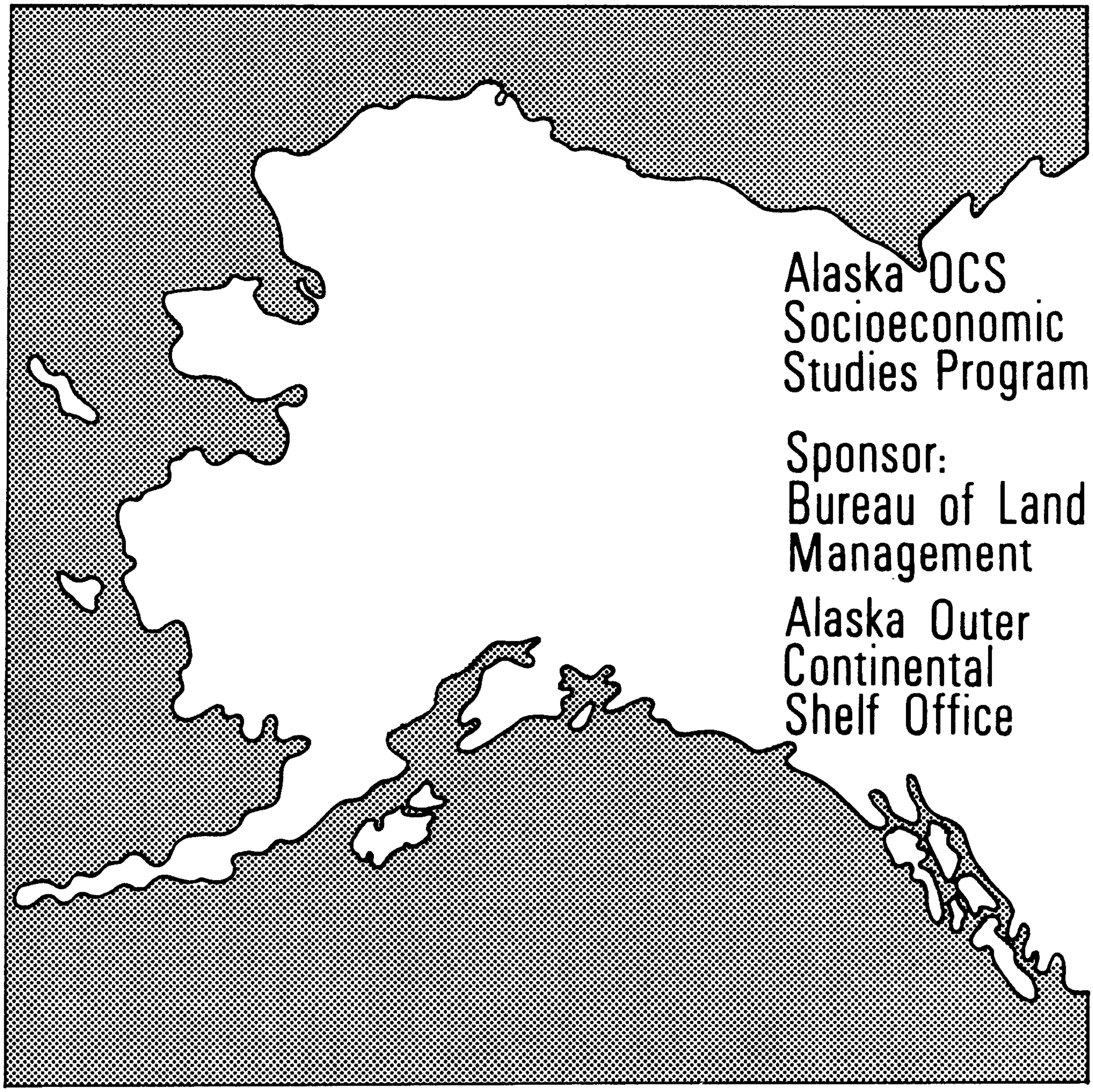
Technical Report Number 63



Alaska OCS Socioeconomic Studies Program

Sponsor:
Bureau of Land Management
Alaska Outer Continental Shelf Office

North Aleutian Shelf 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 63

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
NORTH ALEUTIAN SHELF
PETROLEUM TECHNOLOGY ASSESSMENT
OCS LEASE SALE NO. 75

FINAL REPORT

Prepared for

BUREAU OF LAND MANAGEMENT
ALASKA OUTER CONTINENTAL SHELF OFFICE

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December 1980

Contract No. AA851-CTO-3 Job No. 8699-023-20

NOTICES

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

2. This report is designed to provide preliminary petroleum development data to the groups working on the Alaska OCS Socioeconomic Studies Program. The assumptions used to generate this petroleum technology assessment may be subject to revision.

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

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
North Aleutian Shelf
OCS Lease Sale No. 75
Draft Report

Technical Report No. 63

Prepared by

DAMES & MOORE

December 1980

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1.0 INTRODUCTION

1.1 Purpose

The principal purpose of this study is to identify the petroleum technology that may be used to develop oil and gas resources of the North Aleutian Shelf OCS Lease Sale No. 75. 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.) identifies the most suitable engineering strategies.

The second purpose of this study is to assess the economic viability of various development strategies under different reservoir, environmental, locational, and cost assumptions. The third purpose of this study is to estimate the manpower required to construct and operate the facilities.

This study is structured to provide "building blocks" of petroleum facilities, equipment, costs, and employment that can be used by Bureau of Land Management Alaska OCS Office staff to evaluate nominated lease tracts. A number of feasible field development strategies (types of platforms, transportation options, etc.) are specified, and suitable shore facility sites for representative discovery locations in the lease sale area are identified. The field development strategies are technically feasible and economically viable under the assumptions given.

Petroleum technology will determine or influence the scheduling of offshore and onshore activities, the local employment and infrastructure support requirements, and the potential hazards involved in the production and transportation of hydrocarbons and related potential for environmental impacts.

Thus, the petroleum technology assessment provides the necessary framework to assess environmental and socioeconomic impacts of the North Aleutian Shelf petroleum development.

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 Bureau of Land Management, including environmental impact statements, are required to use U.S. Geological Survey estimates of recoverable oil and gas. The assumptions used in the analysis may be subject to revision as new data become available.

1.2 Scope

This petroleum technology assessment is for the proposed North Aleutian OCS Lease Sale No. 75. Scheduled for October 1983, it will be the third Bering Sea OCS lease sale (following that of Norton Sound Sale No. 57 scheduled for November 1982, and St. George Basin scheduled for December 1982). The study area considered in this report encompasses the call for nominations issued by the BLM Alaska OCS Office (Figure 1-1). This area, which lies to the north of the Alaska Peninsula, is bounded by longitude 160°00' W on the east and longitude 165°00' W on the west and extends from the 3-mile limit northward to latitude 56°30' N. Included within this area are the southern half of the Bristol Bay sedimentary basin (part of which extends onshore on the Alaska Peninsula) and the Amak Basin, which lies almost entirely offshore.

Water depths in this lease sale area range from 120 meters (394 feet) in the west to about 15 meters (50 feet) at the 3-mile limit. Over 50 percent of the area lies in water depths between 55 and 91 meters (180 and 300 feet). The sale area lies at the southern extremity of sea ice in the Bering Sea. Occasional incursions of sea ice into the area can be anticipated. The central portion of the lease sale area lies about 97 kilometers (60 miles) north of Cold Bay and pipeline distances to shore will probably not exceed 129 kilometers (90 miles).

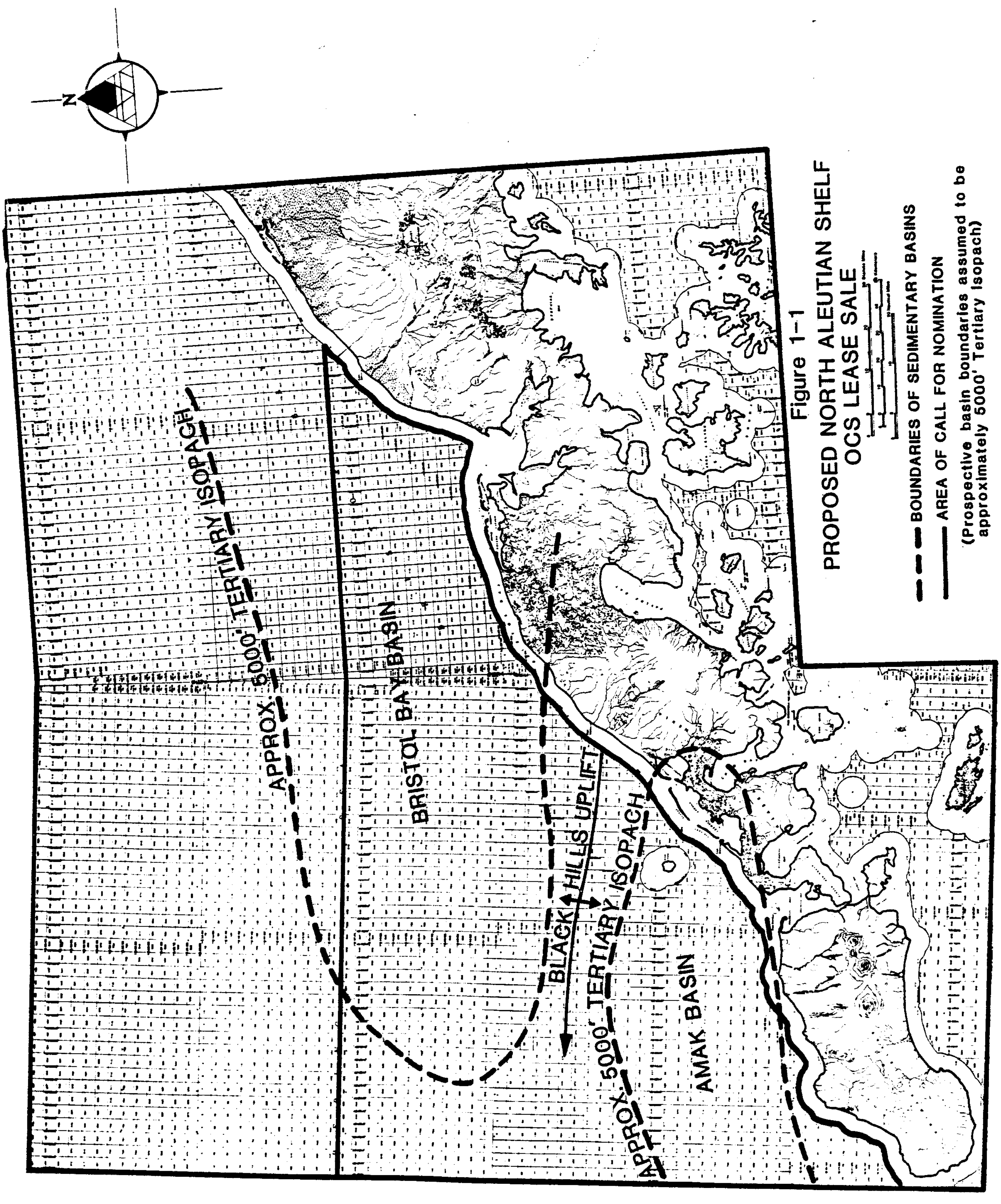


Figure 1-1
PROPOSED NORTH ALEUTIAN SHELF
OCS LEASE SALE

The principal components of this study are:

- An evaluation of the environmental constraints (oceanography, geology) that will influence or determine petroleum engineering and field development and transportation strategies (Chapter 3.0);
- A description of various field development components and strategies and related technical problems (Chapter 3.0);
- A facilities siting evaluation to identify suitable shore sites for major petroleum facilities such as crude oil terminals, LNG plants and support bases (Chapter 7.0);
- An analysis of the manpower requirements to explore, develop, and produce North Aleutian Shelf petroleum resources in the context of projected technology, and environmental and logistical constraints (Chapter 5.0). This includes specification of manpower requirements by individual tasks and facilities;
- A review of the petroleum geology of North Aleutian Shelf to formulate reservoir and production assumptions necessary for the economic analysis (Appendix A);
- An economic analysis of North Aleutian Shelf petroleum resources in the context of projected technology, facility and equipment costs, and various assumed reservoir characteristics; and
- Specification of the manpower, facility, and equipment requirements and probable production for a hypothetical development case corresponding to the U.S. Geological Survey statistical mean oil and gas resource estimate for the basin.

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 oceanographic surveys conducted by the National Oceanic and Atmospheric Administration. No proprietary data was 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 - Sea ice, wave, and current data required for platform design are limited.
- Petroleum geology - Insufficient geophysical data were available to identify all structures, estimate area of structural closure, and estimate thickness of reservoir rock sections.
- Facility Cost - The petroleum facility cost estimates (for platforms, pipelines, terminals, etc.) are tentative; no petroleum exploration and production has yet taken place in areas with similar conditions that may provide operational and cost experience.

1.4 Report Content and Format

This report is written as a companion report to St. George Basin Petroleum Technology Assessment OCS Lease Sale No. 70 (Dames & Moore, August 1980), which presents the results of a study conducted for the adjacent lease sale. As such the analytical approach, basic data gathering, and analysis were structured to accommodate both studies. Much of the baseline data and analysis is, therefore, applicable to this study. Rather than reiterate pertinant information, we have cross-referenced relevant sections in the St. George report and focused upon the contrasts between the two lease sale areas.

This report commences with a summary of findings (Chapter 2.0). The results of the petroleum technology assessment are presented in Chapter 3.0. Siting criteria and suitable shore sites for major petroleum facilities are identified and described in Chapter 4.0. Chapter 5.0 details the manpower requirements by task, activity, and facilities for general OCS petroleum development and the particular technology described in Chapter 3.0. The results of the economic analysis, based upon the resources estimated by the U.S. Geological Survey, are presented in Chapter 6.0. Chapter 7.0 concludes the main body of the report with a description of a hypothetical development case.

Appendix A presents a description of the North Aleutian Shelf petroleum geology and the methods and assumptions of the technology assessment.

Appendix B gives the petroleum development costs and scheduling assumptions upon which the economic analysis is based.

2.0 SUMMARY OF FINDINGS

2.1 Petroleum Geology and Resource Estimates

The U.S. Geological Survey conditional estimates of undiscovered oil and gas resources of the North Aleutian Shelf lease sale that form the basis of this study are (Marlow et al., 1980):

	Probability		Statistical
	95 percent	5 percent	Mean
Oil (billions of barrels)	0.1	2.3	0.7
Gas (trillions of cubic feet)	0.1	5.8	1.5

The North Aleutian Shelf is a term applied to the southern half of Bristol Bay located on the north side of the Alaska Peninsula. The lease sale area covers the southern half of the Bristol Bay sedimentary basin, the offshore extension of the Black Hills uplift, and the offshore Amak sedimentary basin. A portion of the Bristol Bay Basin and Black Hills uplift are expressed on the Alaska Peninsula, but the major parts of these tectonic units are located beneath the waters of Bristol Bay. The Amak Basin lies almost entirely offshore.

The Bristol Bay Basin is a northwest trending elongate sedimentary basin that parallels the long axis of the Alaska Peninsula and is located on the north side of the peninsula. The basin extends northeast from Black Hills for 595 kilometers (370 miles) to about the west edge of Iliamna Lake.

An extremely thick section (more than 15,240 meters or 50,000 feet) of Mesozoic and Tertiary sediments is exposed on the Alaska Peninsula, and provides important stratigraphic information on the prospects of that portion of the basin that lies beneath Bristol Bay.

Based upon analysis of limited geophysical data, review of onshore well data from the Alaska Peninsula, other published data, and qualified analogies with other Pacific Margin Tertiary basins, a set of reservoir and production assumptions was formulated for the economic analysis. These assumptions also provide the basis for specification of a hypotehtical development case corresponding to the U.S. Geological Survey statistical mean resource estimate. The assumptions are:

- Reservoir depths -- 914 meters (3000 feet), 1527 meters (5000 feet), 3048 meters (10,000 feet)
- Recoverable reserves per acre -- 30,000 - 90,000 barrels (assuming secondary recovery)
- Well spacing -- variable according to numbers of wells and other factors, but consistent with ranges in producing fields
- Initial well productivity, oil -- 2000, 3000, and 5000 barrels per day(1)
- Initial well productivity, gas -- 10 and 15 million cubic feet per day(1)
- Gas resource allocation between associated and non-associated -- 30 percent and 70 percent, respectively
- Gas-oil ration (GOR) -- 1000 standard cubic feet per barrel
- Peak production, oil -- about 10 percent of reserves per year; 45 percent of total reserves captured before decline begins; exponential decline at about 10 percent per year(1)
- Peak production, non-associated gas -- about 75 percent of total reserves captured before decline begins

---

(1)Some reviewers of the draft report believed that the initial productivity and decline rates may be optimistic. However, these parameters have also been selected to test the economic and technical impacts of geologic diversity.

No assumption was made on the physical properties of the oil; the range of prices used in the analysis is partly a function of the potential range in crude qualities. This study also considers the effect of crude qualities in the market analysis of North Aleutian Shelf oil production.

2.2 Environmental Constraints

2.2.1 Oceanography

The oceanographic characteristics of the North Aleutian Shelf lease sale area are quite similar to those of the St. George Basin lease sale area lying to the northwest. One of the primary differences is the somewhat shallower overall depth exhibited in the North Aleutian Shelf area with depths ranging from 50 - 120 meters (164 - 394 feet). The minimum depth in the St. George Basin is 100 meters (328 feet).

In addition, the North Aleutian Shelf is entirely within Bristol Bay with the Alaska Peninsula and the Aleutians to the immediate south. Consequently, it is more sheltered than the St. George Basin sale area with respect to the long fetches required to generate large waves. The occurrence of very large waves should be relatively rare, and the shallow depths, limited fetch, and variable wind climate will tend to produce a very choppy, short-period "sea" as opposed to a more regular, longer-period "swell." This may present more of an operational problem than a major design constraint.

The circulation in Bristol Bay consists primarily of a counter-clockwise gyre generated by wind, localized thermohaline effects, and in part by the Coriolis force. The tidal amplitudes around the perimeter of the bay range from 1 - 7 meters (3 - 23 feet) with the higher tides tending to occur at the head of embayments and estuaries.

Sea ice may be encountered throughout the lease sale area. This ice should only occur in isolated floes, but even floes of first-year ice driven by the local wind climate will present a major design consideration.

2.2.2 Geology

The general marine geology, and specifically the petroleum geology, of the North Aleutian Basin province has received little attention in available literature. Two sediment-filled basins believed to have production potential lie partly within the lease area: the Amak and the Bristol Bay Basins. The basins are separated by a basement ridge extending offshore from the Black Hills region of the Alaska Peninsula.

The geological hazards pertaining to petroleum development and production are known only by analogy to other areas on the Bering Shelf. The most likely hazards are expected to be derived from faulting (perhaps with seafloor displacement), from the possible existence of shallow gas pockets in the sedimentary section, from seismic activity associated with local faulting, and from major faulting along the southern side of the Alaska Peninsula and Aleutian Arc.

The seafloor sediments are predominantly sandy and the seafloor itself is extremely flat; the potential for mass movement of bottom sediments is not expected to be significant.

The potential for earthquakes and resulting ground motions is very high for the area and may present the limiting design criterion. The seismic design of structures should follow guidelines established in the American Petroleum Institute RP 2A (Tenth Edition), using Zone 4 criteria and assuming API soil type C.

Active volcanoes lie immediately south of the lease area along the Alaska Peninsula and may present local hazards to onshore or nearshore treatment and transshipment facilities and pipelines.

2.3 Technology, Production Systems, and Field Development Strategies For the North Aleutian Shelf

As with St. George Basin, exploratory drilling in the North Aleutian Shelf is within the operational capabilities of semi-submersibles, drillships, and jackup rigs (in the shallower portions). The principal technical problem may be the need to develop year-round capability in areas where sea ice is a possibility between January and April. Following the lead of Dome Petroleum in the Canadian Beaufort Sea, where reinforced drillships supported by ice breakers drill well into the fall, similar equipment and techniques could make winter drilling feasible in areas of significantly less severe ice conditions. Dynamically positioned semi-submersibles or drillships, possibly supported by ice breakers, may also be an option for winter drilling.

Other problems facing exploratory drilling in this area include the high frequency of summer fogs and potentially severe structural icing in the winter that would pose hazards for both the rigs and their support vessels.

The principal design criteria for production platforms in this area (not necessarily in order of importance) are:

1. Ice loading

2. Seismic loading (more sensitive for gravity designs)

3. Other environmental loading (including winds, waves, and currents)

4. Installation and fabrication capabilities

5. Conductor well spacing

6. Directional drilling

7. Superstructure icing

8. Storage (required for supplies and possibly oil storage)

9. Topside facilities

Among the more important of these criteria are seismic loading, ice loading, wind and waves, and topside requirements.

To identify appropriate drilling and production platforms for the North Aleutian Shelf, we have specified three representative water depths -- 15 meters (50 feet), 46 meters (150 feet), and 91 meters (300 feet). The production platforms feasible for these representative water depths are:

- Steel Jacket: This could be a Cook Inlet structure, at least for the two shallower water depths (15 and 46 meters). The deep water structure (91 meters) probably would be similar to one proposed for the St. George Basin, wherein the jacket would be supported by external skirt piles. A typical structure would have four legs. The platforms for the 15- and 46-meter sites would have internal piles; all would have conductors inside the legs. Until additional ice data are available, the necessary conservative approach requires that platforms must be designed for ice conditions, no matter how minimal the forces appear. External (or conventional) conductors would not be feasible.

- Steel Gravity Structure: As noted above, due to the high possibility of seismic activity in this area, conventional concrete gravity structures cannot be recommended. Some of the problems being experienced on existing concrete gravity platforms in the North Sea (which has little or no seismic activity) could be serious in a Zone 4 seismic area. Therefore, until the design becomes more state-of-the-art, we question the use of concrete gravity platforms in the Zone 4 area. We believe, however, that the steel gravity platform may be feasible, depending on bottom conditions. This platform probably would be a single leg or monopod structure with all conductors internal in the "neck." Although it may have more than one leg, all conductors would be internal.

These platform designs have a limited number of well slots that can be accommodated, since the conductors are located within the platform legs. The optimum number of well slots would be 32 - 48, depending on the size of the conductors and design criteria. The shallow water Cook Inlet structure probably could accommodate 32 slots at most. Designs for deeper water (e.g., 91 meters) probably could accommodate 48. The maximum of 48 slots is based upon state-of-the-art design capabilities for this platform.

Offshore pipelines to reach Alaska Peninsula terminal sites will be less than 129 kilometers (80 miles), and more typical distances will be on the order of 48 - 64 kilometers (30 - 40 miles). Maximum offshore pipeline distances in the Bristol Bay Basin generally will increase westward, since the basin trends offshore in a westerly direction.

Maximum onshore pipeline distances, depending on landfall and terminal locations, will be about 160 kilometers (100 miles). However, assuming a favorable landfall on the Bristol Bay coast, pipeline distances across the peninsula to reach Pacific Ocean terminal sites would range from as little as 19 kilometers (12 miles) to Cold Bay to 105 kilometers (65 miles) to Mitrofania.

An alternative to transporting oil production to shore through a pipeline is offshore loading of crude directly tied up to a mooring/oil transfer buoy. Our remarks concerning the application of offshore loading systems to St. George Basin are equally applicable to the North Aleutian Shelf. The possibility of ice encounter in winter and extensive summer fog detracts from the feasibility of this production system. Further, since pipeline distances to suitable shore terminal sites from discoveries in the North Aleutian Shelf lease sale area generally will be shorter than those in St. George Basin, there will be less incentive, other factors being equal, to select an offshore loading system in the North Aleutian area.

The role of subsea completions in North Aleutian Shelf petroleum development, like that indicated for St. George Basin, probably will be restricted to subsea satellite well-heads connected to a mother platform in fields where the reservoir is shallow, complex, or when low production rates do not justify additional platforms (see discussion in Section 3.3.6 of the St. George report). The relatively shallow waters (15 - 91 meters) of the North Aleutian Shelf lease sale area do not appear to warrant extensive use of subsea completions or complete subsea production systems.

Based upon the results of the technology assessment presented in this report, the basic production system selected for evaluation in the economic analysis as the most likely development strategy in the North Aleutian Shelf is one or more steel platforms (upper Cook Inlet design or steel jacket/upper Cook Inlet hybrid design, depending upon water depth) sharing oil and/or gas trunk pipelines to a terminal located on the Pacific Ocean coast of the Alaska Peninsula. Steel gravity platforms, though regarded as a less likely option, were evaluated. Since offshore pipeline distances can be anticipated to be generally less than 129 kilometers (80 miles), intermediate pump or compressor station platforms may not be required. However, depending upon the pipeline landfall and location of the selected terminal site, intermediate pump or compressor stations may be required onshore.

Uncertainty exists regarding the feasibility and cost of offshore loading systems in North Aleutian Shelf. Because there probably will be less incentive than in St. George Basin to use these systems, we have not evaluated their economics. The reader is referred to the economic analysis in Chapter 6.0 of the final St. George Basin report.

Because of the sea ice conditions in North Aleutian Shelf, floating systems with subsea completions such as the Tension Leg Platform (TLP) or converted semi-submersible early production systems (e.g., North Sea Argyll field) may not be feasible. No attempt was made to cost and evaluate the economics of such systems.

The following production systems were selected for economic screening:

- Single or multiple steel platforms with shared or unshared pipeline to shore terminal -- oil production;
- Single or multiple steel gravity platforms with shared or unshared pipeline to shore terminal -- oil production;
- Single or multiple steel platforms with shared or unshared pipeline to shore LNG plant -- non-associated gas production;

- Single or multiple steel gravity platforms with shared or unshared pipeline to LNG plant -- non-associated gas production; and

- Single or multiple steel platforms with shared oil and gas pipelines to shore terminals -- oil and associated gas production.

2.4 Manpower

Manpower requirements for the development and operation of petroleum production facilities in the North Aleutian Shelf, like the St. George Basin, depend upon many factors. The remoteness of the site will cause contractors and operators to economize on field manpower as much as possible, particularly during construction of major facilities. On the other hand, the remoteness of the area will require greater on-site labor than would be the case in nearshore locations closer to urban areas. This is particularly the case in the operation phase. During the development phase, the most important factors influencing manpower requirements are site conditions, subsea geology, and environment. During the operation phase, the most important factors are the complexity of platform treatment, the extent of secondary recovery, maintenance requirements, and the necessity for well servicing and workover (a function of reservoir characteristics).

2.5 Economics of Offshore Oil Development in the North Aleutian Shelf

2.5.1 Oil

If offshore oil resources are present in the North Aleutian, they will almost certainly be economic to develop. The economics of North Aleutian oil appears even more favorable than that of the St. George Basin, using a very similar set of economic assumptions. After-tax rates of return on investment for the case modeled range from 16.9 - 32 percent, well above any likely hurdle rate that oil companies might use in deciding whether or not to develop these resources. Compared with an assumed well-head value of $27.50 per barrel, North Aleutian oil costs between $19.58 - $25.20 per barrel to produce.

The highest costs modeled correspond to a shallow target (1045 meters, or 4248 feet, deep) located 130 kilometers (80 miles) offshore with reserves of 100 million barrels of oil. Although fairly small, such a field would require three production platforms to develop due to the limited coverage of each platform at such a shallow target. The fact that this unfavorable combination of conditions (size, remoteness, and depth) is nonetheless economic to develop is indicative of the overwhelmingly economic conditions present in the basin.

No minimum economic field size was identified in this study, but fields with reserves less than 50 million barrels are still economic under base case conditions. As reserves vary from 100 - 250 million barrels, equivalent amortized costs (EAC) decrease with size. A 500 million barrel field is slightly less economic than the 250 million barrel field since two platforms are required, thus delaying peak production. A 1 billion barrel field has economies of scale in pipeline utilization that overcome the scheduling delays and yield the lowest price oil case investigated.

Pipeline lengths from 32 - 130 kilometers (20 - 80 miles) offshore and 1 - 80 kilometers (10 - 50 miles) onshore are economic to develop, even with a 100 million barrel field, assuming the pipeline costs are borne between two similar fields. Even with an unshared pipeline, a field 130 kilometers offshore is strongly economic with an after-tax rate of return above 20 percent.

A low initial productivity does decrease the rate of return; however, even a reservoir with wells yielding only 1000 barrels per day has a rate of return above 20 percent. Steel gravity platforms are more costly than steel jacket platforms and take longer to bring into production. They are nonetheless economic even without considering the storage capacity that gravity platforms offer. Water depth has only a minor influence on reservoir economics, although shallower depths are predictably slightly more economic to develop.

2.5.2 Gas

Non-associated gas reserves, if present in the North Aleutians, may or may not be economically attractive to private developers. The length of offshore and onshore pipe required and the size of the reservoir will determine the economic viability of the resources. Assuming a price of $2.22 delivered to an arctic LNG conversion plant, the cases modeled indicate that the after-tax rate of return on investment will range from 4.4 - 21.6 percent.

Length of pipeline is a critical determinant of economic viability. Assuming a base case field with 1 trillion cubic feet reserves and wells yielding 15 million cubic feet per day and requiring 160 kilometers (80 miles) of offshore pipeline and 14 kilometers (10 miles) of onshore pipeline, gas can be produced for $2.09 per 1000 cubic feet, for an after-tax rate of return of 14.31 percent. This assumes the pipeline is shared with a similar field. If the reservoir is isolated from other gas fields, gas costs $2.17 per 1000 cubic feet and yields a rate of return of 12.3 percent, just barely above a 12 percent rate of return investment threshold. Naturally, shorter pipelines offer more economically favorable costs and rates of return. Since onshore pipe is only slightly more expensive than offshore pipe, the important factor is the total pipeline distance from platform to terminal.

Economies of scale are very pronounced in gas production with large reservoirs (3 trillion cubic feet) being decidedly economic, while small reservoirs (i.e., 500 million cubic feet) return too little revenue to justify the high development costs. Although the 3 trillion cubic foot field provides six times more gas, it requires only about 2-1/4 times the capital investment of the 500 million cubic foot field.

The initial productivity affects costs only moderately. A reservoir whose wells yield only 10 million cubic feet per day, as opposed to 15 million cubic feet, returns 12.3 percent as opposed to 13.3 percent on investment. Other factors held constant, gravity platforms are both more costly initially and take longer to bring into full production. As a result, the rate of return for such platforms is 2.5 percent lower than that of a steel jacket platform, indicating that gravity platforms are not likely to be used in the North Aleutians.

2.6 Facilities Siting

The onshore petroleum facilities that may be required by North Aleutian Shelf petroleum development include temporary exploration support bases, construction support bases, permanent operation support bases, crude oil terminals, and LNG plant. Possible support base sites are Cold Bay, Dutch Harbor, Port Moller, and Port Heiden, which appear to be the only communities capable of acting as bases without major capital improvement.

The following sites were identified as potential locations for a crude oil terminal or LNG plant (from west to east on the Pacific Ocean coast of the Alaska Peninsula):

- Morzhovia Bay
- Cold Bay
- Pavlof Bay
- Balboa Bay
- Stepovak Bay
- Mitrofania Bay
- Kuiukta Bay

Each of these sites has some oceanographic or geotechnical limitations. Except for Cold Bay and the northern portion of Pavlof Bay, all these sites lie within the Alaska Peninsula National Wildlife Range, part of the recent emergency land withdrawals under Section 204e of the Federal Land Policy and Management Act of 1976. These withdrawals are temporary and due to expire in November 1981. However, their status after that date remains unknown and may have significant ramifications for siting OCS petroleum facilities including terminals, support bases, and pipelines in the North Aleutian Shelf lease sale area. If the wildlife range designation is extended after its current expiration date, some of the sites considered may be less acceptable. More distant sites, such as those considered for the adjacent St. George Basin lease sale area, may become more viable options for the North Aleutian Shelf.

Depending upon discovery location and the pipeline landfall, the sites to the east of Pavlof Bay will require longer overland pipelines through more rugged terrain than those from Pavlof Bay westward. For example, the minimum overland distance to Cold Bay from the Bristol Bay coast would be about 19 kilometers (12 miles), while that to Mitrofania would be about 105 kilometers (65 miles).

The northwest coast of the Alaska Peninsula does not appear to offer any particularly attractive site for a shore terminal. While using this shoreline for a terminal site would eliminate an overland pipeline that could be as much as 97 kilometers (60 miles) long, there are several negative aspects. These include:

- Extreme distances to deep water
- Lack of natural shelter
- Increased potential for ice encounter

These disadvantages could be overcome by using a combination of offshore loading, as at Drift River, with shelter provided by an offshore breakwater. It is possible that the additional costs of these facilities would be comparable to constructing 64 - 80 kilometers (40 - 50 miles) of pipeline across the Alaska Peninsula. Because of the similar nature of most of the coastal area on the Bristol Bay side of the peninsula, individual sites have not been identified.

3.0 RESULTS OF THE PETROLEUM TECHNOLOGY ASSESSMENT

3.1 Introduction

As described in Appendix A of the St. George Basin report (Dames & Moore, 1980c), the technology assessment has four major elements:

1. 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.

2. A description of individual field development components; in particular, platforms, their design parameters, and installation techniques.

3. Identification of field development strategies that may be adopted to develop the oil and gas resources of the North Aleutian Shelf. 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 are discussions on offshore loading versus pipeline transport, techniques to develop marginal fields, and the application of subsea systems.

4. Identification and selection of field development components and strategies to be evaluated in the economic analysis.

In previous studies on the Gulf of Alaska (Dames & Moore 1979a, b), a detailed description of petroleum technology suitable for deep water, storm-stressed environments was presented. Included within that description was extensive discussion of steel jacket platforms and gravity structures (including design parameters, fabrication, and installation techniques), floating production systems, offshore loading, and many development issues pertinent to this study. The state-of-the-art in arctic and sub-arctic petroleum technology was extensively described in our Norton Sound report (Dames & Moore, 1980). That report presented descriptions of upper Cook Inlet platforms, cones, and monocones that are relevant to this study.

In our St. George Basin study we drew upon our Norton Sound and lower Cook Inlet data to identify production systems, and field development and transportation strategies. The North Aleutian Shelf lies immediately to the east of St. George Basin; consequently, some environmental similarities exist between the two areas. Therefore, a significant portion of the technical discussion contained in the St. George report is relevant to this study and is incorporated by reference rather than by reiteration. Our approach in this report is to focus on the unique combination of oceanographic, meteorologic, geologic, and geographic conditions that characterize the North Aleutian Shelf, while at the same time drawing comparisons with the adjacent St. George Basin and other offshore areas such as the Gulf of Alaska.

A most important qualification with respect to this study is that the publicly available data (meteorology, oceanography, marine geology, petroleum geology) upon which our analysis is based very limited. In particular, data on ice characteristics and marine sediments (information essential to assess the feasiblity of various platform designs or conceptualize on new designs) is sparse. Therefore, our approach with respect to platform design and operational constraints is conservative.

This chapter commences with an evaluation of environmental constraints (oceanography and geology) and is followed by a description of various field development components. The chapter concludes with a discussion of field development strategies applicable to the North Aleutian Shelf that warrant economic evaluation.

3.2 Environmental Constraints to Petroleum Development

3.2.1 Oceanography

3.2.1.1 Introduction

The North Aleutian Shelf lease sale area is situated on the southern edge of Bristol Bay, bordered on the south by the tip of the Alaska Peninsula and Unimak Island. Its northern edge lies at about 56° 30' N. The oceanographic characteristics in this triangular region are somewhat similar to those of the St. George Basin lease sale area lying just to the northwest. However, the wave climate is somewhat milder, due primarily to the sheltering effect of Bristol Basin and the proximity of land to the south.

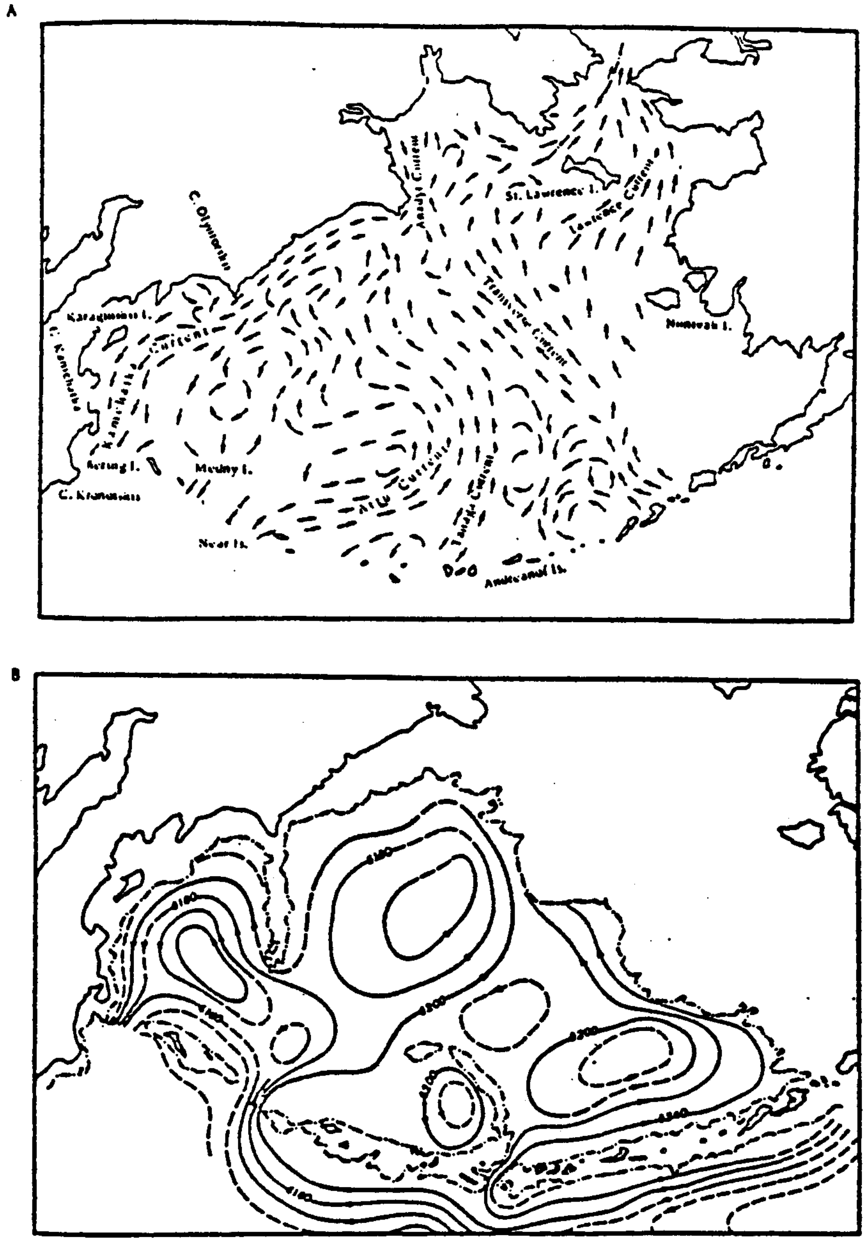
3.2.1.2 Bathymetry

The entire sale area is located on the edge of the Bering Shelf. This large bathymetric feature is defined by a line running from the western edge of Unimak Island out to the Pribilof group. It is reported to be one of the largest, flat bathymetric areas, although just north of the Alaska Peninsula and Unimak Island, the gradients may reach 15 minutes. The maximum depth is 120 meters (394 feet) and the minimum depth (outside the 3-mile limit) is about 15 meters (50 feet). Over 50 percent of the area lies in water depths between 55 and 91 meters (180 and 300 feet). Southwest of the sale area, the Bering Shelf gives way to the continental slope where the depths reach several hundred meters.

3.2.1.3 Tides and Circulation

The primary driving forces for circulation in the North Aleutian lease sale area are the tidal characteristics and wind regime of the region. The Alaska Current flows southeasterly, generally paralleling the southern edge of the Alaska Peninsula and the Aleutian Islands (Figures 3-1 and 3-2). Pacific Ocean water is driven through the straits (or passes) between the Aleutian Islands. Two of these passes directly influence the lease sale area. These

A

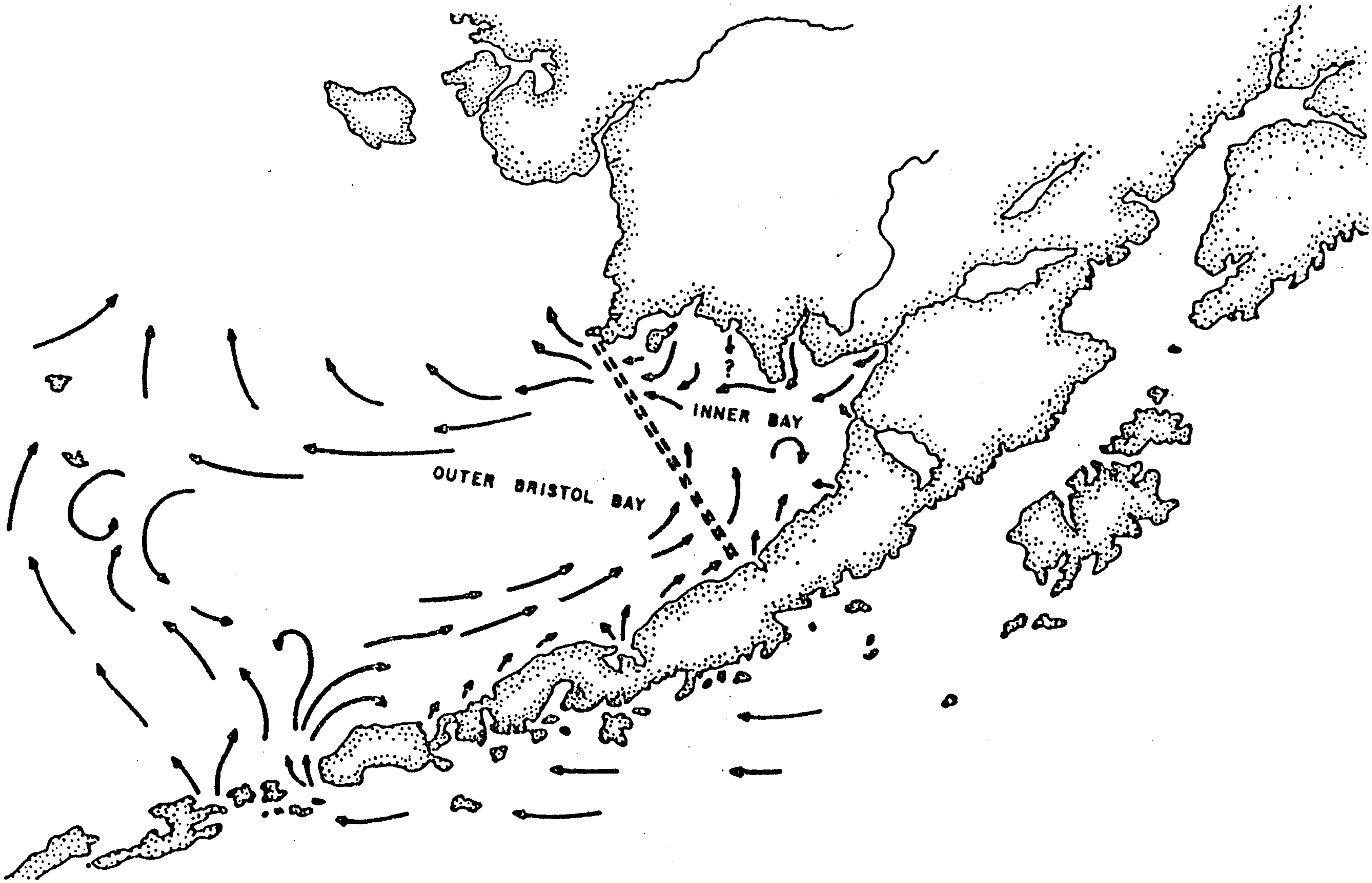


A- SURFACE CURRENTS; B- CURRENTS AT A DEPTH OF 1000 m DETERMINED BY THE DYNAMIC METHOD (ARSEN'EV,1963). NOTE CYCLONIC GYRAL SYSTEMS WITHIN THE DEEPWATER BASINS.

SUMMER SURFACE CIRCULATION IN BRISTOL BAY

SOURCE: LISITSYN, 1969

FIGURE 3-1



SURFACE AND DEEP CURRENTS IN THE BERING SEA

SOURCE: MARINE ADVISORY PROGRAM, UNIV. OF ALASKA

FIGURE 3-2

are Unimak Pass on the western edge of Unimak Island and Isanotski Strait, which separates Unimak Island from the Alaska Peninsula.

Isanotski Strait is quite shallow and narrow; its many shoals hinder flow. The flood tide sets almost due north and may reach speeds of almost 4 knots. The ebb tide sets due south and reaches speeds of 3 knots (U.S. Coast Pilot, 1979). Due to the shallow nature of this pass, these tidal currents may pose a scour problem to a submerged pipeline to Morzhovoi Bay, a possible port site.

Unimak Pass, on the other hand, is deeper and wider and provides the first break in the Aleutians for the large-scale introduction of flow from the Pacific. Both flood and ebb tidal currents may reach velocities around 4 knots in this pass (AEIDC, 1974).

The tides, combined with the pressure of the Alaska Current, produce a net influx of water into the Bering Sea and Bristol Bay. This inflow is turned eastward by the prevailing wind patterns, estuarine thermohaline effects, and somewhat by the Coriolis effect. The driving forces tend to set up a counter-clockwise gyre during the ice-free months of April through November (AEIDC, 1974). The primary axis of this gyre roughly parallels the Alaska Peninsula, following a small trough approximately 50 km (31 miles) offshore. Inshore of this area, the flow is dominated by local influences, especially during the runoff season (AEIDC, 1974).

3.2.1.4 Waves

The North Aleutian Shelf is somewhat sheltered, except from the west and northwest, from the large fetches required to generate large waves. Unimak Island and the Alaska Peninsula to the immediate south protect the site from any long-period swell propagating northward from the Pacific, as do the other Aleutian Islands to the southwest. The Alaska mainland to the north and northeast also limit the fetch.

Due to these limiting factors, the summer wave climate is characterized by waves, 75 percent of which have periods of 6 seconds or less and, similar to the St. George Basin area, 90 - 95 percent of the waves will have heights less than 2.5 meters (8 feet) (Brower, 1977).

Three major factors govern the wave climate in Bristol Bay. These are (1) the brief but severe storms, (2) a relatively limited fetch, and (3) the shallow depth of Bristol Bay. The wind climate in Bristol Bay is extremely variable, resulting in the development of many short-period choppy waves.

Synoptic wave data for Bristol Bay indicate a large percentage of the waves in summer will be from the south and southwest. Due to the proximity of the sale area to the Alaska Peninsula and Unimak Island, this distribution will be tempered somewhat, resulting in a higher distribution of waves out of the west.

The winter wave climate is, as one would expect, more severe than the summer climate. The wave periods tend to be longer, and there is a larger percentage of higher waves even though the limited fetch to the north is decreased by encroaching pack ice.

The extreme wave conditions have been calculated for the Bristol Bay area (Brower, 1977). Based on limited water depths in the lease area, we believe that the reported values (shown below) are too conservative. Less conservative wave heights are shown on Table 3-1.

Return Period (years)	Significant Wave Height (meters)
5	13.0
10	15.0
25	17.5
50	20.0
100	22.5

Source: Brower, 1977

3.2.1.5 Sea Ice Hazards

The North Aleutian Shelf lies at the southern limit of Bering Sea seasonal sea ice. Information on sea ice characteristics for the North Aleutian Shelf can be found in Potocsky (1975). Ice can be expected to grow to a first year thickness of about 18 inches. The area is free of multiyear ice. The first year ice is likely to consist primarily of floes with only limited ridging and rafting. Landfast ice will be encountered in sheltered areas.

Data on ice coverage is limited, and the data base is insufficient to make firm distinctions between specific locations in the lease sale area. However, ice is likely to be encountered from the southwest to the northeast end of the area. A 30-year record of ice data, including satellite and shipboard observations, indicates the southernmost limit for pack ice of concentration greater than 10 percent of the surface area is along a line about 35 miles south of St. George Island, extending southeastward to Port Moller on the Alaska Peninsula.

The pack "edge" is not well defined, and there is a finite risk that individual large floes will migrate some distance from the nominal pack edge. Two opposing forces will be at work on these floes. The prevailing wind systems in the winter are from the north and northeast and tend to force the pack ice to the south toward the site. On the other hand, the net current flow through the area tends toward the east and northeast. The combination of these forces may produce a rather random distribution of isolated ice floes throughout the study area.

The pack edge position also varies from year to year. In some years the lease sale area can be expected to remain completely ice-free.

In summary, there is a finite probability of ice throughout the lease sale area. The available data base is insufficient at this time to permit an evaluation of whether this probability falls in the range of a reasonable design risk. Until further information is available, it is considered prudent and conservative to design for ice.

The ice in the area is likely to be relatively weak, and design loads of 50 kips per foot are probable for vertical-sided indenters. Conventional jacket structures with local reinforcement for ice loads are considered quite feasible.

3.2.1.6 Tsunamis

Tsunamis will not be a major design consideration for offshore structures but may influence the siting and design of shore-based facilities.

Only two tsunamis have been recorded in Bristol Bay. These occurred at Port Heiden on the Alaska Peninsula coast. Three reasons may account for the lack of reported tsunamis in the bay.

First of all, the most seismically active area is south of the Aleutians and the Alaska Peninsula, which minimize the effects of waves on the Bristol Bay coast. Secondly, the bay is relatively shallow; consequently, a substantial amount of energy from a tsunami dissipates before actually impacting the shoreline. Finally, due to the sparse population in the area, occurrences may have happened without being reported.

3.2.1.7 Superstructure Icing and Fog

Superstructure icing may affect the design of structures to be used in the lease sale area, and fog may affect the operation of vessels used in drilling and production.

Superstructure icing is the result of very cold temperature, waves, and windy weather. The spray from waves is blown onto the vessel or structure and freezes upon contact with metal. Moderate icing is defined by the National Weather Service (Brower, 1977) as 1.4 - 2.6 inches per hour. Conditions that could result in moderate icing occur between 20 and 35 percent of the time from December through April. Conditions for heavy icing (accumulations up to 5.7 inches per hour) occur 3 - 4 percent of the time from January through March.

During the summer months, fog may present an operational problem. Fog occurs 20 - 30 percent of the time from May through August and can severely restrict visibility. The months of October through December are the least affected by fog, with occurrences of less than 10 percent. However, in January the occurrences of fog begin to increase until August (Brower, 1977).

3.2.1.8 Comparison of the Oceanographic Characteristics of North Aleutian Shelf, St. George Basin, Upper Cook Inlet and Norton Sound

Table 3-1 provides a comparative summary of the oceanographic characteristics of North Aleutian Shelf, St. George Basin, upper Cook Inlet and Norton Sound. Although Cook Inlet and Norton Sound have similar design parameters, both St. George Basin and North Aleutian Shelf have several unique characteristics.

Cook Inlet and Norton Sound are generally shallower than the St. George and North Aleutian Shelf areas, which have average depths of 122 meters (400 feet) and 69 meters (225 feet), respectively.

Tidal ranges are similar for St. George, North Aleutian Shelf, and Norton Sound. As design or operational constraints, the tides in these areas are less important when compared to Cook Inlet, which exhibits a large tidal fluctuation and associated currents in excess of 8 knots.

A major difference is the wave climates associated with the four areas. The exposed St. George Basin area commonly has waves 6 - 8 meters (20 - 26 feet) and has a 5-year design wave of 13.5 meters (44 feet), whereas the design and significant wave heights for Norton Sound and Cook Inlet are 6.1 and 8.2 meters (20 and 27 feet), respectively. The wave climate of the North Aleutian Shelf is similar to St. George Basin.

TABLE 3-1

COMPARISON OF OCEANOGRAPHIC CHARACTERISTICS OF NORTH ALEUTIAN SHELF, ST. GEORGE BASIN, UPPER COOK INLET AND NORTON SOUND

Area	Water Depths meters (feet)	Tidal Range (Open Water) meters (feet)	Tidal Currents (knots)	Maximum Waves 100-Year meters (feet)	Max. Ice Coverage (Percent)	Max. Ice Thickness cm (inches)	Ice Duration
North Aleutian	15-120 (50-394)	1.0-1.5 (3.2-4.9)	0.3-1.2	~ 23.0 (75)(2)	10-40(1)	48 (18)	Jan-May(1)
St. George	91-152 (300-500)	1.0-1.5 (3.2-4.9)	0.3-1.2	~ 23.0 (75)(2)	10-40(1)	61 (24)	Jan-May(1)
U. Cook Inlet	9-76 (30-250)	4.9-9.0 (13.8-29.5)	8	8.5 (28)	50-70	107 (42)	Nov-Apr.
Norton Sound	15-49 (50-160)	0.5-1.3 (1.5-4.2)	0.7	6.1 (20)	80-100	198 (78)	Oct-May

(1) Highly variable; in some years no ice may be present in the area.

(2) Calculated using realistic fetch lengths, wind durations, measured water depths, and extreme wind speeds reported by Brower (1977).

3.2.2 Geology and Geologic Hazards

3.2.2.1 Major Data Sources and Reference Materials

In contrast to the adjacent St. George Basin, for which an extensive body of data and literature concerning marine geology and potential geohazards has been developed, little information is available describing the North Aleutian Shelf province. The western margin of the area has been included in U.S. Geological Survey reports that are concerned mainly with the St. George Basin province (Marlow et al., 1976; Vallier and Gardner, 1977; Gardner et al., 1979; Marlow et al., 1979). These reports describe only a small part of the North Aleutian Shelf's general bottom and subbottom geology. The physical properties and, to a lesser degree, the geochemical nature of surficial sediments have been described for Bristol Bay by Sharma (1972) and Sharma et al. (1972). Hatten (1971) described the general petroleum geology and petroleum potential of the Bristol Bay Basin based largely on extrapolations of onshore test well data and geologic mapping.

3.2.2.2 Geologic Setting

As defined for leasing purposes, the North Aleutian Shelf lies between 159° and 165° W longitude and between the Alaska Peninsula and 56° 30' N latitude. Two sediment-filled structural basins lie within the area: the eastern half of the Amak Basin lies in the southwestern part of the area, and the Bristol Bay Basin lies in the north central portion of the lease area (Figure 3-3).

The isopaches shown on Figure 3-3 approximate the thickness of sedimentary strata above acoustic basement, and are assumed to be Tertiary deposits with some potential for producing petroleum. The Amak Basin appears to have more than 4000 meters (about 13,000 feet) of Tertiary deposits within a small area near the eastern end of the basin; the broader Bristol Bay Basin shows more than 2000 meters (6500 feet) of each strata. Hatten (1971) shows a basin with more than 4500 meters (15,000 feet) of Tertiary strata along the southern margin of Bristol Bay between Ugashik Bay and Port Moller; this

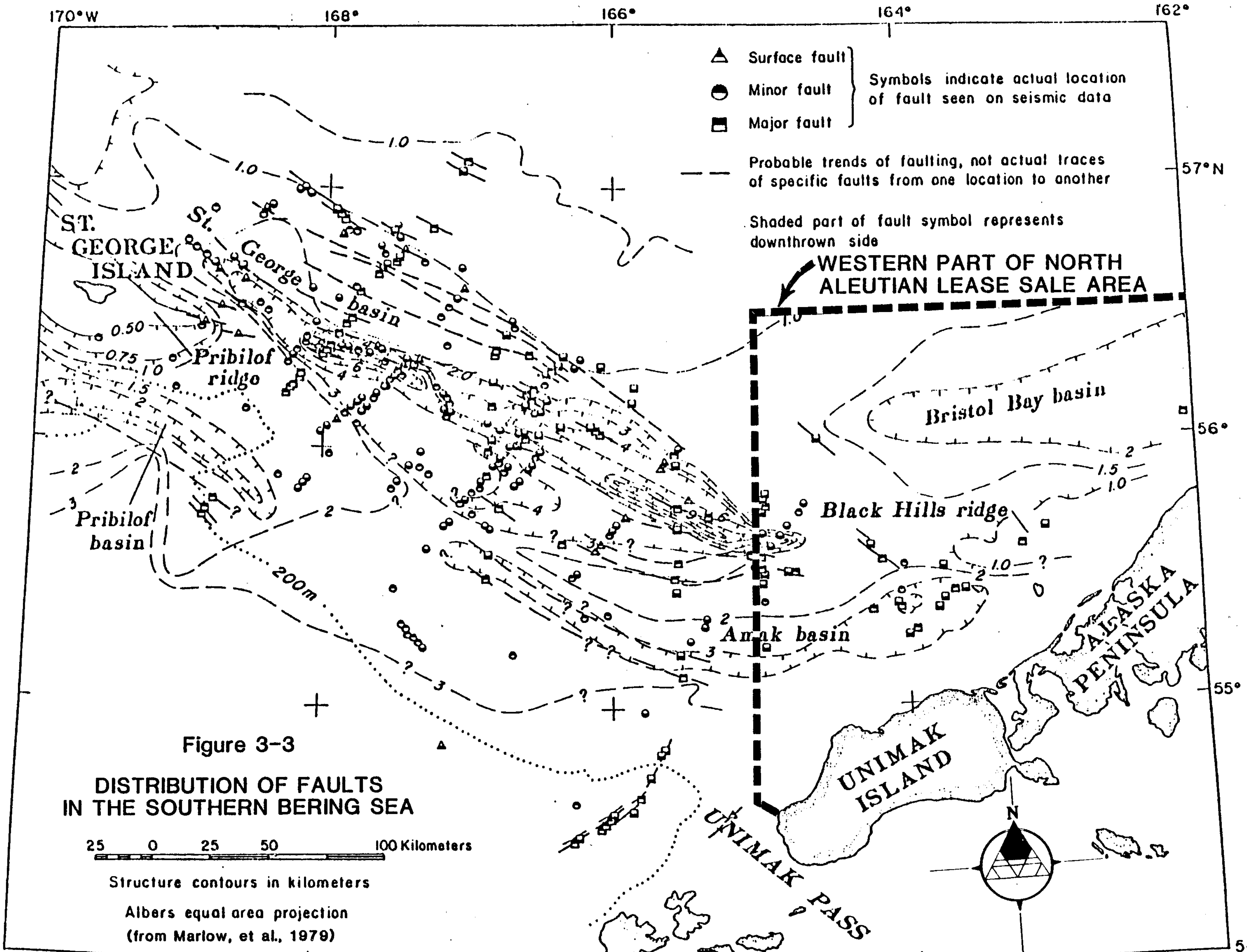


Figure 3-3

DISTRIBUTION OF FAULTS IN THE SOUTHERN BERING SEA

Structure contours in kilometers

Albers equal area projection (from Marlow, et al., 1979) basin may represent the deepest part of the Bristol Bay Basin as shown by Marlow et al. (1979). Separating the Amak and Bristol Bay Basins is a basement high that lies on strike with anticlinal structures of the Black Hills on the Alaska Peninsula.

The extent and nature of faulting within the North Aleutian Shelf province is not well known, but can be inferred by analogy with the adjacent St. George Basin, where faults are numerous, deep-seated, and extend near or to the seafloor. The entire region is highly active and undergoing deformation (Gardner et al., 1979).

3.2.2.3 Geologic Hazards

As is the case for the adjacent St. George Basin, geological hazards to petroleum development of the North Aleutian Shelf will most likely derive from local sediment instability, faulting and related seismicity, and volcanism.

The floor of Bristol Bay is extremely flat with slopes generally less than one degree. The sedimentary cover within the North Aleutian Shelf area comprises coarse sands near shore and fine sands with increasing distance from shore (Sharma et al., 1972). The potential for slumps or slides of unconsolidated sediment appears to be nil. Zones of gas-charged sediments have been found in other areas of the Bering Shelf, and have been interpreted to exist in the St. George Basin (Marlow et al., 1979). Because St. George Basin is immediately adjacent to the North Aleutian Shelf, the possible existence of shallow gas deposits must be considered a potential hazard to platform and pipeline emplacement.

As noted earlier, information about the location and severity of faulting within the North Aleutian Shelf is practically nonexistent. Because the area is currently active, and because of extensive faulting in the St. George Basin, the potential for vibratory ground motion and fault displacement is significant.

The North Aleutian Shelf area lies immediately north and adjacent to the Alaska Peninsula and the Aleutian Arc, a zone of intense seismicity caused by the subduction of the Pacific plate under the North American crustal plate. Maps of pre-1964 earthquake epicenters (e.g., in Vallier and Gardner, 1977) show, within the boundaries of the lease area, two events of magnitudes 6 and 7. (The location and/or existence of the latter event is questionable [M.S. Marlow, personal communication].) The area also lies near a "seismic gap" in the Alaska Peninsula/Aleutian Arc (Page, 1980). Seismic gaps are zones where historical seismic activity is either very minor or nonexistent and therefore are presumed to be more susceptible to major activity than adjacent zones where strain has been released. In view of these factors, the seismic design of structures should follow guidelines established in the American Petroleum Institute RP 2A (Tenth Edition), using Zone 4 criteria and assuming API soil type C.(1)

Active volcanoes lie immediately south of the lease area along the Alaska Peninsula, and may present local hazards to onshore or nearshore treatment and transshipment facilities, and pipelines.

3.3 Field Development Components

3.3.1 Exploration Platforms

As with St. George Basin, exploratory drilling in the North Aleutian Shelf is within the operational capabilities of semi-submersibles, drillships, and jackup rigs (in the shallower portions). The principal technical problem may be the need to develop year-round capability in areas where sea ice is a possibility between January and April. Following the lead of Dome Petroleum in the Canadian Beaufort Sea, where reinforced drillships supported by ice breakers drill well into the fall, similar equipment and techniques could

(1) Zone 4 represents an effective peak acceleration of .25g. Soil type C is defined as deep strong alluvium -- competent sand, silts and stiff clays with thicknesses in excess of about 61 meters (200 feet) and overlying rock-like materials.

make winter drilling feasible in areas of significantly less severe ice conditions. Dynamically positioned semi-submersibles or drillships, possibly supported by ice breakers, may also be an option for winter drilling.

Other problems facing exploratory drilling in this area include the high frequency of summer fogs and potentially severe structural icing in the winter that would pose hazards for both the rigs and their support vessels.

With the exception of the limited facilities at Dutch Harbor and Cold Bay, the southern Bering Sea lacks in-place shore facilities capable of supporting a major exploration program. Dock, storage, warehousing, and support facilities will be required at one or more of the locations identified in Chapter 4.0. Development of these facilities may compete with requirements of a rapidly expanding fishing industry.

Another factor that will influence the pace and cost of exploration operations will be the domestic and worldwide availability of drilling rigs and support equipment (supply vessels etc.) following the lease sale. The number, timing, and success of the U.S. OCS lease sales scheduled for the early 1980's will be important determinants.

3.3.2 Production Platforms

3.3.2.1 Background

The discussion contained in Section 3.3.2.1 of the St. George Basin report also provides the necessary context for consideration of platform design in the North Aleutian Shelf.

3.3.2.2 Platforms for North Aleutian Shelf

The principal design criteria for platforms in this area (not necessarily in order of importance) are:

1. Ice loading

2. Seismic loading (more sensitive for gravity designs)

3. Other environmental loading (including winds, waves, and currents)

4. Installation and fabrication capabilities

5. Conductor well spacing

6. Directional drilling

7. Superstructure icing

8. Storage (required for supplies and possibly oil storage)

9. Topside facilities

Among the more important of these criteria are seismic loading, ice loading, wind and waves, and topside requirements.

Based on the available oceanographic and geologic data for the North Aleutian Shelf, the area is similar to the St. George Basin. Although the ice forces appear to be less in the North Aleutian Shelf, ice must still be considered in platform design (enclosed conductors and zero bracing required at the waterline). Seismic loading will be greater in the North Aleutian Shelf area (Zone 4 versus Zone 3); therefore, gravity structures, particularly concrete, cannot be strongly recommended. The shallow water depths of the North Aleutian Shelf compared to St. George Basin will simplify platform design and installation, which will result in lower costs. To identify appropriate drilling and production platforms for the North Aleutian Shelf, we have specified three representative water depths -- 15 meters (50 feet), 46 meters (150 feet), and 91 meters (300 feet). The production platforms feasible for these representative water depths are:

- Steel Jacket: This could be a Cook Inlet structure, at least for the two shallower water depths (15 and 46 meters). The deep water structure (91 meters) probably would be similar to one proposed for the St. George Basin, wherein the jacket would be supported by external skirt piles. A typical structure would have four legs. The platforms for the 15- and 46-meter sites would have internal piles; all would have conductors inside the legs. Until additional ice data are available, the necessary conservative approach requires that platforms must be designed for ice conditions, no matter how minimal the forces appear. External (or conventional) conductors would not be feasible.

- Steel Gravity Structure: As noted above, due to the high possibility of seismic activity in this area, conventional concrete gravity structures cannot be recommended as feasible. Some of the problems being experienced on existing concrete gravity platforms in the North Sea (which has little or no seismic activity) could be serious in a Zone 4 seismic area. Therefore, until the design becomes more state-of-the-art, we question the use of concrete gravity platforms in the Zone 4 area. We believe, however, that the steel gravity platform may be feasible, depending on bottom conditions. This platform would probably be a single leg or monopod structure, with all conductors internal in the "neck." Although it may have more than one leg, all conductors would be internal.

3.3.2.3 Well Slot Limitations

As discussed in Section 3.3.2.3 of the St. George Basin report, the platform designs identified as feasible for the North Aleutian Shelf limit the number of well slots that can be accommodated since the conductors are located within the platform legs. The optimum number of well slots would be 32 - 48, depending upon the size of the conductors and design criteria. The shallow water Cook Inlet structure could probably accommodate 32 slots at most. Designs for deeper water (e.g., 91 meters) could probably accommodate 48. The maximum of 48 slots is based upon state-of-the-art design capabilities for this platform.

3.3.2.4 Transportation and Installation Techniques

The transportation and installation of steel jacket and gravity structures is described in Section 3.3.2.4 of the St. George report.

3.3.3 Wells

Development drilling is discussed in Section 3.3.3 of the St. George report.

3.3.4 Pipelines

The pipelines for transporting North Aleutian Shelf oil and gas production to shore terminals for further processing and tanker transport to market will generally be shorter than those in St. George Basin. Table 3-2 shows representative pipeline distances from hypothetical discovery locations to potential terminal sites located on the Alaska Peninsula.

Maximum offshore pipeline lengths of about 145 kilometers (90 miles) can be anticipated. Depending upon production and hydrocarbon characteristics, these distances indicate that intermediate offshore pumping or compressor platforms may not be required. A terminal site at Cold Bay would require only 19 kilometers (12 miles) of onshore pipeline. Maximum onshore pipeline distances of about 160 kilometers (100 miles) can be anticipated from discoveries in the eastern part of the lease sale area (assuming offshore pipelines landfall at the closest point). Nevertheless, pipeline investments to develop fields in the North Aleutian Shelf would generally be less than those in St. George Basin.

With water depths generally less than 91 meters (300 feet) and flat, relatively featureless bottom topography, no significant problems for the design and installation of offshore pipelines are anticipated. The controlling depth for a pipelaying operation would be the 10-fathom (18-meter or 60-foot) contour, which is generally no more than 3 - 5 kilometers (2 - 3 miles) from the shoreline on the Bristol Bay coast of the Alaska Peninsula. The pipeline landfall would probably be made by a bottom pull method. Landfast ice, which may occur during the winter at potential landfalls east of Port Moller, will not present an insurmountable engineering problem.

Platforms located in water depths noted above (i.e., 91 meters or less) will require pipelines less than 160 kilometers (100 miles) in length, most likely in the range of 80 - 120 kilometers (50 - 75 miles). It is not possible within the scope of this study to determine whether it is less expensive to use a short submarine pipeline and a relatively long land pipeline or a long submarine line with a short land pipeline. The decision will, in part, be determined by the nature of the onshore terrain, access, and environmental considerations.

Since the submarine pipelines in the study area are much shorter than for St. George Basin, the mobilization cost, as a percentage of total project cost, will be higher if the pipeline cost is given on a per kilometer basis. It also appears that trenching of the submarine lines to the 61-meter (200-foot) contour would be required. This means that 50 - 100 percent of the submarine pipelines must be trenched. The trenching cost on a per kilometer basis may be very high.

We believe that an operator would prefer the longer onshore pipeline located on the Pacific Ocean coast of the Alaska Peninsula rather than attempting to develop a port on the Bristol Bay coast (see Chapter 4.0).

3.3.5 Offshore Loading

As discussed in Section 3.3.5 of the St. George Basin report, an alternative to transporting oil production to shore through a pipeline is offshore loading of crude directly tied up to a mooring/oil transfer buoy. Our remarks concerning the application of offshore loading systems to St. George Basin are equally applicable to the North Aleutian Shelf. Since pipeline distances to suitable shore terminal sites from discoveries in the North Aleutian Shelf lease sale area will generally be shorter than those in St. George Basin, there will be less incentive, other factors being equal, to select an offshore loading system in the North Aleutian area.

3.3.6 Subsea Completions

The role of subsea completions in North Aleutian Shelf petroleum development, like that indicated for St. George Basin, probably will be restricted to subsea satellite wellheads connected to a mother platform in fields where the reservoir is shallow, complex, or when low production rates do not justify additional platforms (see discussion in Section 3.3.6 of the St. George report). The relatively shallow waters (15 - 91 meters; 50 - 300 feet) of the North Aleutian Shelf lease sale area do not appear to warrant extensive use of subsea completions or complete subsea production systems.

3.3.7 Marginal Field Development

The description on marginal field development in the St. George report (Section 3.3.7) is equally applicable to the North Aleutian Shelf. However, other factors being equal, the minimum economic field size in the North Aleutian Shelf generally will be smaller than St. George Basin due to development in shallower water and closer proximity to shore terminals (see Chapter 6.0).

3.4 Production Systems and Field Development Strategies for the North Aleutian Shelf

3.4.1 Contrast with St. George Basin

The discussion concerning the principal criteria influencing an operator's selection of a field development strategy in our final St. George Basin report (Section 3.4) is equally applicable to the North Aleutian Shelf lease sale area. However, the following important geologic, environmental, and locational contrasts with St. George Basin that will affect development strategies, engineering, and economics should be noted:

1. Water depths in the North Aleutian Shelf area are shallower than in St. George Basin and range from about 15 meters (50 feet) in the nearshore areas of the Bristol Bay Basin to about 107 meters (350

feet) in the western portion of the Amak Basin. Most of the lease sale area is located in water depths of less than 84 meters (275 feet). Thus, the maximum water depths in the North Aleutian Shelf lease sale area correspond to the minimum depths likely to be encountered in St. George Basin.

2. There is very limited information on sea ice extent and characteristics with which to assess the probability of ice encounter with platforms and related design loads. Until further information is available, we have considered it prudent and conservative to assume design for ice encounter. However, the ice in the area is likely to be relatively weak and possibly weaker than estimated for St. George Basin.

3. The North Aleutian Shelf area lies adjacent to the Alaska Peninsula and the Aleutian Islands chain, a zone of intense seismicity. The area also lies adjacent to a "seismic gap" in the Alaska Peninsula/ Aleutian Arc. In view of these factors, the seismic design of structures should follow guidelines established in the American Petroleum Institute RP2A (Tenth Edition), using Zone 4 criteria and assuming soil type C (in contrast, for most of St. George Basin, Zone 3 criteria area applicable).

4. Distances to shore in the North Aleutian Shelf are generally less than those in the St. George Basin andd overall pipeline distances to suitable shore terminal sites will be shorter. While offshore pipelines may be shorter, onshore lines may be longer than in the St. George Basin since most of the suitable shore terminal sites lie on the Pacific Ocean side of the Alaska Peninsula (Table A-2).

With these and other factors in mind, we have evaluated the following development issues and have drawn comparisons with the St. George Basin results. These issues are:

- The economics of production systems utilizing steel jacket/Cook Inlet hybrid structures (in deeper waters e.g. 91 meters) and Cook Inlet structures in shallower waters.

- The economics of relative short offshore pipelines (compared with St. George Basin) and significantly longer onshore pipelines.

3.4.2 Selection of Production Systems for Economic Analysis--Summary

Based upon the results of the technology assessment reported in this chapter, the basic production system selected for evaluation in the economic analysis as the most likely development strategy in the North Aleutian Shelf is one or more steel platforms (upper Cook Inlet design or steel jacket/upper Cook Inlet hybrid design, depending upon water depth) sharing oil and/or gas trunk pipelines to a terminal located on the Pacific Ocean coast of the Alaska Peninsula. Steel gravity platforms, though regarded as a less likely option, were also selected for evaluation in the economic analysis. Since offshore pipeline distances can be anticipated to be generally less than 129 kilometers (80 miles) intermediate pump or compressor station platforms may not be required. However, depending upon the pipeline landfall and location of the selected terminal site, intermediate pump or compressor stations may be required onshore.

Uncertainty exists regarding the feasibility and cost of offshore loading systems in the North Aleutian Shelf. Because there probably will be less incentive than in the St. George Basin to use these systems, we have not evaluated their economics. The reader is referred to the economic analysis in Chapter 6.0 of the final St. George Basin report.

Because of the sea ice conditions in the North Aleutian Shelf, floating systems with subsea completions such as the Tension Leg Platform (TLP) or converted semi-submersible early production system (e.g. North Sea Argyll field) may not be feasible. No attempt was made to cost and evaluate the economics of such systems.

The production systems, along with representative pipeline distances and water depths, selected for economic screening reflect the most likely strategies to be adopted for oil and gas development in the North Aleutian Shelf and are summarized in Appendix A, Section III.

4.0 PETROLEUM ONSHORE FACILITIES SITING

4.1 Introduction

In this chapter we identify potential onshore sites for petroleum development activity in the North Aleutian Shelf lease sale area. Two important qualifications concerning this siting analysis need to be noted. First, the analysis considers the North Aleutian lease sale exclusive of other lease sales in the Bering Sea. We recognize, however, that only a few terminal or support base facilities may be developed to serve several Bering Sea lease sale areas. This may be especially true for the adjacent North Aleutian Shelf and St. George Basin. The lease sales for these areas are scheduled only a year apart. Second, this siting analysis is preliminary and focuses on identifying technically feasible sites. It is not the purpose of this study to conduct a detailed environmental or socioeconomic impact assessment of the sites.

4.2 Facility Siting Requirements

Like the St. George Basin, shore facility requirements for North Aleutian Shelf petroleum development will depend upon the availability of suitable land. Much of the Alaska Peninsula and eastern Aleutian chain is subject to existing permanent and temporary Federal land withdrawals. This designation does not necessarily preclude petroleum activities, but accompanying stipulations and environmental studies may limit potential sites. In contrast, the native corporations may encourage development of some of the land associated with pending land conveyances.

Three categories of shore facilities are considered here: service bases, LNG plants, and tanker terminals. The requirements for each type of facility are discussed in detail by Kramer et al. (1978) and summarized in Dames & Moore (1979c) and Table 4-1.

TABLE 4-1

SUMMARY OF PETROLEUM FACILITY SITING REQUIREMENTS

Facility	Land Hectares (Acres)	Water Depths - Meters (Feet)				No. of Jetties/ Berths	Jetty/ Dock Frontage Meters (Feet)	Minimum Turning Basin Width Meters (Feet)	Comments
		Harbor Entrance	Channel	Turning Basin	Berthing Area				
Crude Oil Terminal[1]									Required space in turning basin can be reduced substantially should tug assisted docking and departures be required
Small-Medium (<250,000 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)	
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[2]									In addition to throughput, size of plant will also depend on amount of conditioning required for gas
(400 MMCFD)	24 (60)	13-16 (43-54)	11-14 (37-46)	10-13 (34-42)	10-12 (33-40)	1	304- 610 (1000-2000)	1220 (4000)	
(1,000 MMCFD)	80 (200)	13-16 (43-54)	11-14 (37-46)	10-13 (34-42)	10-12 (33-40)	2			
Construction Support Base[3]	16-30 (40-75)	9.1 (30)	6 (20)	6 (20)	5.5 (18)	5-10	304- 610 (1000-2000)	304- 457 (1000-1500)	Requires additional 61 m of dock space for each pipelaying activity being conducted simultaneously and each additional 4 platform installation per year

[1] Trainer, Scott and Cairns, 1976; Sullom Voe Environmental Advisory Group, 1976; Cook Inlet Pipeline Co., 1978; NERBC, 1976; State of Alaska, 1978.
[2] Dames & Moore, 1974; State of Alaska, 1978.
[3] Alaska Consultants, 1976.

B/D = barrels per day

MMCFD = million cubic feet per day

Briefly, service bases are staging areas for supplying/resupplying drilling materials, support equipment, and labor to offshore drilling and production operations. Service bases will receive goods by ship and cargo planes and transship via ship and helicopter. Service base sites will require airstrips (at least 1524 meters [5000 feet] long) that can handle cargo aircraft under instrument flight rules. Docking facilities (about 60 meters [200 feet] of pier and frontage per ship) for one or more supply ships and harbor depths in excess of 6 meters (20 feet) will be required. Depending on the size of operation and the number of supply boats using the base, 4 - 12 hectares (10 - 30 acres) of level land will be needed adjacent to the docking facilities. The base may be a temporary facility supporting exploratory operations (involving only minor expansion of existing port facilities), a larger facility supporting offshore field construction activities (platform installation, pipelaying, etc.), or a permanent base supporting production operations (supplying materials and equipment, and providing crew transfer facilities).

The size and location of a tanker terminal site will vary greatly depending on throughput requirements and discovery location. Tanker terminals will require access to an airfield, a deep harbor (deeper than 18.3 meters [60 feet] for 100,000 dead weight tons for tankers) and a large land area (up to 300 hectares [740 acres] for a million barrels per day throughput).

During exploration, industry will prefer to use existing facilities for service bases. However, during development and production, existing infrastructure may not be capable or desirous of accommodating the necessary increases in traffic, docking facilities, and land use. Industry may have an economic incentive to build its own permanent service base separate from existing communities. Such a permanent service base may or may not be incorporated as part of a tanker terminal, depending on its location in relation to the field offshore. The sites identified as suitable for crude oil terminals and LNG plants could also be developed for support functions. Potential sites are shown in Figure 4-1.

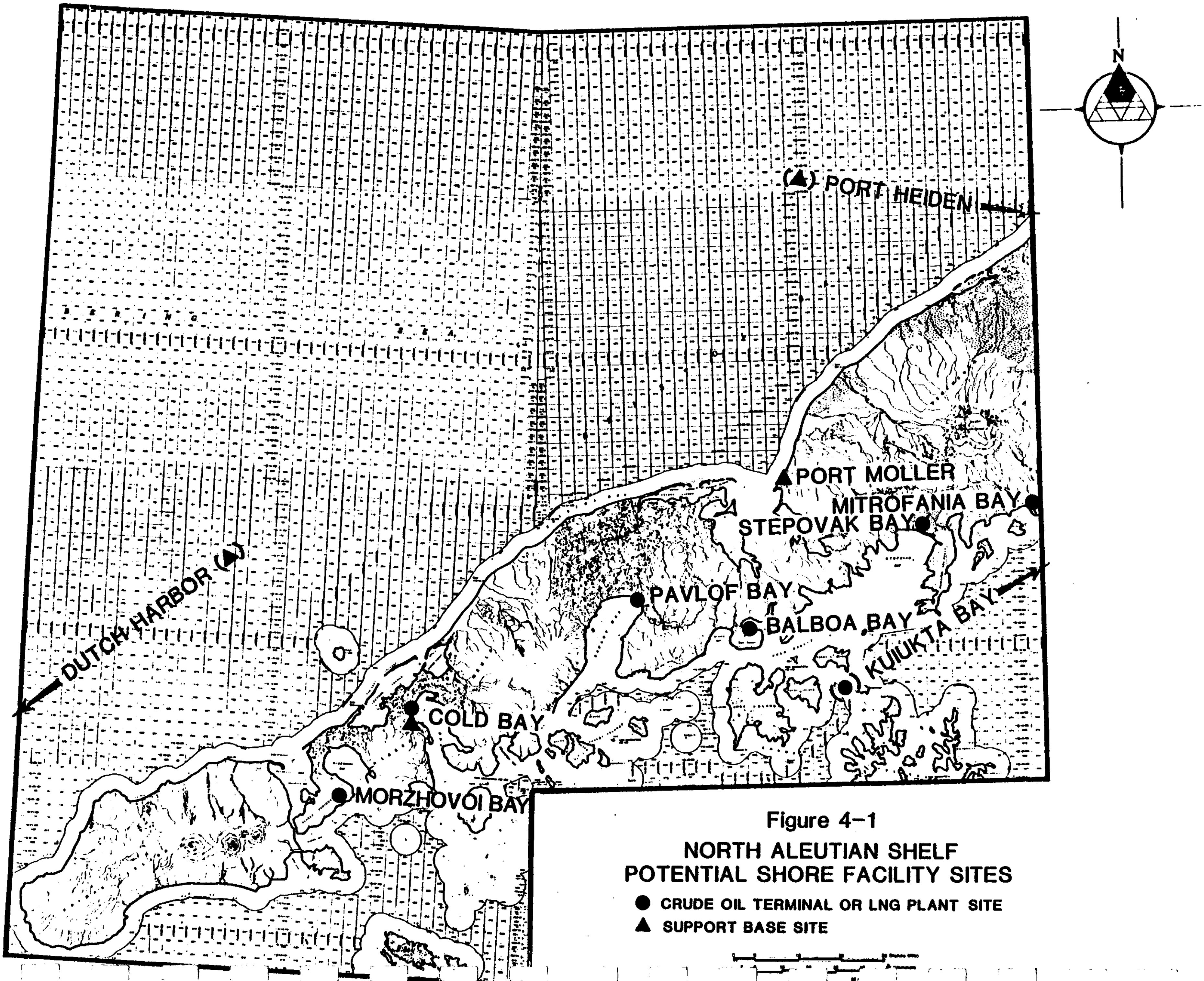


Figure 4-1
NORTH ALEUTIAN SHELF
POTENTIAL SHORE FACILITY SITES
● CRUDE OIL TERMINAL OR LNG PLANT SITE
▲ SUPPORT BASE SITE

4.3 Siting Criteria

The following criteria were used for evaluating potential facility sites.

- Existing infrastructure - docks, airstrips, etc.

- Harbor characteristics including:
  - degree of natural shelter afforded and potential for artificial shelter
  - depth of harbor, berthing area, and entrance (Figure 4-2)
  - size of the turning basin
  - ice conditions
  - bathymetric hazards in approach to harbor (shoals, reefs, etc.)

- Airstrip siting including:
  - proximity to harbor
  - sufficient size to handle large cargo planes
  - clearance from physical obstructions for instrument approaches

- Proximity to discoveries

- Land status - State, Federal, native, and private

- Suitability of land adjacent to harbor for facilities ($\leq$25 percent slope)

- Geological hazards - seismicity, volcanism, tsunamis, flooding, etc.

4.4 Previous Studies

Two previous studies have investigated potential port sites in the area. The Arctic Institute of North America (1973) identified Dutch Harbor, Unalaska Bay and Akutan Harbor as possible sites. Engineering Computer Opteconomics, Inc. (1977) identified Chignik Bay, Stepovak Bay, and Cold Bay. Cold Bay is

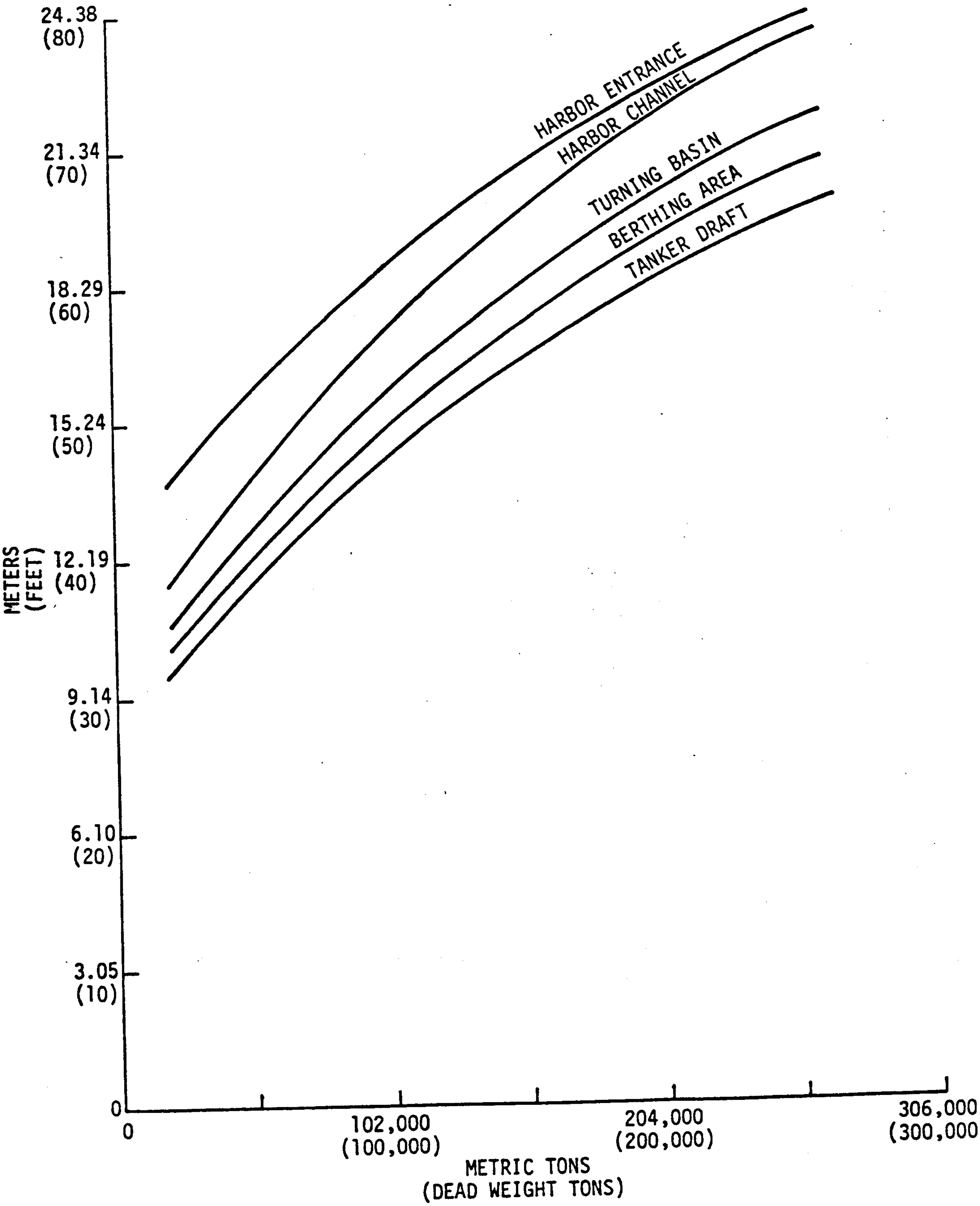


FIGURE 4-2
REQUIRED DEPTHS FOR TANKERS AT MARINE TERMINAL

examined here as both a possible service base and crude oil terminal or LNG plant site. Unalaska Bay and Akutan Harbor were examined as possible tanker terminals for petroleum activity in the St. George Basin but are considered too distant to be competitive with other sites closer to the North Aleutian Shelf lease sale area. Chignik Bay is not considered due to a combination of lack of shelter and the distance offshore to deep water. Stepovak Bay is examined here as a potential tanker terminal.

4.5 Service Base Sites

The existing infrastructure was examined for possible service base sites. Cold Bay, Dutch Harbor, Port Moller, and Port Heiden appear to be the only communities capable of acting as service bases without major capital improvement. Cold Bay, although the most distant from the sale area by sea, is centrally located for helicopter support and has the best existing facilities. Its airport has two paved runways, 3174 and 1562 meters (10,415 and 5126 feet) long, which are lighted and equipped for instrument approaches. Several major air carriers currently use the site for refueling international jet traffic. Cold Bay's harbor includes a 290-meter (850 foot) pier front in 9-10 meters (30 - 33 feet) of water. The harbor size and depths are well in excess of those required for supply boats.

Dutch Harbor is closer to the sale area than Cold Bay by sea, but has generally poorer facilities. Conflicts may arise with the local fishing industry for use of facilities. It is also considerably farther from the sale area for helicopter support. Its airport is only 1311 meters (4000 feet) long, unlighted, gravel surfaced, and not equipped for instrument approaches. It is considered inadequate by the Coast Guard for regular supply activities in heavy cargo aircraft (such as the C-130 Hercules). Plans to make significant improvements in these facilities are presently under consideration by the State and improvements may be complete by the time of the lease sale. Dock facilities and harbor characteristics are adequate to serve a couple of supply boats.

Port Moller is best situated for a service base. It has the only harbor on the northwest side of the Alaska Peninsula with sufficient shelter and harbor depths to serve supply boats. Its proximity to the sale area is its main advantage over other sites. Port Moller has a 1067-meter (3500-foot) gravel airstrip adjacent to the harbor. In addition, there is a 1219-meter (4000-foot) airstrip about 32 kilometers (20 miles) north of the community. Harbor characteristics are marginal due to extensive mud shoals and the narrow channel, but the 9-meter (30-foot) deep channel does lie within 305 meters (1000 feet) of shore in a sheltered location.

Port Heiden's harbor is incapable of servicing supply boats. However, its good airport (1890-meters [6200 feet], lighted, gravel runway) and proximity to the northeast portion of the sale area make it a potential site for helicopter support.

4.6 Tanker Terminal Sites

Based on information gathered from U.S. Geological Survey Topographic Maps, NOS Navigational Charts, regional profiles and resource inventories, F.A.A. aeronautical charts, geologic studies, and biological studies, the following sites are considered for their potential as crude oil terminals or LNG plant sites (Figure 4-1):

- Morzhovia Bay
- Cold Bay
- Pavlof Bay
- Balboa Bay
- Stepovak Bay
- Mitrofania Bay
- Kuiukta Bay

Except for Cold Bay and the northern portion of Pavlof Bay; all these sites lie within the Alaska Peninsula National Wildlife Range, part of the recent emergency land withdrawals under Section 204e of the Federal Land Policy and

Management Act of 1976. These withdrawls are temporary and due to expire in November 1981. However, their status after that date remains unknown, and may have significant ramifications for siting O.C.S. petroleum facilities including terminals, support bases and pipelines in the North Aleutian Shelf sale area. If the wildlife range designation is extended after its current expiration date, some of the sites considered may be less acceptable. More distant sites, such as those considered for the adjacent St. George lease sale area, may become more viable options for the North Aleutian Shelf.

Another factor influencing the siting of onshore petroleum facilities on the Alaska Peninsula will be pipeline access and the length of pipeline required from Bristol Bay across the peninsula to these Pacific Ocean sites assuming, as discussed below, that Bristol Bay does not offer suitable port sites (see Appendix A, Section II.3). Depending upon discovery location and the pipeline landfall, the sites to the east of Pavlof Bay will require longer overland pipelines through more rugged terrain than those from Pavlof Bay westwards. For example, the minimum overland distance to Cold Bay from the Bristol Bay coast would be about 19 kilometers (12 miles) while that to Mitrofania would be about 105 kilometers (65 miles).

Morzhovoi Bay - This bay is on the southern end of the Alaska Peninsula. It has a large deep-water harbor with sufficient adjacent land for shore facilities. The best natural shelter occurs at the east end of the bay where adequately deep water lies 914 - 1824 meters (3000 - 6000 feet) offshore. Assuming an adjacent landfall on the Bristol Bay coast, only 5 - 13 kilometers (3 - 8 miles) of overland pipeline over generally flat terrain would be required to reach the site.

Cold Bay - As described in Section 4.5, Cold Bay is the only site that has significant transportation facilities on the Alaska Peninsula to support petroleum development in the North Aleutian Shelf. Cold Bay can be entered by deep-draft vessels via a 10-fathom (18-meter or 60-foot) natural channel near Kaslokan Point. The western shore of Cold Bay and the peninsula extending south of the bay to Telegraph Hill offer several terminal sites. Adequate water depths (18 meters or more) generally lie between 762 - 1524 meters (2500 - 5000 feet) from shore. A T-head pier with a 236-meter (775-foot) face and water depths of 9.1 - 10 meters (30 - 33 feet) is located at Cold Bay but needs repairs. Only 16 - 19 kilometers (10 - 12 miles) of overland pipeline would be required to reach Cold Bay from the Bristol Bay coast. The Cold Bay area is characterized by generally flat terrain that would pose no significant construction difficulties for pipelines and terminal facilities.

Pavlof Bay - Access to this site across the Alaska Peninsula is State-patented land. Harbor characteristics are generally adequate and suitable land in excess of the requirements for shore facilities is present. The best shelter lies along the north and east sides of the bay where adequately deep water lies 914 - 1524 meters (3000 - 5000 feet) offshore. A trans-peninsula pipeline would be about 40 - 56 kilometers (25 - 35 miles) long and would not encounter any passes. Navigational hazards may present some difficulty in the approach to this harbor.

Balboa Bay (Lefthand Bay) - This site is located just north of Unga Island and represents a good deepwater bay, with generally better harbor characteristics than Pavlof Bay. Its smaller size (only 3 by 6.5 kilometers; 2 by 4 miles) provides better shelter. Deep water occurs within 304 - 914 meters (1000 - 3000 feet) of much of the shore and adjacent land is suitable for shore facilities. Siting of an airstrip suitable for instrument approaches may be a problem due to mountains in the immediate vicinity. About 72 kilometers (45 miles) of pipeline are required to cross the peninsula. Two overland pipeline routes are available to the site from Bristol Bay across the Aleutian Range mountains: (1) from the southern shore of Herendeen Bay via a 427-meter (1400-foot) pass in the mountains, or (2) along the eastern shore of Herendeen Bay via a 91-meter (300-foot) pass in the mountains.

Stepovak Bay - The bay is located east of Port Moller and has generally good characteristics. Shelter is best on the north and east sides of the bay where adequately deep water is 305 - 610 meters (1000 - 2000 feet) offshore. Extensive wetlands at the head of the bay may make Kupreanof Peninsula on the east side of the bay a preferred site for shore facilities. Airstrip siting may be a problem due to mountainous terrain. About 80 kilometers (50 miles) of pipeline would be required to cross the peninsula via a 396-meter (1300-foot) pass to reach the site.

Mitrofania Bay - Several small bays within Mitrofania Bay, located approximately 48 kilometers (30 miles) northeast of Stepovak Bay, could serve as potential terminal sites; however, bathymetry data is lacking for a comparative evaluation. Adjacent land is limited but adequate. An airstrip would have to be located 8 - 16 kilometers (5 - 10 miles) away from the site to avoid mountainous terrain. The 96 kilometers (60 miles) of pipeline needed to cross the peninsula would have to cross the mountains via either a 452-meter (1500-foot) pass or a 335-meter (1100-foot) pass. Routing through the lower pass may be threatened by the active volcano, Mount Venaminof.

Kuiukta Bay - As with Mitrofania Bay, bathymetry data for this bay is lacking. Of the several smaller bays on the west side of Kuiukta Bay, Windy Bay appears to have the most suitable adjacent land. Due to mountainous terrain, the airstrip may have to be located 8 - 16 kilometers (5 - 10 miles) from this bay. Pipeline access to this site from Bristol Bay is provided by one of two routes that follow the shores of Chignik Lake through the Aleutian Range mountains. The most direct route is via a 274-meter (900-foot) pass between Chignik Lake and the bay. A more circuitous route follows Chignik River and Mitrofonia and Spoon Creeks from Chignik Lake to the bay. Total pipeline distance across the Alaska Peninsula is about 80 kilometers (50 miles). The 80 kilometers of pipeline needed to cross the peninsula could be routed by either level land or a 274-meter pass.

Bristol Bay Sites

A review of the published literature and nautical charts of the northwest coast of the Alaska Peninsula indicates that no single area stands out as a particularly attractive site for a shore terminal. Using this coastline would eliminate an overland pipeline that could be as much as 97 kilometers (60 miles) long. On the other hand there are several negative aspects. These include:

- Extreme distances to deep water
- Lack of natural shelter
- Increased potential for ice encounter

These disadvantages could be overcome by using a combination of offshore loading, as at Drift River, with shelter provided by an offshore breakwater. It is possible that the additional costs of these facilities would be comparable to constructing 64 - 80 kilometers (40 - 50 miles) of pipeline across the Alaska Peninsula. Because of the similar nature of most of the coastal area on the Bristol Bay side of the peninsula, individual sites have not been identified.

4.7 Geological Hazards

Geological hazards are high throughout the area due to seismicity, volcanism, and tsunamis. All sites will require engineering to withstand earthquakes of Richter magnitudes greater than 7.0. Recent studies by Davies and House (1979) conclude that there is a high potential for a major earthquake of magnitude greater than 8.0 in the Shumagin Islands seismic gap within the next few decades.

Volcanic hazards are high near Pavlof Volcano and Mount Veniaminof, both of which have erupted ash and lava in the last century. Pavlof Volcano is located on the opposite side of the bay from the Pavlof Bay terminal site; the main hazard here would be from ash fall. Sites in Stepovak Bay, Mitrofania Bay, and Kuiukta Bay are potentially threatened by ash fall from Mount Veniaminof. Pipeline routes across the peninsula to these sites may also be threatened by lava, mud, and ash flows, and severe flooding associated with volcano-glacier interactions. Careful routing and design of the pipeline should be able to minimize these risks.

Tsunami hazards are particularly high for all the sites considered due to their location on the southeast side of the Alaska Peninsula. This location exposes them to tsunamis resulting from major submarine ground motion anywhere in the Northern Pacific. In 1946, for example, a tsunami run-up attained a height of 35 meters (115 feet) and destroyed the Scotch Cape Lighthouse on the southwest end of Unimak Island.

5.0 EMPLOYMENT

A detailed description of employment related to OCS petroleum exloration, development and production including factors affecting labor force size, specific activities, tasks and groups of tasks, and estimates of the likely range of manpower that would be required for these tasks in Alaska is presented in Chapter 5.0 of the St. George Basin report (Dames & Moore, 1980c). The findings presented in that report are similar to development in the North Aleutian Shelf since similar technologies will be employed to develop the oil and gas resources in this area (Tables 5-1 and 5-2).

In the St. George report, our employment analysis is built on information presented in the previous Dames & Moore studies, but it emphasized the inputs of the estimating process rather than the quantitative outputs for various scenarios. The primary focus in the St. George report was the factors that determine labor force size and productivity, and a probable range of each in an Alaska OCS setting. As in the St. George report, we have made a quantitative estimate for only one (medium case) scenario using the OCS manpower computer model (see Chapter 7.0). The reader is referred to Appendix E of Technical Report 49 (Dames & Moore, 1980 a), which describes the Dames & Moore OCS manpower model.

TABLE 5-1

OCS MANPOWER EMPLOYMENT MODEL

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/ Day	Rotation Factor
Exploration	A. Petroleum	1. Exploration well	Rig	Assigned	28	6	2 1	2 1
		2. Geophysical and geologic survey	Crew	5	18	2	1 1	1 1
	B. Construction	3. Shore base construction	Base	Assigned	Assigned		1	1.11
	C. Transportation	4. Helicopter for rigs	Well	Same as Task 1	0	5	1	2
		5. Supply/anchor boats for rigs	Well	Same as Task 1	26	2	1 1	1.5 1
		501. Drilling vessel operation		Same as Task 1	8	0	1	1.5
		502. Geophysical boat operation		Same as Task 2	5	0	1	1.5
Development	A. Petroleum	6. Development drilling	Platform	Assigned	28 if 1 rig 56 if 2 rigs	6 if 1 rig 12 if 2 rigs	2	2
	B. Construction	7. Steel jacket installation, hook-up, commissioning	Platform	10	150	25	2 1	2 1.5
		8. Concrete Installation hook-up, commissioning	Platform	5	150 0	25	2 1	2 1.5
		801. Pump/compressor platform installation	Platform	6	100	15	2 1	2 1.5
		9. Shore treatment plant	Plant	8	0	80	2	1.5
		10. Shore base	Base	Assigned	0	Assigned monthly	0 1	0 1.11
		11. Offshore loading system	System	3	40	10	2 1	2 1.5
		12. Pipeline offshore, gathering, oil and gas	Spread	Assigned	100	25	2 1	2 1.5
		13. Pipeline offshore, trunk, oil and gas	Spread	Assigned	125	35	2 1	2 1.5

TABLE 5-1 (Cont.)

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/ Day	Rotation Factor
		14. Pipeline onshore, trunk, oil and gas	Spread	Assigned	0	500	1	1.11
		15. Pipe coating	Pipe coating operation	Assigned	0	175	1	1.11
		16. Marine terminal	Terminal	Assigned	0	Assigned monthly	1	1.11
		17. LNG plant	Plant	Assigned	0	Assigned monthly	1	1.11
		18. Pump or compressor station onshore	Station	8	0	100	1	1.11
		19. Gravel island	Spread	Assigned	100	15	2 1	1.5 1.11
		20. Vacant						
	C. Transportation	21. Helicopter support for platform	Platform; same as Tasks 7 & 8	Same as Tasks 7 & 8	0	5	1	2
		22. Helicopter support for lay barge	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	0	5	1	2
		23. Supply/anchor boats for platform	Platform; same as Tasks 7 & 8	Same as Tasks 7 & 8	39	12	1 1	1.5 1
		24. Supply/anchor boats for lay barge	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	39	12	1 1	1.5 1
		25. Tugboats for installation and towout	Platform	Same as Tasks 7 & 8	40	0	1	1.5
		26. Tugboats for lay barge spread	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	20	0	1	1.5
		27. Longshoring for platform construction	Platform; same as Tasks 7 & 8	Same as Tasks 7 & 8	0	20	1	1.5
		28. Longshoring for lay barge	Lay barge spread; same as Tasks 12 & 13	Same as Tasks 12 & 13	0	20	1	1.5

TABLE 5-1 (Cont.)

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/ Day	Rotation Factor
		29. Tugboat for offshore loading	Same as Task 11	Same as Task 11	10	0	1	1.5
		30. Supply boat for offshore loading	Same as Task 11	Same as Task 11	13	0	1	1.5
Production	A. Petroleum	31. Platform operation (oil)	Platform	Assigned	36	2	2 1	2 1.5
		311. Platform operation (gas)	Platform		15	4	2 1	2 2
		32. Well workover	Platform	Begins year 6 for each platform	5	0	1	2
	B. Construction	33. Scheduled maintenance and repair for platform	Platform	Begins year 3 for each platform (seasonal)	10	4	1 1	2 1.5
	C. Transportation	34. Helicopters for platform	Platform	Same as Tasks 31, 311, 371	0	2 (2/5 crew)	1	2
		35. Supply boats for platform	Platform	Same as Tasks 31, 311, 371	6 (1/2 crew)	0	1	1.5
		36. Terminal and pipe-line operations	Terminal	Assigned	0	Assigned	2	2
		37. Longshoring for platforms	Platform	Same as Tasks 31, 311, 371	0	3	1	1.5
		371. Pump/Compressor platform operation	Platform	Same as Task 801	15	2	2 2	2 1.5
	D. Manufacturing	38. LNG operations	LNG plant	Assigned	0	Assigned	2	2

[1]Different labor force values may be substituted for these if deemed appropriate by site-specific characteristics.

[2]This is the crew size or estimated average monthly shift labor force over the duration of the project. "Assigned" means that scenario-specific values are used, and that no constant values are appropriate.
Additional notes on next page.

Source: Dames & Moore

NOTES TO TABLE 5-1

Task	
1	Average 28-man crew per shift on drilling vessel and six shore-based positions (clerks, expeditors, administrators); shift on drilling vessel includes catering and oil field service personnel. Number of rigs per year is determined by the number of wells/year x months required to drill each well divided by the number of months in the drilling season.
2	Approximately one month of geophysical work per well based on 200 miles of seismic lines per well at approximately 15 miles/day x .75 (weather factor); crew can work from May through September.
3	Requirements for temporary shore base construction varies with lease area.
4	One helicopter per drilling vessel; two pilots and three mechanics per helicopter; considered onshore employment.
5	Two supply anchor boats per rig; each with 13-man crew.
6	One or two drilling rigs per platform; average 28-man drilling crew and six shore-based positions per rig; shift on drilling vesses includes catering and oil field service personnel.
7, 8, 9	Includes all aspects of towout, placement, pile driving, module installation, and hook-up of deck equipment; also includes crew support (catering personnel).
10	See Table 5-7 (Dames & Moore, 1980c).
11	This task includes all subsea tie-ins of underwater completions.
12	Rate of progress assumed to be average of 1 mile per day for all gathering lines; scale factors not applied to gathering line.
13	Rate of progress averages .75 mile per day of medium-sized trunk line in water of medium depth; scale factors applied in shallow or deeper water and for pipe diameter; rate of progress makes allowance for weather down time, tie-ins, and mobilization and demobilization.
14	Rate of progress averages .3 mile per day of buried medium-sized onshore trunk line in moderate terrain; scale factors applied for elevated pipe or rocky terrain and for pipe diameter.
15	Rate of progress for pipe coating is 1 mile/day for 20- to 36-inch pipe; 1.5 mile for 10- to 19-inch pipe.
16	See Table 5-7 (Dames & Moore, 1980c).
17	See Table 5-7 (Dames & Moore, 1980c).
20	See Table 5-7 (Dames & Moore, 1980c).
21	One helicopter per platform.
22	One helicopter per lay barge spread.
23	Three supply/anchor boats per platform.
24	Three supply/anchor boats per lay barge spread.
25	Four tugs for towout per platform; 10-man crew per boat.
26	Two tugs per lay barge spread; 10-man crew.
29	One tug boat for offshore loading system installation.
30	One supply boat for offshore loading system installation.
31	Assumed to begin in first year of platform production (also tasks 33, 34, 35, and 37).
32	Assumed to begin in sixth year after production starts; average 1/2 crew/platform permanently.
33	Assumed to begin in third year after production starts; seasonal (months 6-9).
34	Two-fifths helicopters per platform.
35	One-half supply boat per platform.
36	Includes onshore pump or compressor station operation, if any.

TABLE 5-2

SPECIAL ASSUMPTIONS FOR NORTH ALEUTIAN USGS MEAN SCENARIO

Task	
3	Assume required expansion of Port Moller employs a crew for four months, with monthly employment profile of 25, 50, 100, 50; starts January of year 1.
10	Assume construction of a medium shore base for development and production phases; requires 12 months of construction with monthly profile of 50, 100, 150, 200, 250, 300, 300, 250, 200, 150, 100, 50; starts January of year 5.
12	Assume one conventional spread at 1 mile/day; therefore two months in year 7 (begin month 6), two months in year 8 (begin month 6), and six months in year 9 (begin month 5)
13	Assume gathering and trunk lines laid offshore by conventional spread in years 8 (start June, 2 months), 9 (start May, 3 months), and 10 (start June, 3 months).
14	Assume onshore pipe laid in 14 months (approximately 1/2 mile per day) by one spread; construction occurs May through November of year 9, and February through August of year 10.
15	Assume pipe coating begins in April of year 8 and lasts for 15 months; thus pipe for use in year 10 is stockpiled.
16	Assume small oil terminal requiring 18 months of construction with monthly employment profile of 40, 80, 120, 150, 200, 235, 270, 310, 350, 310, 270, 235, 200, 150, 120, 80, 40 beginning in April in year 7.
17	Assume small, shore-based, barge-mounted LNG plant, requiring 6 months site preparation with monthly employment profile of 150, 200, 300, 300, 200, 150 beginning in April of year 9.
31	Assume oil production begins in month 10 of each year indicated in development drilling tables.

6.0 THE ECONOMICS OF NORTH ALEUTIAN SHELF PETROLEUM DEVELOPMENT

6.1 Introduction: Modeling Approach

This chapter presents the results of an economic analysis of OCS oil and gas development in the North Aleutian Shelf.

Results for oil development are presented in Section 6.2 and those for gas development are given in Section 6.3. A detailed discussion of the assumptions underlying the economic models appears in Appendix A, Section IV. In addition to indicating the results of alternative reservoir and production characteristics on the rate of return and minimum required prices, the effects of uncertain oil and gas prices and development costs are explored. The distribution of costs between onshore and offshore facilities is analyzed, both in terms of total costs and in terms of their individual contribution to the cost per barrel of oil or 1000 cubic feet of gas. Equivalent amortized cost of oil and gas development and the factors affecting the marketability of North Aleutian Shelf oil and gas are discussed.

The economic viability of OCS oil and gas fields in the North Aleutian Shelf depends on several conditions including reservoir size, depth, location, well productivity, and production method. Since no offshore oil production has taken place and only limited onshore exploration has been conducted, reservoir conditions are uncertain. In the economic analysis, our approach is to evaluate a range of geologic and reservoir characteristics that can reasonably be anticipated in the North Aleutian Shelf (Bristol Bay sedimentary basin) as indicated by the limited available data and analogous basins that have production history.

The number of combinations of reservoir characteristics that might be encountered in the North Aleutian Shelf is very large. As in the case of the St. George Basin study, these variations have been demonstrated by means of a set of benchmark conditions for both oil and gas fields. The base cases are selected to be representative of economically viable reservoir, engineering, and locational characteristics. These characteristics are then systematically varied, one parameter at a time.

The oil and gas prices used in this study are the same as those used for the St. George Basin study. Oil is assumed to cost $27.50 per barrel (wellhead value, North Aleutian Shelf), while gas is assumed to have a landed value at the LNG conversion terminal of $2.22 per 1000 standard cubic feet.

6.2 Economic Analysis Of Oil Field Development

The range of oil field characteristics modeled is illustrated in Table 6-1. The characteristics assumed for the base case are indicated by an asterisk. In order to isolate the effects of each change of characteristics in the analysis, only the parameter under examination is varied. All other parameters are held constant at the base case levels.

6.2.1 Oil Base Case

The base case oil field characteristics are as follows:[1]

Reservoir Size..................	100 million barrels
Reservoir Depth.................	3050 meters (10,000 feet)
Water Depth.....................	45 meters (150 feet)
Initial Productivity (IP)........	2000 barrels per day per well
Recoverable Reserves Per Acre....	60,000 barrels per acre
Pipeline Marine	128 kilometers (80 miles)
Pipeline Onshore	16 kilometers (10 miles)
Production System................	Steel platform, pipeline to shore shared with one other field
Terminal.........................	14 percent of the capacity of a 200,000 barrel per day terminal costing $390 million
Oil Price........................	$27.50 per barrel

(1)For information on the cost of production components and the actual cost engineering of cases, see Appendix B. For information on the economic models and their underlying assumptions, see Appendix A, Part V, St. George Basin Report (Dames & Moore 1980c).

TABLE 6-1

RESERVOIR, PRODUCTION, AND LOCATIONAL FACTORS
EVALUATED IN THE ECONOMIC ANALYSIS -- OIL

Factor/ Characteristics	Units	Range of Parameters Modeled
Reservoir Depth	Meters (Feet)	915 (3000), 1525 (5000) 3,050 (10,000)*
Reservoir Size	Million Barrels	50, 100*, 250, 1000, 2000
Pipeline Distance Marine/Onshore	Kilometers (Miles)	128/16 (80/10)*, 48/80 (30/50), 32/48 (20/30), 32/16 (20/10)
Initial Productivity	Barrels per Day	1000, 2000*, 3000, 5000
Water Depth	Meters (Feet)	15 (50), 45 (150)*, 90 (300)
Platform Type	None	Steel Jacket,* Steel Gravity
Scheduling	None	Normal, St. George Basin Schedule, 1-Year Delayed Production

Source: Dames & Moore

* Indicates the value used in the base case.

Ideally the base case conditions would be most representive of the true conditions in the North Aleutian Shelf. Unfortunately, these representive conditions are presently unknown. Ranges of reservoir conditions have been only roughly estimated (see Marlow et al., 1980). Therefore, the base case is selected somewhat arbitarily, choosing neither the most nor the least economically advantageous basin parameters.

The base case reservoir is relatively large by onshore economic standards but is small by offshore standards. The deep (3050-meter [10,000-foot]) target depth is less economic than a reservoir half as deep, due to well drilling costs, but not as costly as a very shallow field requiring multiple platforms.[1]

Water depth is typical of the fairly shallow water conditions in the North Aleutian Shelf. Initial well productivity of 2000 barrels per day is also the more optimistic of the two conditions modeled, but it is more probable than 1000 barrels per day based on available geologic information. The production system uses a steel jacket platform, which appears to be least costly for this application. The 128-kilometer (80-mile) pipeline to shore is as long as any likely to be required. The onshore distance of 16 kilometers (10 miles) is probably the minimum that will be required.

In all cases, terminal costs are apportioned on the percentage of a 200,000 barrel per day terminal. Since peak production in the base case is 26,800 barrels per day, about 14 percent of terminal capacity is charged to the base case field.

An undiscounted capital expenditure of $296 million over 5 years is required to bring the base case field into production. Fourteen producing wells and four injection wells are assumed to allow a peak annual production near 10 percent of recoverable reserves. When costs and revenue streams are

(1) See Appendix B for discussion of the effects of target depth on oil field design.

discounted to the first year of construction, the net present value at 12 percent is $296 million. Internal rate of return is 24.2 percent. This rate of return is well above the assumed hurdle rate of 12 percent. Thus, this base case development option for this field size is an attractive investment. The equivalent amortized cost (EAC)(1) for oil is $22.48 per barrel.

Compared with the base case oil development conditions modeled for the St. George Basin, the North Aleutian Shelf base case is even more economically attractive. The assumed conditions are almost identical in both cases except for pipeline distances, which are longer, and water depths, which are shallower in the North Aleutian case. The cost of additional pipe was more than offset by the lower platform costs, resulting in an EAC per barrel that is $0.79 lower, and an after-tax rate of return that is 4 percent higher than the St. George base case.

6.2.2 Economic Impact of Alternative Reservoir Target Depths

A complex combination of factors governs the number of platforms needed to produce a given reservoir. These include:

- Reservoir depth
- Deviation angle for directional drilling
- Reservoir size
- Recoverable reserves per acre
- Maximum number of wells that can be accommodated on platform.

The relationship between these factors is discussed more thoroughly in Appendix A. However, it is helpful to view the areal coverage of a platform as a cone with the platform at the peak; the deeper the reservoir, the wider the base of the cone.

(1)For explanation of the EAC model, see Appendix A, Section V of the companion St. George Basin Report (Dames & Moore, 1980c).

Deep reservoirs, while requiring long, costly wells, can be reached from a single platform. Shallow reservoirs may require multiple platforms to produce a given reservoir.

Table 6-2, Case A, illustrates this relationship. As the depth decreases from 3050 to 1525 meters (10,000 to 5000 feet), EAC costs decline 2.6 percent, due to the shorter wells required. At 915 meters (3000 feet), however, three platforms are required to produce the field. Two of the platforms were assumed to be "satellite platforms" with lower dock loads and only the equipment necessary to feed their production to the third "main platform." Thus, the extra platform and equipment cost was only about twice (rather than three times) that of the base case platform. This added cost is sufficient to raise EAC costs 11 percent. Nevertheless, a rate of return of 16.9 percent can still be realized under those adverse conditions.

6.2.3 The Economic Impact of Alternative Initial Well Productivities

The rate at which a single well will produce depends on a number of reservoir characteristics such as permeability, porosity, pressure, oil viscosity, associated gas content, and connate water content. In addition, the numbers of wells and their spacing affect productivity. After integrating all of these factors, oil fields in the North Aleutian Shelf are expected to produce at an initial productivity (IP) of between 1000 - 5000 barrels per day per well.

Compared to the base case IP of 2000 barrels per day, an otherwise identical field with a 1000 barrel per day IP would require twice as many wells to drain the field. Those added wells would raise the cost of platform equipment and operating costs. Total capital investments are 33 percent higher, as shown in Case B, Table 6-2. Operating costs are 60 percent higher for a low IP field. Because of these added costs, the EAC cost per barrel is 5 percent higher, and the rate of return is 20.5 percent or 15 percent lower than the base case.

TABLE 6-2

RESULTS OF ECONOMIC MODELING OF OIL PRODUCTION IN THE NORTH ALEUTIANS

Case	Reservoir Target Depth (Meters)	Pipeline Distance To Shore/ Onshore Dist/ No. Fields Sharing Pipeline (kilometers/No.)	Number of Platforms/ Number of Producing Wells (No.)	Peak Production Per Well/Per Field (MBD/MMBD)	Undiscounted Capital Investment ($ Million)	Reservoir Size - Recoverable Reserves (MMBBL)	Discounted After-Tax Rate of Return On Investment (Percent)	After-Tax Capital Cost ($/BBL)	Equivalent Amortized Cost - (EAC) ($/BBL)
A. Reservoir Depth:									
Base Case (10,000 ft)	3050	128/16/2	1/14	2000/27	296	100	24.2	4.02	22.48
5000 ft. target	1525	"	2/14	"		"	26.5	3.13	21.9
3000 ft "	915	"	3/14	"	320	"	16.9	4.30	25.20
B. Initial Well Productivity:									
Low Productivity	3050	128/16/2	1/28	1000/27	395	100	20.5	5.14	23.61
Base Case (2000 B/D)	3050	"	1/4	2000/27	296	100	24.2	4.02	22.48
High Productivity (3000 B/D)	3050	"	1/9	3000/27	263	100	26.4	3.61	21.94
Very High (5000 B/D)	3050	"	1/6	3000/27	241	100	27.4	3.35	21.69
C. Reservoir Sizes:									
Base Case (100MMBBL)	3050	128/16/2	1/14	2000/27	296	100	24.2	4.02	22.48
250 MMBBL	"	"	1/34	2000/65	597	250	32.0	2.94	19.96
500 MMBBL	"	"	2/68	2000/131	1193	500	30.7	3.38	20.07
1000 MMBBL	"	"	4/136	2000/261	2162	1000	31.3	2.89	19.58
D. Water Depth:									
50 Foot (15 m)	3050	128/16/2	1/14	2000/27	274	100	25.8	3.68	22.16
Base Case 150 Feet (45 m)	"	"	1/14	2000/27	296	100	24.2	4.02	22.48
300 Foot (90 m)	"	"	1/14	2000/27	315	100	24.1	4.15	22.62
E. Pipeline Distance:									
Unshared Pipe	3050	128/16/1	1/14	2000/27	349	100	21.3	4.77	23.21
Short off, Long on	"	48/80/2	"	2000/27	308	100	23.5	4.19	22.65
Base Case	"	128/16/1		2000/27	296	100	24.2	4.02	22.48
Short off, Medium on	"	32/48/2	"	2000/27	289	100	24.6	3.92	22.39
Short off, 50 Foot Water	"	32/16/2	"	2000/27	254	100	27.2	3.40	21.88
F. Steel Jacket vs. Gravity Platform:									
Base Case (Jacket)	3050	128/16/2	1/14	2000/27	296	100	24.2	4.02	22.48
Gravity	"	"	"	"	301	100	23.9	4.31	23.23
G. Scheduling:									
Base Case	3050	128/16/2	1/14	2000/27	296	100	24.2	4.02	22.48
St. George Sched.	"	"	"	"	296	100	25.2	3.89	22.36
1-Year Delay	"	"	"	"	296	100	19.1	4.66	23.54

At IP rates higher than 2000 barrels per day, capital investment and operating costs are lower than those of the base case. Consequently, the resulting EAC costs for 3000 and 5000 barrels per day IP are lower by 2.4 and 3.5 percent, respectively.

In conclusion, the IP rates that are likely to be encountered in the North Aleutian Shelf are not likely to cause any fields to be uneconomic, and may cause some fields to be even more economically attractive if it is assumed that somewhat higher IP's may be sustainable in North Aleutian Shelf reservoirs than those in St. George Basin. (In Appendix A we have selected 3000 barrels per day versus 2000 barrels per day in St. George as a most likely value.)

6.2.4 The Economic Impact of Deeper Water

Increasing the water depth from the base case of 45 meters (150 feet) to 90 meters (300 feet) increases the cost of the platform, and thus raises capital costs by $24 million as shown in Case B, Table 6-2. This increases the EAC only slightly, from $22.48 to $22.62. Most of the additional capital expense is offset by lower Federal taxes. For larger fields, the $40 million cost of the taller platform would be amortized over a greater production and thus be even less significant. Shallow water depths such as 15 meters (49 feet) occur in many promising locations on the shelf. In this case, due to the lower platform costs, an EAC of $22.16, or 1.4 percent lower than the base case, can be expected. In general, water depths likely to be encountered in the North Aleutian Shelf will not greatly influence development feasibility except in otherwise marginal situations.

6.2.5 Economic Impact of Alternative Reservoir Sizes

The minimum economically feasible field size for oil is 50 - 100 million barrels, depending on engineering, locational, and geological assumptions. At the base case depth of 3050 meters (10,000 feet), a single platform can produce a field of up to about 250 million barrels. This is in part due to the presence of sea ice, which limits the number of conducter wells to 48, the number which can be enclosed in the platform legs. For the North

Aleutian Shelf, we have assumed one injection well for each three producing wells.(1) Because of these limitations, only 36 producing wells can be produced from a platform. Assuming 2000 barrels per day per well and an annual peak capacity of 10 percent of the total reserves, only 250 million barrels can be produced from one platform.

As seen in Table 6-2, Case C, EAC costs decline as reservoir size increases from 50 - 250 million barrels. Although capital investments are higher for the larger fields, the capital cost per unit production decreases with field size in this range, since a single platform is adequate for development, and larger pipe diameter is only slightly more expensive than small pipe.

The 500 million barrel field is slightly more expensive per barrel than a 250 million barrel field, because the pipeline is not shared as is assumed in other cases. Furthermore, in multi-platform fields, it is assumed that platforms are phased in at a rate of one per year. Despite the unshared pipeline and the delay in production, there is only an $0.11 difference in EAC between the 250 and 500 million barrel fields.

In a four platform billion barrel field, the economies of scale in pipeline (even though the pipe is assumed to be unshared) results in an EAC of only $19.58, the lowest of any case modeled. The after-tax rate of return is 31.3 percent, second only to the 32 percent return realized on a shared pipeline, 250 million barrel field.

6.2.6 Economic Impact of Alternative Pipeline Configurations

Maximum offshore pipeline distances of 130 kilometers (81 miles) can be anticipated in the North Aleutian Shelf lease sale area (see Appendix A, Section III). Long onshore pipelines (up to 80 kilometers or 50 miles) may be needed if onshore facilities cannot be located on the Bristol Bay coast.

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(1) This compares to a 5:1 ratio used in the St. George Basin study. The difference is due to engineering opinion rather than to differences in reservoir conditions between the two basins.

Since mountainous terrain might be encountered in some locations, onshore pipeline is somewhat more expensive than comparable marine pipeline.

In this study, the pipeline costs were interpolated to reflect the total length (in inverse proportion to unit cost) and to reflect pipe diameter (directly proportional to cost). This method is more sensitive to the incremental or "lumpy" costs assumed in earlier studies. In addition, pipe diameters have been adjusted to reflect the low temperatures (high viscosity) that occur in the sub-Arctic. This results in larger diameter pipes than were assumed for St. George and previous studies.

As expected, Table 6-2, Case D, shows that EAC costs are greatest for long pipelines, especially for long, onshore pipelines. Since all of the cases modeled had rates of return in excess of 20 percent, pipe length is not a limiting economic factor for the cases modeled. Even a 128-kilometer (80-mile) marine pipeline that supports only one 100 million barrel field is economically feasible.

6.2.7 Comparison of Alternative Platform Configurations

As indicated in Case E, Table 6-2, steel gravity platforms are $5 million more costly than Cook Inlet steel jacket platforms at a 90-meter (295-foot) water depth. Although this cost discrepancy disappears for platforms in deeper water, production occurs later for gravity platforms[1] and adversely affects their economic viability. According to Sante Fe Engineering, gravity platforms may take about one year longer to bring into production than a comparable size jacketed platform. With other investments (pipe and terminal) in place, delay is costly. Thus, unless the storage capacity afforded by the gravity platform is needed, gravity platforms are not likely to be used in the North Aleutian Shelf.

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[1] The construction schedule for steel gravity platforms may be 6 - 12 months longer, depending upon water depth, than the Cook Inlet steel jacket platforms.

6.2.8 Impact of Alternative Schedules

In order to demonstrate the effect of slight differences in production scheduling and capital investments between the St. George Basin study and the current study, the base case was run using the St. George schedule. As shown in Case F, Table 6-2, this results in a EAC cost only $0.12 less for the St. George case, although this results in a one percent greater EAC.

To simulate a delay in production (due to permitting problems for example), production was assumed to begin in year 6 rather than year 5, leaving the costly equipment idle for one year. Such a delay raises the EAC $1.06 per barrel and lowers the rate of return from 24.2 to 19.1 percent. Although not modeled, it is safe to extrapolate that more lengthy delays would have a severe effect on economic viability.

6.2.9 The Economics Of Producing Gas In Association With Oil

Historically, most gas produced in association with oil has been either flared (wasted) or reinjected to increase the oil productivity rate. Flaring currently is prohibited by Federal law. The advantages of gas reinjection can also be realized through waterflood techniques (i.e., water injection). One may therefore judge the economics of producing associated gas by determining whether the incremental costs of separating and delivering the gas to market are covered by its revenues.

We did not evaluate the economics of associated gas production in the North Aleutian Shelf since we believe that the results of our St. George Basin analysis (Dames & Moore 1980c, Section 6.2.8) would be equally applicable to this area.

6.2.10 Effects of Cost and Price Uncertainty on Oil Field Development Economics

In view of rapid oil price increases in the past year, and the less dramatic but still high inflation in petroleum development costs, it is impossible to accurately predict relative price and cost movements. The inflation "wash" assumption (that development cost would match petroleum price increases) used in previous OCS economic studies is increasingly difficult to justify. However, it is also difficult to defend any other price/cost inflation scenario. Therefore, to illustrate the effects of various price and cost changes on the base case North Aleutian Shelf oil field, a number of sensitivity cases were studied. The results of that analysis are displayed in Table 6-3. The changes are in real (uninflated) terms relative to other prices and costs.

6.2.10.1 Oil Price Changes

Increasing oil prices to $45.00 (a 64 percent increase from the base case) increases the rate of return dramatically (50.4 percent). EAC cost also increases by 42.8 percent. This increase is due to the greater tax liability incurred by the developer. An 18 percent decline in oil prices (to $22.50) causes a proportionally greater drop in the rate of return as a result of the heavy "front-end" costs of oil field development. Escalating oil prices 3 percent a year relative to costs results in a 19.4 percent increase in the rate of return despite an EAC increase of 17.8 percent.

6.2.10.2 Development Cost Changes

Increasing operating and administrative costs by 25 percent (i.e. to allow for the necessarily approximate nature of the mid-range estimates used in the model runs) has little impact on profitability. Since these costs can be expensed against current year earnings, tax reductions cushion the effects of the increase. A decrease in these costs is likewise cushioned from increasing profitability. Thus, the economic results are not very sensitive to changes in operating costs.

Decreasing capital costs (tangible and intangible) by 20 percent causes an increase in the rate of return on investment to 28 percent. A 25 percent increase in these costs reduces the rate of return to 20.5 percent. Taxes

TABLE 6-3

THE SENSITIVITIES OF OIL PRICES AND DEVELOPMENT COSTS ON NORTH ALEUTIAN SHELF OIL DEVELOPMENT

	Discounted After-Tax Rate of Return versus Base Case		EAC Oil Cost	
	Percentage	Percentage Change	Cost per Barrel ($)	Percentage Change
Base Case	24.2	--	22.48	--
1. Increase oil prices to $45 per barrel	36.4	+ 50.4	32.11	+ 42.8
2. Decrease oil prices to $22.50 per barrel	19.3	- 20.2	19.73	- 12.2
3. Escalate oil prices at 3 percent per year	28.9	+ 19.4	26.49	+ 17.8
4. Decrease operating and administrative costs by 20 percent	25.8	+ 6.6	21.80	- 3.0
5. Increase operating and administrative costs by 25 percent	22.3	- 7.9	23.33	+ 3.8
6. Escalate operating and administrative costs by 3 percent per year	23.9	- 1.2	22.83	+ 1.6
7. Decrease tangible and intangible costs by 20 percent	28.0	+ 15.7	21.69	- 3.5
8. Increase tangible and intangible costs by 25 percent	20.5	- 15.3	23.47	+ 4.4

have little influence on these costs, which are incurred in the early years of development. EAC costs are not as sensitive to these cost changes since the costs are spread over the productive life of the development.

6.3 Analytical Results of Non-Associated Gas Development in the North Aleutian Shelf

An approach similar to that used for oil development was employed in analyzing gas development economics. The gas field conditions that were modeled are shown in Table 6-4. Most gas-containing reservoirs are assumed to be in deep formations; therefore, no shallow gas reservoir cases were modeled.

6.3.1 Base Case Assumptions and Results in Analyzing Gas Development Economics

Gas base case conditions for water depth, reservoir depth, and distance from shore were identical to those used for the oil case analyses. In addition, the following parameters were assumed in the base case:

Reservoir size..................	1 trillion cubic feet
Initial Productivity............	15 million cubic feet per day per well
Recoverable reserves per acre....	200 million cubic feet
Production system................	Steel platform with half-shared 128-kilometer (80-mile) marine pipe, 16-kilometer (10-mile) onshore pipe
Terminal.........................	None included

No terminal or LNG conversion charges were included, since the boundary of the system modeled was at the gate of an LNG plant. The $2.22 per thousand cubic feet gas price used represents an end-of-pipe price at the Alaska

TABLE 6-4

RESERVOIR, PRODUCTION, AND LOCATIONAL FACTORS
EVALUATED IN THE ECONOMIC ANALYSIS -- GAS

Condition	Units	Range of Parameters Modeled
Reservoir Depth	Meters (Feet)	3050 (10,000)
Reservoir Size	Trillion Cubic Feet	0.5, 1.0*, 3.0
Pipe Distance Marine/Onshore	Kilometers (Miles)	128/16 (80/10)*, 48/80 (30/50), 32/48 (20/30), 31/16 (20/10)
Initial Productivity Per Well	Million Cubic Feet	10.0, 15.0*
Water Depth	Meters (Feet)	15 (50), 90 (150)
Platform Type	None	Steel Jacket*, Steel Gravity

*Indicates the value used in the base case.

Peninsula terminal.[1] Implicit in these economic assessments of individual fields is the assumption that there will be sufficient gas produced from the North Aleutian Shelf to sustain an LNG plant and a shipping link to the Lower 48.

Like the oil base case, the gas base case uses both favorable and unfavorable reservoir, production, and locational characteristics. The one trillion cubic feet reservoir size is not very large compared to the possible giant gas fields (2 - 3 trillion cubic feet) that may exist in the North Aleutian Shelf. The assumed 128-kilometer (80-mile) marine, 16-kilometer (10-mile) onshore pipe is also an unfavorable assumption. Other field conditions represent a favorable bias such as the high IP and deep target.

Under these assumptions, a capital investment of $228 million over the first 5 years is necessary for development of the base case field. Eleven wells[2] are drilled from the platform to yield a peak flow of 158 million cubic feet per day. The field produces for 19 years before reaching its economic limit. Operating costs exceed revenues after that year. The net present value after-tax cash flow, discounted back to the first year of development at 12 percent, totals $100 million. Table 6-5 shows the rate of return on investment to be 14.3 percent. This return, while well above the 12 percent hurdle rate, is lower than most of the North Aleutian Shelf oil development cases modeled. The EAC gas cost is $2.09 per million cubic feet, below the $2.22 assumed selling price.

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(1) For discussion of this assumption, see Appendix A, Section V of the St. George Basin Report.

(2) In response to comments regarding the short life of the St. George Basin gas fields, fewer wells were assumed in North Aleutian gas production. This results in a peak production of 6 percent of reserves per year, as opposed to 10 percent in the St. George Basin study.

TABLE 6-5

RESULTS OF ECONOMIC MODELING OF GAS PRODUCTION IN THE NORTH ALEUTIANS

Case	Reservoir Target Depth (Meters)	Pipeline Distance To Shore/ Onshore Dist/ No. Fields Sharing Pipeline (Kilometers/No.)	Number of Platforms/ Number of Producing Wells (No.)	Peak Production Per Well/Per Field (MMCFD)	Undiscounted Capital Investment ($ Million)	Reservoir Size - Recoverable Reserves (TCF)	Discounted After-Tax Rate of Return On Investment (Percent)	After-Tax Capital Cost ($/MCF)	Equivalent Amortized Cost - (EAC) ($/MCF)
Initial Well Productivity:									
Base Case 15MMCFD	3050	128/16/2	1/11	15/158	228	1.0	14.3	0.42	2.09
10MMCFD	3050	"	1/16	10/153	255	1.0	12.2	0.49	2.17
Deep Water (90 Meters)	3050	"	1/11	15/158	233	1.0	13.15	0.45	2.13
Shallow Water (15 Meters)	3050	"	1/11	15/158	205	1.0	15.53	0.38	2.05
Reservoir Size:									
0.5 TCF	3050	128/16/2	1/16	15/86	177	0.5	4.4	0.60	2.58
Base Case 1.0 TCF	3050	"	1/11	15/158	228	1.0	14.3	0.42	2.09
3.0 TCF	3050	"	1/33	15/475	407	3.0	21.6	0.29	1.76
Pipeline Distance:									
Base Case	3050	128/16/2	1/11	15/158	228	1.0	14.3	0.42	2.09
Unshared Pipe	"	128/16/1	1/11	15/158	271	1.0	12.3	0.49	2.17
Short Offshore, Long on	"	48/80/2	"	"	218	1.0	14.6	0.41	2.07
Short Off, Medium On	"	32/48/2	"	"	211	1.0	15.1	0.38	2.06
Short Off	"	32/16/2	"	"	191	1.0	16.3	0.35	2.02
Platform:									
Base Case (Steel Jacket)	3050	128/16/2	1/11	15/158	228	1.0	14.3	0.42	2.09
Gravity	"	128/16/2	1/11	15/158	233	1.0	11.8	0.46	2.17

6.3.2 Economic Impact of Alternative Well Productivities

North Aleutian Shelf wells are assumed to produce in the range of 10 - 15 million cubic feet per day. Fields with lower IP wells would require more wells per platform to produce a given size field at a given rate. As seen in Table 6-5, Case A, development of a 10 million cubic feet per day well reservoir would require more capital investment than the base case. This results in a rate of return of 12.2 percent, just above the 12 percent hurdle rate. The EAC cost per thousand cubic feet ($2.17) is barely below the maximum selling price. Thus, North Aleutian Shelf gas development is quite sensitive to IP.

6.3.3 Economic Impact of Water Depth

Decreasing the water depth at the platform from the base case of 45 meters (90 feet) to 15 meters (50 feet) reduces capital investment by $28 million as shown in Table 6-5. This raises the rate of return to 15.4 percent and lowers the EAC cost per thousand cubic feet by $0.04. Since deep waters are not likely in the North Aleutian Shelf, water dpeth will not strongly affect economic viability of gas production.

6.3.4 Economic Impact of Reservoir Size

Other conditions held constant, a smaller reservoir costs more per thousand cubic feet to develop, has higher EAC costs, and consequently a lower rate of return than a larger reservoir. In addition, the cost of a platform and pipeline for a small field is amortized over less production. As shown in Table 6-5, a field with 500 billion cubic feet of recoverable reserves yields a rate of return of only 4.4 percent, well below the 12 percent hurdle rate. Thus, the minimum economic gas field size is slightly below one trillion cubic feet in the North Aleutian Shelf. By contrast, a large gas field of 3 trillion cubic feet has an after-tax rate of return of 21.6 percent, well above the hurdle rate and comparable to oil field rate of return.

6.3.5 Economic Impact of Alternative Pipeline Configurations

As seen in Table 6-5, pipeline lengths shorter than the 128-kilometer (80-mile) marine and 16-kilometer (10-mile) onshore lengths of the base case lower EAC costs slightly and enhance profitability. An unshared base case pipeline is, of course, less profitable than a shared pipe, but nevertheless just exceeds the 12 percent rate of return hurdle. Since this fairly unfavorable case is still economic, pipeline distance alone is not likely to deter gas production in the North Aleutian Shelf.

6.3.6 Effects of Cost and Price Uncertainty on Gas Field Development Economics

As shown in Table 6-6, increasing the price received for gas at the shore terminal from $2.22 to $3.60 per thousand cubic feet (a 75 percent increase) raises the rate of return to 24.7 percent, 74 percent higher than the base case. Higher revenues would also cause the EAC to rise 36.4 percent because of the greater tax liability. Decreasing the gas price to $1.75 per thousand cubic feet (a 21 percent decrease) drops the rate of return to 9 percent, below the economic limit of feasibility. Taxes lower the EAC 12 percent to $1.83, or just above the received price. Escalating relative gas prices by 3 percent per year raises the rate of return to 19.2 percent, a rate of return of 35 percent greater than the base case.

As in oil development, taxes reduce the impact of either increases or decreases in operating and administrative costs. Increasing these costs 25 percent causes a reduction of only 2.5 percent in the rate of return, while a cost decrease of 20 percent produces a rate of return only 2 percent higher. EAC cost changes are even less sensitive to operating and administrative cost changes.

Decreasing capital costs by 20 percent increases the rate of return from 14.2 to 16.8 percent. Likewise, increasing capital costs by 25 percent reduces the rate of return to 11.7 percent, or just below the economic hurdle rate. EAC costs are not as sensitive to those cost changes since the costs are amortized over the life of the field.

TABLE 6-6

THE SENSITIVITY EFFECTS OF GAS PRICE AND DEVELOPMENT CHANGES ON NORTH ALEUTIAN SHELF GAS DEVELOPMENT

	Discounted After-Tax Rate of Return versus Base Case		EAC Gas Cost	
	Percent	Percentage Change	Cost per Thousand Cubic Feet ($)	Percentage Change
Base Case	14.2	--	2.09	--
1. Increase gas prices to $3.60 per thousand cubic feet	24.7	73.9	2.85	36.4
2. Decrease gas prices to $1.75 per thousand cubic feet	9.0	-36.6	1.83	-12.4
3. Escalate gas prices by 3 percent per year	19.2	35.2	2.46	17.7
4. Decrease operating and administrative costs by 20 percent	16.2	14.1	2.00	- 4.3
5. Increase operating and administrative costs by 25 percent	11.7	-17.6	2.20	5.3
6. Decrease tangible and intangible capital costs by 20 percent	16.8	18.3	2.00	- 4.3
7. Increase tangible and intangible costs by 25 percent	11.7	-17.6	2.20	5.3

6.4 Relationship of North Aleutian Shelf Oil and Gas Supplies to U.S. Energy Balance

6.4.1 Introduction: The Supply of North Aleutian Shelf Oil and Gas

Potential oil and gas supplies from the North Aleutian Shelf could be available to the United States no sooner than 1992 if the lease sale is held on schedule in 1983. Chapter 7.0 develops the likely supply patterns for the U.S. Geological Survey statistical mean resource estimate, assuming a high level and rapid exploration and development program. Indeed, the potential supplies are not insignificant. Gas could flow at over 400 million cubic feet per day during the late 1990's. Oil could flow in excess of 150,000 barrels per day during the late 1990's. Hence, development of these offshore resources will entail significant onshore developments in the Aleutians or Alaska Peninsula or both.

The following sections highlight the economic issues concerning the marketing potential of North Aleutian Shelf oil and gas in the United States, in particular Alaska's contribution to future U.S. oil supplies, the relationship of these supplies to PAD V supply/demand balance and the impact of North Aleutian Shelf production on Pad V. In-depth presentation of some of the issues presented in the June 1980 Norton Basin Marketability Study (Dames & Moore, 1980b) is not reproduced in this report. The reader is referred to that study for a detailed discussion on world oil supply and demand, oil supply forecasts, and the U.S. energy situation.

6.4.2 Alaska's Link To U.S. Future Oil Supplies

The security of the U.S. oil supply has become a major impetus behind U.S. energy policy. While the current recession has created a small surplus in the world oil market, exporters still possess great leverage and importers remain vulnerable. U.S. officials remain worried about the impact of import supply disruptions on the U.S. economy and quality of life. The U.S., as well as much of the rest of the world, will remain critically dependent on oil from the politically unstable Middle East until sometime in the next century when alternative technologies and sources of energy are developed. Minor import supply disruptions will continue to have major economic disruptions. When these will occur cannot be forecast. To the extent that U.S. energy policies can stimulate domestic production or reduce demand for oil, the U.S. will become less vulnerable to unpredictable disruptions.

John Swearingen, Chairmen of Standard Oil of Indiana, summed it up at a meeting of the Commonwealth Club of San Francisco, February 1, 1980: "The U.S. must do everything possible to reduce its reliance on unstable sources of supply."

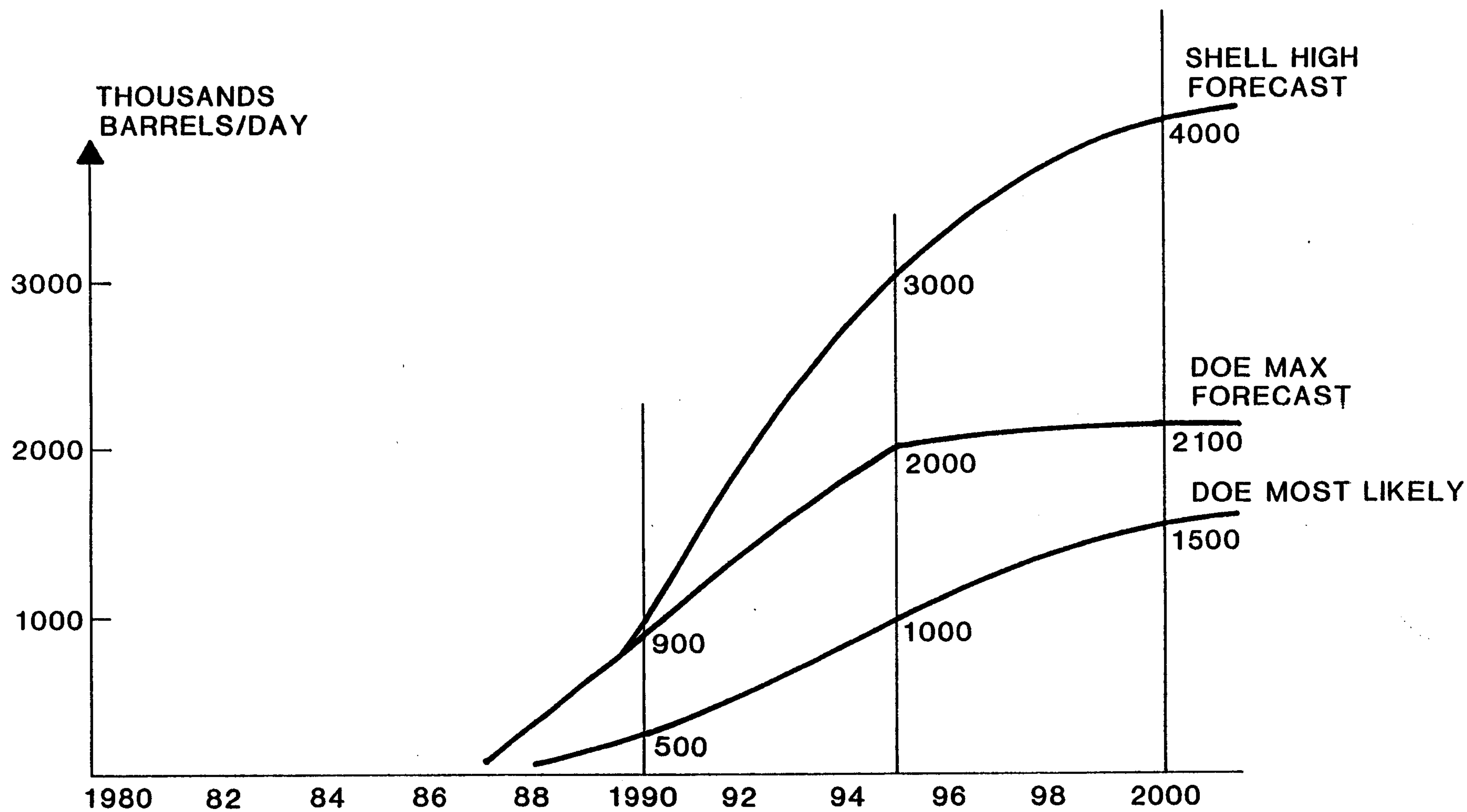
Alaska's OCS appears to be America's best hope for new oil supplies. One-half to two-thirds of America's estimated undiscovered reserves are expected to be found under Alaska waters. However, fewer than 1 million of Alaska's 200 million OCS acres have been leased and explored.

Transforming Alaska's OCS frontier into oil producing areas will be a herculean task. Consequently, Alaska's vast OCS potential will not be explored, discovered, developed, and supplied to the Lower 48 in significant quantities before the early 1990's under the existing Department of Interior 5-year lease schedule.

The estimated production levels shown on Figure 6-1 are based on Department of Energy (DOE) and Shell estimates.

6.4.3 Petroleum Administration District V With Special Reference To California

The future supply and price of oil to U.S. Petroleum Administration District V (PAD V), the seven western-most states including Alaska and Hawaii, will be shaped mostly by conditions in the world petroleum market, although Federal, Alaska, and California energy policies will have important impacts on supply. In 1978, oil consumption in PAD V amounted to 2.6 million barrels per day; of this, California consumed 2.1 million barrels per day, about 80 percent of the district total. Table 6-7 shows the District V 1978, 1979, and



Source: Dames & Moore, July, 1980

Figure 6-1

THE TIMING OF POTENTIAL NEW OIL SUPPLIES
FROM THE ALASKA OCS

TABLE 6-7

U.S. DISTRICT V SUPPLY/DEMAND
(Thousand Barrels per Day)

DEMAND	1978	1979	1980 IQ
District V Consumption	2624	2754	2625
Interdistrict and Foreign Product Shipments	136	115	75
Total Demand	2760	2839	2700
SUPPLY			
Production			
California Crude and NGL	951	995	965
Alyeska Pipeline Throughput	1065	1250	1500
Cook Inlet Production	137	121	100
Subtotal PAD V Production	2153	2366	2565
Foreign Imports			
Crude Oil	571	560	400
Products	120	150	100
Subtotal	691	710	500
Interdistrict Product Receipts	167	155	50
Refinery Process Gain	112	115	110
Total Supply	3123	3346	3225
ALASKA CRUDE INTERDISTRICT SHIPMENTS	363	507	525
MEMO:			
Refinery Capacity	2889	2868	N/A
Crude Runs	2361	2419	N/A
Percent Utilization	82	84	N/A

Sources: Oil Company (Confidential), 1979.
Dames & Moore.

preliminary first quarter 1980 supply/demand balance for crude oil and petroleum products. The table illustrates several situations about PAD V petroleum flows caused by the refiner's need to balance crude mixes to make the products demanded.

Table 6-7 shows that:

- Although California and Alaska are among the top four oil and gas producing states, PAD V must import oil from foreign sources to cover 25 percent of its product demand.

- California crude production provides about 35 percent of PAD V product demand.

- PAD V imports 600,000 - 700,000 barrels per day of foreign crude and products at the same time it transships to Districts I-IV 500,000 barrels per day of Alaska crude.

- Similarily, products are shipped out of PAD V to Districts I-IV even though PAD V is an importer of manufactured products.

- Products are shipped into PAD V from foreign refineries and from Districts I-IV even though PAD V refineries are less than 85 percent utilized.

Existing California refineries are not capable of processing all the available California and Alaska crude without producing a surplus of heavy products (fuel oils) and a deficit of light products (gasoline.) This situation is further complicated by the southern California environmental requirement that fuel oils must contain less than 0.25 percent sulfur. Indonesian crude is the perfect feed stock to blend with domestic crudes to make low sulfur fuel oil and to meet California's demand for light products.

It is possible to retrofit the existing refineries with expanded hydrocracking and residuum de-sulfurization (RDS) capacity to process additional quantities of either North Slope or heavy California crudes. Whether these refinery modifications will occur depends on economics and state and national energy policy issues.

Unless refinery modifications are made, little more than 1 million barrels per day of North Slope quality crude can be processed in PAD V, and Prudhoe production above 1.3 million barrels per day will continue to move to PADs I-IV.

6.4.4 Impact Of North Aleutian Shelf Production On PAD V

Table 6-8 shows how new production from the North Aleutian Shelf could impact PAD V's supply/demand balance. Without question, a great deal of uncertainty surrounds all the issues that underlie the determinants of both supply and demand.

The PAD V demand forecast shown on Table 6-8 reflects the consumption changes that have occurred since the radical political changes in the Middle East and now calls for petroleum use to grow at 1.0 percent annually to 1990 and then flatten out. It assumes total 1980 consumption averages near the first half actual consumption totals. This forecast assumes more conservation and shifting to alternate fuels than the California Energy Commission conventional forecast--but less than the California Energy Commission alternative resource forecast.

PAD V consumption of petroleum products is sensitive to natural gas supplies. The demand forecast shown in Table 6-8 assumes "most likely" gas supplies. California utilities, if allowed by regulation, could use gas instead of fuel oil. Large supplies of new Alaska gas could reduce the demand for crude oil.

The supply excluding Alaska on Table 6-8 includes both California production and Indonesian imports. Production from California reserves is expected to peak at 1.1 million barrels per day by the mid-1980's, remain at peak through the early 1990's and then slowly decline. Modification of refineries is assumed to reduce, but not eliminate, the requirement for high gravity, low sulfur foreign crude imports. These imports are estimated to range between

TABLE 6-8

Impact of Potential New Alaska Production on PAD V Supply/Demand Balance
(1000 Barrels per Day)

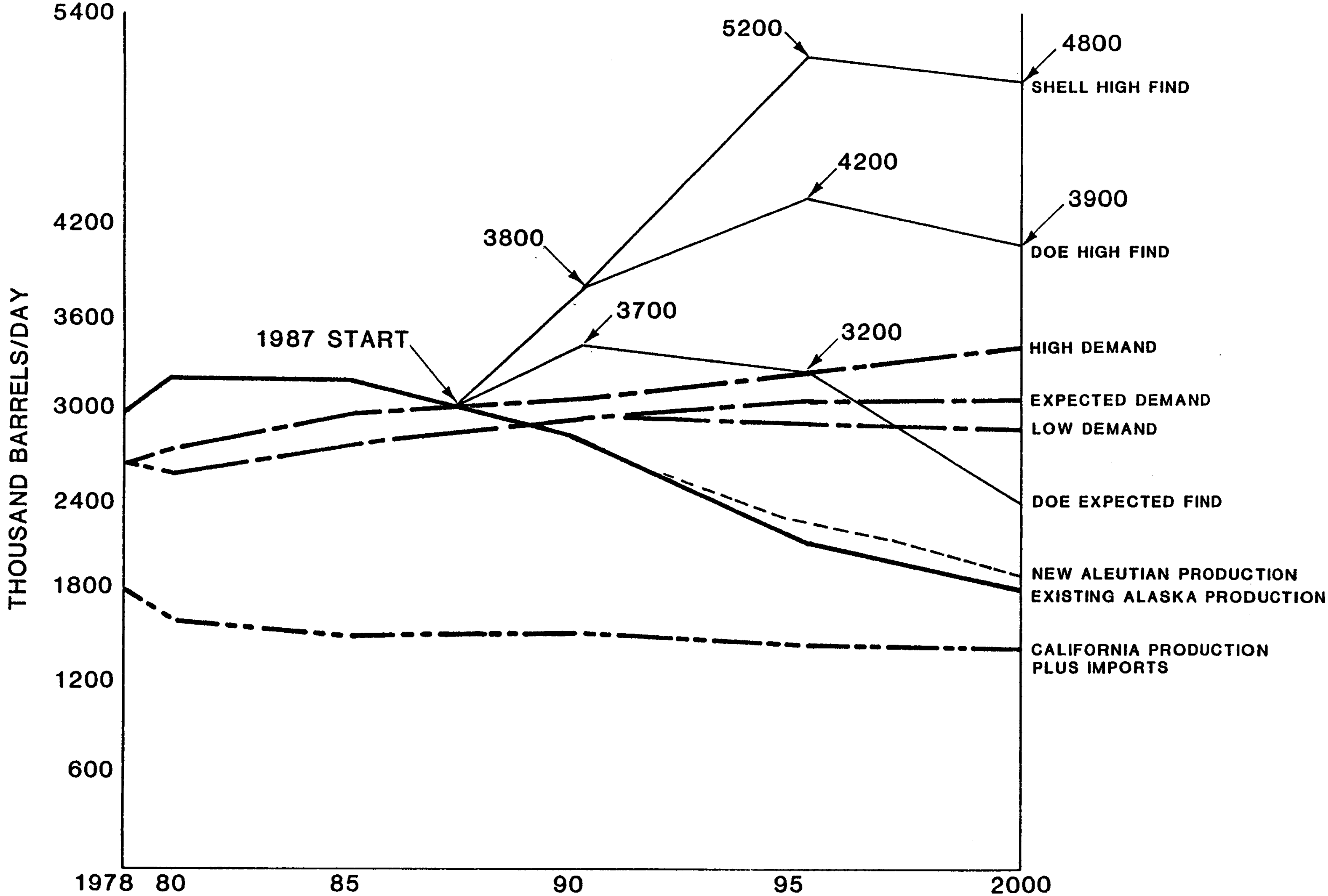
	1980	1985	1990	1995	2000
DEMAND	2700	2860	3025	3125	3125
Supply, excluding Alaska	1710	1590	1600	1500	1450
Existing Alaska Production	1610	1670	1300	700	370
TOTAL SUPPLY	3320	3260	2900	2200	1820
Supply Surplus/(deficit)	620	400	(125)	(925)	(1305)
Projected North Aleutian Shelf Production	--	--	--	138	145
Supply Surplus/(deficit) with North Aleutian Shelf Production	620	400	(125)	(787)	(1160)

Source: Dames & Moore, July, 1980

300,000 - 400,000 barrels per day after 1985 to balance the refineries' crude mix. Other imports will have to be added toward the end of the decade if new Alaska reserves are not discovered and produced by then. Oil supplies from existing sources for PAD V are shown to decline from just over 3.3 million barrels per day in 1980 to 2.9 million barrels per day by 1990 and just over 1.8 million barrels per day by 2000. New Alaska supplies will be required to balance PAD V demand requirements.

After 1985 Prudhoe Bay production from existing reserves will begin to decline. When the Prudhoe Bay field starts to decline, the west coast surplus of Alaska crude shown as 620,000 barrels per day in 1980 and 400,000 barrels per day in 1985 will quickly disappear. By 1990, PAD V will be short 125,000 barrels per day due to declining existing Alaska production. North Aleutian Shelf production will start up in 1992 with a modest 5800 barrels per day. By 1995, when the supply deficit is expected to reach 925,000 barrels per day, North Aleutian Shelf production will reach 138,000 barrels per day. The 1995 North Aleutian production will reduce the deficit to 787,000 barrels per day, a 15 percent reduction, and reduce the 2000 deficit by 11 percent to 1.2 million barrels per day.

Figure 6-2 shows the supply/demand picture in PAD V. North Aleutian Shelf production will add only a small increment to production during the 1990's, peak in 1997, and decline thereafter. Additional reserves from other Alaska basins will be required to balance PAD V throughout the last decade of this century. After the early 1990's, PAD V will require more oil than the entire DOE low-find Alaska estimates to remain in balance. In the high-find new Alaska discoveries case, Alaska crude will remain surplus on the west coast and can continue to move east to PADs I-IV.



Source: Dames & Moore, April, 1980

Figure 6-2
PAD V SUPPLY & DEMAND BALANCE

7.0 SELECTED PETROLEUM DEVELOPMENT OPTION FOR THE U.S. GEOLOGICAL SURVEY MEAN OIL AND GAS RESOURCE ESTIMATE

7.1 Introduction

This chapter presents specifications on a hypothetical oil and gas development case for the North Aleutian Shelf corresponding to the U.S. Geological Survey conditional statistical mean oil and gas resource estimate. The conditional estimates of undiscovered recoverable oil and gas for this area are (Marlow et al., 1980):

	Probability		Statistical
	95 percent	5 percent	Mean
Oil (billions of barrels)	<0.1	2.3	0.7
Gas (trillions of cubic feet)	0.26	7.2	2.24

For the purposes of formulating a development case, the natural gas resource (2.24 trillion cubic feet) has been assumed to be about 70 percent non-associated gas and 30 percent associated, following the analysis presented in the U.S. Geological Survey resource report (Marlow et al., 1980).

Table 7-1 shows the assumed fields, their reserves, and location and timing of discovery. Exploration, development, and production details of the hypothetical development case are presented in Table 7-2. Table 7-3 specifies the major onshore facilities, and their construction and operation schedules.

The development case hypothesized here assumes a relatively rapid exploration and development schedule. This schedule is characterized by a high level of exploratory activity with a commensurate rate of discovery that results in five commercial oil fields and one gas field discovered within six years of

TABLE 7-1

DEVELOPMENT OPTION SPECIFICATIONS FOR FIELDS COMPRISING U.S. GEOLOGICAL SURVEY STATISTICAL MEAN RESOURCE ESTIMATE

Field Size Oil (MMBBL)	Field Size Gas (BCF)	Location	Reservoir Depth Meters	Reservoir Depth Feet	Production System (1)	Platforms No./Type*	Number of Production Wells	Initial Well Productivity Oil (B/D)	Initial Well Productivity Gas (MMCFD)	Peak Production Oil MB/D	Peak Production Gas MMCFD	Water Depth Meters	Water Depth Feet	Pipeline Distance to(2) Shore terminal Kilometers (Miles) Oil	Pipeline Distance to(2) Shore terminal Kilometers (Miles) Gas	Timing of Discovery
200	400	West	1,524	5,000	Steel jacket platform(s) with shared pipeline to shore terminal	25	28	2000	--	53.8	107.5	90	294	116 (72)	193 (120)	1985
100	--	West	1,524	5,000	" "	15	14	2000	--	26.9	--	90	294	145 (90)	-- --	1986
--	1500	Central	3,048	10,000	" "	15	16	--	15	--	230.4	75	246	-- --	138 (86)	1986
200	300	Central	1,524	5,000	" "	25	28	2000	--	53.8	80.7	57	186	138 (86)	138 (86)	1987
100	--	West	1,524	5,000	" "	15	14	2000	--	26.9	--	77	252	93 (58)	-- --	1987
100	--	East	1,524	5,000	" "	15	14	2000	--	26.9	--	27	90	183 (114)	-- --	1988

s = steel
MMBBL = million barrels
BCF = billion cubic feet
B/D = barrels per day
MB/D = thousand barrels per day

NOTE: (1) All oil fields share one of two oil trunkline systems; all gas producing fields share one gas trunkline system
(2) Distance represents spur plus trunkline
(3) Trunkline diameters -- oil 16 inches, gas 24 inches
(4) Terminal Sites: (a) crude terminal - Cold Bay, (b) LNG plant -- Cold Bay

Source: Dames & Moore

TABLE 7-2

HYPOTHETICAL PETROLEUM DEVELOPMENT CASE FOR NORTH ALEUTIAN SHELF(1)

Calendar Year	Year After Lease Sale	(2) Exploration and Delineation Wells: Exploration	(2) Exploration and Delineation Wells: Delineation	Exploration Rigs Operating	Commercial Discoveries: Oil	Commercial Discoveries: Gas	(3) Offshore Production Platforms or Onshore Stations	(4) Intermediate Pump/Compressor Platforms	(5) Development Wells	Pipeline Construction Kilometers (Miles) Per Year: Offshore Oil Trunk	Offshore Oil Spur	Offshore Gas Trunk	Offshore Gas Spur	Onshore Oil Trunk	Onshore Oil Spur	Onshore Gas Trunk	Onshore Gas Spur	(6) Production: Oil MMBBL	(6) Production: Gas BCF
1984	1	4		2															
1985	2	9		3	1														
1986	3	10	2	4	1	1													
1987	4	11	4	5	2														
1988	5	5	4	3	1														
1989	6	4	2	2															
1990	7	3		1			1												
1991	8						3	1											
1992	9						3	1	6	96.5 (60)				19 (12)					
1993	10						1		29		29 (18)	45 (28)	55 (34)			93 (58)		2.10	4.20
1994	11								48	23 (14)	51 (32)		22 (14)	116 (72)	61 (38)		37 (23)	10.48	37.76
1995	12								48									20.67	87.33
1996	13								13									50.37	135.91
1997	14																	65.14	147.48
1998	15																	67.83	151.99
1999	16																	66.19	148.59
2000	17																	61.23	143.05
2001	18																	52.78	134.53
2002	19																	45.90	128.74
2003	20																	38.50	121.12
2004	21																	33.64	116.21
2005	22																	28.79	112.10
2006	23																	24.65	108.05
2007	24																	21.10	104.62
2008	25																	18.06	98.76
2009	26																	15.46	82.43
2010	27																	13.23	70.97
2011	28																	10.07	50.51
2012	29																	6.12	47.97
2013	30																	1.47	39.20
2014	31																		32.51
2015	32																		27.[illegible]
2016	33																		20.30
2017	34																		
2018	35																		
TOTALS		46	12	20	5	1	8	2	144	119.5 (74)	80 (50)	45 (28)	77 (48)	135 (84)	61 (38)	93 (58)	37(23)	661.84	2161.19

NOTES:

1. The assumptions upon which this development case is based are summarized in Table 7-8 and further discussed in Appendices A and B.
2. Year-round capability is a probability in North Aleutian Shelf.
3. Hybrid steel jacket/upper Cook Inlet Design.
4. One intermediate pump station and one intermediate compressor station required onshore due to length of trunk pipelines.
5. Includes non-producing wells for injection of water or gas at a ratio of 1:3 to producers.
6. Total resource corresponding to U.S. Geological Survey estimate not produced due to application of economic limit to production flows. To exhaust reserves corresponding to assumed field size (i.e. beyond economic limit) makes the field longer by 2 - 4 years.
7. Includes associated gas from oil fields. Thirty percent of gas resource of basin is assumed to be associated.

TABLE 7-3

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

Facility	Year After Lease Sale		
	Construction	Start-up Date(1)	Shut-Down Date(2)
Cold Bay Oil Terminal	6-8	9	29
Cold Bay LNG Plant	6-9	10	32

(1) For the purpose of manpower estimation, start-up is assumed to be January 1.

(2) For the purpose of manpower estimation, shut-down is assumed to be December 31.

Source: Dames & Moore

the lease sale.[1] Many factors could alter the speed and course of events, such as the availability of drill rigs following the lease sale or environmental restrictions on year-round drilling.

This hypothetical development case draws upon the results of the technology assessment (Chapter 3.0), facilities analysis (Chapter 7.0), employment evaluation (Chapter 5.0), and economic analysis (Chapter 6.0) as well as the assumptions detailed in Appendices A and B. The field developments specified are all economic within parameters of the analysis stated in Appendix A.

7.2 Development Strategy, Facilities, and Production

This scenario postulates that discoveries are made in three areas of the Bristol Bay sedimentary basin (Figure 7-1): (1) three oil fields are located in the western portion of the sale area; (2) one oil field and a gas field are located in the central part of the sale area; and (3) a small oil field is located near Port Moller. These fields are developed with either Cook Inlet platforms or hybrid Cook Inlet/steel jacket designs (in water depths over 61 meters; 200 feet). An oil terminal and LNG plant are constructed at Cold Bay and serve all the fields. Two pipeline systems, one oil and one gas, take production from the central and eastern fields to Cold Bay. A separate trunk oil line takes crude from the three western fields to Cold Bay.

---

(1) Alternate exploration schedules, discovery timings, field development strategies, reservoir characteristics, and assumptions on the ratio of associated to non-associated gas reserves (comprising the U.S. Geological Survey estimate) were evaluated to assess their effects on facility and field lives). We recognize that facility and equipment requirements are very sensitive to certain assumptions. The number of platforms required for a given reservoir size is very sensitive to the reservoir depth assumption while, for deeper reservoirs where reservoir depth is not a limiting factor, the technical constraints of platform design on number of well slots of the selected platform design place a similar penalty. Other important sensitivities relate to optimal economic recovery of oil or gas and infrastructure sharing arrangements.

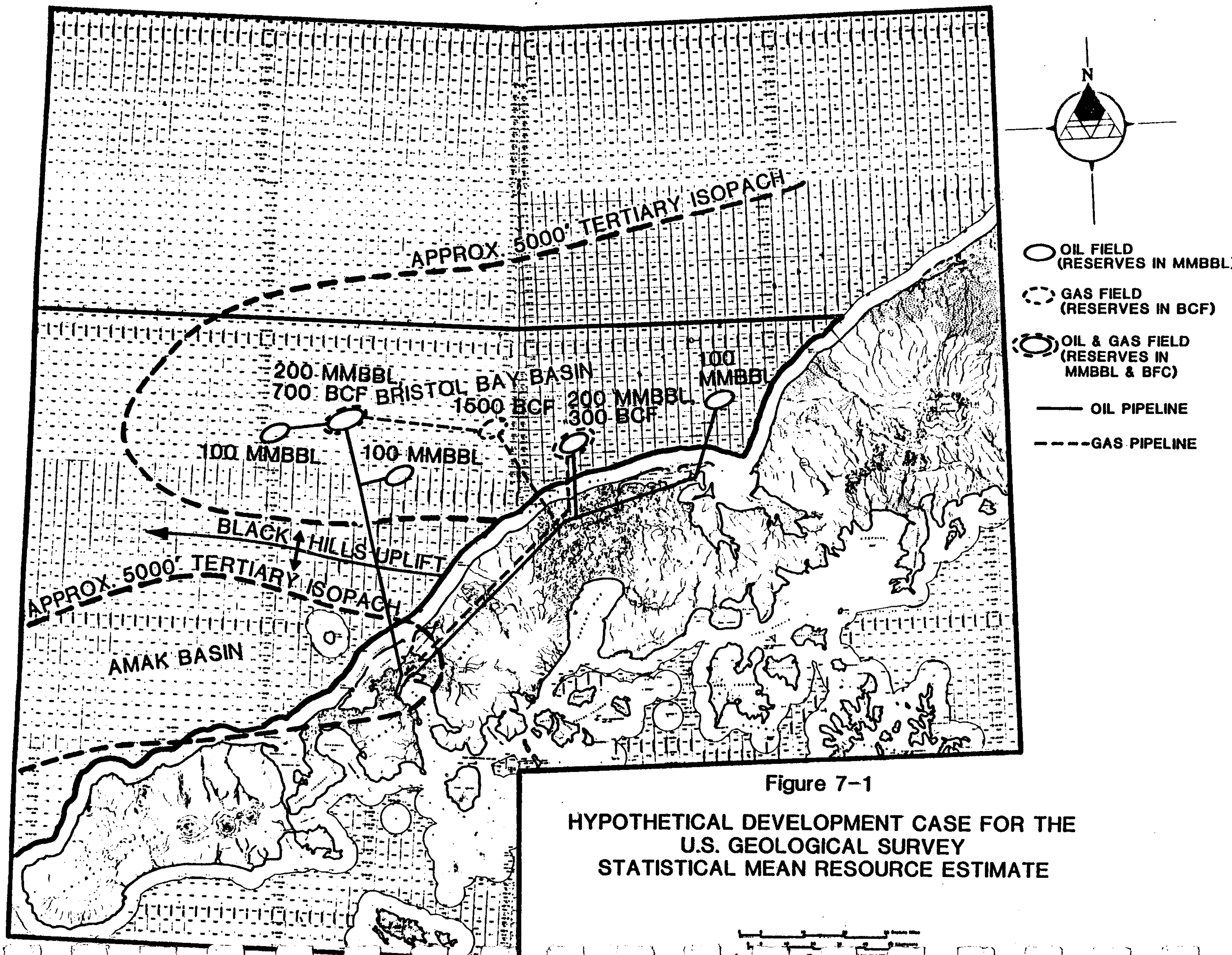


Figure 7-1

HYPOTHETICAL DEVELOPMENT CASE FOR THE U.S. GEOLOGICAL SURVEY STATISTICAL MEAN RESOURCE ESTIMATE

A depth of 1524 meters (5000 feet) has been assumed for the oil fields while the gas field is assumed to be 3084 meters (10,000 feet) deep. Initial well productivities of 2000 barrels per day and 15 million cubic feet per day are assumed. Oil production commences in 1992, gas in 1993; production of terminates in 2012, gas in 2013. Only two of the oil fields have sufficient reserves of associated gas to justify production; the other oil fields are assumed to have low gas/oil ratios with the associated gas used as platform fuel and the remainder reinjected into the reservoir. At peak production in the mid 1990's the North Aleutian Shelf contributes 186,000 barrels per day of crude and 461 million cubic feet per day of natural gas to the nation's energy supplies.

7.3 Employment

Employment estimates for exploration, construction, and operation of the facilities and equipment specified in Tables 7-2 and 7-3 and consistent with the results and assumptions of the manpower analysis (Chapter 5.0) are given in Tables 7-4 through 7-7.

7.4 Assumptions

The principal technical assumptions implicit in the development case specifications (Tables 7-1, 7-2, and 7-3) are listed in Table 7-8 and further discussed in Appendices A and B.

USGS STATISTICAL MEAN OIL AND GAS RESOURCE DEVELOPMENT-NORTH ALEUTIAN
08/25/80

TABLE 7-4

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	968.	104.	0.	0.	564.	112.	0.	1532.	216.	1748.
2	2178.	234.	0.	0.	1269.	252.	0.	3447.	486.	3933.
3	2904.	312.	0.	0.	1692.	336.	0.	4596.	648.	5244.
4	3630.	390.	0.	0.	2115.	420.	0.	5745.	810.	6555.
5	2178.	234.	0.	2100.	1269.	252.	0.	3447.	2586.	6033.
6	1452.	156.	0.	0.	846.	168.	0.	2298.	324.	2622.
7	726.	78.	2100.	1580.	976.	343.	0.	3802.	2001.	5803.
8	672.	72.	7700.	4350.	2014.	962.	0.	10386.	5384.	15770.
9	4224.	384.	9750.	6705.	2619.	1761.	0.	16593.	8850.	25443.
10	9000.	744.	5550.	4005.	1729.	1423.	600.	16279.	6772.	23051.
11	11592.	816.	940.	91.	741.	1011.	600.	13273.	2518.	15791.
12	7752.	336.	160.	64.	576.	960.	600.	8488.	1960.	10448.
13	6408.	192.	280.	112.	576.	960.	600.	7264.	1864.	9128.
14	6468.	192.	320.	128.	576.	960.	600.	7364.	1880.	9244.
15	6648.	192.	320.	128.	576.	960.	600.	7544.	1880.	9424.
16	6828.	192.	320.	128.	576.	960.	600.	7724.	1880.	9604.
17	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
18	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
19	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
20	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
21	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
22	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
23	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
24	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
25	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
26	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
27	6888.	192.	320.	128.	576.	960.	600.	7784.	1880.	9664.
28	5040.	144.	240.	96.	432.	840.	600.	5712.	1680.	7392.
29	2268.	72.	120.	48.	216.	180.	600.	2604.	900.	3504.
30	1344.	48.	80.	32.	144.	120.	600.	1568.	800.	2368.

USGS STATISTICAL MEAN OIL AND GAS RESOURCE DEVELOPMENT-NORTH ALEUTIAN
08/25/80

TABLE 7-5

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

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	0.	0.	0.	0.	0.	203.	149.	28.	10.	390.	5	390.
2	270.	219.	39.	15.	543.	316.	224.	43.	15.	598.	5	598.
3	360.	292.	52.	20.	724.	406.	297.	56.	20.	779.	5	807.
4	450.	365.	65.	25.	905.	519.	373.	71.	25.	987.	5	987.
5	270.	219.	89.	21.	599.	316.	224.	343.	48.	931.	6	931.
6	180.	146.	26.	10.	362.	203.	149.	28.	10.	390.	5	417.
7	90.	73.	13.	5.	181.	492.	415.	197.	46.	1150.	12	1333.
8	379.	340.	412.	66.	1197.	1558.	1410.	595.	151.	3714.	7	3714.
9	1327.	1206.	420.	146.	3099.	1972.	1821.	1153.	248.	5194.	7	5194.
10	1743.	1613.	340.	191.	3886.	1630.	1549.	824.	223.	4226.	2	4441.
11	1331.	1271.	249.	149.	3000.	1074.	1053.	203.	124.	2454.	1	3000.
12	806.	782.	170.	126.	1884.	734.	710.	174.	134.	1752.	1	1884.
13	582.	558.	146.	126.	1412.	652.	628.	174.	140.	1594.	6	1594.
14	587.	563.	146.	126.	1422.	667.	643.	178.	142.	1630.	6	1630.
15	602.	578.	146.	126.	1452.	682.	658.	178.	142.	1660.	6	1660.
16	617.	593.	146.	126.	1482.	697.	673.	178.	142.	1690.	6	1690.
17	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
18	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
19	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
20	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
21	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
22	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
23	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
24	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
25	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
26	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
27	622.	598.	146.	126.	1492.	702.	678.	178.	142.	1700.	6	1700.
28	456.	438.	132.	117.	1143.	516.	498.	156.	129.	1299.	6	1299.
29	207.	198.	71.	64.	540.	237.	228.	83.	70.	618.	6	618.
30	124.	118.	64.	59.	365.	144.	138.	72.	63.	417.	6	417.

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TABLE 7-6

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	136.	80.	0.	0.	0.	0.	0.	0.	0.	0.	72.	896.	0.	0.	0.	564.
	OFFSITE	0.	80.	0.	0.	0.	0.	0.	0.	0.	0.	0.	896.	0.	0.	0.	282.
2	ONSITE	306.	180.	0.	0.	0.	0.	0.	0.	0.	0.	162.	2016.	0.	0.	0.	1269.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	0.	635.
3	ONSITE	408.	240.	0.	0.	0.	0.	0.	0.	0.	0.	216.	2688.	0.	0.	0.	1692.
	OFFSITE	0.	240.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2688.	0.	0.	0.	846.
4	ONSITE	510.	300.	0.	0.	0.	0.	0.	0.	0.	0.	270.	3360.	0.	0.	0.	2115.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	0.	0.	0.	3360.	0.	0.	0.	1058.
5	ONSITE	306.	180.	2100.	0.	0.	0.	0.	0.	0.	0.	162.	2016.	0.	0.	0.	1269.
	OFFSITE	0.	180.	231.	0.	0.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	0.	635.
6	ONSITE	204.	120.	0.	0.	0.	0.	0.	0.	0.	0.	108.	1344.	0.	0.	0.	846.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1344.	0.	0.	0.	423.
7	ONSITE	501.	95.	0.	0.	0.	1405.	0.	0.	0.	0.	54.	672.	0.	2100.	0.	976.
	OFFSITE	159.	95.	0.	0.	0.	155.	0.	0.	0.	0.	0.	672.	0.	2100.	0.	488.
8	ONSITE	1574.	130.	0.	1575.	0.	2105.	0.	0.	0.	0.	0.	0.	672.	7200.	500.	2014.
	OFFSITE	595.	130.	0.	173.	0.	232.	0.	0.	0.	0.	0.	0.	672.	7200.	500.	1007.
9	ONSITE	2331.	189.	0.	1050.	3500.	0.	1300.	0.	480.	0.	0.	0.	4224.	9000.	750.	2619.
	OFFSITE	788.	189.	0.	116.	385.	0.	143.	0.	480.	0.	0.	0.	4224.	9000.	750.	1310.
10	ONSITE	2001.	191.	0.	0.	3500.	0.	0.	0.	480.	600.	0.	0.	9000.	4800.	750.	1729.
	OFFSITE	563.	191.	0.	0.	385.	0.	0.	0.	480.	600.	0.	0.	9000.	4800.	750.	865.
11	ONSITE	1255.	183.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	11632.	900.	0.	741.
	OFFSITE	286.	183.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	11632.	900.	0.	371.
12	ONSITE	688.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7912.	0.	0.	576.
	OFFSITE	272.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7912.	0.	0.	288.
13	ONSITE	592.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	6688.	0.	0.	576.
	OFFSITE	296.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	6688.	0.	0.	288.
14	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	6788.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	6788.	0.	0.	289.
15	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	6968.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	6968.	0.	0.	288.

** [illegible] TTA[illegible] KEY [illegible] ACT[illegible] IES

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TABLE 7-6 (Contd)

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7148.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7148.	0.	0.	288.
17	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
18	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
19	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
20	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
21	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
22	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
23	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
24	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
25	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
26	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
27	ONSITE	608.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	576.
	OFFSITE	304.	192.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	7208.	0.	0.	288.
28	ONSITE	456.	144.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	5280.	0.	0.	432.
	OFFSITE	228.	144.	0.	0.	0.	0.	0.	0.	480.	600.	0.	0.	5280.	0.	0.	216.
29	ONSITE	228.	72.	0.	0.	0.	0.	0.	0.	0.	600.	0.	0.	2388.	0.	0.	216.
	OFFSITE	114.	72.	0.	0.	0.	0.	0.	0.	0.	600.	0.	0.	2388.	0.	0.	108.
30	ONSITE	152.	48.	0.	0.	0.	0.	0.	0.	0.	600.	0.	0.	1424.	0.	0.	144.
	OFFSITE	76.	48.	0.	0.	0.	0.	0.	0.	0.	600.	0.	0.	1424.	0.	0.	72.

** SEE ATTACHED KEY OF ACTIVITIES

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TABLE 7-7

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

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	1532.	216.	1748.	2710.	296.	3006.	226.	25.	251.
2	3447.	486.	3933.	6098.	666.	6764.	509.	56.	564.
3	4596.	648.	5244.	8130.	888.	9018.	678.	74.	752.
4	5745.	810.	6555.	10163.	1110.	11273.	847.	93.	940.
5	3447.	2586.	6033.	6098.	2997.	9094.	509.	250.	758.
6	2298.	324.	2622.	4065.	444.	4509.	339.	37.	376.
7	3802.	2001.	5803.	7062.	2408.	9470.	589.	201.	790.
8	10386.	5384.	15770.	19765.	6514.	26279.	1648.	543.	2190.
9	16593.	8850.	25443.	31877.	10950.	42826.	2657.	913.	3569.
10	16279.	6772.	23051.	31694.	8990.	40684.	2642.	750.	3391.
11	13273.	2518.	15791.	26176.	4067.	30242.	2182.	339.	2521.
12	8488.	1960.	10448.	16688.	3504.	20192.	1391.	292.	1683.
13	7264.	1864.	9128.	14240.	3432.	17672.	1187.	286.	1473.
14	7364.	1880.	9244.	14440.	3456.	17896.	1204.	288.	1492.
15	7544.	1880.	9424.	14800.	3456.	18256.	1234.	288.	1522.
16	7724.	1880.	9604.	15160.	3456.	18616.	1264.	288.	1552.
17	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
18	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
19	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
20	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
21	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
22	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
23	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
24	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
25	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
26	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
27	7784.	1880.	9664.	15280.	3456.	18736.	1274.	288.	1562.
28	5712.	1680.	7392.	11208.	3132.	14340.	934.	261.	1195.
29	2604.	900.	3504.	5100.	1686.	6786.	425.	141.	566.
30	1568.	800.	2368.	3064.	1524.	4588.	256.	127.	383.

** TOTAL INCLUDES ONSITE AND OFFSITE

TABLE 7-8

SUMMARY OF ASSUMPTIONS FOR
HYPOTHETICAL DEVELOPMENT CASE[1,2]

Exploration Start-Up

Exploration commences 8 months after the lease sale (i.e. summer 1984); all schedules cited in this report relate to 1984 as year 1.

Discovery Success Rate

One significant discovery for every eight exploration wells.

Delineation Wells

Two wells for fields of less than 500 million barrels oil or 2 trillion cubic feet gas, and three for fields of 500 million barrels oil and 2 trillion cubic feet gas and larger.

Drilling Season

12 months.

Decision to Develop

The decision to develop is made 24 months after discovery.

(1) These are the assumptions adopted for the hypothetical development case only. A broader suite of assumptions governs the economic analysis (see Appendix A).

(2) Some of the assumptions are analytical simplifications required by the OCS Manpower Model.

TABLE 7-8 (continued)

Delays

Delays created by litigation and regulatory problems, including permitting preceding or subsequent to the lease sale, are not allowed for in our schedules since such delays are highly unpredictable. Our schedules reflect technical feasibility and assume expeditious award of leases and post-lease permitting. Recognizing that significant delays can occur, we have evaluated the economic impact of delay on a project (see Chapter 6.0).

Platform Fabrication and Installation

Steel jacket platforms in water depths greater than 46 meters (150 feet) are designed, fabricated, and installed within 30 months of the decision to develop. Steel platforms located in water depths of 46 meters or less are designed, fabricated, and installed within 24 months. Platform installation and commissioning is assumed to take 10 months. Development well drilling is thus assumed to start about 10 months after platform tow-out.

Steel platform tow-out and emplacement is assumed to take place in June.

Development Drilling

Platforms sized for 25 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 25 well slots are assumed to have one drill rig operating during development well drilling.

Drilling progress is assumed to be 30 days per well per drilling rig (12 per rig per year) for 1524-meter (5000-foot) reservoirs and 60 days (6 per rig per year) for 3048-meter (10,000-foot) reservoirs.

TABLE 7-8 (continued)

Production Start-Up

Production is assumed to commence when about ten of the oil development wells have been drilled and when about six gas wells have been completed.

Reservoir Depth

Oil - - 1524 and 3048 meters (5000 and 10,000 feet)
Gas - - 3048 meters (10,000 feet)

Initial Well Productivity

Oil - - 2000 barrels per day
Gas - - 10 million cubic feet per day

Allocation of Gas Resource Between Associated and Non-Associated

Associated -- 30 percent; non-associated -- 70 percent

Gas - Oil Ratio (GOR)

1000 - 2000 standard cubic feet per barrel

Workover

Well workover is assumed to commence 5 years after production start-up.

Oil Terminal Construction

Oil terminal design and construction takes between 36 and 48 months, depending on design throughput.

TABLE 7-8 (continued)

LNG Plant Construction

LNG plant design and construction takes between 36 and 48, months depending on design throughput.

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APPENDIX A

PETROLEUM GEOLOGY AND ANALYTICAL ASSUMPTIONS

I. INTRODUCTION

This appendix details 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 Appendix A of our final report entitled "St. George Basin Petroleum Technology Assessment OCS Lease Sale No. 70" (Dames & Moore, August 1980). Many of the assumptions of this study, including most of the economic assumptions, are identical to those of the St. George study.[1] Such assumptions are incorporated by reference and are not reiterated in this appendix. Most of this appendix, therefore, is devoted to a description of the petroleum geology of the lease sale area and related assumptions, and those economic and technical assumptions that differ from those of the St. George study.

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[1] The subheading numeration is identical to that of Appendix A of the final draft of St. George Basin report; the reader is advised to consult that document.

II. PETROLEUM GEOLOGY, RESERVOIR AND PRODUCTION ASSUMPTIONS

II.1 Introduction

This section reviews the petroleum geology of the North Aleutian Shelf to provide the geologic specifications for the reservoir and production assumptions that are essential parameters for the economic analysis. The assumptions are presented in the second part of this section.

It cannot be over emphasized that there is insufficient geologic, geophysical and drill data to make predictions with a high degree of certainty on the reservoir characteristics in the Bristol Bay and Amak Basins. Our approach in this study is 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.

This petroleum geology evaluation is based upon a review of U.S. Geological Survey and the State of Alaska published reports (see Marlow et al. 1980; McClean 1977; Lyle et al. 1979), publicly available U.S. Geological Survey geophysical records (8 lines), and a detailed analysis of all onshore well logs and samples by our petroleum geologist.

II.2 Summary of St. George Basin Petroleum Geology

II.2.1 Regional Stratigraphy

The North Aleutian Shelf is a term applied to the southern half of Bristol Bay located on the north side of the Alaska Penninsula. The lease sale area covers the southern half of the Bristol Bay sedimentary basin, the offshore extension of the`Black Hills uplift, and the offshore Amak sedimentary basin. A portion of the Bristol Bay Basin and Black Hills uplift are expressed on the Alaska Peninsula, but the major parts of these tectonic units are located beneath the waters of Bristol Bay. The Amak Basin lies almost entirely offshore.

The Bristol Bay Basin is a northwest trending elongate sedimentary basin that parallels the long axis of the Alaska Peninsula and is located on the north side of the peninsula. The basin extends northeast from Black Hills for 595 kilometers (370 miles) to about the west edge of Iliamna Lake.

An extremely thick section (more than 15,240 meters or 50,000 feet) of Mesozoic and Tertiary sediments are exposed on the Alaska Peninsula, and provide important stratigraphic information on the prospects of that portion of the basin that lies beneath Bristol Bay.

II.2.1.1 Triassic

The oldest Mesozoic rocks exposed on the Alaska Peninsula are fossiliferous Triassic rocks that outcrop on the tips of Cape Kekurnoi, between Puale and Alinchak Bays, about 64 kilometers (40 miles) northeast of Wide Bay. Here the sequence consists of about 427 meters (1400 feet) of thin bedded, dense, organic limestone, with interbeds of sandstone and shale in the upper part. Chert is also an important constituent.

In the subsurface, Triassic rocks were penetrated in only one test well, Amoco Cathedral River Unit #1 (29-T51S-R83W). The bottom 30 meters (100 feet) of this well, from 4328 - 4359 meters (14,200 - 14,300 feet) penetrated a Triassic section consisting predominantly of light grey to white, microcrystalline quartzite, with thin interbeds of black, hard, siliceous shale. Based on the lithology and pronounced degree of induration of these rocks, our petroleum geologist considers these rocks to be part of the economic basement with respect to oil and gas exploration.

II.2.1.2 Jurassic

Extensive exposures of volcanic tuffs, flows, conglomerates, and sandstones believed to be of Early Jurassic age, are present at the head of the Alaska Peninsula. Volcanic-rich rocks of this age are widespread in southwest Alaska, and are present in the subsurface of the outer parts of the Peninsula, particularly in the Amoco Cathedral River Unit #1.

Fossiliferous Lower Jurassic rocks are exposed on the Alaska Peninsula near Puale Bay. Here, 701 meters (2300 feet) of sandstone, shale, tuff, and conglomerate conformably overlie fossiliferous Upper Triassic rocks and are overlain by upper Middle Jurassic clastic rocks.

A 677-meter (2220-foot) thick section of Lower Jurassic rocks was encountered in the Amoco Cathedral River Unit #1 well, from 3652 - 4328 meters (11,980 - 14,200 feet). This section consisted of interbedded black shale, silty shale, siltstone, and welded tuff. Thick beds of volcanic pebble conglomerate were penetrated from 4028 - 4165 meters (13,215 - 13,665 feet). A strong show of gas was recorded on the mud log at 3787 - 3795 meters (12,425 - 12,450 feet) from fine grained sandstone. On a 3-hour drill stem test of the interval between 3637 - 3798 meters (11,931 - 12,460 feet), gas came to the surface in 25 minutes and burned with a 2-meter (6-foot) flare. However, the rate was too small to measure. Over 396 meters (1300 feet) of highly gas-cut mud was recovered in the drill pipe. The small flow rate and no fluid recovery suggests low porosity and permeability for this zone.

The Amoco Cathedral River Unit #1 encountered a thick Middle Jurassic section comprising the Kialagvik and Shelikof Formations. About 225 meters (740 feet) of Kialagvik were drilled from 3426 - 3652 meters (11,240 - 11,980 feet). This interval consisted predominantly of hard siltstone with very thin interbeds of very fine-grained calcareous sandstone. The Shelikof Formation in this well was 2329 meters (7640 feet) thick and consisted of an interbedded succession of siltstone, shale, and sandstone. The shales and siltstones were primarily part dark gray and siliceous. The sandstone was generally light gray, quartzose, very fine to fine-grained, with occasional coarse-grained intervals. Oil shows were recorded on the mud log through several of the sandstone intervals. The sandstones were well-sorted with little clay matrix, but were well-cemented with calcareous and/or siliceous cement. Although calculated log porosities in a few of the more porous sands were as high as 18 percent, casing drill stem tests of these intervals proved tight and yielded only a little water.

It is our petroleum geologist's opinion that the siliceous and calcareous matrix cement in the sands is the product of diagenetic alteration produced late in the tectonic history of the area, probably during a late Tertiary orogenic period.

II.2.1.3 Late Jurassic - Early Cretaceous

Late Jurassic and earliest Cretaceous sediments constitute a thick and distinctive sequence throughout the Alaska Peninsula. These rocks are characteristically rich in arkosic detritus, and include the Naknek and Staniukovich Formations and Herendeen Limestone.

The Naknek Formation is well-exposed along a 482-kilometer (300-mile) belt on the Alaska Peninsula. The southwestern exposures are in the Black Hills along the Bering Sea coast. In general, the Naknek is at least 1524 meters (5000 feet) thick over most of the peninsula; locally, it may exceed 3048 meters (10,000 feet). Lithologically, the Naknek is composed mainly of arkosic to feldspathic sandstone, given to block feldspathic siltstones, dense dark grey to black claystones, and locally abundant conglomerates. In places the formation contains more than 1829 meters (6000 feet) of black shale.

The Naknek has been encountered in the subsurface in the Amoco Cathedral River Unit #1 and Cities Service Painter Creek #1. The Amoco Cathedral River Unit #1 (located on the Black Hills uplift), which was spudded in the middle part of the Naknek, drilled 1097 meters (3600 feet) of the formation. The lithology in this well consisted predominantly of feldspathic sandstone with minor interbeds of siltstone and shale. The sandstones were very fine-grained with siliceous cement and with correspondingly low porosity and permeability.

A 1381-meter (4530-foot) thick Naknek section was drilled in the Cities Service Painter Creek #1. The Naknek in this well was a very coarse facies and consisted mainly of conglomerate and sandstone with minor interbeds of shale. For the most part the sandstones and conglomerates were impervious, but while drilling from 844 to 846 meters (2770 to 2777 feet) the well started flowing water with slight shows of gas. Some gas shows were logged, but were not considered of sufficient magnitude to warrant testing.

The Naknek sediments become finer-grained, and coarser sandstones and conglomerates become markedly fewer, away from the core of the Alaska Peninsula, and in general, the formation becomes finer-grained southwestward along the peninsula.

The Staniukovich Formation conformably overlies the Naknek, and the rocks are similar in many respects to those of the Naknek, especially in their pronounced arkosic nature. The strata of both formations show a decrease in grain size and abundance of conglomerates southeastward across the peninsula and southwestward along the axis of the peninsula. Available data suggest a granitic source terrain northwest of the axis of the peninsula.

In the subsurface, the Staniukovich was encountered in two test wells, the Pan Am Hoodoo Lake #2 (35-T50S-R76W) and the Cities Service Painter Creek #1. A 454-meter (1490-foot) thick Staniukovich section in the Hoodoo Lake #2 consisted mainly of siltstone with scattered interbeds of very fine-grained, hard siliceous to calcareous cemented sandstone.

In the Cities Service Painter Creek #1, the Staniukovich is 238 meters (780 feet) thick and consists of sandstone and conglomerate with some interbeds of shale. Minor oil and gas shows were recorded on the mud log, but a drill stem test proved the formation to be impervious.

Except at Staniukovich Mountain, the Staniukovich Formation is everywhere uncomformably overlain by Upper Cretaceous rocks, and in many places the formation has been completely removed by mid-Cretaceous erosion. At Staniukovich Mountain, the sequence is comformably overlain by the Herendeen Limestone.

The lower Cretaceous Heredeen Limestone is exposed in the Port Moller-Herendeen Bay area, and consists of about 244 meters (800 feet) of arenaceous limestone. In the subsurface a 311-meter (1020-foot) thick section of Herendeen was drilled in the Pan Am Hoodoo Lake #2, which was comprised of interbedded limestone, marlstone, and calcareous sandstone. The limestones were non-porous sandy and bioclastic, and no oil or gas shows were recorded.

II.2.1.4 Upper Cretaceous

Upper Cretaceous rocks are widespread on the Alaska Peninsula southwest of Wide Bay, and consist of a transgressive sequence grading upward from non-marine clastic rocks through marine sandstones into black siltstones and shales. The lower sandy sequence constitutes the Chignik Formation, with the Coal Valley Member at the base, and the upper argillaceous sequence comprises the Hoodoo Formation.

The Chignik Formation consists of about 610 meters (2000 feet) of marine subgraywackes and feldspathic subgraywackes. Thin, black siltstones are locally common, as are pebble conglomerates of volcanic, granitic, and sedimentary detritus. The basal Coal Valley Member is non-marine and contains carbonaceous material, seams of coal, and multicolored claystones, siltstones and sandstones.

Subsurface penetrations of the Chignik occur in the Pan Am David River #1A (12-T50S-R80W), Pan Am Hoodoo Lake #2, and Cities Service Painter Creek #1.

In the Pan Am David River #1A, a 478-meter (1569-foot) thick Chignick section between 3719 - 3962 meters (12,200 feet - 13,769 feet) consisted of interbedded sandstone, siltstone and shale. Gas shows were logged on the mud log below 3962 meters (13,000 feet), and on a 7-hour and 13-minute drill stem test of the interval 4126 - 4197 meters (13,536 - 13,769 feet). The well flowed water at a rate of 545 barrels per day, and gas at only 9000 cubic feet per day. Calculated porosities from the density log through the tested interval averaged 12 percent.

An 268-meter (880-foot) thick Chignik section was drilled from 2368 - 3636 meters (7770 - 8650 feet) in the Pan Am Hoodoo Lake #2. Only the basal Coal Valley Member was preserved in this well, consisting of conglomerate, sandstone, siltstone, and thin coal seams. A core taken from 2377 - 2380 meters (7798 - 7807 feet) recovered conglomerate and pebbly sandstone that was thoroughly cemented with silica.

A 610 - 914-meter (2000 - 3000-foot) thick series of black siltstones and shales, named the Hoodoo Formation, overlies the Chignik, and is most completely exposed between Herendeen and Pavlof Bays. Small amounts of fine-grained sandstone with streaks of calcareous siltstone also occur.

II.2.1.5 Cenozoic

Cenozoic rocks are considered by our petroleum geologist to be the most important in the Bering Sea region in terms of potentially favorable stratigraphy for oil and gas exploration. Rocks of all Cenozoic epochs are present on the Alaska Peninsula. Southwest of Wide Bay, these consist of 7,620 - 9144 meters (25,000 - 30,000 feet) of interbedded marine and non-marine clastic rocks.

The Cenozoic rocks can be divided conveniently into several major intervals. A thick Paleocene, Eocene, and Oligocene sequence rests unconformably on older rocks and contains abundant volcanic detritus and black siltstone. Miocene rocks, locally uncomformable on the Paleogene beds, consist of shallow marine and non-marine sandstones and conglomerates that contain much non-volcanic debris. Volcanic rocks dominate the thinner and more restricted Pliocene beds.

The oldest Tertiary rocks in the basin belong to the Paleocene and Eocene Tolstoi Formation and consist of a sequence of black siltstones with interbedded volcanic sandstones, conglomerates, flows, sills, and volcanic debris that are at least 1524 meters (5000 feet) thick over much of the Alaska Peninsula and may reach 3048 meters (10,000 feet) in thickness at Ivanof Bay.

In outcrop, the Tolstoi sandstones and conglomerates consist of mafic volcanic debris with only occasional grains of chert and argillite. The sandstones can be classified as volcanic subgraywackes and are generally impervious.

In the subsurface, the Tolstoi is 1524 meters (5000 feet) thick in the Pan Am David River #1-A test well, but only 607 meters (1990 feet) of Tolstoi are present in the Pan Am Hoodoo Lake #2, located only 32 kilometers (20 miles) east-northeast of the David River #1A. The Tolstoi is absent by depositional overlap some 450 kilometers (280 miles) further northeast in the Mobil Great Basins #1 and #2 test wells where Oligocene Stepovak sediments rest unconformably on Jurassic Granitic rocks.

The Tolstoi lithology in David River #1A consisted of an interbedded series of sandstone, siltstone, and claystone with sporadically occurring thin seams of coal, pebbly sandstone, and tuff. The sandstones were rich in volcanic debris, and the siltstones had abundant carbonaceous material. Minor oil and gas shows were recorded on the mud log, and two drill stem tests were run near the base of the Tolstoi. Both flowed small amounts of gas (4900 - 9000 cubic feet per day) and water at rates of 315 - 410 barrels per day. The waters were brackish with salinities of 6100 - 8900 ppm, indicating that the Tolstoi was deposited in a predominantly non-marine to nearshore, shallow marine environment.

The upper 433 meters (1420 feet) of Tolstoi in the Pan Am Hoodoo Lake #2 consisted mainly of dark brown to black, carbonaceous sandy siltstone with thin interbeds of lignitic to sub-bituminous coal. The lower 174 meters (570 feet) was dominantly sandstone with sandy siltstone interbeds. Sidewall samples taken in the sandstones were described as mainly quartzose, but cemented with calcite, or the interstices filled with clay. The predominance of quartz is interesting, specifically because the Tolstoi sandstones in outcrop are typically volcanogenic, whereas those in the subsurface, at least in the Pan Am Hoodoo Lake #2, appear to be quartz rich. This is indicative of a different source terrain to the north. Tolstoi equivalent sediments beneath the Bering Sea may be represented by much cleaner sandstone facies that have been sourced from a granitic, or reworked older sedimentary terrain to the northeast.

Minor oil shows and fair gas shows were logged throughout the Tolstoi section in the Hoodoo Lake #2. However, two drill stem tests run in sandstones near the base of the formations indicated these rocks to be tight and yielded only 18 and 67 meters (60 and 220 feet) of drilling mud. The last 27 meters (90 feet) of mud recovered from the second test was slightly cut with oil.

The Tolstoi is conformably overlain everywhere by the Oligocene Stepovak Formation, and the gradational contact of these two units within this thick sequence of volcanogenic rocks is often difficult to place.

The Stepovak consists of more than 2134 meters (7000 feet), and possibly up to 4512 meters (15,000 feet), of interbedded volcanic sandstones and conglomerates with units of up to 305 meters (1000 feet) of black siltstone.

In the subsurface, Stepovak sections of varying thicknesses have been penetrated in five of the ten wells drilled on the Alaska Peninsula. About 853 meters (2800 feet) of Stepovak strata were drilled in the Pan Am David River #1A, which represents the southwesternmost subsurface penetration on the peninsula. Sandstone was the dominant Stepovak lithology in this well with carbonaceous siltstone and bentonitic clay comprising most of the remainder. The sandstones were fine to coarse, occasionally pebbly, and were composed principally of quartz with common volcanic grains, all set in a clay matrix. The clay matrix reduced the effective porosity to such a degree that all of the sands on the electric log appeared tight.

The 1103-meter (3620-foot) thick section described as Stepovak in the Pan Am Hoodoo Lake Unit #2, from 658 - 1762 meters (2160 - 5780 feet), consisted mainly of siltstone and mudstone with interbeds of sandstone. The sandstones were fine- to medium-grained and composed predominantly of quartz. Several porous sands were recorded on the electric log, and one of the prospective sand zones had sonic-derived porosities ranging from 15 - 18 percent.

The Gulf Oil Corporation Sandy River Federal #1 (10-46S-70W), located 62 kilometers (42 miles) northeast of the Pan Am Hoodoo Lake #2, drilled a 746-meter (2449-foot) thick Stepovak section consisting of clayey sandstone, siltstone, and shale in the upper part, and altered volcanics interbedded with coarse volcanic conglomerate and "granite wash" sandstone in the lower part.

Common but minor oil shows were logged throughout the Stepovak in this well. Two drill stem tests were run. One from 3272 - 3275 meters (10,735 - 10,745) feet recovered 137 meters (450 feet) of drilling mud and 640 meters (2100 feet) of slightly gas-cut saltwater during a 46-minute flow period. Based on the drill stem test results and on E-log analysis, the Stepovak sands cannot be considered adequate reservoir objectives in this well.

The next closest subsurface control for the Stepvok is 266 kilometers (165 miles) to the northeast in the General Petroleum Corporation Great Basins #1 (2-27S-46W). A 1632-meter (5355-foot) thick Stepovak section drilled in this well consisted of an interbedded shale and siltstone sequence with subordinate amounts of sandstone and scattered thin coal beds. The sandstones were predominately of low porosity and permeability.

The Stepovak in the General Petroleum Great Basins #2 (35-25S-50W) was 736 meters (2415 feet) thick. Its lithology was similar to that in the Great Basins #1, except that there was a much higher percentage of porous reservoir sands in Great Basins #2. The sandstones in this well were coarse to pebbly, consisting mainly of quartz. Approximately 76 meters (250 feet) of net porous sand were encountered in this well.

Based on the majority of subsurface penetrations, it would appear that the Stepovak does not constitute an adequate reservoir objective on the Alaska Peninsula. However, the quartzose character of some of the sandstones suggests a possible granitic source to the northwest beneath the Bering Sea. Potential traps located out in Bristol Bay may contain more favorable Stepovak reservoir sands.

The Meshik Formation is a volcanic facies equivalent of the Stepovak, and consists of at least 1524 meters (5000 feet) of coarse volcanic breccia, and volcanic conglomerates with some sandstones and carbonaceous siltstones.

In the subsurface, thick volcanic sections were drilled in two wells in the central part of the Alaska Peninsula: 1766 meters (5795 feet) in the Gulf Port Heiden #1 (20-27S-59W), and 1676 meters (5500 feet) in the Great Basins Nagashik #1.

Unconformably overlying the Oligicene Stepovak over most of the Alaska Peninsula is the Miocene Bear Lake Formation. This unit is about 1524 meters (5000 feet) thick in outcrop; and consists of interbedded sandstones, conglomerates, and siltstones. The sandstones and conglomerates differ from all earlier Tertiary deposits in the great abundance of non-volcanic clasts, in the greater rounding and better sorting of grains, and in the poor consolidation of much of the rock. The sandstones commonly contain more than a third quartz and chert, about a third sedimentary lithic fragments, and less than a third volcanic fragments.

Significant thicknesses of Bear Lake sediments with porous and permeable sands have been penetrated in eight of the wells drilled on the Alaska Peninsula. The thickest Bear Lake section was drilled in the Gulf Oil Company Sandy River Federal #1, where 2371 meters (7780 feet) of Bear Lake was encountered. This consisted of 1316 meters (4318 feet) of net sandstone that comprised 55.5 percent of the section. The lithology and reservoir qualities of the Bear Lake sands will be discussed later in the section concerning reservoir rocks (II.2.3).

A number of methane gas shows were logged in the Gulf Sandy River #1 between 1463 and 1829 meters (4800 and 6000 feet). These are believed to be associated with thin coal beds. Oil shows were recorded on the mud log near the base of the Bear Lake below 3048 meters (10,000 feet).

The Bear Lake is overlain by the Pliocene Milky River Formation with strong discordance. It is the pronounced unconformity at the base of the Pliocene that is responsible for the great variation in thickness of the Bear Lake in the subsurface.

The Pliocene Milky River Formation includes a sequence of volcaniclastic sediments consisting of interbedded conglomerates, sandstones, and mudstones. The formation attains a thickness of about 914 meters (3000 feet) in the subsurface.

Volcanism continued from the Pliocene to the present and provides the only deposits of this age along the axis of the Alaska Peninsula.

II.2.2 Structure of the Alaska Peninsula

The Alaska Peninsula can be divided into two areas that reflect slightly different geological histories and minor differences in structural configuration. The structure northeast of Wide Bay is dominated by the Bruin Bay fault, a major strike-slip fault that separates Upper Jurassic sediments on the southeast from generally older sediments and plutonic rocks on the northwest. The overall structure of this part of the peninsula is a broad arch, the axis of which approximately coincides with the Bruin Bay fault. Anticlines are present only as minor structures in a narrow zone along this fault.

Southwest of Wide Bay, the geological structure is dominated by three major *en echelon* anticlinal complexes containing highly deformed rocks as young as early Pliocene. The major faults in this region are closely related to the tectonism that produced the folds. Local differences in degree of folding appear to be the result of differences in structural competence of the sedimentary rocks involved. The thick, black siltstones and shales of the late Cretaceous and early Tertiary exhibit the most severe distortion, with local isoclinal and recumbant folds. The more massive sandstones and conglomerates of the Jurassic and middle to late Tertiary are more broadly folded and are broken by sharply defined, high angle faults. In outcrop, the more highly deformed belts of the Alaska Peninsula seem to reflect the tectonic response of differences in lithology rather than significant variation in the type of fundamental deformation.

The major folds and faults southwest of Wide Bay show many features of simple compressional deformation, but the broad crests, overall symmetry, and the common occurrence of steep faults suggest that basement faulting may be the most important factor in deformation.

Structural deformation in Tertiary sediments beneath the Bristol Bay lowlands is gentle, with broad and rather low relief structural culminations formed over pre-Tertiary "basement" highs. Farther to the north, beneath the waters of Bristol Bay, deformation is even less intense than that exhibited onshore. The principal features offshore are tensional faulting and sedimentary drape over pre-Tertiary "basement" highs. Marine seismic data indicate the Bristol Bay Basin to be a large, back-arc half-graben that contains a very thick section of very gently folded, Tertiary marine and non-marine clastic and volcanic rocks. The basin becomes more marine and deeper toward the southwest, where about 4572 meters (15,000 feet) of prospective Tertiary sediments occur north of Herendeen Bay. The Bristol Bay Basin is bounded on the north by the Goodnews Arch, which is an offshore and southwesterly extension of Mesozoic and Paleozoic rocks of the Ahklum Mountains. A strong angular unconformity appears on several of the marine seismic lines, and it is our petroleum geologist's opinion that the horizon may be the base of the Miocene Bear Lake Formation.

The southwest trend of Bristol Bay Basin is due to its genetic relation to the Alaska-Aleutian Arc that forms the southern boundary of this basin.

The oldest exposed rocks at the western end of the Alaska Peninsula are upper Jurassic siltstones and sandstones of the Naknek Formations. The westernmost exposure of these rocks is in the Black Hills bordering the southern Bering Sea shelf. Gravity, magnetic and seismic evidence show that the anticlinally deformed rocks of the Black Hills extend offshore northwesterly along the Bering shelf margin, and may connect with the north side of the Pribilof

Ridge. This positive feature of Mesozoic rocks separates the Tertiary Bristol Bay Basin from the Amak Basin. Farther to the west this positive feature bifurcates and separates St. George Basin from the Amak and Bristol Bay Basins.

Eight regional CDP marine seismic lines shot by the U.S. Geological Survey were the only seismic data available for this analysis. Although these lines are widely spaced and seem to have been randomly oriented, they do reveal basin symmetry and structures that are representative in the Bristol and Amak Basins. The seismic data show that these basins are structural grabens and closed or silled depressions. In these closed basins, ocean circulation is restricted, oxygen is not replenished in the water, and organic matter can be preserved in a manner favorable for hydrocarbon generation.

A reflective sequence of sedimentary strata can be seen to infill Bristol Basin. These beds are essentially unfolded, unlike that in the onshore portion of the basin. Deformation of the layered Tertiary sequence is mainly by normal faults that appear to be related to offsets in the acoustic basement. Offset along some of the faults appears to increase with depth, implying that the faults are growth features.

A pronounced angular unconformity is visible on several seismic lines on the steep flanks of the Black Hills uplift, and along the northern basin margin. Projection of onshore geology to the offshore indicates that this unconformity is probably at the base of the Miocene Bear Lake Formation.

Visible on the eight seismic lines shot by the U.S. Geological Survey were eleven prospective "basement" highs, many of which showed drape of the overlying sediments. A few of these structural highs are located at the margins of the basin and offer good potential for housing large hydrocarbon accumulations. These hinge line features with their basin edge location provide uninterrupted drainage from large basinal fetch areas; many of the world's giant oil and gas fields are similarly located along basin hinge lines.

Potential fault traps occur on the south side of the Black Hills uplift. Here, several seismic lines that crossed the edge of the uplift demonstrated steeply dipping normal faults with rollover anticlines into the faults.

Of the seismic lines available, those crossing the Amak Basin showed no indication of prospective basement highs with sediment drape over them. However, it should be emphasized that the seismic control is too sparse to condemn this portion of the lease sale area.

It must be further stated that the seismic control over the entire proposed lease sale area is insufficient to permit mapping of structural closures, and is only suitable to denote the two-dimensional positioning of the axes of prospective basement highs.

Eleven deep test wells have been drilled in the onshore portion of the Bristol Bay Basin on the Alaska Peninsula. At least eight of these were located on the basis of some geophysical work and were drilled on loosely spaced seismic grids. Interpretive seismic contour maps on seven of the eight prospects were released to the public and were carefully reviewed by our petroleum geologist. Although actual seismic lines were not released, there was sufficient information on the released maps with which to draw some conclusions as to the probable reason for their failure to find oil and gas fields.

The General Petroleum Great Basins #1 (2-27S-48W) was located on a seismically defined, anticlinal reversal, but no seismic lines were shot to determine if the feature was actually doubly plunging. The General Petroleum Great Basins #2 (35-25S-50W) was drilled on a seismically-defined, anticlinal closure, but was located some 1676 meters (5500 feet) structurally below the crest of the closure.

The Great Basins Ugashik #1 (8-32S-52W) was also drilled on a seismically-defined, four-way dip closure, but the well penetrated a thin prospective Bear Lake section resting on a thick Oligocene Meshik volcanic series. Our petroleum geologist attributes the lack of success of this well to the absence of potential source rocks (Stepovak and Tolstoi) in close association with the Bear Lake reservoir sands.

The Gulf Oil Corporation Port Heiden #1 (20-37S-59W), located 77 kilometers (48 miles) southwest of Ugashik #1, also found a Bear Lake section resting on Meshik volcanics. The same reason for failure at Ugashik #1 may be attributed to Port Heiden #1.

The Gulf Oil Corporation Sandy River Federal #1 (10-46S-70W) was located on a seismically-defined, anticlinal closure some 124 kilometers (77 miles) southwest of Port Heiden #1. Although no seismic lines were available to determine the presence of structural growth over the Sandy River structure, a comparison of the two released seismic contour maps showed that the two horizons are fairly conformable, considering the large interval between them (about 1829 meters [6000 feet]). It may well be that this structure does not display the desired early "growth" that our geologist considers essential for the accumulation of large hydrocarbon fields.

Pan Am David River #1A (12-50S-80W), located some 105 kilometers (65 miles) southwest of the Gulf Sandy River Federal #1, was drilled on a seismic closure, but almost 610 meters (2000 feet) structurally below the crest of the feature. In addition, only a thin prospective reservoir section was encountered in the Bear Lake.

Pam Am Hoodoo Lake #1 and #2 were drilled on a fault-closed structure about 35 kilometers (22 miles) east of David River #1A. The critical closing fault is the David River, which extends from offshore Cathedral River approximately 97 kilometers (60 miles) east to Herendeen Bay. The fault is indicated by seismic, aeromagnetic, gravity, and geologic data. Cretaceous and Jurassic rocks are exposed on the south (upthrown) side of the fault with Miocine rocks exposed on the downthrown side. The indicated stratigraphic throw on the fault is about 3048 meters (10,000 feet), and our geologist believes that this fault may be a southwesterly continuation of the major strike slip

Bruin Bay Fault. Our geologist attributes the failure of the Hoodoo Lake wells to their location within an interpreted fault closure that was formed too late, probably during the Plio-Pleistocene, to have trapped any early migrating oil. Further, he does not know of any major oil or gas accumulations in which the controlling updip fault is a major regional strike slip fault.

The Amoco Cathedral River #1 (29-51S-83W) is located on the Black Hills uplift, an outcropping surface high on which upper Jurassic Naknek rocks are exposed. The Cathedral River #1 spudded in the Naknek and bottomed at 4339 meters (14,301 feet) in Triassic rocks. The most important negative factor concerning the Cathedral River structure is the young age of deformation (probably Plio-Pleistocene) relative to the age of the prospective reservoir rocks. There are no important hydrocarbon fields around the Pacific rim in Mesozoic reservoirs that have been deformed into closed structures during a Plio-Pleistocene orogeny.

The remaining three tests on the Alaska Peninsula, Cities Service Painter Creek #1 (14-35S-51W), Pure Oil Company Canoe Bay #1 (8-54S-78W), and Phillips Big River #A-1 (15-49S-68W), were all located on the basis of surface geology. Essentially all were tests of the Mesozoic, but were located on surface anticlinal features formed during the Plio-Pleistocene. As previously mentioned, this combination is considered unfavorable for large oil and gas fields.

In summary, it appears that none of the 11 tests drilled on the peninsula found the desired combination of good reservoir and source rocks present over a growth structure. These growth structures do exist in the offshore, as evidenced on the seismic lines. Based on a projection of the onshore stratigraphy to the offshore, the necessary combination of Miocene Bear Lake reservoirs with Oligocene and Eocene source rocks should be present over basement "growth" structures beneath the waters of Bristol Bay.

II.2.3 Reservoir Rocks

Significant thicknesses of potential reservoir rock occur throughout the Alaska Peninsula. Outcrop sections and well data indicate that thick reservoirs should be present in the Miocene Bear Lake Formation. Greater quartz content, combined with depositional environments, make this formation a primary drilling objective in the offshore. Potential reservoirs should have the large areal extent typical of tabular sand bodies that result from linear clastic shoreline deposition. Geometry consistent with beaches, upper and middle shoreface deposits, and offshore bars should be present in the subsurface.

Sand percentages within the Bear Lake, in the eight subsurface penetrations on the peninsula, range from 33.1 - 67.4 percent. The greatest amount of net sand is 1330 meters (4362 feet) or 67.4 percent, as drilled in the Pan Am Hoodoo Lake #1. Bear Lake sands exhibit very good reservoir qualities in most of the Alaska Peninsula test wells. In the deepest test, Gulf Sandy River #1, porosities of 25 - 27 percent, as derived from sonic and density logs, were calculated from sands at depths of 3200 - 3231 meters (10,500 - 10,600 feet). Sidewall core permeabilities as high as 1165 mdcys were recorded at 1995 meters (6545 feet) in the Gulf Port Heiden #1.

A microscopic examination by our geologist of well cutting samples of all Alaska Peninsula wells showed that the Bear Lake sands are quite rich in quartz grains, and contain a combination of quartz and feldspar with subordinate volcanic and chert grains and sedimentary lithic fragments. Shows of oil and gas were recorded on the mud log in basal Bear Lake sands in the Gulf Sandy River #1.

The Oligocene Stepovak has very thin, tight sandstones in the onshore wells and may not have good reservoir characteristics offshore. The low porosity and permeability result from the abundance of volcanic detrities including matrix clay, and the relatively dense nature and high degree of induration. However, about 76 meters (250 feet) of net sand in the Oligocene Stepovak Formation, with apparent good reservoir characteristics, were encountered in the General Petroleum Great Basins #2 (25-25S-50W).

Some massive sandstones that are present in the Eocene Tolstoi and Cretaceous Chignik Formations are of poor quality onshore but cannot be ruled out as possible reservoir rock in nearby submerged lands. Two Tolstoi sandstone intervals in the Pan Am David River #1A yielded small flows of gas and saltwater at rates of 310 and 400 barrels per day from the intervals 3303 - 3316 meters and 3522 - 3526 meters (10,835 - 10,880 feet and 11,555 - 11,568 feet), respectively.

A comparison of average porosity versus depth for producing reservoirs in California shows a rapid loss of porosity with depth of approximately 1.52 percent per 305 meters (1000 feet). This rapid loss is probably a direct function of the arkosic nature of California sandstones. Sandstone porosities on the Alaska Peninsula are very similar to those in California. It follows that good reservoir quality sands in the Bristol Bay Basin below 3962 meters (13,000 feet) are not likely to be encountered.

II.2.4 Source Rocks

A source rock analysis of six onshore wells on the Alaska Peninsula was made by our geologist. This analysis dealt with the thermal alteration index (TAI) to determine the degree of thermal alteration or hydrocarbon precussor (Kerogen) maturation of potential source rocks in the prospective stratigraphic section in the offshore Bristol Bay Basin.

The present condition of the kerogenous material in Tertiary rocks in these wells shows source rock capabilities, whereas the Mesozoic does not appear to provide adequate source rock potential. The TAI data suggest that the Bristol Bay province would be gas prone in the upper Bear Lake and oil prone in the middle and lower Bear lake, Oligocene Stepovak, and Eocene Tolstoi Formations. The Cretaceous Chignik, Herendeen, and Staniukovich Formations appear to be within the gas generating range as are the Jurassic Naknek and Shelikof Formations. The reason for the tendency toward gas in the Mesozoic rocks is their advanced state of maturation to a nearly over-mature stage.

Source rock analysis was performed by the U.S. Geological Survey on the General Petroleum Great Basins #1 and Pan Am Hoodoo Lake #2. The Bear Lake formation in the Great Basins well has abundant organic carbon, but vitrinite reflectance values suggest it to be immature. The kerogen is predominantly woody with minor amounts of amorphous sapropel. It has a high extractable bitumen content with a correspondingly low hydrocarbon fraction, which is interpreted to reflect the coal-rich and/or woody character of the organic material. The organic matter in the Oligocene Stepovak Formation in this well exhibits about the same properties as the Bear Lake. If source rocks similar to those in the Great Basins #1 well were present in deeper offshore parts of Bristol Bay Basin, chances of hydrocarbon generation would be greatly improved due to higher temperatures.

The most favorable source rocks examined were the Eocene Tolstoi in the Pan Am Hoodoo Lake #2. This unit was high in total organic carbon content, and was within the oil generating range. It exhibited a modest vitrinite reflectance.

II.2.5 Comparison To Other Pacific Margin Basins

About 40 percent of all the known basins of the world are within the Circum-Pacific belt. Most of the sedimentary basins in this belt contain oil and gas and account for almost a third of world oil production.

Basin evaluation in the Circum-Pacific belt can be related to plate tectonics. The process of subduction has produced several prominent systems around the Pacific. These systems include a trench, outer arc-ridge, fore-arc basin, magmatic arc, and back-arc basin.

Sedimentary basins characterized by continental to marine shelf depositional regimes are common products of active lithospheric plate junctions of the northeast Pacific region. Most of these basins formed in both fore-arc and back-arc positions. Bristol Bay is a back-arc basin. Its position relative to the Aleutian Trench subduction zone is analagous to the position of the oil productive back-arc Sumatra and Java Indonesian basins relative to the Java trench subduction zone. In both examples, volcanic arcs form the "backbone" of the archipelagos.

It is of interest to note that during the early Tertiary, the Indonesian region became increasingly volcanic, much the same as the Alaska Peninsula. In later Tertiary time, rapid clastic sedimentation occurred in enclosed and partially closed marine environments in both the Bering Sea and Indonesia.

Oil production in the Indonesian basins is mainly from sand reservoirs of upper Miocine and Pliocene age, with upper Miocene the most important. Productive structures are gently- to moderately-folded, block-faulted basement highs with producing zones draped over the basement highs. Most of the structures were slightly positive elements during late Miocene and Pliocene time as evidenced by thining of the section over the crest of the features. This same occurrence of basement block-faulted structures with overlying sediment drape occurs in Bristol Bay Basin.

In almost every respect, the Bristol Bay Basin is similar to the back-arc basins of Sumatra and Java. Similarities include: its tectonic setting behind a magmatic island arc; its half-graben, silled basin symmetry; the presence of block-faulted basement highs that grow during sedimentation; and the characteristics of the Tertiary stratigraphic succession.

Geological and geophysical investigations of island arcs and of the back-arc basins that separate them from the continental borderlands suggest that these back-arc basins have heat flow values that are commonly higher than normal oceanic values, and indicate that steep geothermal gradients exist within the sedimentary section.

Indonesia includes several giant oil and gas fields associated with high earth temperatures along the block-fault, black-arc basin trend. The giant Minas field in central Sumatra and recent discoveries in the Java Sea produce from sandstones of Miocene age at shallow depths with a very high geothermal gradient of 5.5°F per hundred feet.

The geographic coincidence of deep earthquakes with high earth temperature along the back-arc basin in Indonesia suggests an empirical means of predicting high temperature trends that might favor oil and gas accumulation in similar tectonic settings elsewhere around the Pacific rim. The Bristol Bay Basin coincides with a possible hot trend as evidenced by the high geothermal gradient that is based on compilations of deep well-log bottom hole temperatures. One Bristol Bay well had a relatively high gradient of 2.2°F per hundred feet.

II.2.6 Traps

Three distinct traps occur in Bristol Bay Basin:

- Basement highs located on the north margin of the basin;
- Basement highs with sediment drape within the deep parts of the basin; and
- Fault closures against the steep flanks of the Black Hills uplift.

Our geologist believes that the first two offer the best chance for large oil and gas discoveries if closures can be seismically demonstrated over these features.

The Bristol Bay Basin covers an area of about 119,000 square kilometers (46,000 square miles), which makes it one of the largest Tertiary basins around the Pacific rim (larger than any of the California basins). Based on analysis of the limited seismic data available for this study, potential trap density in the Bristol Bay Basin appears to be quite good, although it should be emphasized that insufficient seismic coverage was available to map closure on the observed features.

II.3 Assumptions

II.3.1 Initial Production Rate

II.3.1.1 Oil

To a great extent the discussion on initial well production rates in Appendix A Section II.3 of the final St. George Basin report is also applicable to the Bristol Bay and Amak Basins. Although we evaluated initial well productivities of 1000 and 2000 barrels per day for reservoir depths between 1524 and 3048 meters (5000 and 10,000 feet) for St. George Basin, we believe that initial well productivities of 2000 and 3000 barrels per day would be more realistic for Bristol Bay Basin for these reservoir depths given the relatively favorable reservoir rock characateristics (porosity, permeability, thickness, etc.) described above. For sensitivity testing we will also evaluate a few cases assuming 5000 barrels per day.

The initial well production rate parameter will be utilized in our analysis as stated in Appendix A, Section II.3.1.1 of the final St. George Basin report.

II.3.1.2 Non-Associated Gas

Initial productivity per well for non-associated gas is essentially unknown at this time. However, geochemical data on well samples suggest that the predominance of kerogen in the onshore portion of the province is gas prone. For economic sensitivity testing, we will evaluate gas well productivities ranging from 5 - 15 million cubic feet per day.

II.3.2 Reservoir Depth

Analysis of the U.S. Geological Survey seismic data and onshore wells provides control for the reservoir depth assumptions. Reservoir depths may range from shallow, 914 - 1524 meters (3000 - 5000 feet), to intermediate, 1524 - 3048 meters (5000 - 10,000 feet), to deep, 3048 - 4572 meters (10,000 - 15,000 feet).

The most common reservoir depths should be intermediate (1524 - 3048 meters), where prospective sediments are draped over the basement highs located within the basin, and also within fault closures on the flanks of the Black Hills uplift.

Shallow objectives (less than 1524 meters) can be expected where prospective sediments are draped over the shallow "basement" highs located along the north margin of the basin.

Deep objectives (3048 - 4572 meters) will be limited to sediment drape over a few basement highs located deep within Bristol Bay Basin.

Based upon the depth range of the objectives, we have evaluated the following representative reservoir depths: (1) 914 meters (3000 feet), (2) 1524 meters (5000 feet), and (3) 3048 meters (10,000 feet).

The role and effects of the reservoir depth assumptions in the analysis are explained in Appendix A, Section II.3.2, of the final St. George Basin report.

II.3.3 Recoverable Reserves

For the reasons stated in Appendix A, Section II.3.3, of the final St. George Basin report, we believe that a range of 20,000 - 60,000 barrels per acre recoverable reserves (primary recovery) is also a reasonable assumption for the Bristol Bay Basin. The role of the recoverable reserves parameter in the analysis is also explained in the above noted section of the St. George report.

II.3.4 Production Profiles

We adopted the same oil, associated gas, and non-associated gas production profiles utilized in the St. George study (see Appendix A, Section II.3.4, of the final St. George report).

II.3.5 Field Size and Field Size Distribution

Three economically important traps may be present in Bristol Bay Basin offshore. These are:

- Potential sand reservoirs draped over pre-Tertiary basement horsts;
- Fault closures against the steep-sided flanks of the Black Hills uplift; and
- Stratigraphic traps of buttressing sand units against pre-Tertiary basement highs.

All three potential traps are visible on the eight U.S. Geological Survey seismic lines that cross the Bristol Bay Basin. Eleven structurally positive axes were noted, but insufficient data is available to determine if closures exist on these axes. Also, it is not known if several of the positive axes are part of the same anticlinal feature.

An unknown number of fault closures exist in the basin. These are primarily potential closures against the steep flanks of the offshore extension of the Black Hills uplift. Rollover anticlines on the downthrown sides, like in the Gulf Coast, were observed on a few seismic lines.

Potential stratigraphic traps of buttressing sands against pre-Tertiary basement highs are visible, particularly on the north side of the basin margin and against the flanks of the Black Hills uplift.

Sufficient seismic data was not available to determine area of closure, which is necessary to determine field size. However, a sufficient seismic network is available to determine that frequency of occurrence is moderate.

If the assumption is made that offshore North Aleutian traps will be hydrocarbon bearing, and assuming seismic data were available to identify structures and estimate the areas of closure, etc., the 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 Pacific Margin basins. It should be emphasized, however, that any analogical approach to prediction of petroleum resources is extremely hazardous because each basin is unique. One critical difference in geologic parameters can completely negate the effect of many similarities.

Factors affecting percent fill 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.

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

The field sizes selected for economic screening are consistent with, or reflect, the following factors:

- U.S. Geological Survey resource estimates;

- Geology (discussed above), which indicates that "giant" fields (billion barrels or more) are a possibility; and

- Anticipated economic conditions and the requirement to examine a reasonable range of economic sensitivities.

We have evaluated the same range of field sizes as we did for the St. George study. These range from 50 million - 2 billion barrels for oil and 500 billion - 3 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, not the actual field size distribution.

II.3.6 Allocation of the U.S. Geological Survey Gas Resource Estimate Between Associated and Non-Associated and Gas-Oil Ratio (GOR)(1)

An assumption about the allocation of the U.S. Geological Survey gas resource estimates between associated and non-assoicated is not critical to the economic analysis because we have evaluated the economics of both non-associated gas production and associated gas production. In terms of the overall gas production potential of the basin, however, the treatment of the associated/non-associated gas problem in the analysis is critical. In many Alaska offshore areas, non-associated gas resources may be less economic to produce than the same amount of associated gas. This is because the incremental investment to produce associated gas (with oil the primary project) is

(1) In formulating a hypothetical development case corresponding to the U.S. Geological Survey statistical mean resource estimate for the St. George Basin, we found that the facilities and equipment requirements and aggregate basin gas production profile (peak, production life etc.) were very sensitive to assumptions on the gas resource estimate allocation, GOR, and field production profile (both oil and non-associated gas). Other factors such as deferred or delayed production of associated gas can complicate the picture. Because of these complexities, we suggest that the assumptions used in formulating a hypothetical development case for the U.S. Geological Survey statistical mean resource estimate be discussed with BLM staff upon completion of our economic and technical analyses that form the basis for the development case.

less than the total development costs for a non-associated gas field with the same recoverable reserves. In addition, the allocation of the total basin resource estimate between associated and non-associated gas affects the facilities and equipment requirements to develop offshore fields. If most of the gas was non-associated and located in separate fields from oil, there would be more fields (with related platforms, etc.) than if the gas was associated and produced incrementally with the oil in the same fields.

To develop manpower and facility requirements corresponding to the U.S. Geological Survey statistical mean gas estimates, we have followed the U.S. Geological Survey allocation of the gas resource between associated and non-associated (for the statistical mean resource estimate) of approximately 70 percent non-associated/30 percent associated (Marlow et al., 1980).

The U.S. Geological Survey estimates (Miller et al., 1975) do not specify or imply any ratio of associated to non-associated gas reserves; oil and gas resource estimates are made in separate iterations. It should be noted that U.S. historic production data indicates that 80 percent of the U.S. gas resources is non-associated.

To evaluate the economics of associated gas production, we have assumed a GOR of 1000 standard cubic feet per barrel. A GOR ranging from 1000 - 1500 standard cubic feet per barrel has been selected for the hypothetical development case described in Chapter 7.0.

II.3.7 U.S. Geological Survey Resource Estimates

The U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources of the North Aleutian Shelf lease sale area are presented in Table A-1.

The hypothetical development case formulated in Chapter 7.0 is based upon the U.S. Geological Survey statistical mean conditional estimate, which is as follows:

TABLE A-1

U.S. GEOLOGICAL SURVEY UNDISCOVERED RECOVERABLE OIL AND GAS RESOURCE ESTIMATES FOR THE NORTH ALEUTIAN SHELF LEASE SALE

	95 Percent Probability	5 Percent Probability	Statistical Mean	Marginal Probability
Oil (billions of barrels)				
Conditional	<.1	2.3	.7	.3
Unconditional	0	1.0	.2	--
Assoc./dissolved gas (trillion cubic feet)				
Conditional	.1	2.5	.7	.3
Unconditional	0	1.3	.2	--
Non-assoc. gas (trillion cubic feet)				
Conditional	<.1	5.8	1.5	.4
Unconditional	0	2.9	.6	--
Aggregated Gas (trillion cubic feet)				
Conditional	.26	7.2	2.24	.58
Unconditional	0	3.2	.82	--

Notes:

1. Conditional estimates are those quantities of oil and gas that may be present, assuming that commercial quantities of oil and gas do exist.

2. Unconditional estimates are those quantities of oil and gas that may be present, assuming the chance or risk factor that no hydrocarbons actually exist.

Source: Marlow et al., 1980.

Oil (billions of barrels)	0.7
Associated/dissolved gas (trillion cubic feet)	0.7
Non-associated gas (trillion cubic feet)	1.5

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 is to evaluate the relationships among the engineering strategies that may be adopted to develop North Aleutian Shelf 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:

- Single or multiple steel platforms with shared or unshared pipeline to shore terminal--oil production;
- Single or multiple steel gravity platforms with shared or unshared pipeline to shore terminal--oil production;
- Single or multiple steel platforms with shared or unshared pipeline to shore LNG plant--non-associated gas production;
- Single or multiple steel gravity platforms with shared or unshared pipelines to LNG plant--non-associated gas production; and
- Single or multiple steel platforms with shared oil and gas pipelines to shore terminals--oil and associated gas production.

In addition to evaluating various development strategies, we have selected a number of "development issues" for economic analysis based upon various geologic, technical, environmental, and locational characteristics of the lease sale area. The principal environmental and locational characteristics of the North Aleutian Shelf lease sale area that will affect development strategies, engineering, and economics can be summarized as follows:

- Water depths in the North Aleutian Shelf area are shallower than the St. George and range from about 15 meters (50 feet) in the nearshore areas of the Bristol Bay Basin to about 107 meters (350 feet) in the western portion of the Amak Basin. Most of the lease sale area is located in water depths of less than 84 meters (275 feet). Thus, the maximum water depths in the North Aleutian Shelf lease sale area correspond to the minimum depths likely to be encountered in St. George Basin.

- There is very limited information on sea ice extent and characteristics with which to assess the probability of ice encounter with platforms and related design loads. Until further information is available, we have considered it prudent and conservative to assume design for ice encounter. However, the ice in the area is likely to be relatively weak.

- The North Aleutian Shelf area lies adjacent to the Alaska Peninsula and the Aleutian Island chain, a zone of intense seismicity. The area also lies adjacent to a "seismic gap" in the Alaska Peninsula/ Aleutian Arc. In view of these factors, the seismic design of structures should follow guidelines established in the American Petroleum Institute RP2A (Tenth Edition), using Zone 4 criteria and assuming soil type C (in contrast, for most of St. George Basin, Zone 3 criteria are applicable).

- Distances to shore in the North Aleutian Shelf are generally less than those in the St. George Basin and overall pipeline distances to suitable shore terminal sites will be shorter. While offshore pipelines may be shorter, onshore lines may be longer than the St. George since most of the suitable shore terminal sites lie on the Pacific Ocean side of the Alaska Peninsula (Table A-2).

TABLE A-2

REPRESENTATIVE PIPELINE DISTANCES IN KILOMETERS (MILES) FROM THE NORTH ALEUTIAN SHELF TO POSSIBLE PORT SITES

POSSIBLE PORT SITES	PIPELINE DISTANCE KILOMETERS (MILES)		
	Offshore		Onshore
	Minimum	Maximum(1)	Minimum(2)
Morzhovoi Bay	5 (3)	96 (60)	32 (20)
Pavlof Bay	"	"	56 (35)
Balboa Bay	"	"	64 (40)
Stepovak Bay	"	"	80 (50)
Kuiukta Bay	"	"	89 (55)
Mitrofania	"	"	105 (65)
Cold Bay	"	"	19 (12)

Notes:

(1) To closest landfall from center of offshore basin.

(2) Distances could be longer depending on location of pipeline landfall.

Source: Dames & Moore calculations.

With these and other factors in mind, we have evaluated the following development issues and have drawn comparisons with the St. George Basin results. These issues are:

- The economics of production systems utilizing steel jacket/Cook Inlet hybrid structures in deeper waters (e.g., 91 meters; 299 feet) and Cook Inlet structures in shallower waters.

- The economics of relative short offshore pipelines (compared with St. George) and significantly longer onshore pipelines.

- Development in water depths that are generally much shallower than St. George Basin.

Since developing discoveries in the North Aleutian Shelf will generally involve significantly shorter pipelines than those required to bring St. George Basin production to shore, we have not evaluated the economics of offshore loading in the North Aleutian Shelf. This decision is based upon the relatively favorable economics of pipelining strategies revealed in our St. George Basin analysis. Although offshore loading may have a role in the North Aleutian Shelf, there is less reason to adopt such a production system than in St. George Basin.

III.3 Pipeline Distances and Transportation Options

Table A-2 shows representative pipeline distances from different parts of the lease sale area to the potential shore terminal sites identified in Chapter 4.0. The pipeline distances costed and screened in the economic analysis are consistent with distances from these locationally representative discovery sites to the potential shore terminal sites. The most distant point to shore by a direct route in the Bristol Bay Basin (defined by the 1524-meter, or 5000-foot, Tertiary isopoch) is about 145 kilometers (90 miles). Minimum distance to shore is related to the 3-mile limit that forms the shoreward boundary of the lease sale area. Maximum offshore pipeline distances in the Bristol Bay Basin generally will increase westward since the basin trends offshore in a westerly direction.

Maximum onshore pipeline distances will be about 160 kilometers (100 miles). In general, the further east on the Pacific coast of the Alaska Peninsula a site is located, the longer will be the cross-peninsula pipeline and the more rugged the terrain to be traversed.

III.4 Other Technical Assumptions

The assumptions on well spacing and well completion rates (we are assuming the same range of reservoir depths as the St. George study) are identical to those specified in the final St. George Basin report (see Section III.4, Appendix A). However, respect to development wells we have changed our assumption relating to well allowances. Critiques of our assumption of 5:1 ratio of producers to non-producers indicate that a ratio of 3:1 may be more appropriate. Assuming a ratio of 3:1 will increase the investment in wells and numbers of wells per platform for oil fields.

IV. ECONOMIC ANALYSIS

We have adopted the same economic assumptions made for our recently completed St. George Basin study as described in Appendix A, Section IV, of the final report. With one exception, no factors have changed since completion of that study that would warrant any changes in our economic assumptions.

In spite of the recent $2.00 per barrel oil price increase announced by Saudi Arabia, price increases from other OPEC oil producers, and continued disequilibrium in world oil prices, we have preferred to hold our price assumptions unchanged for the North Aleutian analysis. By continuing the same assumptions, the economic characteristics of the North Aleutian area can be directly compared with the results of St. George Basin economic analysis reported in Chapter 6.0 of that report. The price assumptions and economic results in the St. George study reflect the significant increase in world oil prices that took place in 1979 and the overwhelming positive impact on OCS petroleum development of those price increases. However, our St. George and North Aleutian economic analyses do 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 the mid 1980's. Our studies have been mandated to evaluate each sale individually and in isolation; the combined or cumulative economic, socioeconomic, and infrastructure affects of several closely-spaced (chronologically) lease sales are not reflected.

Our economic assumptions, which are discussed in Appendix A of the final St. George Basin report, are summarized below.

- Time Values of Money: We have assumed an 8 - 12 percent discount rate to bracket after-tax real rate of return. Constant (1980) dollar prices and costs are used for sensitivity testing. We have also evaluated the effects of increasing and decreasing relative costs and prices by constant factors.

- Oil Prices: Average mid-range laid-in value of $27.50 with upper and lower prices of $45 and $22.50 to bracket real price changes that may occur during the productive life of a field are assumed. In addition, the effects of a 3 percent annual price escalation are explored.

- Natural Gas Prices: A mid-range price of $2.22 is assumed and upper and lower prices of $3.50 and $1.75 are evaluated for sensitivity testing. In addition, the effects of a 3 percent annual price escalation are explored.

- Effective Income Tax Rate: We have assumed a ratio of 46 percent of taxable income after various deductions.(1)

- 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 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.

(1)Does not include the windfall profits tax, which does not apply to new frontier oil.

- 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 - 24 months of discounting from the ultimate cash flow andd makes minimum field size calculated smaller than if the lags were included. Investment schedules are further discussed in Appendix B of this report and the final St. George Basin report.

APPENDIX B

FIELD DEVELOPMENT COMPONENT COSTS AND SCHEDULES

I. DATA BASE

This appendix presents the field development and operating cost estimates used in the economic analysis. Exploration costs are not included (see discussion in Appendix A). The cost estimates given in this appendix were developed by engineering staff of Santa Fe Engineering Services Co. and Dames & Moore.

Several important qualifications need to be discussed with respect to estimating petroleum facility and equipment costs for frontier areas such as St. George Basin and the North Aleutian Shelf. Predictions on 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 water depth, seismicity, and sea ice conditions that characterize the North Aleutian Shelf. As such, there is little or no engineering and direct cost experience upon which to make these cost estimates.

The approach in this study, which involves estimates made by marine engineers, differs from that of previous Dames & Moore Alaska OCS studies. In the course of studies on the Gulf of Alaska (Dames & Moore, 1979a and b), lower Cook Inlet (Dames & Moore, 1979c) and Norton Sound (Dames & Moore, 1980), 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.

Petroleum development cost data is either direct cost experience of projects in current producing areas such as the Gulf of Mexico and North Sea, or projections based upon experience elsewhere modified for the technical and environmental constraints of the frontier area. For sub-arctic and arctic areas, facility cost projections may involve estimates for new technologies, construction techniques, etc. that have no base of previous experience.

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

II. PUBLISHED DATA BASE

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

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

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

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

III. COST AND FIELD DEVELOPMENT SCHEDULE UNCERTAINTIES

As stated elsewhere in this report, the purpose of the economic analysis is not to evaluate a site-specific prospect with relatively well-known reservoir and hydrocarbon characteristics but to bracket the resource economics of the lease basin, which comprises a number of prospects that will have a range of reservoir and hydrocarbon characteristics. 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-10 have been structured to accommodate this necessary simplification.

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 also play a role in field development costs, such as market conditions. The price an operator pays for a steel platform, for example, will be influenced by national or international demand for steel platforms at the time he places his order, whether he is in a 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. There may also be significant differences in the cost of platforms fabricated in the United States versus other countries such as Japan; currently (1980), the cost savings of platforms fabricated in Japan more than offset additional transportation costs to the U.S. west coast.

TABLE B-1

COST ESTIMATES FOR INSTALLED PLATFORMS

Platform Type	Water Depth Meters	Water Depth Feet	Number of Well Slots	Cost ($ Millions 1980) Low	Cost ($ Millions 1980) High
Steel Jacketed	91	300	32	60	69
Steel Jacketed	46	150	32	44	52
Steel Jacketed	15	50	32	25	31
Steel Gravity	91	300	32	60	69
Steel Gravity	46	150	32	49	56
Steel Gravity	15	50	32	41	47

Notes:
1. The water depths reflect the range anticipated in the lease sale area.
2. In addition to fabrication of the gravity structure in a Lower 48 yard, and fabrication of the steel platform in a Japanese yard, these estimates include the cost of platform installation, which involves site preparation, tow-out, set-down and pile driving.
3. The above estimates do not include any allowance for the installation or hook-up of topside facilities (see Table B-2).

Source: Sante Fe Engineering Services Co.

TABLE B-2

COST ESTIMATES OF PLATFORM EQUIPMENT AND FACILITIES FOR OIL PRODUCTION

Peak Capacity Oil (thousand barrels per day)	Cost ($ Millions 1980)	
	Low	High
less than 25	25.0	30.0
25-50	30.0	60.0
50-100	75.0	150.0
100-200	120.0	240.0
greater than 200	200.0	340.0

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 concurrrent with platform installation, thus avoiding a second mobilization and demobilization of the equipment.

Source: Santa Fe Engineering Services Co.

TABLE B-3

COST ESTIMATES OF PLATFORM EQUIPMENT AND FACILITIES FOR GAS PRODUCTION

Peak Capacity Gas (million cubic feet per day)	Cost ($ Millions 1980) Low	High
less than 100	32.5	39.0
100-200	52.0	65.0
200-300	71.5	84.5
300-400	84.5	97.5

Notes: 1. The cost of topside facilities would be essentially the same for all the platform types being considered.

2. See notes 1 and 2 on Table B-2.

Source: Santa Fe Engineering Services Co.

TABLE B-4

COST ESTIMATES OF DEVELOPMENT WELLS

Well Type	Reservoir Depth Meters	Reservoir Depth Feet	Cost ($ Millions 1980) Low	Cost ($ Millions 1980) High
Development Well (Each)	762	2,500	2.1	2.415
	1,524	5,000	2.8	3.22
	3,048	10,000	4.65	5.35

Notes:

1. These well depths reflect the potential range of reservoir depths anticipated in the North Aleutian Shelf.

2. We have assumed that the wells are directionally drilled (below mud line only).

3. The above cost estimates do not include certain "one time only" costs that would apply whether one hole or several dozen were drilled. Major items such as mobilization and demobilization of rigs are not included, which could be several million dollars, depending on where they originate. We assume all drilling would be by contractors, therefore, the cost of the rigs are not included ($10-15 million each). We have assumed heavy casing material would be required, and have included transporation costs for all items, assuming they originate in the Lower 48.

4. We have assumed that contractors own and operate the rigs.

Source: Santa Fe Engineering Services Co.

TABLE B-5

COST ESTIMATES FOR MARINE PIPELINE

Diameter (inches)	Average Cost per Mile ($ Millions 1980)	
	Low	High
30-39	1.7	2.5
20-29	1.3	1.6
10-19	0.9	1.2
less than 10	0.65	0.82

Notes: 1. The above costs assume no pipeline insulation or burial. One shore approach and one platform riser per line are included. Costs are not significantly sensitive to water depths for this area but because of high mobilization costs, the per mile cost is very sensitive to total length.

2. The above costs per mile are based on an average pipeline overall length of 32 - 121 kilometers (20 - 75 miles):
(Low costs are for 121 kilometers)
(High costs are for 32 kilometers)

3. It has been assumed that trenching will be required to the 61-meter (200-foot) contour. Trenching length required is 32 - 48 kilometers (20 - 30 miles) and costs vary from $650,000 - $950,000 per mile and are essentially independent of pipe size. These costs are additive to above figures.

4. See text for additional discussion of cost sensitivities related to offshore pipelines.

Source: Santa Fe Engineering Services Co.

TABLE B-6

COST ESTIMATES FOR ONSHORE PIPELINE

Diameter (inches)	Average Cost per Mile ($ Millions 1980) Low	High
30-39	2.0	2.5
20-29	1.5	2.0
10-19	1.2	1.7
less than 10	1.0	1.4

Notes:

1. The above costs per mile are based on a total length of 19 - 56 kilometers (12 - 35 miles). We have assumed the pipeline would be insulated.

2. We have assumed there is no permafrost, therefore, no unusual pipe supports. The pipeline may be above ground or buried.

3. We have assumed that there may be several river crossings with part of the route in mountainous terrain.

4. No right-of-way costs have been included. Camp facilities are included, but it has been assumed that the supply base used for the submarine lines can be used as a staging area for onshore operation. Per mile costs are not very sensitive to total length, as it is assumed that additional pipeline spreads will be added as length increases to keep construction time reasonably constant.

Source: Santa Fe Engineering Services Co.

TABLE B-7A

COST ESTIMATES OF OFFSHORE LOADING SYSTEM

System	Cost ($ Millions 1980)
Single Anchor Leg Mooring (SALM) each	25.0

Note: This estimate includes the cost of design, fabrication, and installation.

TABLE B-7B

OFFSHORE LOADING BUOY/MOORING SYSTEM ANNUAL OPERATING COST ESTIMATES

System	Cost ($ Millions)
One Platform plus SALM	35.0

Source: Dames & Moore

TABLE B-8

ESTIMATES OF OIL TERMINAL[1] COSTS

Peak Throughput (thousand barrels per day)[2]	Cost ($ Millions 1980)
< 100	300
100-200	390
200-300	600
300-500	860

Notes: 1. The shore terminals costed here are assumed to perform the following functions; pipeline terminal (for offshore lines), crude stabilization, LPG recovery, tanker ballast treatment, crude storage (sufficient for about 10 days' production), and tanker loading of crude.

2. The terminal costs cited here range from about $1800 to $3000 per barrel per day of capacity.

Sources: Dames & Moore estimates compiled from various sources including Wood, Mackenzie & Co., 1978; Duggan, 1978; Cook Inlet Pipeline Co., 1978.

TABLE B-9

ESTIMATES OF ANNUAL FIELD OPERATING COSTS

System	Cost ($ Millions 1980) Wells per Platform <10	<20	>20
1 Platform Field, Well-Terminal	20*	25*	40*
2 Platform Field, Well-Terminal	40*	50	90
3 Platform Field, Well-Terminal	45*	100	110
4 Platform Field, Well-Terminal			125*
5 Platform Field, Well-Terminal			250*

*Only these values were required for the cases investigated in this study.

Source: Dames & Moore estimates compiled from various sources including Wood, MacKenzie & Co., 1978; A.D. Little, Inc., 1976; Gruy Federal, Inc., 1977.

TABLE B-10

MISCELLANEOUS COST ESTIMATES

In the economic analysis, 5 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.

Most of the cost estimates presented in Tables B-1 through B-10 are specified as a range -- low and high -- to accommodate the uncertainties in estimating facility and equipment costs as well as to reflect certain simplifying assumptions. All the cost figures cited in Tables B-1 through B-10 are given in 1980 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 three types of platform: (1) Cook Inlet steel jacket hybrid (for water depths $\leq$ 61 meters; $\leq$ 200 feet), (2) Cook Inlet four-pile jacket structure (for water depths > 61 meters), and (3) steel gravity platform. The cost estimates in Table B-1 are for the fabrication and installation of the platform substructure or jacket and are provided for representative water depths in the North Aleutian Shelf lease sale area.

Several studies have been conducted to establish relationships between platform costs and various design parameters such as water depth and number of well slots (e.g., A.D. Little, 1976). However, our engineers do not know of any general relationships between platform costs and water depth, etc. that would enable costs to be interpolated. Design parameters are seldom constant; each platform is individually "custom" designed. Many factors contribute to the cost of the platform. As an example, the number of conductor wells in a platform jacket (e.g., conventional 8-leg) has little to do with the cost of the jacket. They represent only minor amounts of steel, whether they be 12 or 48 in number. The cost of the equipment on deck is another matter. Obviously, the more wells, the greater the cost. Likewise, for deck load, a large self-contained multi-faceted drilling/production platform can have a very large deck load, which will be a major factor in the design of the platform. Cost estimate indexes may be used (e.g., so many dollars per barrel of oil produced); however, these can be misleading unless it is known how complex the design of the platform is.

A recent study by Asheim et al. (1980) has attempted to correlate North Sea platform costs (substructure and superstructure) with the physical characteristics of offshore fields (water depth, production rates, gas/oil ratio, etc.). The platform substructure, or jacket, is designed to carry the superstructure a certain height above the sea floor and to withstand winds and waves. Asheim et al. found that the absolute substructure cost can be correlated linearly against production capacity and water depth (Figure B-1). Production capacity was used instead of superstructure weight (data for which was scarce) as an index of the load on the substructure, because proportionality between capacity and equipment weight can be expected for similar production processes. The number of wells was not reported as a realistic parameter for construction cost correlations because changes in cost caused by adding or subtracting a small number of well slots was probably insignificant compared to the total platform construction costs.

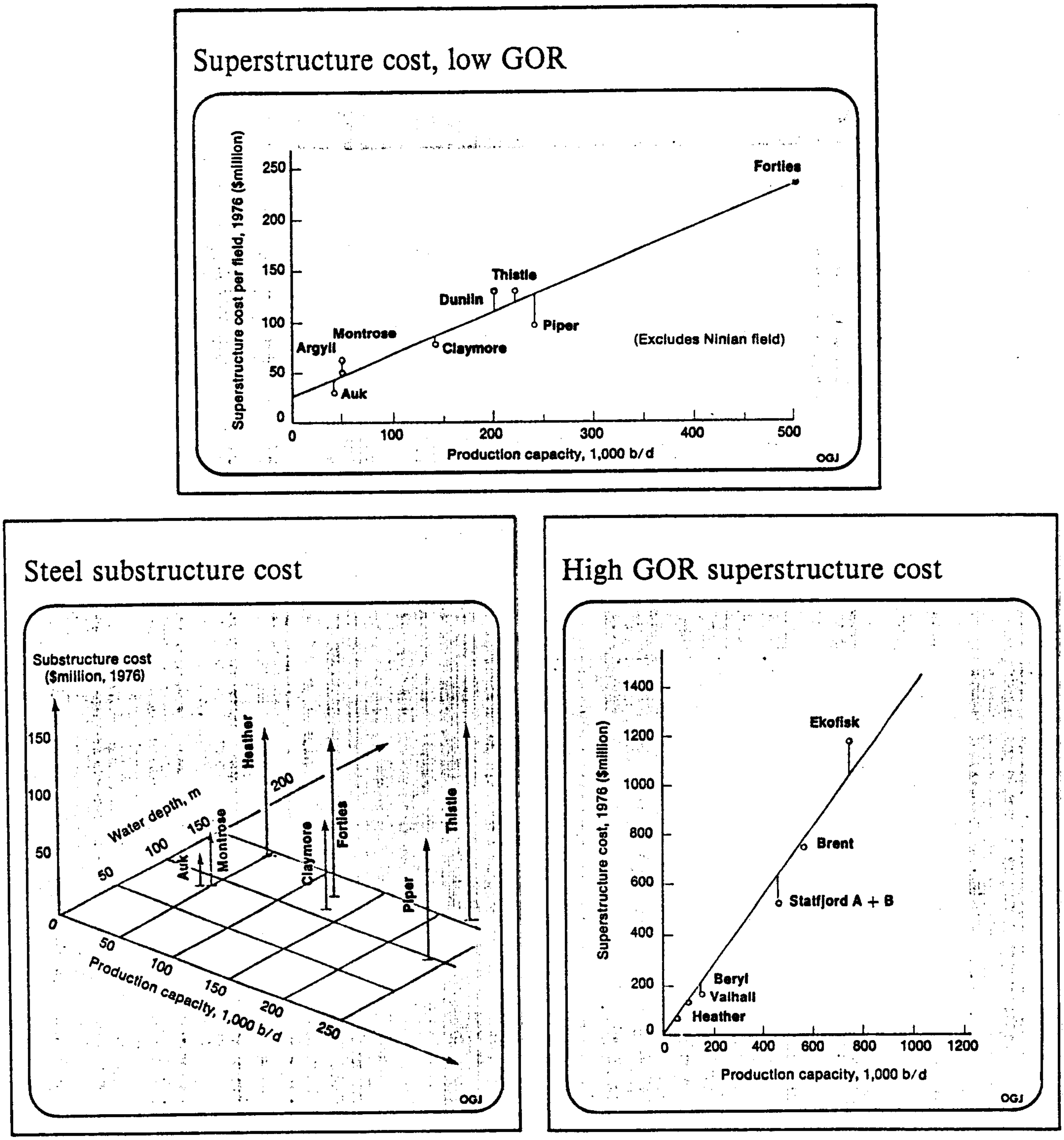
For water depths between 85 and 165 meters (279 and 541 feet) and processing capacity between 40,000 and 220,000 barrels per day (the range of real data used by Asheim et al.), the plane that offered the best cost correlation between steel jacket platform costs, water depths, and process capacity was:

$$cs = -94.1 + 1.348\ w + 0.223\ q$$

where:

- cs = steel jacket cost ($ million, 1976)
- w = water depth (m)
- q = production capacity (1000 stock tank barrels per day)

Only three data points were available to construct a similar investment cost function for North Sea concrete platforms. Differences in process equipment relating to contrasts in gas/oil ratio, platform storage capacity, and sea bottom foundation conditions, which may also influence substructure costs, complicate the picture. For water depths between 115 and 155 meters (377 and 508 feet) and production capacity between 150,000 and 300,000 barrels per day, the plane through the three data points correlating concrete platform costs, water depth, and process capacity was:



Source: Asheim et al. (Oil & Gas Journal, May 5, 1980)

Figure B-1

COST CORRELATIONS FOR NORTH SEA PLATFORMS

$$cc = 4.9546 + 0.1591\ w + 0.6727\ q$$

where:

cc = concrete substructure cost ($ million, 1976)

w = water depth (m)

q = production capacity (1000 stock tank barrels per day)

Similar correlations were made by A.D. Little, Inc. (1976) in their study of offshore petroleum development costs. Dames & Moore cost estimates for the Gulf of Alaska (Dames & Moore, 1979a, b) were in part derived through a similar methodology.

III.2. Platform Process Equipment (Tables B-2 and B-3)

As noted above, our platform processing equipment costs (Tables B-2 and B-3) vary with throughput and assume that other parameters are fixed as noted in the tables.

Although there is a 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 the hardware. As the gas-oil ratio increases, the size of the pressure or production vessels and pipelines increase. Large and 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. Further, the 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. The range of costs cited in Tables B-2 and B-3 accommodates contrasts in the characteristics of the fluids produced.

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).

On offshore platforms, space requirements for larger process vessels and pipelines and the increased equipment requirements for gas processing are usually insufficient to dramatically affect the platform costs.

In their study of North Sea platform costs, Asheim et al. (1980) found that the absolute superstructure cost can be correlated linearly against production capacity, provided that a distinction is made between low and high gas/oil ratio fields (Figure B-1). Low gas/oil ratio fields (i.e., less than 500 standard cubic feet of gas per stock tank barrel) in the North Sea generally have been developed without special equipment for conservation, while fields with higher gas/oil ratios (7500 standard cubic feet per barrel) usually have equipment for gas processing, reinjection, or sales. Thus, the investment cost function of the platform superstructure can be expected to show a step change between no gas conservation and gas processing for injection and sale. For North Sea platforms, the following correlations were made between superstructure costs and production capacity:

<u>Low Gas/Oil Ratio Superstructure</u>

$$ce = 0.415\ q + 26.32$$

where:

ce = superstructure cost ($ million, 1976)
q = producing capacity (1000 stock tank barrels per day)

<u>High Gas/Oil Ratio Superstructure</u>

$$ce = 1.4064\ q$$

where:

ce = equipment cost ($ million, 1976)
q = production capacity (1000 stock tank barrels per day)

In the economic analysis, we have evaluated the economics of associated gas production assuming field(s) with high gas/oil ratios (see Chapter 6.0).

The costs for platform process equipment for a secondary recovery program (e.g., water injection) are minimal 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. More space will also be required for equipment. However, given the platform designs considered, this would have little effect on overall installed platform costs.

III.3 Marine Pipelines (Table B-5)

The costs presented in Table B-5 are for a 121-kilometer (75-mile) pipeline and a 32-kilometer (20-mile) pipeline that represent the maximum and minimum distances anticipated from the lease sale area to landfalls on the Alaska Peninsula. Most of the pipelines in the North Aleutian Shelf will be laid in water depths less than 91 meters (300 feet).

III.4 Onshore Pipelines

Onshore pipelines would be required to take production from offshore pipeline landfalls to terminal sites located on the Alaska Peninsula. Onshore lines, ranging from 19 kilometers (12 miles) to over 105 kilometers (65 miles), probably would be required for the Alaska Peninsula sites since these are located on the Pacific Ocean side of the peninsula. If Cold Bay is the selected site, more typical onshore pipeline distances of 19 - 56 kilometers (12 - 35 miles) can be anticipated, depending on the location of the pipeline landfall. Onshore pipeline costs in these areas can be anticipated to be somewhat greater than in the Cook Inlet area but significantly less than in the Arctic where permafrost engineering, remote locations, and other factors related to construction in a harsh environment would impose cost premiums.

III.5 Oil Terminal Costs (Table B-8)

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; and 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-8, it is assumed that the marine terminal combines the functions of a partial processing facility (to upgrade crude for tanker transport) and a storage and loading terminal. It is also possible that an Aleutian Island or Alaska Peninsula 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 northern Bering Sea would be transfered from reinforced tankers to conventional tankers bound for the Lower 48 states.

IV. METHODOLOGY

The cost tables presented in this appendix are the basic inputs in the economic analysis. Each case analyzed is essentially defined by reserve size, reservoir characteristics, production technology (type of platform, transportation option, distance from shore terminal) and water depth. 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-10 using a building block approach; in some cases this involves deletion or substitution of a facility or equipment item. The construction of cases is further explained in Appendix A.

The cost components of each case are then scheduled as indicated in the examples presented in Table B-11. The schedules of capital cost expenditures are based upon typical development schedules in other offshore areas modified for the environmental conditions of North Aleutian Shelf assuming certain field construction schedules (see discussion below).

TABLE B-11

EXAMPLE OF TABLES USED IN ECONOMIC ANALYSIS CASE
SINGLE STEEL PLATFORM, PIPELINE TO SHORE TERMINAL

A. SCHEDULE OF CAPITAL EXPENDITURES FOR FIELD DEVELOPMENT - PLATFORM COMPONENT

Facility/Activity	Year - Percent of Expenditure							
	1	2	3	4	5	6	7	8
Platform Fabrication	10	30	30	20				
Platform Equipment	10	40	40	10				
Development Wells[1] - 48[2]					12.5 (6)	25 (12)	25 (12)	125 (6)
Miscellaneous		33	33	34				

Notes: 1. Example presented is for 48 wells based on assumption of two rigs working at a completion rate of 60 days per rig assuming a deep (3048-meter, 10,000-foot) reservoir; for different numbers of wells the expenditures are prorated approximately at the assumed completion rate.

2. Figure in parentheses is the number of wells drilled per year.

3. Year 1 is year decision to develop is made.

B. SCHEDULE OF CAPITAL COST EXPENDITURES - PIPELINE AND TERMINAL COMPONENTS

Facility/Activity	Year - Percent of Expenditure					
	1	2	3	4	5	6
Oil Pipeline (10 to 20 inch) 241 km (150 miles)			30	30	40	
Terminal (100,000 - 300,000 barrels per day)	10	30	30	30		

Source: Dames & Moore

V. EXPLORATION AND FIELD DEVELOPMENT SCHEDULES

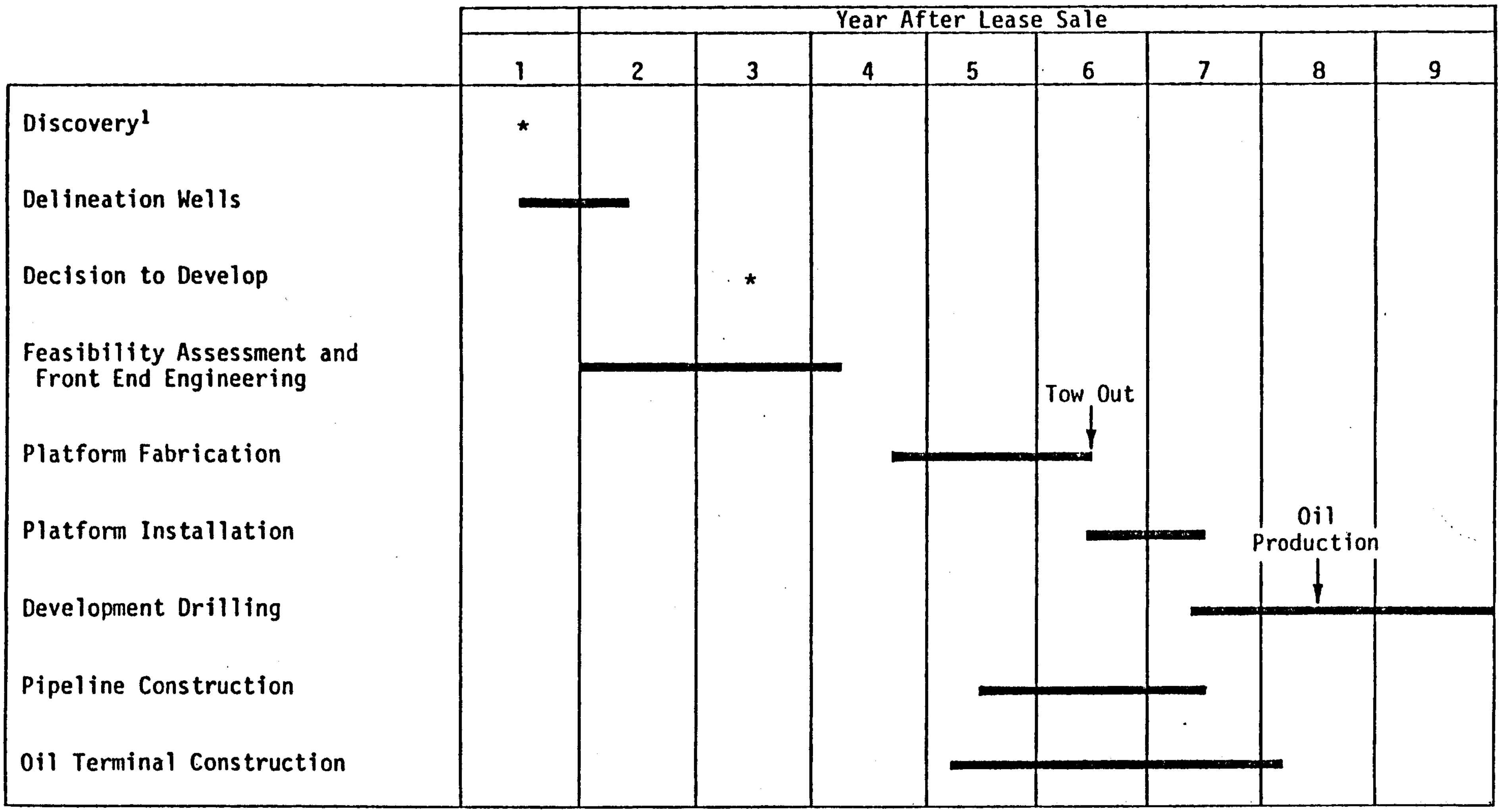
This appendix also discusses the assumptions made in defining the exploration and field development schedules contained in the development option for the U.S. Geological Survey statistical mean resource estimate (Chapter 7.0). These schedules are basic inputs into the economic analysis (scheduling of investments) and manpower calculations (facility construction schedules) as described in Appendix A. As with facility costs, exploration field construction schedules are somewhat speculative due to unknown factors relating to technology, environmental conditions (oceanography, etc.), and logistics. Nevertheless, the economic and manpower analyses require a number of scheduling assumptions.

Figure B-2 illustrates the field development schedule for a medium-sized oil field involving a single steel platform, pipeline to shore, and shore terminal in a non-ice, but harsh oceanographic environment such as the Gulf of Alaska or North Sea.

The sequence of events in field development from time of discovery to start-up of production involves a number of steps commencing with field appraisal, development planning, and construction. The appraisal process involves evaluation of the geologic data (see Figure B-3) obtained from the discovery well, followed by a decision to drill delineation (appraisal) wells to obtain additional geologic/reservoir information. There is a trade-off between additional delineation wells to obtain more reservoir data (to more closely predict reservoir behavior and production profiles) and the cost of the drilling investment. Using the results of the geological and reservoir engineering studies, a set of development proposals is formulated. This would also take into account locational and environmental factors such as meteorologic and oceanographic conditions. The development proposals involve preliminary engineering feasibility with consideration of the number and type of platforms, pipeline versus offshore loading, processing requirements, etc.

FIGURE B-2

EXAMPLE OF MEDIUM-SIZED FIELD COMPLETION SCHEDULE
SINGLE STEEL PLATFORM, OIL PIPELINE TO SHORE, SHORE TERMINAL[2]
IN NON-ICE-INFESTED ENVIRONMENT

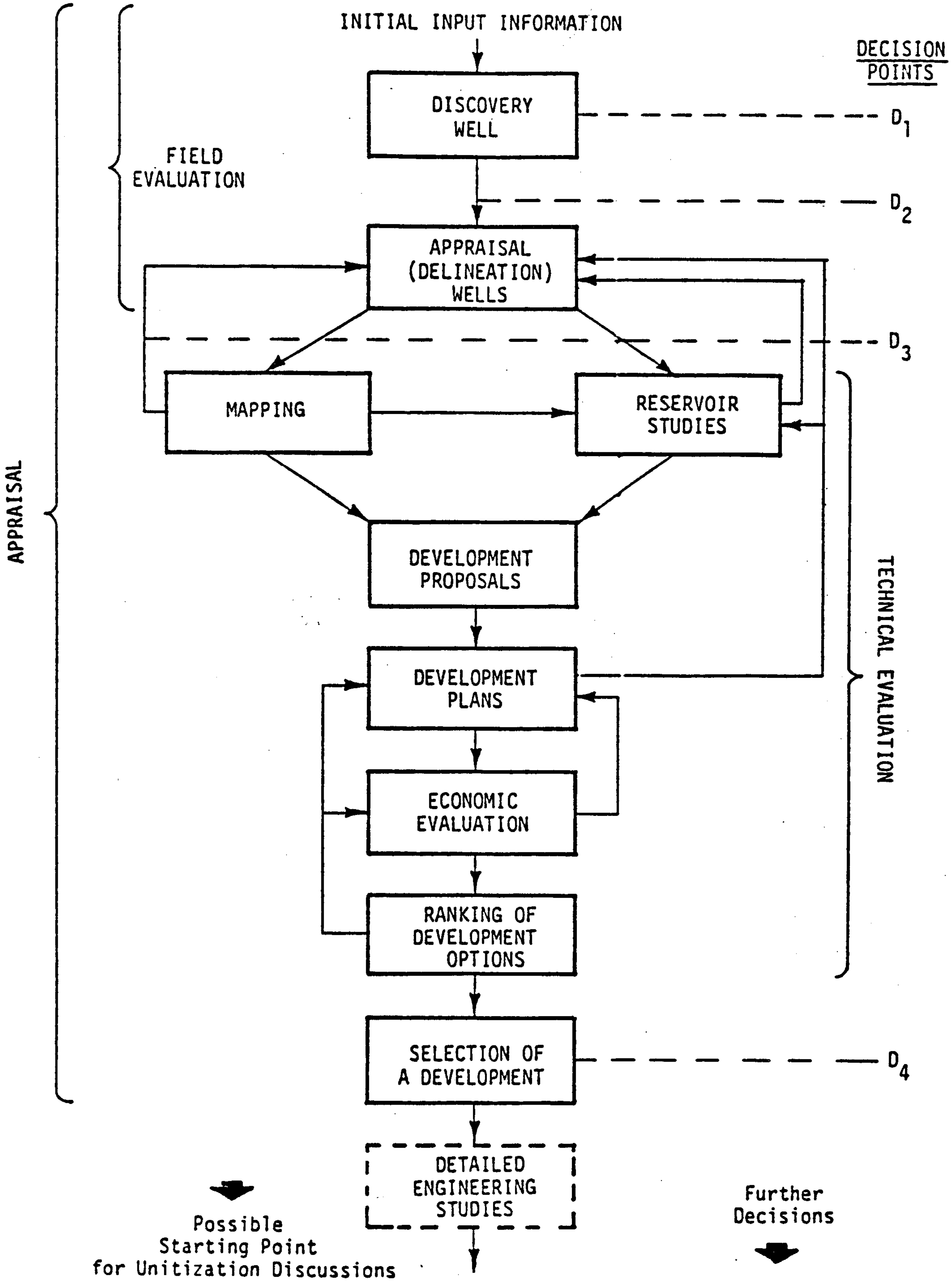


Source: Dames & Moore

[1]For illustrative purposes, discovery is assumed to occur in year following lease sale which is assumed to be first year of exploration.
[2]Seasonality of the level of some activities is not reflected in this figure.

Note: This schedule does not take into account legal and regulatory delays, including permit acquisition, since these factors are very difficult to predict.

FIGURE B-3



THE APPRAISAL PROCESS

Source: Birks (1978)

As illustrated on Figure B-2, the development proposals are screened for technical feasibility and other sensitivities, reducing them to a small number to be examined as development plans. These are further screened for technical, environmental, and political feasibility. Industry conducts an economic analysis of these plans similar to that conducted in this study. In the economic evaluation, facilities, equipment, and operating expenditures are costed, and expenditures and income scheduled. A ranking of development plans according to economic merit is then possible. Options are weighed according to technical, environmental, and political factors to select a development plan for subsequent engineering design. The feasibility appraisal process is complete. At this time, the operator will make a preliminary decision to develop or not develop.

If the decision is made to proceed, the operator will conduct preliminary design studies that involve marine surveys, compilation of detailed design criteria, evaluation of major component alternatives, and detailed economic and budget evaluation. Trade offs between technical feasibility and economic considerations will be an integral part of the design process. The preliminary design stage will be concluded when the operator selects the preferred alternatives for detailed design. The decision to develop will then be made.

The field development and production plan will then have to pass regulatory agency scrutiny and approval. In the United States, the operator will have to submit an environmental report, together with the proposed development and production plan, to the U.S. Geological Survey in accordance with U.S. Geological Survey Regulation S250.34-3, Environmental Reports presented in the Federal Register, Vol. 43, No. 19, Friday, January 27, 1978.

With the decision to develop, final design of facilities and equipment commences and contracts placed with manufacturers, suppliers, and construction companies. Significant investment expenditures begin at this time. Engineering and design work takes from 1-2 years following decision to develop, depending upon the facility and equipment. Design and fabrication of the major field component -- the drilling and production platform -- would take about 3 years for a large steel jacket such as Chevron's North Sea Ninian Southern Platform (Hancock et al., 1978). Onshore fabrication of a steel jacket platfrom will vary from about 12 - 24 months depending upon size and complexity of the structure (Antonakis, 1975). For a concrete gravity structure, fabrication may take as long as 36 months. An additional 7 - 10 months of offshore construction will be required for pile driving, module placement, and commissioning.

A critical part of offshore field development is scheduling offshore work in the summer "weather window." In the Gulf of Alaska, St. George Basin or North Sea, platform tow-out and installation would occur in early summer, May or June, to permit maximum use of the weather window. If the weather window was missed, delays up to 12 months could result.

Construction of offshore pipelines and shore terminal facilities are scheduled to meet production start-ups, which are related to platform installation and commissioning and development well drilling schedules. If shore terminal and pipeline hookups are not planned to occur until after production can feasibly commence, offshore loading facilities may be provided as an interim production (and long-term backup) system. The operator has to weigh the investment costs of such facilities against the potential loss of production revenue from delayed production.

Development well drilling begins as soon as feasible after platform installation. If regulations permit, the operator may elect to commence drilling while offshore construction is still underway even though interruptions to construction activities on the platform occur during the drilling process. The operator has to weigh the economic advantages of early production versus delays and inefficiencies in platform commissioning. Development drilling will generally commence from 6 - 12 months after tow-out on steel jacket platforms. Development wells may be drilled using the "batch" approach whereby a group of wells are drilled in sequence to the surface casing depths, then drilled to the 13-3/8-inch setting depth, etc. (Kennedy, 1976). The batch approach not only improves drilling efficiency but also improves material-supply scheduling. On large platforms, two drill rigs may be used for development well drilling, thus accelerating the production schedule. One rig may be removed after completion of all the development wells, leaving the other rig for drilling injection wells and workover.

V.1 North Aleutian Shelf Exploration and Field Development Schedules

The summer weather window for platform installation, though longer than in the northern Bering Sea (e.g. Norton Sound), is nevertheless tight and restricted to the period May through mid-October. Fall storms, summer fog and sea ice incursions (January through April) all pose restrictions on offshore construction activities and operations. Superstructure icing in winter is another problem for offshore construction activities.

These problems will also affect exploratory drilling. Water depths and other oceanographic conditions indicate that exploratory drilling can be conducted from semi-submersibles, drillships, and jackups (in the shallower waters). Drilling probably can be conducted in winter provided rigs have a quick disconnect capability and/or they are supported by ice breakers in case of incursions of sea ice.

VI. SCHEDULING ASSUMPTIONS

Based upon our engineering analysis, review of industry practices and environmental conditions in the North Aleutian Shelf, the following assumptions have been made on exploration and field development schedules. These assumptions are critical inputs to the economic and manpower analyses. The assumptions are:

- Exploration commences 8 months after the lease sale (i.e., summer 1984); all schedules cited in this report relate to 1984 as year 1.

- An average completion rate of 4 months per exploration/delineation well is assumed with an average total well depth of 3048 - 3692 meters (10,000 - 13,000 feet).

- The number of delineation wells assumed per discovery is two for field sizes of less than 500 million barrels oil or 2 trillion cubic feet gas, and three for fields of 500 million barrels oil and 2 trillion cubic feet gas and larger.

- The decision to develop is made 24 months after discovery.

- Significant capital expenditures commence the year following decision to develop; that year is year 1 in the schedule of expenditures in the economic analysis.

- Steel jacket platforms in water depths greater than 46 meters (150 feet) are designed, fabricated, and installed within 30 months of the decision to develop. Steel platforms located in water depths of 46 meters or less are designed, fabricated, and installed within 24 months. Platform installation and commissioning is assumed to take 10 months. Development well drilling is thus assumed to start about 10 months after platform tow-out.

- Steel platform tow-out and emplacement is assumed to take place in June.

- Platforms sized for 25 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 25 well slots are assumed to have one drill rig operating during development well drilling.

- Drilling progress is assumed to be 20 days per oil development well per drilling rig, i.e. 12 wells per year for 762-meter (2500-foot) reservoirs, 30 days per well (12 per rig per year) for 1524-meter (5000-foot) reservoirs and 60 days (6 per rig per year) for 3048-meter (10,000-foot) reservoirs.

- Production is assumed to commence when about 10 of the oil development wells have been drilled and when about 6 gas wells have been completed.

- Well workover is assumed to commence 5 years after production start-up.

- Oil terminal design and construction takes between 36 and 48 months depending on design throughput.

- LNG plant design and construction takes between 36 and 48 months depending on design throughput.

- Delays created by litigation and regulatory problems, including permitting preceding or subsequent to the lease sale, are not allowed for in our schedules since such delays are highly unpredictable. Our schedules reflect technical feasibility and assume expeditious award of leases and post-lease permitting. Recognizing that significant delays can occur, we have evaluated the economic impact of delay on a project (see Chapter 6.0).