery program. However, it should be emphasized that the number of non-producing wells will vary considerably with reservoir characteristics and reservoir management program. Well allowances are factored into the economic and manpower analyses.

III.4.2 Well Completion Rates

III.4.2.1 Exploration Wells

As indicated in the petroleum geology review, the depth to basement varies considerably across the Barrow Arch area from less than 1,500 meters (5,000 feet) on the flanks of the basin to well over 10,000 meters (33,000 feet) in the interior portions. Prospective reservoirs probably lie at depths ranging from less than 1,500 meters (5,000 feet) to about 7,500 meters (25,000 feet). Consequently, other factors apart, there will be considerable variation in the completion schedules of exploratory wells. Based upon drilling experience in the other OCS areas, medium to deep exploratory wells can be expected to take 3 to 5 months to drill. Actual schedules will vary according to geologic conditions, testing requirements and technical difficulties. For the purposes of manpower estimation and analytical simplification, we have assumed that exploratory and delineation drilling averages 4 months per well.

III.4.2.2 Development Wells

Potential reservoir depths range from 1,000 to 5,000 meters (3,000 to 15,000 feet). Since most of the development wells will be drilled directionally from platforms, their actual length (measured depth) will be greater. Directional wells drilled into the Sadlerochit reservoir (2,400 to 2,800 meters or 8,000 to 9,000 feet) at Prudhoe Bay take an average of 30 days to drill. We will assume 46 days for the 3,000-meter (10,000-foot) reservoirs assumed in the Barrow Arch basin analysis. Wells drilled from offshore platforms may be drilled on the batch principle.

APPENDIX B

ECONOMIC ASSUMPTIONS AND FIELD DEVELOPMENT COMPONENT COST AND SCHEDULES

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APPENDIX B
ECONOMIC ASSUMPTIONS
AND
FIELD DEVELOPMENT COMPONENT COSTS AND SCHEDULES

I. ECONOMIC ANALYSIS

We have adopted the same economic assumptions made for our recently completed Navarin Basin study (Dames & Moore, 1982a). Except for changes in prices and costs, no factors have changed since completion of that study that would warrant any changes in our economic assumptions.

In keeping with our earlier analyses, the Chukchi Sea economic analysis does not reflect the significant cost inflation that could occur as a result of equipment bottlenecks resulting from the proliferation of OCS lease sale activity in other Alaska OCS areas. Our studies have been mandated to evaluate each sale individually and in isolation; the combined or cumulative economic, socioeconomic, and infrastructure effects of several closely-spaced (chronologically) lease sales are not reflected.

Our economic assumptions for the Chukchi Sea are summarized below:

- o <u>Time Value of Money</u>: We have assumed 12 percent discount rate bracket after-tax real hurdle rates. Constant (1982) dollar prices and costs are used.

- o <u>Oil Prices</u>: The value of oil F.O.B. in the Aleutians is $31.50. This results a laid-in Los Angeles price of $34.15 per barrel.

- o <u>Natural Gas Prices</u>: The value of gas is assumed to be $6.75 per thousand cubic feet C.I.F. an LNG tanker at Point Conception. This price is based on an equivalent value per BTU of diesel oil ($42.50 per barrel). Unlike earlier analyses, the California rather than the net-back Alaska value is used in this study. This was done because the gas is assumed to be liquified offshore and transported by dedicated tankers direct to market. Cost for regassification is assumed to be $0.70 per thousand cubic feet.

- Effective Income Tax Rate: We have assumed a ratio of 46 percent of taxable income after various deductions.

- Royalty: We have assumed 16-2/3 percent of the value of production.

- Tax Credits, Depreciation and Depletion: Investment tax credits of 10 percent apply to tangible investments. Depreciation of tangible investments are calculated by the units-of-production method. No depletion is allowed over the production life of the field. Bonus and lease expenses are treated as sunk costs and assumed away for the development decision analysis.

- Fraction of Investment as Intangible Cost: Expenses are written off as intangible drilling costs to the maximum extent permissible by law. Expenses incurred before production are assumed to be expensed against other cash flows of the producer.

  The allocation of tangible investment costs varies with the component parts of offshore development. A 50/50 split between tangible and intangible offshore development costs is used in this analysis.

- Investment Schedule: 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 are expensed against corporate overhead. This is a critical assumption that removes 12 to 36 months of discounting from the ultimate cash flow and makes minimum field sizes calculated smaller than if the lags were included. Investment schedules are further detailed on Table B-9.

II. COST DATA BASE

This section presents cost estimates for the field development and operations used in the economic analysis. Exploration costs are not included (see discussion in Appendix A). The cost estimates given were developed by engineering staff of SF/Braun and supplemented by Dames & Moore.

Several important qualifications need to be discussed with respect to estimating petroleum facility and equipment costs for frontier areas such as the Barrow Arch planning area. Predictions about the costs of petroleum development in frontier areas (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. No offshore area developed to date has the particular combination of sea ice, water depths, weather, remoteness and lack of harbor and onshore facilities that characterize the Barrow Arch planning area. As such, there is little or no engineering and direct cost experience upon which to make these cost estimates.

Petroleum development cost data are based on either direct cost experience of projects in current producing areas such as the Gulf of Mexico and North Sea or about to be produced areas such as the U.S. or Canadian Beaufort Sea, or projections based upon experience elsewhere modified for the technical and environmental constraints of the frontier area. For arctic areas, facility cost projections may involve estimates for new technologies, construction techniques, etc. that have no base of previous experience (e.g., offshore LNG). It should be emphasized that in-depth research on production technologies and related costs for the Arctic Ocean basins has begun only in recent years.

The approach in this study involved cost estimating by petroleum, drilling, pipeline and marine engineers. In the course of earlier Alaska OCS studies on the Gulf of Alaska (Dames & Moore 1979a and b), lower Cook Inlet (Dames & Moore 1979c), Norton Sound (Dames & Moore 1980a), St. George Basin (Dames & Moore 1980c), and Navarin Basin (Dames & Moore 1982), a considerable data base on petroleum facility costs for offshore areas was obtained that provided supplemental information for this study. Those data were based on published literature, interviews with oil companies, construction companies, and government agencies involved in OCS research.

In addition to the difficulties in obtaining relevant and comparable cost data (which applied as well to our earlier Bering Sea studies), the extreme ice conditions and lack of comparable development experience in the arctic regions imposed even greater cost estimation uncertainties. As a result, Barrow Arch cost estimates are even more speculative than those for earlier studies. Where primary source data were unavailable (particularly in the case of gas production), cost estimates were obtained from the National Petroleum Council's recent report U.S. Arctic Oil and Gas (1981).

III. COST AND FIELD DEVELOPMENT SCHEDULE UNCERTAINTIES

As explained in Chapter 6.0 of 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 development economics of the lease area, which comprises a number of prospects that will have a range of reservoir and hydrocarbon characteristics. This requires a set of assumptions on reservoir and hydrocarbon characteristics and technology (see Appendix A). The facilities cost data, presented in Tables B-1 through B-8 present these assumptions.

It should be emphasized that field development costs actually 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 processing equipment costs 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. In order to focus on the key development issues and keep the analysis manageable, not all these economic sensitivities can be accommodated.

Other factors, such as market conditions, also play a role in field development costs. The price an operator pays for a concrete platform, for example, will be influenced by availability of fabrication and graving dock facilities and whether he is in a buyer's or seller's 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 costs presented in Tables B-1 through B-8 reflect our estimates of the facility and equipment costs, based on the stated simplifying assumptions. All the cost figures are given in 1982 dollars.

Briefly discussed below are the principal uncertainties relating to the cost estimates for the various facility components. Important assumptions are noted in the tables.

III.1 Platform Fabrication and Installation (Table B-1)

Cost estimates are presented for four types of offshore production systems--concrete monocones, gravel islands, caisson-retained gravel islands, and artificial production and loading atolls (APLA) -- in water depths representative of the high interest areas in the Chukchi Basin. These costs include design, manufacture, tow-out, and installation of monocones and retaining structures and mobilization and operation of gravel dredges.

III.2 Platform Process Equipment (Tables B-2 and B-3)

There is little difference in cost related to the decision to produce or reinject associated gas. For the range of figures and type of construction we have assumed, the major cost is equipment installation, not the cost of hardware. Costs for waterflood are included as are costs for drilling equipment. Drilling supplies and operating costs are included in the cost of wells. The gas-oil ratio is assumed to be 500:1 for all oil fields.

As the gas-oil ratio increases, the size of the pressure or production vessels and pipelines increase. Larger, more sophisticated equipment is required to handle the gas. At some point, depending on the amount of gas handled, the amount of entrained liquids, and costs, it becomes economical to take the natural gas liquids, stabilize them, and inject this stream into the oil pipeline. Associated gas may be reinjected into the reservoir to maintain pressure and to prolong the flowing life of the well. If natural gas production is not economically feasible, reinjection of associated gas is the only viable solution to the flaring ban imposed upon producing fields.

On offshore platforms, especially gravel islands or APLA's, space requirements for larger process vessels, pipelines and the increased equipment requirements for gas processing usually will not dramatically affect the platform costs.

The costs for platform process equipment for a secondary recovery program (e.g., water injection) are much reduced if planned from the beginning. When water is injected, some of the drilling slots must be used, thus reducing the number available for production and, in turn, reducing the production rate and revenue flow. Also, more space is required for equipment. However, given the platform designs considered, this would have little effect on overall installed platform costs.

III.3 Production Wells (Table B-4)

Production wells are assumed to be drilled from platform-mounted rigs. Two rigs would be used initially in developing the specified oil fields. These rigs are able to drill a well every 56 days for a total of 13 wells per platform per year during production step-up. Once the initial drilling period is over, one rig would be removed, while the second would remain on the platform for workovers.

Gas wells are similar in design and cost to oil wells. Since fewer wells are assumed drilled from each platform, only a single rig would be installed on each gas platform.

III.4 Marine Pipelines (Table B-5)

Because of the unique considerations of landfalls, hook-ups, trenching, burying, and mobilization and demobilization, it was necessary to cost out the pipeline requirements of each scenario individually. These costs appear in Table B-5. Where appropriate, the cost of each of the above considerations was factored into the cost estimates. For example, Scenario 4A, where mobilization occurs for only one pipe string, the cost for that string reflects the extra mobilization/demobilization costs for the lay barge.

The costs for pipeline in the Chukchi Sea are much higher than those reported in technology assessments for the sub-arctic due to the very short (estimated 70-day) open-water working season.

III.5 Oil Terminal Costs (Table B-6)

Particular uncertainty exists regarding crude oil terminal costs in the more remote areas of Alaska. 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. Rugged terrain 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's Valdez terminal. 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. Consequently, these costs are more speculative than most presented in this report.

Two studies have addressed the economics of terminal siting and marine transportation options in the Bering Sea (Global Marine Engineering 1977, Engineering Computers Opteconomics 1977). A third study addressing these problems was conducted for the Alaska Oil and Gas Association (AOGA) and is currently proprietary.

As indicated in Table B-6, it is assumed that the Point Belcher or Cape Thompson marine terminal would combine the functions of a partial processing facility (to upgrade crude for tanker transport) and a storage and loading terminal. It is assumed that an Aleutian Island terminal would serve as: (1) a transshipment facility for fields that may employ offshore loading, and/or (2) a transshipment terminal where crude from the Chukchi Sea would be transferred from ice-breaking tankers to conventional tankers bound for the Lower 48 states. The Aleutian terminal includes the cost of a deep water mooring for loading VLCC tankers, and the cost of tanker ballast treatment facilities. All costs for terminals of 300,000 barrels per day throughput apply to all scenarios except Scenario 5. For that scenario, the 100,000 barrels per day throughput costs apply.

III.6 Costs Estimates for Tankers, Tugs and Workboats (Table B-7)

Production of the Chukchi Basin's oil and gas resources requires ice-breaking oil and LNG tankers and ice-breaking workboats and tugs. In all oil development, Class 7 1.5 million barrel (200,000 DWT) tankers are assumed for the shuttle between the Chukchi Sea and the Aleutian Island terminal.

No ice-reinforced LNG tankers exist at present, although they are being designed. The design configuration and cost for those vessels is taken from the National Petroleum Council (Section E of the 1981 draft).

Workboats with ice-breaking capability would be required at a Chukchi Sea terminal and to serve the offshore platforms. Costs on Table B-7 are based on a 290-foot 2,000-DWT vessel developing 18,000 horsepower. These estimates were provided by SF/Braun.

III.7 Annual Operating Costs (Table B-8)

The costs for owning and operating offshore production units, pipelines, marine terminals and ships are shown on Table B-8. These costs were obtained from the National Petroleum Council (1981) and from McMullin (1980). General and administrative costs decline significantly as the number of platforms increase. A distinction is made between the high level of administrative support required during construction and the lower level of administrative activity needed once the production routine is established.

III.8 Miscellaneous Costs Estimate

In the economic analysis, 10 percent of the total field development costs (including pipelines and terminals) has been added to the total capital expenditures for costs that cannot be readily classified (e.g., flare booms). This cost is based on a review of the North Sea field development costs.

III.9 Scheduling of Capital Expenditures and Method of Analysis (Table B-9)

The cost tables presented in this appendix are the basic inputs in the economic analysis. Each case analyzed is essentially defined by recoverable reserves, reservoir characteristics, and production technology (type of platform, transportation option, distance from shore terminal). To cost a particular case, the economist matches the engineering to the assumed reservoir conditions, selects the production technology, and takes the related required cost components from Tables B-1 through B-8 using a building block approach; in some cases this involves deletion or substitution of a facility or equipment item. The reservoir engineering of cases is further explained in Appendix A.

The cost components of each case are scheduled as indicated on Table B-9. The schedules of capital cost expenditures are based upon typical development schedules in other offshore areas modified for the environmental conditions of the Chukchi Basin and making certain assumptions on field construction schedules.

TABLE B-1

COST ESTIMATES FOR INSTALLED PLATFORMS AND ARTIFICIAL ISLANDS[1]

PLATFORM TYPE	WATER DEPTH METERS	FEET	INSTALLED COST ($ Millions 1982)
Concrete Monocones:	36	120	480
	60	200	670[2]
Gravel Islands	15	50	165
Caisson-Retained Gravel Islands	15	50	130
	27	90	216
	36	120	340

Notes: (1) In addition to fabrication of the gravity structure in a Lower 48 yard, these estimates include the cost of platform installation, which involves site preparation, tow-out, set-down and pile driving. The above estimates do not include any allowance for the installation or hook-up of topside facilities (see Tables B-2 and B-3).

(2) At this depth, a 36-meter (120-foot) monocone would be placed on a submerged berm island 24 meters (80 feet) high.

Source: SF/Braun

TABLE B-2

COST ESTIMATES FOR PLATFORM EQUIPMENT[1] AND FACILITIES FOR OIL PRODUCTION

PEAK CAPACITY OIL (Barrels Per Day)	COST[2] ($ Million 1982)
100,000 to pipeline	300[3]

Notes: (1) The cost of topside facilities would be essentially the same for all the platform types being considered.

(2) The above cost estimates include installation, hook-up, and commissioning. It is assumed that module installation would be concurrent with platform installation, thus avoiding a second mobilization and demobilization of the equipment.

(3) Gas/oil ratio is assumed 500:1. If significantly lower ratios are encountered, these costs could be up to 20 percent lower. Waterflood equipment is included.

Source: SF/Braun

TABLE B-3

COST ESTIMATES FOR PLATFORM EQUIPMENT AND FACILITIES FOR GAS PRODUCTION

PEAK CAPACITY GAS (Thousand MCF Per Day)	COST ($ Million 1982)
250-330 (production equipment)	360

Notes: 1. The cost of topside facilities would be essentially the same for all the platform types being considered.

2. The above cost estimates include installation, hook-up, and commissioning. It is assumed that module installation would be concurrent with platform installation, thus avoiding a second mobilization and demobilization of the equipment.

3. This cost only applies to offshore loading equipment. Onshore LNG equipment is discussed under terminals.

Source: National Petroleum Council (1981).

TABLE B-4

COST ESTIMATES OF PRODUCTION WELLS
(OIL OR GAS)

WELL TYPE	RESERVOIR DEPTH METERS	RESERVOIR DEPTH FEET	COST ($) MILLION (1982)
Production Well			
(Drilled from on-platform rig)	3,000	10,000	6.0

Source: SF/Braun

Notes: 1. Well is assumed to be directionally drilled (below the mud line).

2. Includes rig cost for two rigs, one of which will remain on the platform for workovers; in the gas scenarios include one rig.

3. Includes mobilization costs, operating cost, and consumables.

TABLE B-5

COST ESTIMATES FOR MARINE & ONSHORE OIL AND GAS PIPELINES

SCENARIO	MARINE PIPELINES	COST ($MILLION 1982)	ONSHORE PIPELINES	COST ($MILLION 1982)
OIL				
1A, 1B	Trunk = 7 km (4 mi) @ 22" Feeder = 2-9 km (6 mi) @ 12"	43 74	Point Franklin to Point Belcher 34 km (21 mi) @ 22"	113
2	See Above	43 74	See Above Plus 498 km (310 mi) Point Belcher to TAPS including 3 pump stations	113 2,100
3A, 3B	Trunk = 43 km (27 mi) @ 26" Feeders = 2-9.6 km (6 mi) @ 12"	138 74	Wainwright to Point Belcher 27 km (17 mi) @ 26"	93
3C	Trunk = 43 km (27 mi) @ 28" Feeders = 2-9.6 km (6 mi) @ 12"	158 74	Wainwright to Point Belcher 27 km (17 mi) @ 28"	121
4A	Feeders = 2-9.6 km (6 mi) @12"	82	None	
4B	Trunk = 86 km (54 mi) @ 32" Feeders - 2-9.6 km (6 mi) @ 12"	424	Wainwright to Point Belcher 27 km (17 mi) @ 26"	93
5	Trunk = 51 km (32 mi) @ 16"	168	Cape Sabine to Cape Thompson 97 km (60 mi) @ 16" including one pump station	350
GAS				
6	Trunk = 43 km (27 mi) @ 36" Feeders = 2-9.6 km (6 mi)	223 74	Wainwright to Point Belcher 27 km (17 mi) @ 30"	130

Notes:
1. Trenching and/or insulation is assumed where required.
2. Includes mobilization/demobilization of a ship-type lay barge.
3. Includes cost of landfalls and hookups.

Source: SF/Braun

TABLE B-6

ESTIMATED COST OF OIL TERMINALS

Peak Throughput (Thousand Barrels Per Day)	Chukchi(1) Terminal Capital Cost	Aleutians(2) Terminal Capital Cost
100	500	600
300	950	1300

Notes: (1) Including facilities for any final crude stabilization, storage of 10 days' throughput and docking and loading for shuttle tankers.

(2) Includes facilities for docking and unloading shuttle tankers, storage of 10 days' throughput, tanker ballast water treatment, diesel fuel storage, shuttle tanker maintenance, and VLCC docking and loading.

Source: SF/Braun and Dames & Moore

TABLE B-7

ESTIMATES OF COSTS AND ANNUAL OPERATING EXPENSES FOR TANKERS AND WORK BOATS

VESSEL TYPE	CAPITAL COST ($ MILLION 1982)	ANNUAL OPERATING COST ($ MILLION 1982)
1. Ice-Capable 200,000 DWT Oil Tanker	380	29
2. Ice-Capable 140,000 cubic meters LNG Tanker	310	31
3. Ice-Breaking Workboats (support vessels) - 140 feet	75	28
4. Tugs - Port Duty	60	22
Sea Duty	60	35

Sources: SF/Braun and National Petroleum Council.

TABLE B-8

OPERATING AND GENERAL AND ADMINISTRATIVE COST FOR CHUKCHI OIL PRODUCTION
($ MILLION 1982)

	Scenario							
	1A	1B	2	3A	3B	4	5	Gas
Facility Production	80	80	80	80	80	80	40	890
Pipelines								
Marine								
Onshore: To Terminal	1	1	1	2	2	2	20	2
To TAPS			131					
TAPS			$6.50BBL					
Ships								
Tankers	119	119		119	119	119	40	216
Ice Breakers:								
Sea Duty	22	22		22	22	22	22	22
Port Duty	35	35	35	35	35	35	35	35
Support Vessels	28	28	28	56	56	56	28	56
Terminals								
Receiving	20	20		20	20		18	40
Transshipment	42	42		42	42	42	38	0
TOTAL - ANNUAL COST	347	347	275	376	376	356	239	451
Operating Cost	312	312	248	338	338	320	215	406
General & Administrative	35	35	27	38	38	36	24	45

Source: National Petroleum Council (1981), Dames & Moore

TABLE B-9

SCHEDULING OF CAPITAL INVESTMENTS FOR PETROLEUM DEVELOPMENT FACILITIES IN THE CHUKCHI SEA

	Year[1]								
	1	2	3	4	5	6	7	8	9
Scenario 1a, 1b, 2, 3a	Percent of Expenditure								
Island (or Monocone) Construction	10	30	30	30					
Deck Equipment	0	10	25	25	25	15			
Pipelines	0	10	15	50	25				
Pipelines to TAPS or Cape Thompson	10	15	25	25	25				
Terminals	5	20	20	25	20	10			
Tankers	0	6	19	25	25	19	6		
Support Vessels	0	25	25	25	25				
Wells	0	0	0	15	30	30	25		
Scenarios 3b, 4, 5									
Island (or APLA) Construction	10	25	25	25	15				
Deck Equipment	0	0	10	25	25	25	15		
Pipelines	0	10	15	50	25				
Terminals	0	5	20	20	25	20	10		
Oil Tankers (Exc. Scenario 5)	0	0	6	19	25	25	19	6	
Tankers (Scenario 5)	0	0	25	25	25				
LNG Tankers			14	20	25	25	11	5	
Support Vessels	0	0	25	25	25	25			
Wells	0	0	0	0	15	30	30	25	

Notes: (1) Years are counted from decision to develop.