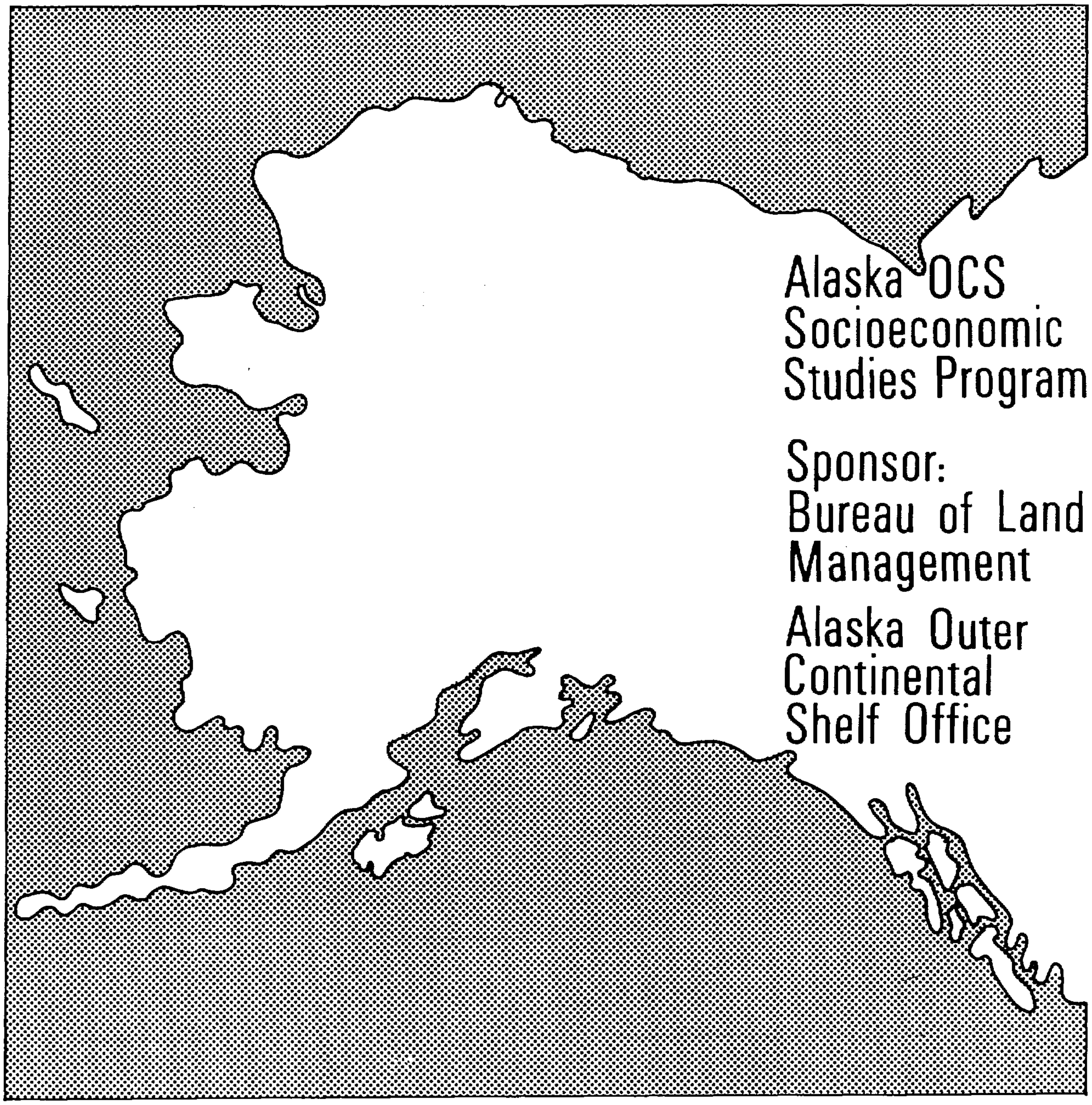
Technical Report
Number 56



St. George Basin 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: No. 56

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
ST. GEORGE BASIN
PETROLEUM TECHNOLOGY ASSESSMENT

FINAL REPORT

Prepared-for

BUREAU OF LAND MANAGEMENT
ALASKA OUTER CONTINENTAL SHELF OFFICE

By

Peter T. Hanley
William W. Wade
Marvin F. Feldman

of

DAMES & MOORE

in association with
Santa Fe Engineering Services Co.
Brian Watt Associates, Inc.
Gordon S. Harrison
Walter S. Harris, Inc.

August 1980

Contract No. AA851-CTO-3
Task 9DA

Job No. 8699-023-20

NOTICES

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

2. This final report is designed to provide preliminary petroleum development data to the groups working on the Alaska OCS 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
St. George Basin
OCS Lease Sale No. 70
Petroleum Technology Assessment
Final Report

Technical Report No. 56

Prepared by

DAMES & MOORE

August 1980

e ’

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

LIST OF TABLES

LIST OF TABLES (continued)

LIST OF TABLES (continued)

e

LIST OF FIGURES

TABLE OF CONTENTS

APPENDIX A

TABLE OF CONTENTS (continued)

APPENDIX A

LIST OF TABLES

APPENDIX'A

LIST OF FIGURES

APPENDIX A

TABLE OF CONTENTS

APPENDIX B

LIST OF TABLES

APPENDIX B

LIST OF FIGURES

APPENDIX B

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 St. George Basin. 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 the Bureau of Land Management Alaska OCS Office 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, 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 St. George Basin 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 U.S. Geological conditional estimates of undiscovered recoverable oil and gas for the St. George Basin are (Marlow et al., 1979):

	Probability		Statistical
	95 percent	5 percent	Mean
Oil (billions of barrels)	0.8	6.4	2.7
Gas (trillions of cubic feet	4.5	18.6	10.3

The assumptions used in the aria" ysis may be subject to revision as new data become available.

1.2 Scope

This petroleum technology assessment is for the proposed St. George Basin OCS Lease Sale No. 70. Scheduled for December 1982, it will be the second Bering Sea OCS lease sale (following that of Norton Sound, Sale No. 57, scheduled for November 1982). The study area considered in this report encompasses the high-interest tracts nominated by the oil industry in the 1979 call for nominations issued by the BLM Alaska OCS Office (Figure l-l). Most of these tracts have been selected by BLM for further evaluation preparatory to tract selection and environmental impact assessment. About 320 tracts are involved, covering an area of approximately 1.1 million hectares (2.6 million acres).

Water depths in this potential lease sale area range from 100 meters (328 feet) on the Bristol Bay side to 150 meters (492 feet) on the western edge of the tracts (the bathymetric contours generally trend northwest-southeast).

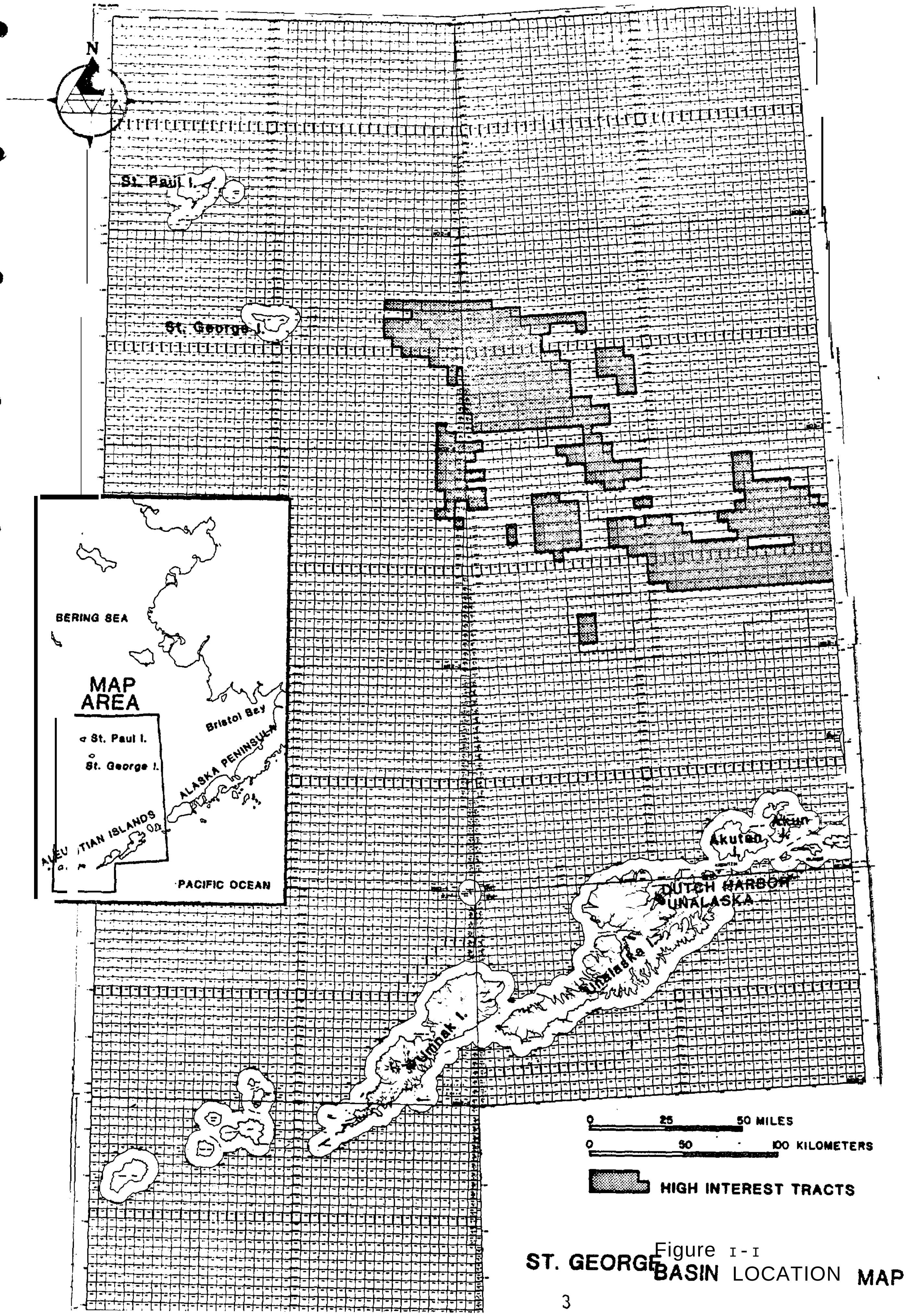


Figure I-I
ST. GEORGE BASIN LOCATION MAP

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, as the 10-year maximum extent of ice essentially bisects the sale area from northwest to southeast. The central portion of the sale lies almost equidistant from the Pribilof Islands and Dutch Harbor, about 241 kilometers (150 miles). The closest points to the Pribilofs (St. George Island) and Alaska Peninsula are 64 kilometers (40 miles)', and 72 kilometers (45 miles), respectively.

The principal components of this study are:

- An evaluation of the environmental constraints (oceanography, geology, biology) 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 St. George Basin 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 St. George Basin to formulate reservoir and production assumptions necessary for the economic analysis;

- An economic analysis of St. George Basin 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 were available to this study, although both agency and industry reviews of important technical, geologic and economic assumptions were made.

The principal data gaps include:

- Oceanography - 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 - 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 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 are presented in Chapter 6.0 along with a section on the problems of marketing oil and gas from the St. George Basin based upon the resources estimated by the U.S. Geological Survey. Chapter 7.0 concludes the main body of the report with a description of a hypothetical development case for the USGS statistical mean oil and gas resource estimate.

Appendix A presents the methods and assumptions of the technology assessment and explains how the information in this report can be used to develop petroleum scenarios for various combinations of technical, geologic, economic, and locational conditions.

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 undiscovered recoverable oil and gas resource estimates for St. George Basin that are used in this study are (Marlow et al., 1979):

	Probability 95 percent	Probability 5 percent	Statistical Mean
Oil (billions of barrels)	0.8	6.4	2.7
Gas (trillions of cubic feet)	4.5	18.6	10.3

The St. George Basin is generally regarded to have a high potential by industry and the U.S. Geological Survey. It is an elongated Tertiary sedimentary depression located on the Bering Sea continental shelf between the Pribilof Islands and the Alaska Peninsula. The basin is a long (322 kilometers or 200 miles), narrow (32 - 48 kilometers or 20 - 30 miles) structural graben whose long axis strikes northwest, parallel to the continental margin of the southern Bering Sea.

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 were formulated for the economic analysis. These assumptions also provide the basis for specification of a hypothetical development case corresponding to the U.S. Geological Survey statistical mean resource estimate. The assumptions are:

- Reservoir depths--762 meters (2,500 feet), 1,527 meters (5,000 feet), 3,048 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 -- 1,000, 2,000, and 5,000 barrels per day

- Initial well productivity, gas -- 10 and 15 million cubic feet per day

- Gas resource allocation between associated and non-associated -- 40 percent and 60 percent, respectively

- Gas-oil ratio (GOR) -- 1,000 standard cubic feet per day

- 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

- Peak production, non-associated gas -- about 75 percent of total reserves captured before decline begins

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 marketing analysis of St. George Basin oil production.

2.2 Environmental Constraints

2.2.1 Oceanography

The Bering Sea is characterized by a harsh winter climate and a summer season, which although much milder than winter, cannot be termed “mild.” The primary wind direction in the winter is from the north and northeast and during the summer is from the west and southwest, although the direction is extremely variable all year.

Several factors will present major design and operating challenges for petroleum facilities in the St. George Basin lease sale area. One such factor is the average water depth of the area. Almost all of the high interest lease sale tracts are between the 100- and 130-meter (328- and 427-foot) isobaths. This is well within present state-of-the-art technology for platforms and pipelines, but is definitely an economic consideration.

Although the wave climate within this region is harsh and large waves (5-year return wave of 13.5 meters or 44 feet) are frequent, the design constraints are less severe than those developed for platforms in the North Sea, and thus, once again, are primarily economic considerations.

One rather unique feature of the region is the seasonal possibility of unconsolidated pack ice. In areas such as the Beaufort Sea ice is present, but as a solid mass, and hence, continuous ice forces become the major design parameter. In this area, however, the ice pack is no more than one-eighth coverage (1 okta)(1) and occurs in isolated floes of first-year ice. The prevailing winter winds may drive some of these floes to any point within the lease sale area, and consequently, dynamic or impact loading from ice floes will be a design consideration throughout the area.

Petroleum development within the St. George Basin lease sale area is well within present state-of-the-art technologies with regard to the major oceanographic design constraints of bathymetry, wind and wave climate, the presence of pack ice, and the possibility of severe superstructure icing.

---

(1) An okta is a unit of ice coverage and is designated in one-eights; for example, one okta is equivalent to one-eight coverage, 2 oktas to one-fourth, etc.

2.2.2 Geology

The marine geology of the St. George Basin and surrounding areas of the southern Bering Sea Shelf has been described largely on the basis of surficial sediment samples and acoustic reflection profiles obtained by the U.S. Geological Survey. The data base is deficient insofar as a substantial amount of information derived from geophysical surveys and exploratory drilling is proprietary, the accessible data will serve, however, to generally define the major geological features and potential geological hazards.

The seafloor sediments above the shelf break comprise mixtures of unconsolidated sands and silts of unknown thickness and engineering properties. The surficial sediments are flat-lying and are believed to be relic deposits. With the exception of possible localized zones of gas-charged sediments, there is no indication of unstable sediments occurring within the high-interest areas of the St. George Basin. The suspected deposits of shallow gas are sufficiently common to warrant their consideration in preliminary design studies; analogous deposits have been verified in Norton Sound and other Bering Sea Shelf areas.

Faulting is common in the St. George Basin and appears to follow the northwest-southeast structural grain of the area. Fault displacement increases with depth in the sedimentary section, indicating active growth structures, and in some locations offsets near-surface strata and the seafloor. Specific tracts will have to be individually evaluated, but the probability of active fault structures occurring in or near any given block is judged to be moderate to high.

Because of the demonstrable occurrence of Holocene faulting, the location of fault epicenters within the St. George Basin, and the proximity of the area to the seismically active Aleutian Island Arc, the exposure of petroleum development and production structures to seismic risk is high. Preliminary design criteria for such facilities should follow guidelines developed by the American Petroleum Institute (API) for its Zone 3 condition and Soil Type C (deep, strong alluvium).

Volcanic activity from centers either on the Aleutian Islands or the Pribilof Islands appears to constitute hazards only to shore-base facilities, and is not expected to be a controlling factor for development of the St. George Basin.

2.2.3 Environmental Constraints

The fisheries of St. George Basin account for one-third of the total annual catch and value of fishery resources form the entire Bering Sea (.13 million metric tons, $275 million in 1977). The catch chiefly consists of the traditional demersal species, namely cod, flounders, and rockfish with pollock the dominant species and primary target fish. The region serves as major spawning and nursery sites of many of the commercially important groundfish species and is second in world production in terms of harvest yields of demersal fish (bottomfish) per unit effort. Additional fish stocks that migrate through the region including the entire adult and juvenile Bristol Bay salmon populations, spawning herring stocks and, during some years, up to one-half of the Bering Sea commercial crab stocks.

Marine mammal activities are intensive and extensive in this region. For example, the Pribilof Islands serve as breeding and nursery grounds for the entire U.S. population of northern fur seals (1.4 million of the 1.9 million world population). Several other marine mammals including ice seals, harbor seals, sea lions, walruses and various whales range seasonally through the area in migratory, feeding, breeding or calving activities. Some species, namely the fur seal, gray and humpback whales, may spend more than 6 months in the region annually.

a The southern Bering Sea is one of the most important regions in Alaska waters for seabirds. The Pribilof Islands support very large colonies of breeding seabirds; St. George Island is considered the largest seabird colony in the northern hemisphere. Foraging seabirds from these colonies use this region extensively during the summer months. The sooty and short-tailed shearwaters from the southern hemisphere are by far the most numerous seabird from late spring through the summer. Millions of additional seabirds pass through the lease area as they migrate to the north Pacific and Gulf of Alaska from breeding colonies in the northern Bering Sea. During the winter the ice edge habitat (to 8 oktas) in the southern Bering Sea is of critical importance to over-wintering seabirds.

2.3 Technology, Production Systems, and Field Development Strategies

Exploratory drilling in the St. George Basin is within the operational capabilities of semi-submersibles, drillships, and jackup rigs (in the shallow portions of the lease sale area). Apart from equipment availability, the key to an intensive exploratory effort will be the development of techniques to drill year-round in an area where ice incursions may occur from January through April. Dynamically-positioned drillships, possibly supported by ice breakers (as used by Dome Petroleum in the Canadian Beaufort Sea), may provide this year-round capability.

Among the important design considerations for production platform design in this area are:

- Ice loads
- Seismic loading
- Other environmental loads (waves, winds)
- Installation and fabrication capabilities
- Conductor well spacing
- Directional drilling

- Superstructure icing

- Storage requirements

- Topside facilities

Two types of platform design are probably feasible in St. George Basin:

- Steel Jacket -- Cook Inlet hybrid structure with minimal bracing through the water line area and conductors located inside the legs; and

- Concrete or steel gravity structure -- North Sea gravity structure with a single leg (monopod) or several legs.

The steel platform would most likely be constructed in Japan and barged to the St. George Basin. The gravity structures would have to constructed at a deepwater site (as yet unbuilt) somewhere on the U.S. west coast. With conductors located within the legs of these structures, there is a limitation on the maximum numbers of well slots that can be housed on the platform (on the order of 48).

Long pipelines will be required to shore terminals located on the Alaska Peninsula or in the Aleutian Islands. Distances up to 321 kilometers (200 miles) can be anticipated and most of the potential lease sale area lies between 75 150 miles (120 - 241 kilometers) from suitable shore terminal sites. There will be considerable incentive for fields to share a few trunklines to a shore terminal(s). With pipeline distances of over 160 kilometers (100 miles) intermediate booster pump or compressor stations probably will be required.

An alternative to crude oil pipelines is offshore loading of crude directly to tankers via a single point mooring system such as a Single Anchor Leg Mooring (SALM). To be economic, such a system needs backup storage, perhaps for as much as several weeks' production. Thus, a gravity structure with its storage capablity would be favored. Although industry considers offshore loading a viable alternative, extensive weather and maintenance downtime combined with the problems of winter sea ice and summer fog in St. George Basin will impose considerable technical difficulties for the design and operation of such a system. At this time, therefore, the adoption of such a system is highly speculative.

Floating systems, such as converted semi-submersibles, tension leg platforms, and various concrete designs, in St. George Basin are unlikely because of the sea ice conditions.

Subsea completions may have a role in St. George Basin. Given the high cost of platforms in this sub-arctic area and the possibility of shallow reservoirs in some areas, using subsea satellite wells with pipelines to mother platforms would minimize the number of platforms required to drain a field. However, the state-of-the-art for subsea completions in a sub-arctic area has not been determined.

In summary, the most likely overall development strategy for St. George Basin, assuming reserves on the order of those estimated by the U.S. Geological Survey, would involve several fields sharing two large diameter trunk pipelines (one oil, one gas) to a crude terminal and LNG plant located in the Aleutian Islands or southwestern Alaska Peninsula. Only if fields were widely scattered and near the maximum distance from shore would offshore loading be a serious option.

Based upon the results of the technology assessment, the following production systems were selected for economic evaluation:

- Single or multiple steel platforms with shared or unshared pipeline to shore terminal -- oil production

- Single or multiple 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 gravity platforms with shared or unshared pipelineto shore LNG plant -- non-associated gas production

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

- Single gravity platform with single anchor leg mooring offshore loading system and shuttle tankers to an Aleutian transshipment terminal.

2.4 Manpower

Nanpower requirements for the development and operation of" petroleum production facilities in the St. George Basin are dependent upon many factors. Contractors and operators will economize on field manpower as much as possible during construction of major facilities at remote sites. However, during the operational phase, a remote site may require greater on-site labor for some tasks than would nearshore locations closer to urban areas. 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 Oil and Gas Field Development

The economics of developing oil and gas fields in the frontier regions of Alaska's OCS have improved greatly with the 1979 jump in world oil prices. However, this significant improvement in economics could rapidly disappear if OCS development costs escalate under the pressure of developing several of the lease sale areas simultaneously. Alaska oil development costs have jumped 20 - 30 percent from year-to-year in the past during development. So, too, North Sea development costs shot up when demand for people and equipment vastly exceeded supplies. Costs in the Bering Sea could easily follow this scenario and exceed oil price inflation during the 1980s. Hence, minimum economic field size could easily revert to the 200 million barrel range established consistently in prior OCS studies.

2.5.1 Oil

Pegged to an average of several imported crudes, the 1980 well-head value of a barrel of oil in the St. George Basin is $27.50. Even with the likely long pipeline distances from the St. George Basin to suitable shore terminal locations on the Aleutian chain, 100 million barrel fields earn more than a 15 percent after tax, inflation adjusted (real) internal rate of return (ROR). Offshore loading probably would not be indicated unless a field were extremely far from shore and isolated from other fields with which it could share pipelines. Pipelining is much more attractive economically than offshore loading options.

The minimum field size to earn a 12 percent hurdle(1) rate is between 50 - 100 million barrels, depending on the field's location relative to other fields, the distance to shore terminal, and the ability to share trunklines and infrastructure.

The equivalent amortized cost (EAC) of development ranges typically between $23.00 - $25.00 per barrel in the St. George Basin. Very large single and multi-platform fields -- 350 million barrels with one platform, 1.0 billion barrels with 4 platforms -- show unit costs of about $20.00 per barrel. Economies of scale appear to be totally captured at 350 million barrel fields.

---

(1) For purposes of this study, the hurdle rate is defined as the average annual return on investment that is just high enough to induce a developer to make the investment.

Oil produced in the St. George Basin beginning in 1990 can all be used to replace declining Prudhoe Bay production in PAD V unless new Beaufort Sea production is on-stream. In this case, St. George oil will be transshiped to PADs I-IV, either via the Northern Tier pipeline or through the Panama Canal.

2.5.2 Gas

Natural gas discovered in the St. George Basin must be converted to LNG and shipped to market, probably Point Conception, California, the intended west coast LNG terminal. Our analysis assumed the cost to convert and ship LNG would be in the range of $3.50 per thousand cubic feet. With No. 2 diesel fuel worth nearly $6.00 in BTU equivalence to 1,000 cubic feet gas, the well-head value of St. George natural gas is approximately" $2.50 per thousand cubic feet. Under these assumptions, gas fields in the range of 750 billion - 1 trillion cubic feet are economic -- depending on shared infrastructure and pipeline distances to shore. Equivalent amortized cost of development typically are near $2.00 per million cubic feet.

Most development options for gas fields of 1 trillion cubic feet earn between 12 - 16 percent ROR. Hence, non-associated gas is less profitable to develop than oil, which earns nearly 20 percent, in the St. George Basin.

The uncertainty in the cost of converting gas to LNG overhangs gas development economics. Gas can be developed in the St. George Basin if it can earn $2.00 per thousand cubic feet or more at the wel l-head. It will be sold in the Lower 48 if it can be converted to LNG and shipped to market for some cost up to about $5.00 maximum (in 1980 dollars).

2.6 Facilities Siting

The onshore petroleum facilities that may be required by St. George Basin petroleum development include temporary exploration support bases, construction support bases, permanent operation support bases, crude oil terminal(s) and LNG plant.

Potential temporary bases for exploration activities without requiring major capital improvement by industry include Cold Bay, Dutch Harbor and St. Paul. Unalaska Bay and Akutan Harbor are potential sites but lack the necessary infrastructure and would require major investments to develop.

The following sites were identified as having some potential as sites for a crude oil terminal or LNG plant:

- Makushin, Makushin Bay, Unalaska Island
- Unalaska Bay, Unalaska Island
- Akutan Harbor, Akutan Island
- Morzhovai Bay, Alaska Peninsula
- Lost Harbor, Akun Island
- Zapadni Bay, St. George Island

Each of these sites has some oceanographic or geotechnical limitations. In terms of environmental sensitivity, Zapadni Bay is the most sensitive as a result of the fur seal rookery and hauling out area at the head of the bay and major sea bird colonies. Makushin Bay and Unalaska Bay have considerable fishery resources which could conflict with oil development. Environmental problems at the other sites could likely be mitigated.

3.0 RESULTS OF THE PETROLEUM TECHNOLOGY ASSESSMENT

3.1 Introduction

As described in Appendix A, 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 the individual field development components, in particular platforms, their design parameters, and installation techniques.

3. Identification of the field development strategies that may be adopted to develop the oil and gas resources of St. George Basin. The field development strategy involves the sum of the various field development components (platforms, wells, process equipment, pipelines, terminals etc.) and the transportation system for either oil or gas. Included in this evaluation is a discussion of such problems as offshore loading vs. 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 deepwater 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, 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 monotones that are relevant to this study. We do not propose, therefore, to reiterate these descriptions to any extent; rather, the reader is referred to those technical descriptions that provide a background for the conclusions in this report. While certain comparisons can be made between the oceanographic and geologic setting of St. George Basin and other offshore areas, such as the Gulf of Alaska, it should be emphasized that St. George Basin has a unique combination of water depths, meteorologic conditions (storms and fog), seismicity, and sea ice as well as considerable distances to suitable shore terminal sites. A second and 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 is very limited. In particular, data on ice characteristics and marine sediments, information essential to assess the feasibility of various platform designs or conceptualize on new designs, is sparse. Our conclusions, therefore, should be regarded as tentative and preliminary. In particular, our approach with respect to platform design and operational constraints is conservative.

This chapter commences with an evaluation of environmental constraints (oceanography, geology and biology) and is followed by a description of various field development components. The chapter concludes with a discussion of field development strategies that may be applicable to St. George Basin and warrant economic evaluation.

3.2 Environmental Constraints to Petroleum Development

3.2.1 Physical Oceanography

3.2.1.1 Introduction

The St. George Basin lies in the Bering Sea, west of Bristol Bay and just southeast of the Pribilof Islands. Excluding the Pribilof Island group, the nearest landfalls are the Alaska mainland to the east and the Aleutians to the south. The sale area is exposed to the harsh marine environment characteristic of the Bering Sea.

The marine environment is a key factor in the selection of technological strategies for the development of petroleum resources in this area. The bathymetry, wave climate, and seasonal possibility of pack ice will present major design and operating challenges to the petroleum industry.

3.2.1.2 Bathymetry

The tracts of high interest within the entire St. George Basin sale area lie in water depths between 100 meters (328 feet) and 150 meters (492 feet). Of these tracts, approximately 40 percent are situated between the 130-meter (426-foot) and the 140-meter (459-foot) bathymetric contours.

To the immediate south and southwest of the sale area, the ocean floor drops sharply to depths in excess of 1,600 meters (5,250 feet) and then abruptly rises to form the Aleutian Chain. In contrast, the sea floor of St. George Basin exhibits a rather gradual slope with no major trenches between the sale area and the Pribilof Islands, to the northwest, and the Alaska mainland to the east. This area, known as the Bering Sea Shelf, with the St. George lease sale area on the edge, has no troughs or basins to indicate glaciation. Buffington et al. (1950) state that "Aside from a few islands and rocky banks near the shelf margin, there is an amazing lack of relief. Some of the echograms show absolute flatness." According to Shepard (1963), this constitutes the largest area with such low relief anywhere on the surface of the earth.

The following table summarizes the distance from three representative locations within the lease sale area to St. Paul Island and Dutch Harbor. In addition, the maximum depth encountered along each straight-line path is presented to indicate potential pipeline problems and distances.

TABLE 3-1

REPRESENTATIVE DISTANCES TO SHORE
FROM ST. GEORGE BASIN

Location	To St. Paul Island		To Dutch Harbor	
	Straight-Line Distance-km(mi)	Max. Water Depth-m(ft)	Straight-Line Distance-km(mi)	Max. Water Depth-m(ft)
Northwest (56°10'N, 168°50'W)	134 (83)	110 (361)	320 (199)	1200 (3937)
Central (55°45'N, 161 °80'W)	248 (154)	150 (492)	230 (143)	1200 (3937)
Southwest (54°550N, 166 °0'W)	365 (227)	150 (492)	156 (492)	800 (2625)

As seen from this table, the straight-line distances to Dutch Harbor are associated with extremely deep water. Laying pipe at these depths is beyond current experience. More circuitous routes could, in most cases, be selected that would greatly reduce these maximum encounter depths. For example, routes between Dutch Harbor and the representative sites could be chosen, without greatly increasing the overall distances, but while reducing the maximum water depth to less than 200 meters (656 feet).

3.2.1.3 Tides and Currents

Current information is both scarce and conflicting for this area of Alaska. Only a limited oceanographic interest has been shown in the area between the Pribilof and Aleutian Islands and the mainland of Alaska. Much of the information that has been gleaned has been in support of commercial fishing operations and much has been undertaken by foreign governments. Observations by ships of passage compiled by the U.S. Navy have supplied some of the information. Brewer et al. (1977) have synthesized much of the avail able knowledge but point out that changes are being made as more recent and specific information becomes available.

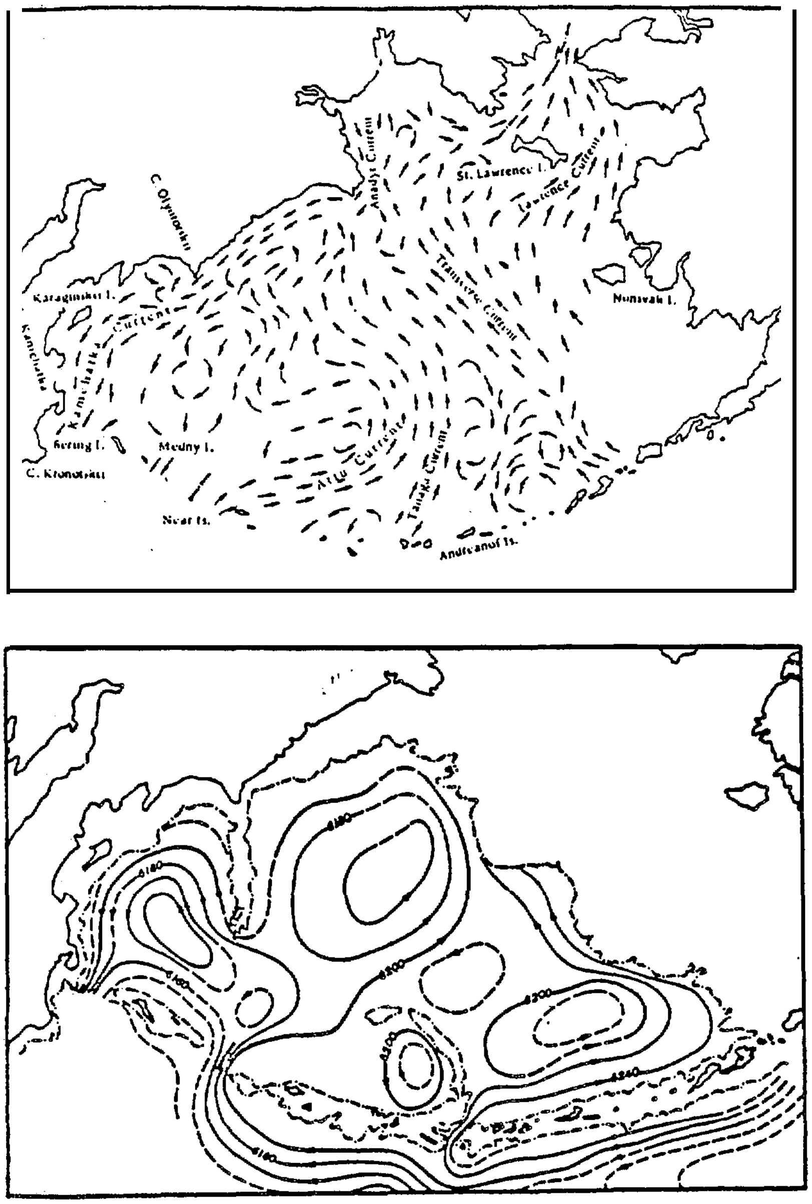
One of the major influences on the circulation in the eastern Bering Sea is the presence of the strong permanent Alaska Current flowing east to west in the northern Gulf of A aska and southwestward along the Aleutians. Between the islands these waters penetrate the eastern Bering Sea and form the Transverse Current that flows in a north-northwesterly direction (Lisitsyn, 1969) (Figure 3-l). The net surface speed of this flow to the northwest is on the order of 0.1 - 0.3 knots (Brewer et al., 1977).

Other information indicates a circulation cell within the Bristol Bay region. This cell rotates in a counterclockwise direction, flowing east-northeast along the Alaska Peninsula. Apparently the source of this water is the Alaska Current moving into the eastern Bering Sea through the inter-island straits in the Aleutians. Upon nearing the Alaska mainland, the gyre circulates around Bristol Bay, then flows westward mixing ultimately with water at the edge of the continental shelf near the Pribilof Islands. If this pattern is in fact correct, then the proposed lease area would lie approximately on the western boundary of this gyre (Figure 3-2) (Arctic Environmental Information and Data Center, 1974).

Overlying this primary circulation are wind-driven and tidal currents. The tidal currents in the open sea are not as strong as those within the influence of coasts. For example, the tidal currents in some of the straits between the Aleutian Islands can reach velocities between 4 - 6 knots. However, the tidal currents around the Pribilof Islands, closer to the St. George Basin, are much less.

In 1976, the NOAA ship <u>Surveyor</u> observed currents setting northwest at approximately 2.5 knots about 3.4 kilometers (2.1 mi" es) southwest of Otter Island. Velocities of 1.5 knots have been observed in the east-west tidal currents around St. George Island. Observations west of Walrus Island between July and August indicated tidal currents to-be rotary, tending to move clockwise with velocities in excess of 2 knots at times (Coast Pilot, 1979).

Since the influence of these islands will tend to increase the tidal current velocities relative to the open sea, the velocities reported by Lisitsyn (1969) are probably more representative of the site. He reported that the

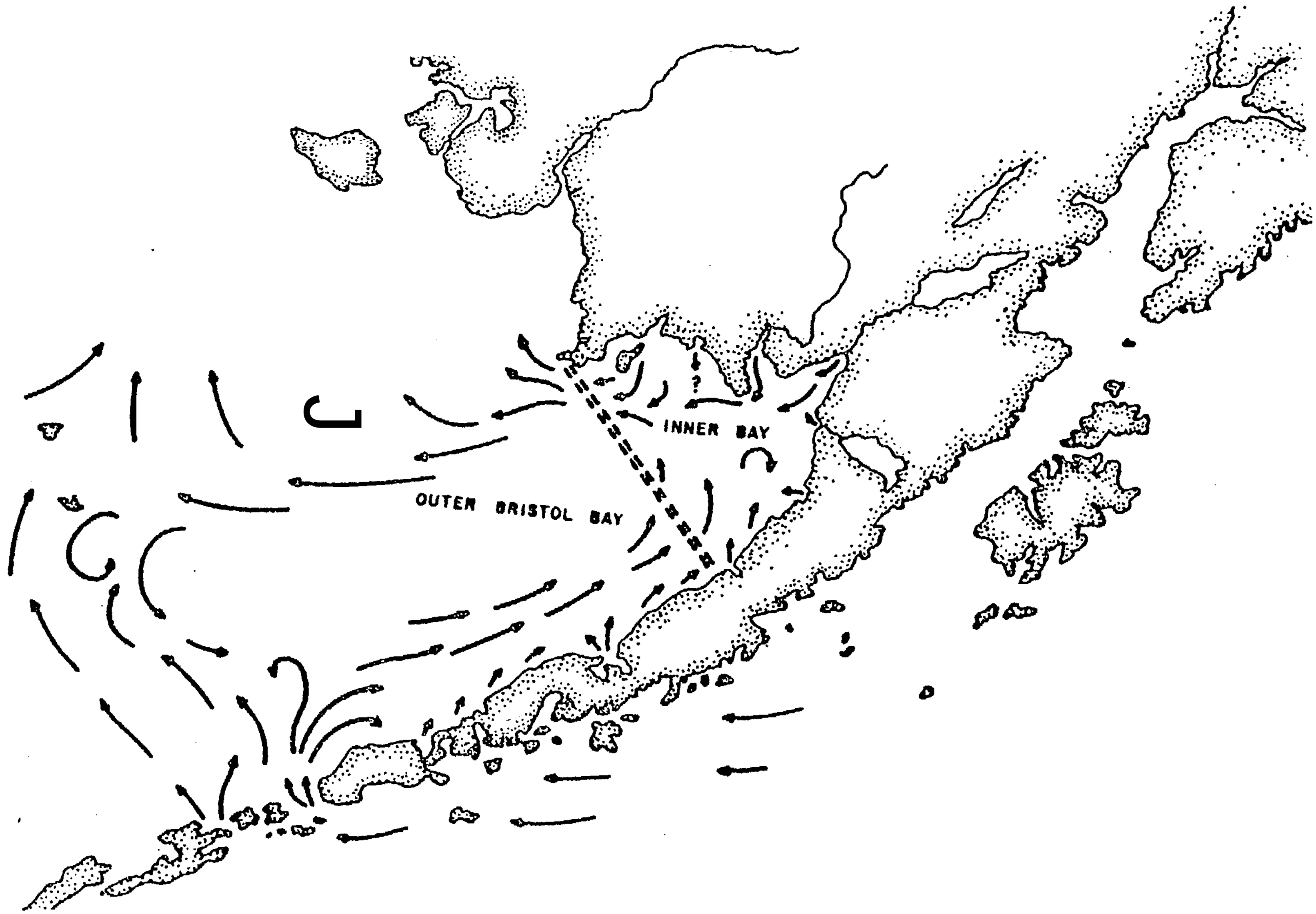


A- SURFACE CURRENTS; B- CURRENTS AT A DEPTH OF 1000 m DETERMINED BY THE DYNAMIC METHOD (ARSEN'EV,1963). NOTE CYCLONIC GYRAL SYSTEMS ' WITHIN THE DEEPWATER BASINS.

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

tidal currents in the open Bering Sea are also rotary, exhibiting velocities of between 0.3 - 1.2 knots.

Owing to the predominant windy nature of this region, wind-driven currents will also be a major factor in the complex circulation patterns. Although the prevailing wind directions in summer are from the west and southwest and in winter are from the northeast, winds are quite variable all year. Because the mean wind speed is between 10 - 15 knots during the summer and between 15 - 20 knots during the winter, it is not unreasonable to postulate the existence of wind-driven currents, from various directions, of up to 0.5 knots.

Thus, with a reinforcing combination of the primary circulation, the tidal currents, and wind-driven currents, it is possible to have currents within the lease sale area of between 2 - 3 knots.

The tidal range, itself, generally is not a major factor in the open sea as it is in some bays and inlets. It has been reported (Lisitsyn, 1969) that the level of the open water in the Bering Sea may fluctuate tidally between 1.0 - 1.5 meters (3.2 - 4.9 feet). According to Arctic Environmental Information and Data Center (1974), the tidal bulge enters from the Pacific with an amplitude of about 2 meters (6.6 feet) over much of the shelf.

3.2.1.4 Waves

The three primary factors affecting the generation of waves on the ocean are the wind velocity, the duration of wind velocity, and the fetch, or distance, over which the wind blows. The location of the St. George Basin lease sale area exposes it to long deepwater fetches to the west and northwest and also to the north during the ice-free summer months.

The Alaska mainland and relatively shallower depths to the east will, in light of the prevailing wind systems, tend to preclude extremely large waves from this direction.

The Aleutians to the south have two possible effects. The first is to dissipate energy from long-period swells traveling north from the Pacific by shoaling, refraction, and diffraction. The second is to act as a boundary in the generation of waves by south and southeast winds that predominate during the summer months. The majority of the waves during the summer are characterized by heights less than 2 meters (6.6 feet) and periods less than 6 seconds (Brewer et al., 1977).

In September, the prevailing wind patterns begin to shift until, in the winter months (December - March) the predominant wind and wave direction is from the northeast. As the prevailing northeasterly winds tend to drive the pack ice south toward the lease area, the presence of a large concentration of sea ice will tend to dampen the generation of waves. The fetch is reduced by large concentrations of ice that inhibit wave growth. Consequently, in years when the pack ice reaches far south, wave development within the sale area will be minimized. This inhibited wave growth would occur during the months of February and March, when the ice reaches its maximum extent.

If, on the other hand, the pack ice does not migrate this far south, the possibility of well-developed wave growth is enhanced. A reasonable assumption, based on the persistence of winter winds in excess of 30 knots (Brewer et al., 1977), is that at least 20 percent of the significant wave heights will exceed 2.5 meters (8 feet). With reduced ice coverage, this value may increase to 40 or 50 percent.

Although operations are affected by the daily wave climate, design conditions are based upon estimated worst-case conditions. The following table presents design conditions calculated for the area around St. George Basin.

Return Period - Yrs	Significant Wave Height - m (ft)
5	13.5 (44.3)
10	15.0 (49.2)
25	17.5 (57.4)
50	20.0 (65.6)
100	22.5 (73.8)

Source: Brewer et al., 1977

3.2.1.5 Sea Ice Hazards

Information on sea ice characteristics for the St. George Basin area can be found in Potocsky (1975). Ice grows to a thickness of about 60 centimeters (24 inches) in this region. It is to be expected that on'ly first-year ice will be encountered. There are no records of multiyear ice features or glacier ice fragments being encountered in the study area.

Data on ice coverage suggest that the mean position for the southern edge of the ice pack at its maximum advance lies north of the study area; thus, the entire area may be completely ice-free in some years. For example, during seven consecutive years of ice observations at St. Paul Island, no ice was reported in three of those years. Navigation was never suspended nor required the assistance of an ice breaker in any of those seven years (U.S. Coast Pilot, 1979). In bad ice years, the pack edge can be expected to advance into the study area from the north from about mid-January to its point of maximum advance in late April. Break-up and retreat follows quite rapidly. The data suggests that the maximum edge of the ice pack approximately bisects the lease sale area; thus, the southern part will presumably be ice free. However, the definition of the pack edge is at best approximate and ice may be encountered over the entire study area.

Ice concentration data shows typical concentrations between 3 - 7 oktas, with a better than 20 percent chance of large floes. Therefore, there is a chance that any structure placed in this area will encounter floating sea ice. Available data are insufficient to evaluate the probability of encounter at any specific location.

Some rafting and minor ridging will occur, but there is no reason to anticipate major pressure ridge features in this area.

There are no published data on typical ice velocities. Maximum velocities are likely to be governed by wind drag since currents in the area are generally small. It is not unreasonable to expect ice velocities of several knots under severe storm conditions.

Ice strength is a complex function of salinity, crystal type and orientation, strain rate, and direction of loading. There are no published data on the engineering properties of the sea ice in the Bering Sea, but in terms of structural loading due to sea ice, we expect that conditions will not be too different from those in Cook Inlet.

It is anticipated that tower structures with cylindrical legs above the waterline will experience ice loads of approximately 90 kips/foot[(1)] of leg diameter. In some cases it will be possible to reduce the total ice load by incorporating cone shaped structural elements near the waterline so as to fail the ice in flexure. Both the failure and ride-up components of force as outlined by Ralston (1977) should also be considered. Prudent design will require adequate spacing of the structural legs to minimize blockage problems, and enclosed housings for conductors and marine risers.

The technology for developing the type of structure required in this environment has been thoroughly tested in Cook Inlet. We see no reason to doubt the possibility of developing viable structures for this area.

3.2.1.6 Air-Water Temperature Differences

Air-water temperature differences can result in superstructure icing in winter and fog in the summer. Superstructure icing results from the combination of high winds, cold temperatures and sea spray, conditions often found throughout the area. If moderate icing (2.5 - 12.7 centimeters [1 - 5 inches] in 24 hours) conditions are defined as those in which winds in excess of 10 knots accompany air temperatures below 0°C, icing should occur during at least 30 percent of the winter; possibly as much as 50 - 60 percent in February and March. Winds in excess of 20 knots accompanied by temperatures of less than -8°C occur 5 - 10 percent of the time in January and February. These conditions may result in severe icing, greater than 13 centimeters (5 inches) in 24 hours.

---

(1) Derived by assuming a 300-psi indentation pressure on the nominal 24-inch thick single ice sheet or a 150 psi average pressure for the case of rafted ice involving two thicknesses.

The summer counterpart of superstructure icing is fog. Although fog is not a major design consideration, it may well be an important operational and safety consideration. From May - September, fog occurs 20 - 30 percent of the time, making it a major hazard to navigation. The U.S. Coast Pilot advises that navigators in the summer be prepared to approach the Pribilof Islands without the aid of visible land sightings.

3.2.1.7 Tsunamis

High seismicity characterizes the regions to the south and east of the lease area and results in displacements of the sea floor and tsunami generation. Displacement is discussed in Section 3.2.2.3. For the most part, tsunamis do not pose a great threat to offshore activities; however, they can be of serious concern to shore facilities. It is difficult to assess the magnitude and impact of a tsunami without a detailed site-specific evaluation since their development apparently depends on water depth, the amount of associated sea floor displacement, and the general configuration of the sea bottom and shoreline.

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

Although the design parameters for Cook Inlet and Norton Sound are similar, the St. George Basin is rather unique. Both Cook Inlet and Norton Sound are shallower than the St. George area, which has an average depth range of 125 - 130 meters (410 - 426 feet).

Cook Inlet exhibits a large tidal fluctuation and associated tidal currents in excess of 8 knots. Tidal effects may be equally important in St. George Basin as in Norton Sound but, as a design or operational constraint, tides are certainly less important at either area when compared to Cook Inlet.

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

3.2.2 Geology and Geologic Hazards

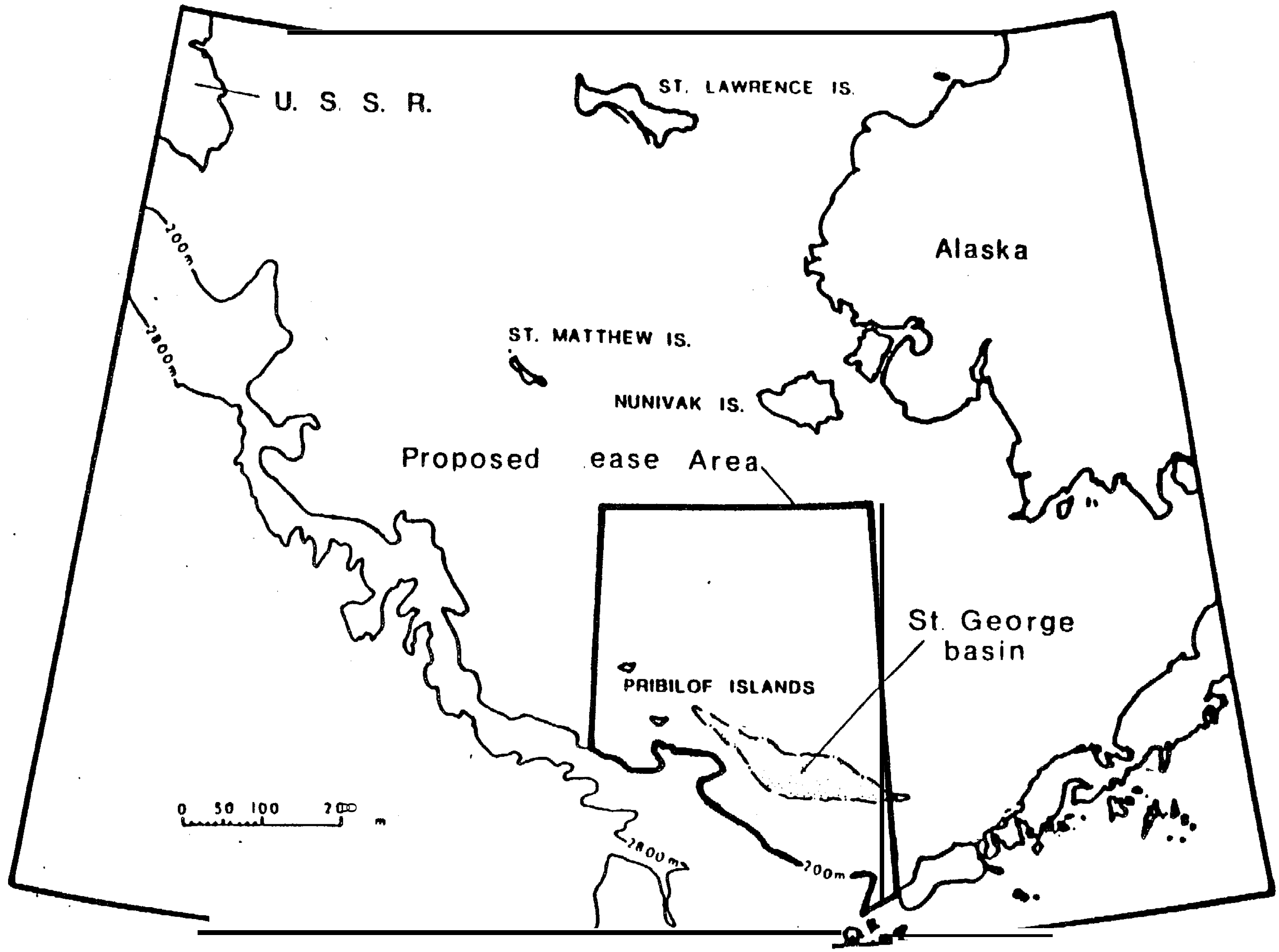
3.2.2.1 Major Data Sources and Reference Materials

A voluminous body of existing knowledge is available that describes in varying detail the structural, tectonic, and environmental geology of the Bering Sea Shelf. Although the southern part of the shelf has received less attention than other areas, it has been the subject of a series of papers prepared by the U.S. Geological Survey that have reviewed and condensed nonproprietary data. Marlow et al. (1976) described the regional geologic setting, geologic history, petroleum geology, environmental hazards, and oil and gas potential of the southern Bering Sea Shelf. The classification and distribution of fault structures, as defined 'by acoustic subbottom profiles, were described for the St. George Basin area by Vallier and Gardner (1977). Sedimentary and chemical properties of surficial sediments, and further description of faulting were discussed by Gardner et al. (1977). Most recently, Marlow et al. (1979) reviewed the geology of the St. George Basin and appraised the resource potential in view of the petroleum geology, geologic hazards, and available technology.

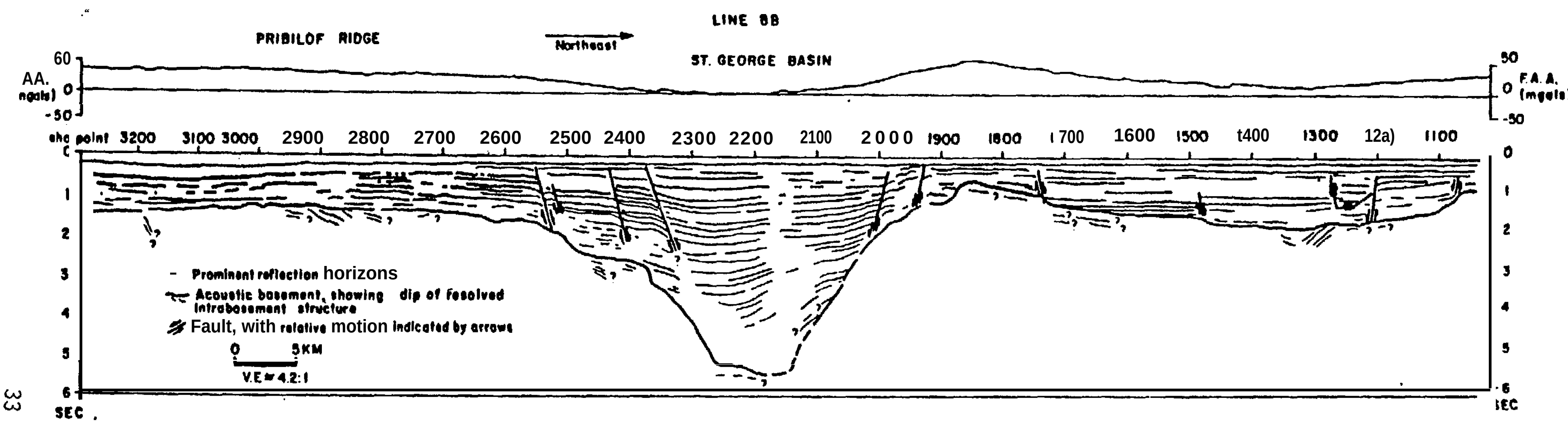
3.2.2.2 Geologic Setting

The St. George Basin is a structural depression lying near the southern margin of the Bering Sea continental shelf (Figure 3-3); there is no bathymetric expression of the basin on the seafloor. The basin trends west-northwest by east-southeast (parallel to the present continental margin), and has longitudinal and cross-sectional dimensions of approximately 300 by 50 kilometers (186 miles by 31 miles).

An interpretive cross section through the central part of the St. George Basin is shown on Figure 3-4. The subbottom geology has been distinguished



LOCATION OF PROPOSED LEASE AREA & OUTLINE OF ST. GEORGE BASIN



INTERPRETIVE DRAWING OF A SEISMIC-REFLECTION PROFILE OF ST. GEORGE BASIN

NOTE: THE VERTICAL EXAGGERATION APPLIES ONLY TO THE WATER LAYER (ASSUMED VELOCITY OF SOUND IN SEA WATER OF 1.5 KM/SEC) AND WILL DECREASE WITH DEPTH IN THE SECTION.

SOURCE: MARLOW ET AL., 1977

FIGURE 3-4

by two major units defined by their characteristic acoustic signature: a lower acoustic basement, which probably represents folded Mesozoic strata unconformably overlain by a sequence of bedded, presumably semi-consolidated, Cenozoic strata (the "main layered sequence").

The St. George Basin is bounded on the north by the Nunivak Arch, a broad basement high, and on the south by narrow basement highs that separate the sediment-filled St. George Basin from the deep-water Aleutian (bathymetric) Basin. The graben that forms the basin is delineated by major boundary faults that Vallier and Gardner (1977) describe as having normal displacement. They occur in groups, exhibit growth features with depth, and are seen at various locations to offset the acoustic basement, the entire sedimentary section, and (less commonly) the seafloor. Other major and minor faults occur throughout the St. George Basin region, and appear to be most common within the central parts of the basin.

The southern Bering Sea Shelf in general, and the St. George Basin in particular, are considered to be tectonically active and still in the formative process (Gardner et al., 1979). The area lies within 500 kilometers (310 miles) of the Aleutian Trench, the present site of subduction of the Pacific plate under the North American plate, and several earthquake epicenters have been recorded beneath the southern Bering Sea Shelf. The St. George Basin and adjacent areas have been subjected to earthquakes with magnitudes as high as 5.7 (Gardner et al., 1979), but the correlation of specific events and structures is unknown. Recurrence rates of earthquakes for the area bounded by latitudes 50° and 60° N and longitudes 160° - 170° W have been as high as 6.4 earthquakes per year from 1963 - 1974 for magnitudes of 4.0 - 8.4, and 0.013 earthquakes per year of magnitudes 8.5 - 8.9 from 1899 - 1974 (Meyers et al., 1976).

The St. George Basin and surrounding areas lie adjacent to the volcanically active Aleutian Arc; the Pribilof Islands, located on the northwestern edge of the basin may also be active.

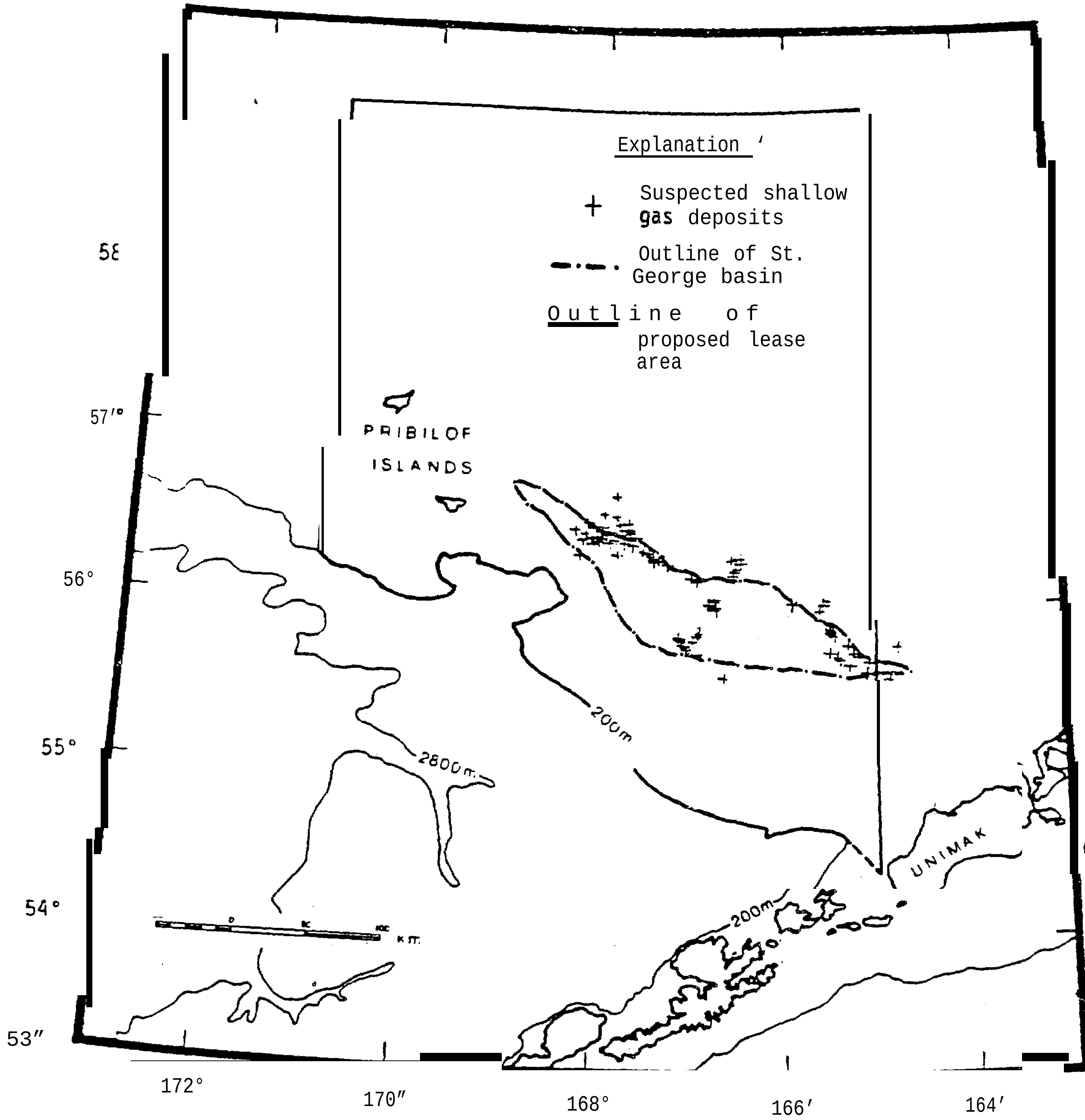
3.2.2.3 Geologic Hazards

The principal geologic hazards to petroleum development of the St. George Basin will be related to seabed morphology and sediment character, faulting and seismic activity, and volcanism.

The seafloor in the high-interest areas of OCS Lease Sale No. 70 exhibits a slope of much less than one degree, and the potential for slumping is consequently negligible. Areas lying below the shelf break at 170 meters (557 feet) are susceptible to slumping and sediment instability, but all lie outside the high-interest tracts. Of greater potential significance are zones of suspected shallow gas deposits (Figure 3-5) that have been reported by Mat"low et al. (1979) and Gardner et al. (1979). These zones have been identified either through sediment geochemical study or by interpretation of acoustic subbottom reflection profiles, and may extend from the near surface down to depths of 200 - 300 meters (656 - 984 feet). Gas seeps are not reported in the areas of suspected gas-charged sediments, and Marlow et al. (1979) suggest that these zones do not necessarily constitute geologic hazards. Nonetheless, sufficient indications exist of gaseous zones, either at the surface or at depth, and their possible presence must be considered in platform and pipeline design.

The engineering properties of the seafloor sediments are not well known beyond simple grain size and sorting characteristics. Inasmuch as Gardner et al. (1979) believe that the sediments in the St. George Basin are relic and do not reflect present-day deposition, it appears unlikely that thick accumulations of underconsol idated sediment will be found to present hazards to platform emplacement.

The tracts with the highest industry interest lie between the 100 - 150 meter (320 - 492 foot) isobaths and are within the depth range that may be influenced by surface waves (Gardner et al., 1979). Although no evidence of mobile bed-forms has been reported, the possibility of sediment scour or burial during severe sea states should be evaluated during the design of structures to be set on the seafloor.



DISTRIBUTION OF ACOUSTIC ANOMALIES
("BRIGHT SPOTS" OR "WIPE-OUT ZONES")
IN SEISMIC REFLECTION DATA

FIGURE 3-5

From a geological standpoint, fault rupture and fault-related ground acceleration may present the limiting design criteria for development and production of the St. George Basin. The area is tectonically active, as shown by both epicenter locations and the existence of numerous faults within the margins of the basin; many of the latter are deep structures that can be traced into shallow sediments or to the seafloor.

The exposure to seismic hazards could vary significantly within the area because of the existence of Quaternary faulting in the region, and the possibility of major earthquake activity increasing toward the southern margin of the area near the Aleutian Islands. Given that neither the available data nor the scope of this investigation allows quantification of possible significant differences, a regional seismic risk should be adopted for preliminary design calculations. The most suitable approach to such a regional seismic design is to apply the American Petroleum Institute (API) guidelines for Zone 3 (API RP 2A, Tenth edition). The response spectrum method should be used, and for conservatism it should be assumed that the seafloor soil conditions are similar to API soil Type C (designated as deep, strong alluvium).

The geologic hazards presented by volcanic activity will derive from area-wide ash falls, from local magma flows, and from ground motion induced by base surges from caldera eruptions. All three factors probably will be inconsequential in the St. George Basin, per se, but may be locally important to coastal facilities and should be evaluated in the siting of shore-based processing and transshipment facilities.

3.2.3 Biology

The living marine resources of the eastern Bering Sea, in particular the St. George Basin, are some of the most extensive and economically important in the world. Currents bring nutrient-rich waters from the Pacific Ocean via the Aleutian passes up along the continental slope resulting in unusually high levels of bioproductivity (National Marine Fisheries Service, 1979).

These very high levels of primary production provide the nutritional basis for the vast numbers of fish, shellfish, and top-level trophic consumers such as birds and mammals in the St. George Basin.

In economic terms, this productivity results in one of the world's largest fisheries, second only to the North Sea in terms of harvest yields of demersal fish per unit area, and totals about 1.5 million metric tons of groundfish per year. The major species in this fishery are pol lock, five species of flounder, true cod, sablefish, and ocean perch with pollock being the most important species. The St. George Basin also has very large stocks of such commercially important species as king crab, tanner crab, and shrimp.

This region is also of major importance for migrating populations of most of the Bering Sea's herring population (approximately 250,000 metric tons) and the millions of Bristol Bay salmon enroute between the Pacific Ocean and the spawning ground (National Marine Fisheries Service, 1979).

Impacts to these major species from petroleum development would likely depend on the chronology of spawning activity, method of egg and larval distribution, nursery sites and migration (Table 3-2).

The marine mammal resources of the eastern Bering Sea are some of the most unique and extensive in the world. A total of 25 species can be expected to be present during some time of the year (Fay, 1974). The occurrence and abundance of these species are quite seasonal from winter residents (e.g., "ice" seals and bowhead whales), summer residents (e.g., fur seals, sperm whales, grey whales) to year-round residents (e.g., beluga whales). During the summer months the Bering Sea contains more marine mammals per unit area than any other ocean area (Laevasta and Favorite, 1980).

The Pribilof Islands are used by 1.4 million of the 1.9 million world population of northern fur seals for breeding and rearing young. These fur seals are capable of traversing the St. George Basin area on a single feeding foray from the Pribilofs (National Marine Fisheries Service, 1979). Total residence in the region may exceed six months.

TABLE 3-2

CHRONOLOGY OF EVENTS FOR IMPORTANT FISH SPECIES IN THE BERING SEA

	January	February	March	April	May	June	July	August	September	October	Nov. - Dec.
Pollock	100m over the basin	begin spawning in surface waters	aggregation increases, spawning continues 100m seaward	spawning continues	spawning; peaked concentrations move north; eggs & larvae drift NW	spawning complete; move to 60-70m; larvae-at shelf edge	seaward of 50m	same	same	move south	100m by end of Dec.
Halibut	spawning 300-500m	eggs disposed			move to midshelf up to cold zone	move inshore	move northward	same	same	move south	seaward of 200m by end of Dec.
Herring	100-200m	same		migrate shoreward	spawn along coast	spawning complete, disperse along coast	dispersed	move seaward	same	move towards wintering areas	on winter grounds in Nov.
Yellowfin sole	100-200m	same		easterly shoreward migration	move east	move north along peninsula	spawning around Nunivak I.	dispersed	same	returning to winter grounds	on winter grounds in Nov.
Salmon	-	· -		-~	juvenile salmon at coast, adults at outer shelf	throughtout shelf; sockeye appearing in Bristol Bay	ubiquitous Smelts over shelf	adults reach spawning; smelts and juvenile undefined			

NOTE: Depths in meters are bathymetric locations on continental shelf

Seventeen cetaceans are known to occur in the St. George Basin including eight endangered species (e.g., blue, grey, humpback, fin, sei, right, " bowhead, and sperm whales). The most commonly sighted species are the dall porpoise and mimke whale, which are ubiquitous to the region (National Marine Fisheries Service, 1979). The grey whales, numbering over 10,000 and migrating from as far south as Mexico, arrive in the summer to feed throughout this region and remain up to 8 months (Braham et al., 1977).

The pelagic waters of the St. George Basin are one of the three most important foraging areas for seabirds in Alaska waters (Bartonek et al., 1977). Approximately 40 species of seabirds use this region, and numbers may exceed 27 million (Fay, 1974). Estimates for the entire Bering Sea range up to 40 million in the summer months, thus exceeding those in the rest of the northern hemisphere (Laevaster and Favorite, 1980). These include both resident breeding birds from local colonies (i.e., murres, auklets, and kittiwakes) and migrant species from the southern hemisphere (i.e., sooty and short-tailed shearwaters). Shearwaters are the most numerous birds in the summer followed by murres (Myres and Guzman, 1977).

The major bird colonies are located on St. Paul and St. George Islands, with St. George being considered the largest seabird colony in the northern hemisphere (approximately 2.5 mil lion birds) (Hickey, 1976). The highest concentration of these nesting seabirds occurs within 3 kilometers (2 miles) of the colonies, and most birds forage within 48 - 56 kilometers (30 - 40 miles) of the colonies (Hunt, 1977).

The continental shelf and shelf break are the most important waters for birds in the summer months. During the winter, because of a complex set of variables, bird distribution is hard to characterize, but the "ice front" to 8 oktas of ice cover is the most important habitat (Divoky, 1978).

Potential conflicts or constraints that these renewable resources will create with respect to the development of the oil and gas resources of the St. George Basin can be divided into two principal categories: (1) localized physical effects in the vicinity of drilling rigs and undersea pipelines, and (2) oil spills during the operational phase affecting both local and remote systems of the Bering Sea.

The first category will likely involve the disturbance of the immediate bottom areas around each rig referred to as the "spoil cone." The areas immediately around pipelines will be disturbed during burial but would quickly be recolonized. The disturbances would not be expected to create major environmental problems.

Oil spills from blowouts, pipeline ruptures, or tanker accidents would be the major concerns. This second category is the most critical consideration and could have catastrophic consequences to the rich ecosystem of the St. George Basin.

3.3 Field Development Components

3.3.1 Exploration Platforms

Exploratory drilling in the St. George Basin is within the operational capabilities of semi-submersibles, drillships, and jackup rigs (in the shallower portions). The principal technical problem will probably be the need to develop year-round capability in areas where incursions of sea ice are a possibility between January and April. Following the example of Dome Petroleum in the Canadian Beaufort Sea, where ice-reinforced drillships supported by icebreakers drill well into the fall, similar equipment and techniques could make winter drilling feasible in areas of significantly less severe ice conditions as well. 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 rigs and 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 have to compete with the requirements of a rapidly expanding fishing industry.

Another factor that will influence the pace and cost of exploration operations in St. George Basin 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 related to the U.S. OCS lease sales scheduled for the early 1980s will determine this equipment availability.

3.3.2 Production Platforms

3.3.2.1 Background

Depending upon reservoir characteristics, environmental conditions (water depths, etc.) and economics, offshore platforms may serve as integrated drilling and production units, or as single function facilities (drilling, processing, pump station, compressor station, crew accommodation). In the latter case, several platforms would be required to produce a field. In deep water, economic constraints favor oil field development with as few platforms as possible and by integrated drilling/production units; this has been the trend in the North Sea. Piled steel jacket structures have dominated since offshore oil and gas production commenced in the Gulf of Mexico in the late 1940s. Concrete gravity platforms for oil and gas production have been developed mainly for the North Sea and were pioneered by the Ekofisk oil storage tank that was installed in the Norwegian sector of the North Sea in 1973.

Alternatives to the steel jacket and concrete gravity structures are a number of "hybrid" designs combining facets of the steel jacket, concrete gravity and floating (semi-submersible) platforms. These include the guyed tower, articulated platform, tension leg platform, and steel gravity platform developed in response to the increasing costs of “conventional” platforms with increasing water depths and, concomitantly, the need to develop marginal fields. These designs minimize the amount of offshore construction work, are comparatively inexpensive, and may speed field development resulting in earlier production and cash flow to the operator.

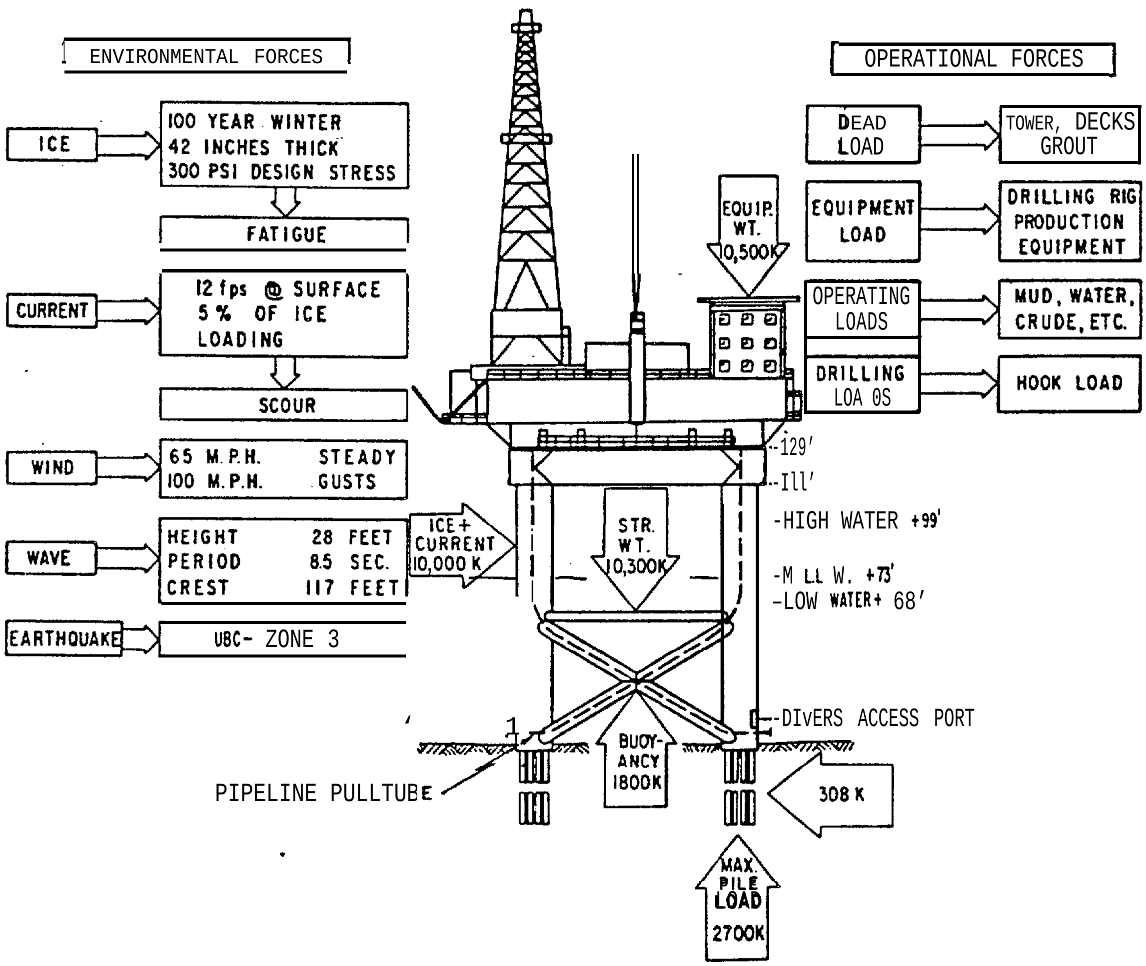
In sub-arctic areas with seasonal ice, platform technology was pioneered in upper Cook Inlet in the early and mid-1960s where a total of 14 production platforms have been installed. Of these, most are four-legged structures, two have three legs, and Union installed a single-legged monopod platform (Visser, 1969). The environmental forces for which these platforms have been designed include a lateral load of 10,000 kips and vertical load of 10,500 kips (Figure 3-6). In the final design, wind, wave, and earthquake forces were neglected because they were found to be small compared to ice forces. Tidal variations in upper Cook Inlet are in excess of 9 meters (30 feet) and result in, currents in excess of 8 knqts.

To accommodate these environmental forces, Cook Inlet platforms incorporate these design principles:

- Columnar legs without cross-bracing in the tidal zone, reinforced with concrete inside;
- Risers located within the legs; and
- Special “pull tubes” within the platform structure to reduce dependence on diver assistance in pipeline hook-ups.

3.3.2.2 Platforms for St. George Basin

The experiences in the stormy North Sea and upper Cook Inlet provide engineering” lessons with some application to the St. George Basin. However, there are certain unique combinations of environmental conditions that will involve state-of-the-art design. The principal design criteria for platform design in this area are (not necessarily in order of importance):



DESIGN LOADS ON TOWER-TYPE STRUCTURE, COOK INLET

SOURCE: VI SSER, 1969

FIGURE 3-6

1. Ice loading

2. Seismic loading (more sensitive for gravity designs)

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

4. Installation and fabrication capabilities

5. Conductor well spacing

6. Directional drilling

7. Superstructure icing

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

9. Topside facilities

Of the above, our engineers believe that Items 1 through 6, 8 and 9 are individually state-of-the-art design criteria. However, when certain items are taken in combination, they are not. For example, designing for Zone 3 seismicity is state-of-the-art, whereas designing for seismicity plus ice loading is not. Item number 7, superstructure icing, does not appear to represent state-of-the-art design.

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

Based on very tentative estimates of expected ice forces in St. George Basin (which are based on very limited data), a comparison to Cook Inlet platforms can be made. With respect to ice forces, it is likely that conditions in the St. George Basin will not be too different from Cook Inlet in terms of ice thickness, crystal structure, and limited rafting and ridging, although the ice may be weaker in the St. George Basin area. The greatest difference between the two areas is in water depth. Whereas most Cook Inlet platforms have been installed in fairly shallow water, our proposed -St. George Basin sites range in water depths from approximately 107 - 150 meters (350 - 490 feet). We therefore visualize the following types of production platforms as being feasible for these specific sites:

- Steel Jacketed Platform(1)
  This would be a hybrid "Cook Inlet" structure that would have minimal bracing through the water line area. It probably would be supported by external or skirt piles and have four legs. All conductor wells would be inside these legs.

- Concrete or Steel Gravity Platform(1)
  This structure would probably be a North Sea gravity structure. It may have a single "leg" (monopod) or several legs. Preliminary bottom conditions indicate such a structure would be feasible. Again, all conductors would be internal in the leg(s).

3.3.2.3 Well Slot Limitations

One of the technical constraints of a platform design with conductors located within legs is a limitation on the number of well slots that can be housed on a production platform. In a conventional (e.g., Gulf of Mexico) platform, there are few constraints as to the number of well slots that can be incorporated into the design since the conductors are open and pass through conductor guides at horizontal bays in the jacket. However, in an area affected by sea ice, such as the St. George Basin, open-well conductors cannot be considered. In the Cook Inlet designs, the larger the diameter the legs can be made, the greater the number of conductors that can be accommodated. However, as the diameter inc 'eases, so do the ice forces;

---

(1) For a detailed description of steel jacket and North Sea concrete gravity platforms, their 'design parameters, fabr cation and installation, the reader is referred to Dames & Moore (1979a, p. 47-64).

therefore, additional internal stiffening will be required, which will reduce the number of conductors inside the legs. The same analogy is true for the monopod structure. At this time we feel the largest legs that could be considered on a Cook Inlet structure would be on the order of magnitude of 4.0 - 5.2 meters (13 - 17 feet) outside diameter (0. D.). The largest diameter monopod shaft would be on the order of 10 - 18 meters (32 - 60 feet).

In both cases, the optimum number of well slots would be on the order of 32 - 48, depending on the size of the conductors and design criteria.

Based on state-of-the-art design criteria, the maximum number of well conductors that can be reasonably-considered in a closed conductor platform design is 48. Anything over 48 could become a considerable design problem.

3.3.2.4 Transportation and Installation Techniques

The transportation and installation techniques that would be employed for the platforms described above are:

- Steel Platform
  We visualize that this platform would be floated horizontally on its own legs to the site, and upended in place by controlled flooding of the legs. Alternatively, it could be barge-mounted and launched. However, pending a detailed design, it is difficult to predict the exact installation technique.

- Gravity Platform
  The gravity structure would have to be constructed in a deepwater "graving dock" that is dry during construction and flooded to float out the structure after it is built. A construction site large enough for an oil platform does not now exist, either in Alaska or the U.S. west coast, and therefore the selection and construction of the site must be considered in the economics and scheduling of such a platform installation.

After flooding, the platform base would be floated out of the graving dock, towed vertically at a deep draft to the site, and ballasted down on the bottom.

The decks for both the steel and gravity platforms would be modularized and lifted into place with a crane ship similar to the platform deck construction in the North Sea.

Two support bases for such a platform installation would probably be required. The first could be Anchorage, which could serve as a "home base" for derrick barge/construction crews, although the workers may be rotated from residences elsewhere. We would assume the onshore facility point would serve as a supply base for construction materials offshore. The supply base would be set up prior to the platform installation and all supplies stockpiled (i.e., pipeline material, etc.).

Platform installation would require at least one large derrick vessel and one smaller crane vessel. If the platform is piled in place, one vessel is required to operate the pile installation equipment. Several deck cargo barges, work boats and tugs will be required. The following are representative equipment requirements and typical daily rates for an equipment spread required to install a steel platform:

Item	Number	Daily Rate
Large Crane Ship	1	$160,000
Smaller Derrick Barge	1	80>000
Deck Cargo Barge	12	3,500 each
Work Boats	6	6,000 each
Tugs	4	7,000 each

Actual costs will depend on the size of vessel required, where it originates, market demand, and various other factors. The rates do not include mobilization or demobilization.

3.3.3 Wells

Most production wells will be drilled directionally from the production platforms. As noted in Section 3.3.2.3, the platform designs suggested for St. George Basin place constraints on the maximum number of wells that can be housed on the platforms (about 48). Furthermore, slant drilling is not possible from these platforms. In contrast, the' current record for well slots in conventional steel jacket designs is over 90.

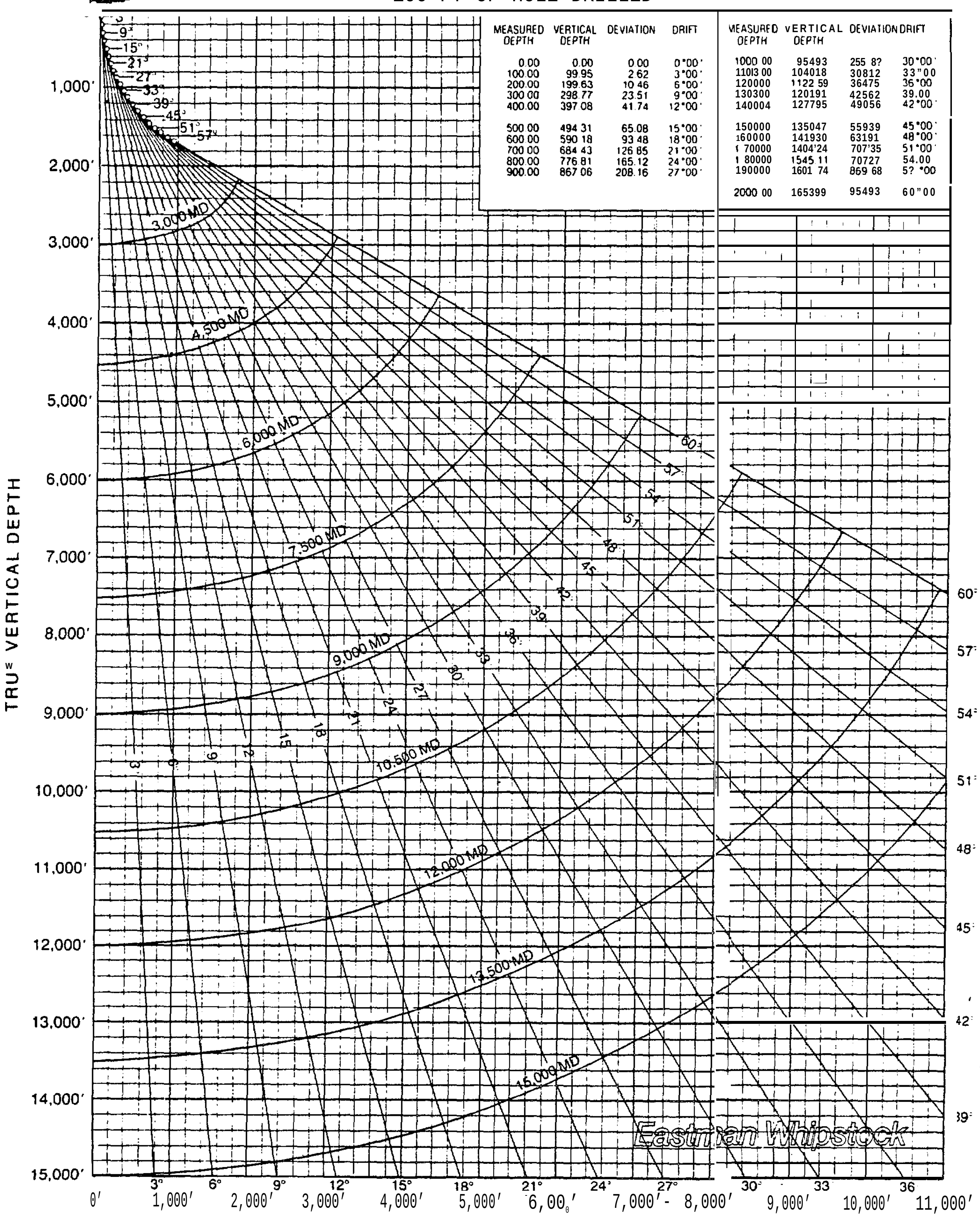
There are also technical limitations on directional drilling as well as cost premiums for angles of over 50°. A graph showing a typical rate of increase in drift for the generally adopted maximum slant angle of 60° is shown on Figure 3-7. Depending on seabottom soil conditions, a typical kick-off point(1) would be about 152 meters (500 feet). On some offshore platforms, however, this buildup could commence above the sea bottom using the height of the platform. However, with conductors located within the legs of the Cook Inlet hybrid structure, this is not possible. Further discussion of directional drilling and its role in the analysis is presented in Appendix A, Section III.

Development well drilling will commence 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. For the platforms specified in Section 3.3.2, development drilling could commence about 10 months after the platform is installed on site. Development wells may be drilled in a "batch" where a group of wells are drilled in sequence to the surface casing depths, then drilled to the 13-3/8 inch setting

---

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

UNIFORM 3°00′ INCREASE IN DRIFT PER
100 FT OF HOLE DRILLED



MEASURED DEPTH	VERTICAL DEPTH	DEVIATION	DRIFT
0.00	0.00	0.00	0°00′
100.00	99.95	2.62	3°00′
200.00	199.63	10 46	6°00′
300 00	298.77	23.51	9°00′
400.00	397.08	41.74	12°00′
500.00	494 31	65.08	15°00′
600.00	590 18	93 48	18°00′
700 00	684 43	126 85	21°00′
800.00	776.81	165.12	24°00′
900.00	867 06	208.16	27°00′

MEASURED DEPTH	VERTICAL DEPTH	DEVIATION	DRIFT
1000 00	95493	255 8?	30°00′
11013 00	104018	30812	33"00
120000	1122 59	36475	36°00
130300	120191	42562	39.00
140004	127795	49056	42°00′
150000	135047	55939	45°00′
160000	141930	63191	48°00′
1 70000	1404'24	707'35	51°00′
1 80000	1545 11	70727	54.00
190000	1601 74	869 68	5? °00
2000 00	165399	95493	60"00

DIRECTIONAL DRILLING CHART

SOURCE: EASTMAN WHIPSTOCK, IN C,

FIGURE 3-7

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.

3.3.4 Pipelines

Long pipelines will be required to transport St. George Basin oil and gas production to shore terminals for further processing and tanker transport to market (Table 3-l). If, for example, it is assumed that all crude would be transported via pipeline to a site on Unalaska Island, the distances from the sale area would generally be over 160 kilometers (100 miles). To reach Unalaska Island (as well as Akutan, Akun and Unimak Islands) directly, a pipeline would have to traverse an indentation of the continental slope with water depths as much as 1,200 meters (3,900 feet). For a large diameter pipeline, however, the present state-of-the-art pipelaying is around 200 meters (650 feet). Therefore, such trunklines would have to detour around this portion of the continental slope and remain in water shallower than 200 meters (650 feet). This would increase the length of pipelines to Aleutian Island terminal sites by as much as 80 kilometers (50 miles), depending upon the location of the field(s) and terminal site (no detours would be required for landfalls on the Alaska Peninsula).

A reasonable development hypothesis for St. George Basin petroleum development (see Section 3.4) would be two large diameter trunklines (one oil, one gas) with feeder lines connecting several platforms or fields. Since pipeline distances of over 160 kilometers (100 miles) can be anticipated, booster pump and compressor stations may be required.

Some of the important engineering design considerations for pipelines in the St. George Basin are:

- Water depth (see discussion above)

- Possible requirement for booster station(s). As an alternative to a booster station, it may be possible to leave the associated gas in the oil which would lower the pour points. This would then require separation onshore and lower throughput.

- Diameter and wall thickness. Given the characteristics of this area, such as water depth, pipeline diameters larger than 40 inches are not recommended. If the throughput required it, a second line might have to be built, which would increase field development costs .

- Water, crude, and gas temperatures. Preliminary information indicates that pipeline insulation would not be necessary. However, if insulation were required, the pipeline cost (and possibly the schedule) would be affected.

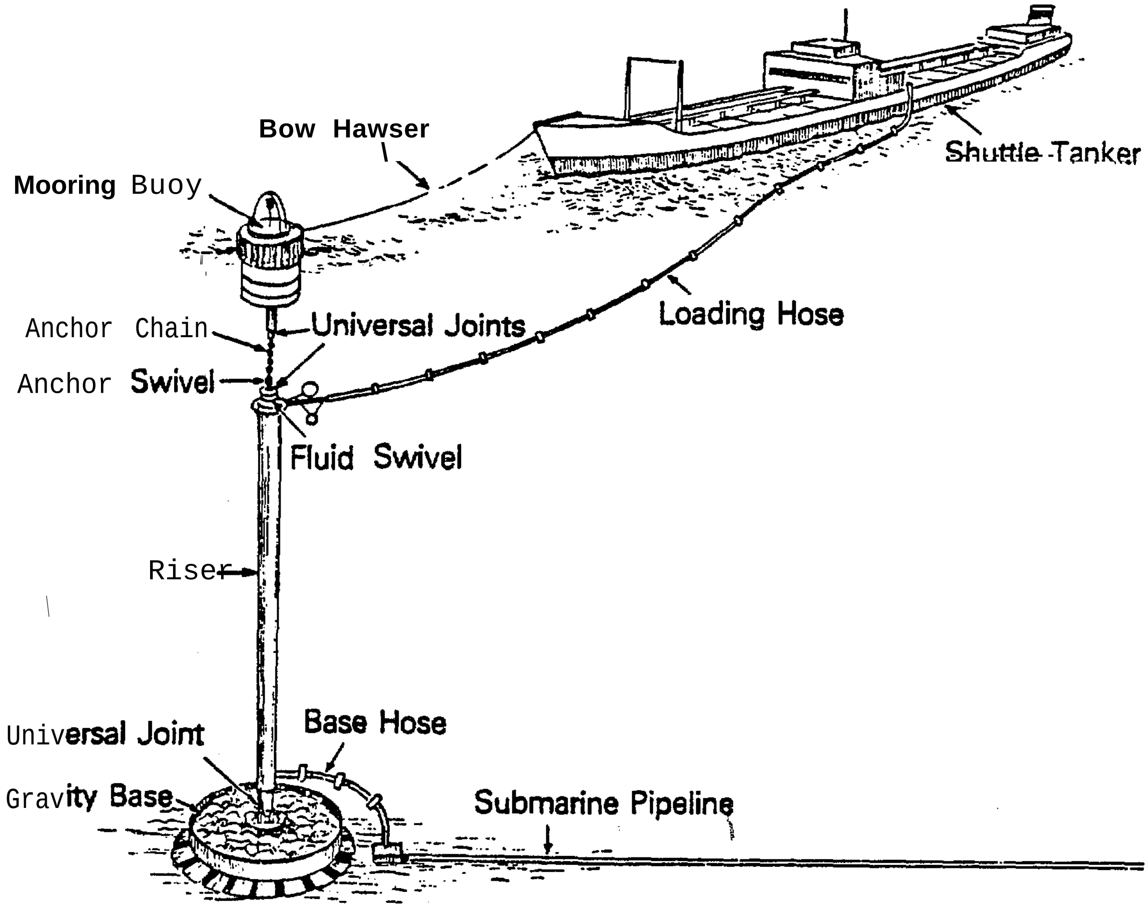
For installing large diameter pipelines, the most suitable vessel would be one of the "third generation" semi-submersible lay barges such as Viking Piper. Such a barge can lay about 1.6 kilometers (1 mile) per day of large diameter line, and about 3.2 kilometers (2 miles) per day of small diameter line. One advantage of the semi-submersible lay barge is that it can operate in waves up to 4.6 meters (15 feet) while a conventional lay barge is restricted to waves of less than 1.5 meters (5 feet). Smaller diameter gathering and spur lines could be laid by reel barges that are now capable of laying pipe up to 24 inches in diameter. Landfall portions of the lines would be pulled to shore. Pipelines at the platforms would be connected using a conventional "J" tube. Burial would be required at landfalls to maintain stability at the beach line. Although regulations have not been established for this area, burial could be required to the 61-meter (200-foot) contour or for the entire length of the line.

Two trunklines, one for oil and a separate line for gas, installed over the distances indicated in Table 3-1, would probably involve two construction spreads and a total elapsed time of about 24 months (i. e., two construction seasons) .

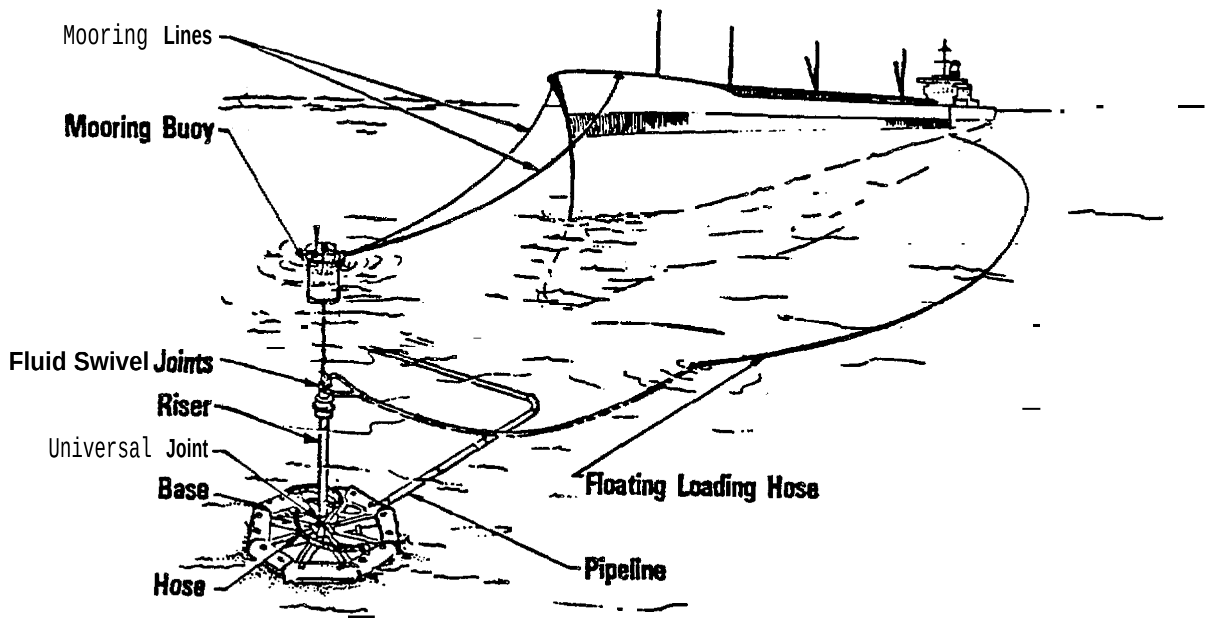
Support of pipelaying operations in St. George Basin will require an adjacent service base with dock and storage area for pipeline materials. At this base, protection and weight coatings would be applied to the pipes. Typical pipe requirements for a lay barge are about 100 - 200 lengths of 12 meters (40 feet) per day with a weight of 1,000-2,000 tons per day. The voyage to the center of St. George Basin from an Aleutian support base (about 240 kilometers or 150 miles) would take just over half a day each way. With a storage capability of 30 tons, about three or four supply vessels would be required to transport pipe to one pipeline spread in the center of St. George Basin. However, specialized pipe supply vessels can handle up to 150 lengths of pipe corresponding to a deck load of as much as 2,500 tons. A major problem in pipe resupply is transfer of pipe from the supply boat to the lay barge. This operation can experience considerable downtime due to bad weather.

3.3.5 Offshore Loading

An alternative to a pipeline is offshore loading of crude directly to tankers tied up at a mooring and oil transfer buoy. A number of single point mooring and oil transfer systems have been developed including the Catenary Anchor-Leg Mooring (CALM), the Single Anchor Leg-Mooring (SALM), Exposed Location Single Buoy Mooring (ELSBM) and Spar buoy (which has storage capability). Two examples of offshore loading systems are shown on Figure 3-8. Offshore loading systems have been used both as early production systems (prior to pipeline hookup) and as permanent parts of the field development strategy. In the latter case, offshore loading may be employed to develop an isolated field that cannot justify investment in a pipeline. The potentially long pipeline distances involved in development of St. George Basin will certainly make pipeline investment a major factor in the economics of field development. Thus, the alternative of offshore loading cannot be immediately discounted. However, there are some general disadvantages with offshore



Single buoy mooring—Esso Standard Libya.



Single anchor leg mooring (SALM)—Malaysia.

EXAMPLES OF SINGLE POINT MOORING OFFSHORE LOADING SYSTEMS

SOURCE: SANTE FE ENGINEERING SERVICES CO,

FIGURE 3-8

loading and there are some problems specific to St. George Basin with respect to the feasibility of such systems.

For offshore tanker loading the vapor pressure of the crude must be limited to 8 - 14 pounds Reid Vapor Pressure (RVP) since tankers can only carry oil with a limited vapor pressure (Penick and Thrasher, 1977). Consequently, condensates have to be removed and reinfected into the reservoir, thus reducing the sales value of the produced fluid. On the other hand, a pipeline can be designed as a high vapor pressure system to accommodate gas liquid components mixed with the crude oil and thereby increase the value realized of produced fluids.

Offshore loading systems operate best in good to moderate environmental areas. The few systems that have been installed to date in moderate to severe environmental areas have had limited success.

Two environmental elements in the St. George Basin would make installation of such a system rather questionable. These are sea ice and excessive fog. Fog occurs in the summer, up to 40 percent of the time, while structural ice is a problem in winter. These factors could limit or shut down operations completely. In order for a system to function in an area affected by ice, design features that are not state-of-the-art would have to be developed. Ice breaking tugs would probably be required during the winter months. The system would have to consider the severe temperatures. A small fleet of shuttle tankers reinforced for ice would be required. Only a few offshore loading systems have been installed in water depths over 100 meters (330 feet), which corresponds to the minimum water depths in the St. George Basin potential lease sale area.

In the St. George Basin, a high production rate will be needed to justify the large cost of development. A large amount of offshore storage will be required in the form of a floating storage vessel, as part of the platform, or as a separate submerged storage tank. In order for the system to be economic, the throughput (e.g., 100,000 barrels per day loaded into shuttle tankers) would have to approximately equal the same throughput of a pipeline. We see this as highly unlikely due to the ice, fog, and various storm conditions.

Although the cost of offshore loading systems appears at first to be much less than the cost of a pipeline, there are additional costs to consider. These costs include extra storage, charters of a small fleet of shuttle tankers, work boats, and possibly ice breakers, hiring of crews, and the construction and maintenance of shore facilities. In Alaska, offshore loading does not necessarily obviate the costs of a shore terminal. This is because shuttle tankers would offload their cargoes at an Aleutian trans-shipment facility where the crude would be transferred to large tankers destined for the Lower 48.

In summary, although the application of offshore loading cannot be completely ruled out, we find it unlikely that its use could be justified as a permanent system. Table 3-3 summarizes the major considerations in selection of pipelines and offshore loading systems.

3.3.6 Subsea Completions

Subsea technology has evolved in response to the increasing water depths and cost of fixed platform production systems. Theoretically, a subsea production system can either be an adjunct in a field development strategy involving fixed platforms or a complete production system. As a complete system, most surface equipment functions (oil/gas separation, storage, etc.) are conducted on the sea floor and production is conveyed directly to shore or to a floating terminal for offshore loading to tankers.

The principal design problems in subsea production systems are maintenance and operation. In the design of subsea wells two principal concepts have been employed -- "wet" Christmas trees and "dry" Christmas trees. The wet Christmas tree exposes all the components and requires divers for installation and maintenance. Typically the wet Christmas tree is completely assembled and tested before installation on the sea floor from a drilling

TABLE 3-3

CRUDE OIL TRANSPORTATION SYSTEM COMPONENTS
OFFSHORE PLATFORM TO REFINERY

	Pipeline System	Offshore Loading
Capital Expenses	Seabed Pipeline Onshore Receiving Storage Tanker Loading Facilities	Tanker Loading Installation Including Short Seabed Pipeline
		(Refinery Receiving Facilities)
Operating Expenses	Pipeline Operations Pipeline Maintenance Terminal Operations Terminal Maintenance Tanker Operations	Tanker Loading Installation Operations and Maintenance
	Cost per barrel decreases with higher volume, increases with greater pipe length.	Cost per barrel similar for all locations, increases slightly with water depth.

Source: Allcock, 1978.

rig. The dry Christmas tree is totally enclosed in a chamber and can be serviced by men working in an atmospheric environment on the sea floor. A number of subsea productions systems have been developed including those by Exxon, Lockheed, Deep Oil Technology, and Subsea Equipment Associates Ltd. (sEAL). These systems variously employ single well-head completions, multiple well templates, and combinations of "wet" and "dry" subsea equipme nt. Atypical subsea system is shown on Figure 3-9.

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

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

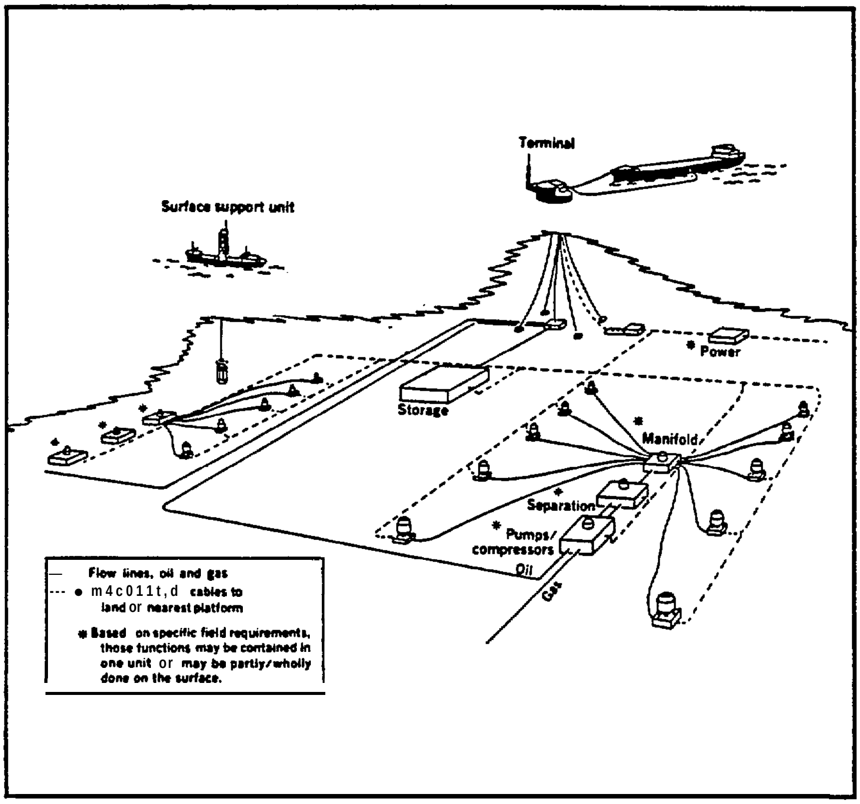
- Exploratory and delineation wells, which are normally plugged and abandoned, can be turned into satellite subsea producers.

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

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

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

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



A SUBSEA PRODUCTION SYSTEM

SOURCE: GOODFELLOW, 1977

FIGURE 3-9

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

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

Complete subsea production systems are considered state-of-the-art. However, subsea satellite well heads, with pipelines to a mother platform, do appear to be feasible with shallow/low production reservoirs. They are being used presently in various areas of the world, and we feel they wou" d indeed be applicable to development of the St. 'George Basin.

3.3.7 Marginal Field Development

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

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

The search for more cost-effective engineering solutions is particularly important as offshore petroleum development moves into deeper waters with the cost of fixed platforms rising exponentially with water depth. Listed below are some possible solutions and trends in petroleum technology for marginal field development; not all of these, however, are applicable to St. George Basin. The trends and solutions include:

- Development of "slimmer" steel jacket platforms requiring less steel.
- Development of floating or tethered platform systems such as the tension leg platform, converted or specially-designed semi-submersible platforms, and various floating concrete designs. These would be utilized in combination with subsea completed wells.
- Use of subsea production systems either as an adjunct to fixed platforms or as a complete production system (see Section 3.3.6).
- Two-stage development programs using an early (temporary) production system while further reservoir evaluation assesses the viability of a development plan employing fixed platforms, pipelines and major shore facilities.
- Employment of offshore loading in conjunction with a floating system, subsea system, or fixed platform with storage when long pipelines cannot be economically justified or shared.

3.4 Production Systems and Field Development Strategies For the St. George Basin

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

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

3.4.1 Field Size

Economic analysis defines the necessary reserve size thresholds to justify production under alternative production systems including pipeline versus offshore loading. Other factors being equal, the more distant from shore and the more isolated the field, the more attractive it may be to produce directly to tankers, sea ice and meteorologic conditions apart.

3.4.2 Reservoir and Production Characteristics

Reservoir and production characteristics are major determinants of transportation (pipeline capacity, storage requirements) and platform equipment requirements. A field development plan will identify "the optimal platform requirements, and identify and schedule the development well program, gas and water reinfection wells and rates, and platform equipment processing requirements that are, in part, determined by the transportation option selected.

3.4.3 'Quality and Physical Properties of Oil and Gas

Important crude properties to be considered in the design of a transportation system (pipeline and/or tanker) include:

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

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

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

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

Gas produced in association with the oil can either be transported to shore by pipeline or reinfected into the reservoir (some will be used as platform fuel), depending upon the volume of produced gas and gas market economics. Reinfected gas can be marketed later as economic circumstances change. If the crude is produced directly to tankers, associated gas will be reinfected or flared. (Gas reinfection equipment is a major cost component.) The feasibility of gas reinfection may be a problem in floating platforms with limited deck load capacity.

As the gas-oil ratio increases, the size of the pressure or production vessels and pipelines increases. Large and more sophisticated equipment is required to handle the gas. At some point, depending on the amount of gas 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 reinfected into the reservoir to maintain pressure and to prolong the 1 ife of the well field. Further, reinfection of associated gas is the only viable solution to the flaring ban imposed upon producing fields if natural gas production is not economically feasible.

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, pipelines, and the increased equipment requirements for gas processing, are usually insufficient to affect dramatically the platform costs.

3.4.4 Distance to Shore

Other factors being equal, the closer a field is to shore the more likely that production will be transported to shore by pipeline than by tanker. As indicated in Table 3-3, the unit transportation costs for oil increase with greater pipe length whereas the transportation cost per barrel in an offshore loading system is similar for all locations with only a slight increase with water depth. However, the ultimate destination of the crude and the number of terminal handlings are also important considerations.

Since it is about 240 kilometers (150 miles) from the center of the St. George Basin lease sale area to potential terminal sites in the Aleutians and on the Alaska Peninsula, the significant investments required for such long pipelines will encourage sharing trunk lines to the greatest extent possible. If discoveries are few, small and widely scattered, offshore loading may be an attractive alternative. The most likely strategy, however, given the resources estimated by the U.S. Geological Survey, would be a number of fields sharing at most two or three large diameter trunklines to an Aleutian transshipment terminal or LNG plant.

3.4.5 Meteorologic Conditions

The most important contrast between pipeline transport and offshore loading is the constraints placed on the latter by weather. Offshore loading onto tankers in the St. George Basin, like the North Sea, will be restricted by weather conditions. There is insufficient meteorologic sea state data for the St. George Basin to accurately estimate the amount of weather downtime when tankers cannot load. In the North Sea, total downtime, including weather, of offshore loading production systems ranges from 20 - 30 percent.(l) Typical shuttle tankers of 70,000 deadweight tons can remain on station in seas up to 8 meters (25 feet). It should be noted, however, that the tankers cannot moor to the system in these sea states'.

Without storage capability an offshore system experiences costly production interruptions. Further, some reservoirs may be damaged and production potential may be limited by such stop-go production. Therefore, the operator has to compare the economic benefits of storage versus the additional investment costs of storage facilities.(2) Design of offshore storage facilities has to match production rates, frequency and size of tankers, and expected weather and maintenance (of the single point moorings) downtime. Furthermore, the storage and loading system must allow for very high pumping rates when a tanker is available to load.

---

(1) In addition to weather, there is downtime related to maintenance and repair. These factors are considered in the design of a platform to estimate storage requirements. With technical and cost constraints on the maximum amount of storage that could be provided on a platform, there may still be times when production will have to be curtailed. Since we do not know the actual downtime factors, our approach in the assessment of offshore loading system economics in Chapter 6.0 has been to evaluate the effects of curtailed production at 80, 70, and 60 percent of capacity.

(2) To date only concrete platforms have provided sufficient storage capability to permit sustained, maximum production rates. However, a steel gravity structure with storage capability is under construction for Phil lip's Maureen field in the North Sea. Storage capacities of concrete platforms in the North Sea have ranged from 800,000 - 1,200,000 barrels. Shell/Esso's Brent spar storage buoy, an interim production and back-up storage facility, "has 300,000 barrels of storage, but it is not intended to handle peak production since the Brent field produces into a pipeline.

Another weather and sea-state problem concerns the ability to repair and maintain single point moorings and subsea equipment in an area such as St. George Basin where the wear and tear on such offshore facilities will be high.

3.4.6 Environmental Conditions

As noted in Section 3.3.2.2, two principal design criteria for platforms will be sea ice and seismic loadings. In upper Cook Inlet, the ice loading criterion has been prominent to the extent that design for ice loads has at the same time accommodated seismic loading (Visser, 1969). Because information on sea ice in the study area is very limited, the ice forces estimated and platform designs postulated are very tentative. Nevertheless, sea ice will be a significant factor in selection of production systems, including the feasibility of offshore loading. It will also be a factor to consider in year-round exploration operations and resupply logistics. Ice-breaker support may be required.

Water depths in the St. George Basin are comparable to the central North Sea, and do not present any special problems for platform design, pipelaying, or subsea completions.

3.4.7 Location of Terminals

Virtually all St. George Basin crude will be exported to the Lower 48. A very small amount may be refined in Alaska at Kenai Peninsula plants. One or more onshore pipeline terminals will serve as transshipment facilities. The terminal (s) will stabilize the crude, recover 1 iquid petroleum gas (LPG), treat tanker ballast, and provide storage for about 10 days' production. An Aleutian Island or Alaska Peninsula terminal that serves fields in the St. George Basin could also serve fields in other Bering Sea lease sale areas, such as the North Aleutian Shelf area and Norton Sound. In fact, the Aleutian Islands and southwestern tip of the Alaska Penisula are strategically placed for support and transshipment functions for most of the 3

Bering Sea and Chukchi Sea basins. Tankers reinforced for ice breaking may shuttle crude from offshore fields to a terminal in the Aleutians where the crude will be transferred to larger tankers destined for the U.S. west coast.

3.4.8 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 St. George Basin is one or more steel platforms (steel jacket/upper Cook Inlet hybrid design) sharing oil and/or gas trunk pipelines to a terminal in the Aleutian Islands. Gravity platforms, though regarded as a less likely option, were also selected for evaluation in the economic analysis in the shared-pipeline-to-shore terminal cases. Since some long pipeline distances can be anticipated, intermediate pump or compressor station platforms may be required. Therefore, incremental investment in such facilities was assumed for pipeline distances greater than 160 kilometers (100 miles).

Considerable uncertainty exists on the feasibility and cost of offshore loading systems in St. George Basin. However, it was decided to examine a few cases assuming a concrete gravity platform with storage and a single anchor leg mooring (SALM) system.

Because of the sea ice conditions in St. George Basin, 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) probably are not feasible. No attempt was made to evaluate the economics of such systems.

Appendix A, Section III summarizes the economic analysis of the most likely combinations of production systems, water depths, pipeline distances, and development strategies.

4.0 PETROLEUM ONSHORE FACILITIES SITING

4.1 Facility Siting Requirements

Shore facility requirements for petroleum activity in the St. George lease sale will depend upon the availability of suitable land. Much of the land 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 these facilities are discussed in detail by Kramer et al. (1978) and summarized in Dames & Moore (1979c) and Table 4-1.

Briefly, service bases are staging areas for supplying 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 1,524 meters [5,000 feet] long) that can handle large cargo aircraft operating under instrument flight rules. Docking facilities (about 60 meters [200 feet] of 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, from 4 - 12 hectares (10 - 30 acres) of level land will be needed adjacent to the docking facilities.

The size and location of a tanker terminal site will depend on throughput requirements and discovery location. Tanker terminals will require access to an airfield, a deep harbor (deeper than 18 meters [60 feet] for 1,000,000 deadweight ton tankers), and a large land area (up to 300 hectares [740 acres] for a million barrels per day throughput).

TABLE 4-1

SUMMARY OF PETROLEUM FACILITY SITING REQUIREMENTS

Facility	Land Hectares (Acres)	Water Depths - Meters (Feet): Harbor Entrance	Channel	Turning Basin	& Area	No. of Jetties/ Berths	Jetty/ Dock Frontage Meters (Feet)	Minimum Turning Basin Width Meters (Feet)	Comments
rude Oil Terminal[1]									
Small-Medium (<250,000 B/D)	30 (75)	15-23 (50-75)	14-20 (46-66)	13-19 (42-61)	12-18 (40-58)	1	457 (1500)	1220 (4000)	Required space in turning basin can be reduced substantially should tug assisted docking and departures be required
Large (500,000 B/0)	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)	
NG 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 (1 000-2000)	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

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 towns. 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 on Figure 4-1.

4.2 Siting Criteria

The following criteria were used for evaluating potential facility sites:

- Existing infrastructure - docks, airstrips, etc.

- Harbor characteristics including:
  - degree of natural shelter 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

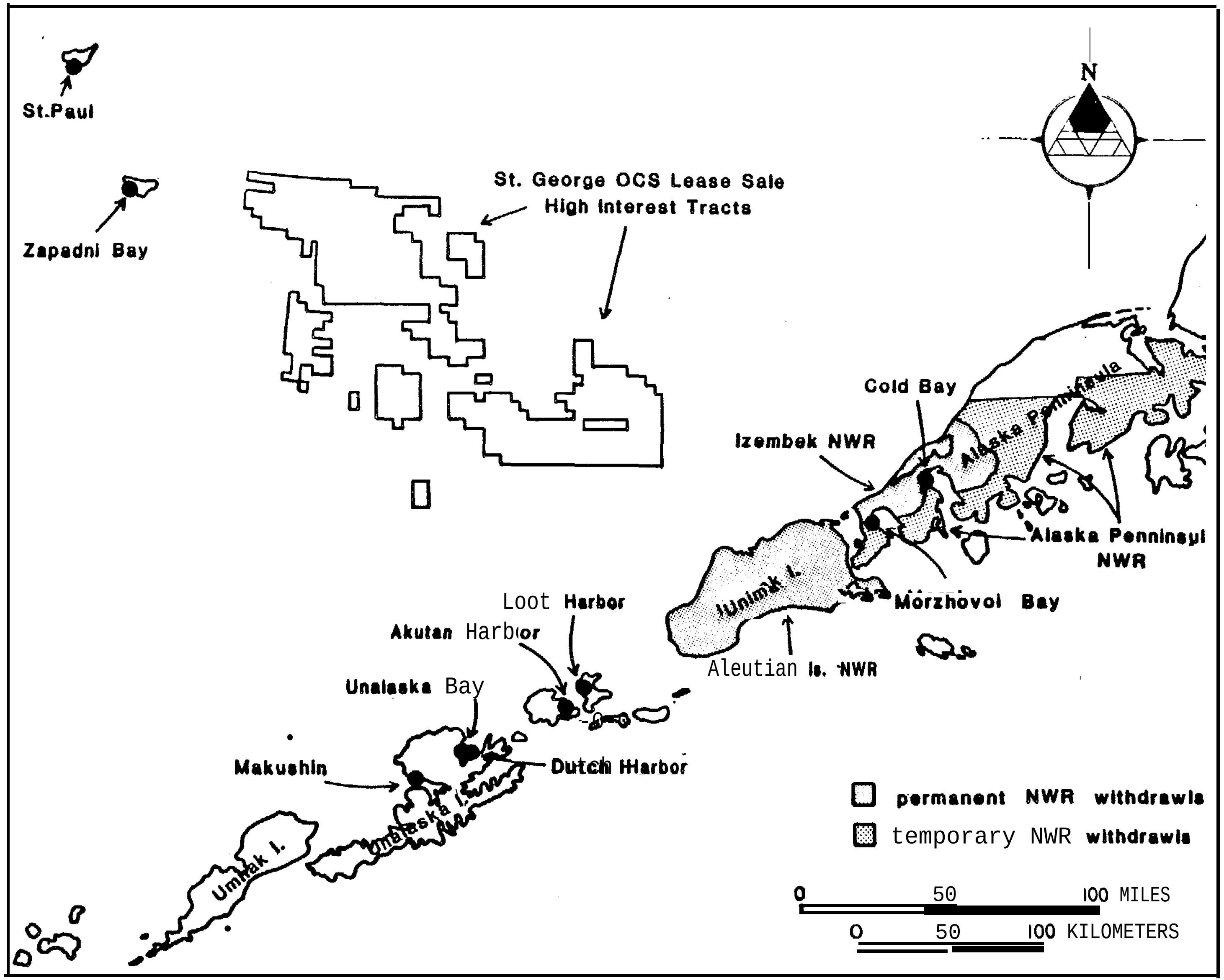


Figure 4-1 St. George Basin - Potential Onshore Facilities Sites

Note: The Alaska Marine Resources NWR (not shown) includes all Federal land on islands that was not selected by the State or Natives under ANCSA nor otherwise withdrawn prior to Feb. 11, 1980. This withdrawl may [illegible]

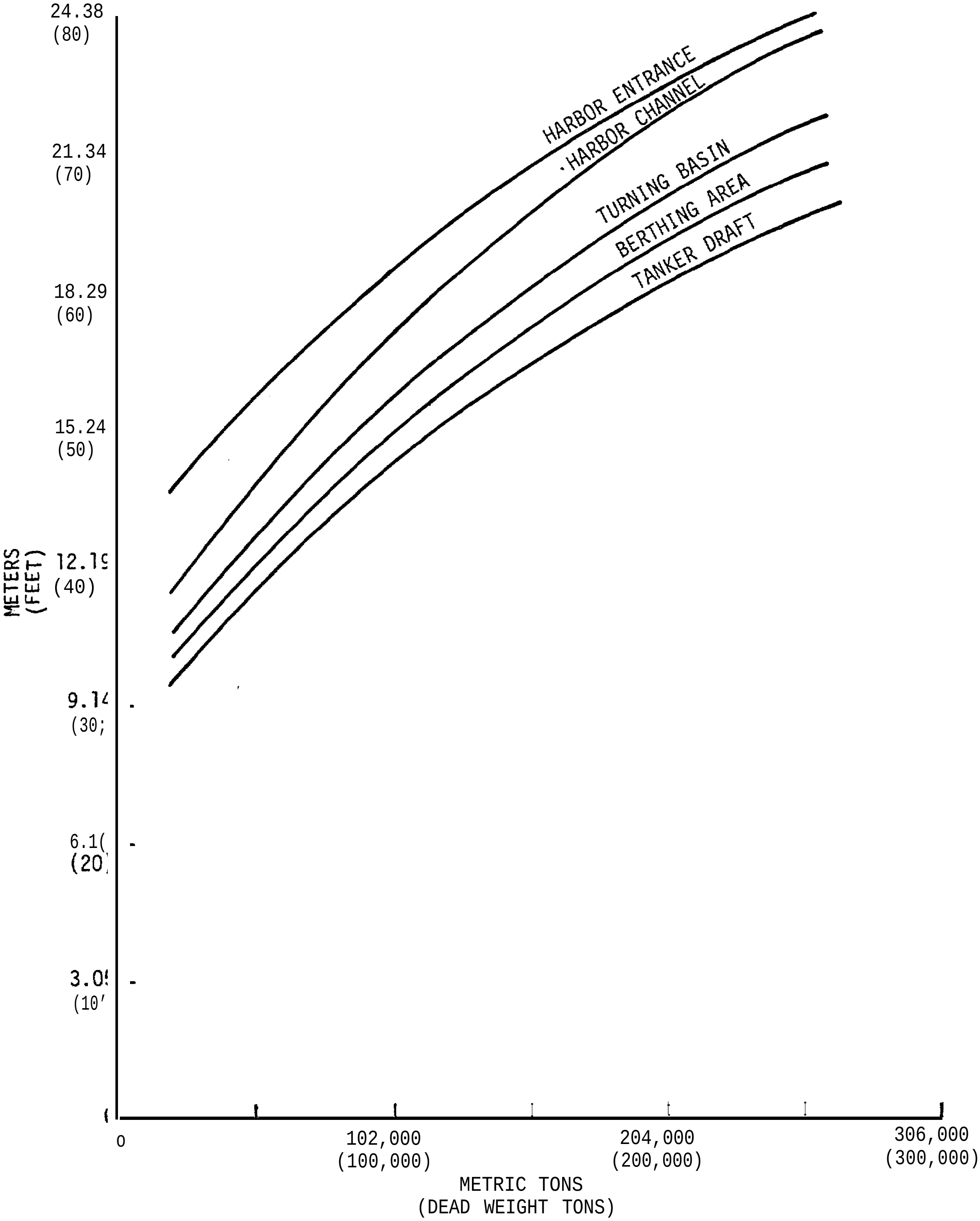


FIGURE 4-2

REQUIRED DEPTHS FOR TANKERS AT MARINE TERMINAL

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

- Geological hazards - seismicity, volcanism, tsunamis, flooding

- Biological sensitivity

4.3 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. Both Chignik Bay and Stepovak Bay are too distant to be economically competitive with other sites closer to the sale area. Both Dutch Harbor and Cold Bay are considered, in this report, to be excellent possibilities for service bases but their harbor entrances and approaches are too shallow and hazardous for them to serve as tanker terminals. Unalaska Bay and Akutan Harbor lack the infrastructure necessary to be considered as service bases but both are considered here as possible tanker terminal sites.

4.4 Service Base Sites

The existing infrastructure was examined for possible service base sites. Cold Bay, Dutch Harbor, and St. Paul 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, has the best facilities. Its airport has two paved runways 3,174 and 1,562 meters (10,415 and 5,126 feet) long, is lighted, and is 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 in 9 - 10 meters (30 - 33 feet) of water. The harbor's size and depths exceed those required for supply boats.

Dutch Harbor is slightly closer to the sale area than Cold Bay, particularly for sea transportation, but has generally poorer facilities. Conflicts may arise with the local fishing industry for use of facilities. Its airport is only 1,311 meters (4,300 feet) long, unlighted and not equipped for instrument approaches. Although Coast Guard C-130 Hercules occasionally use the strip, it is not considered adequate for regular supply activities in such large cargo aircraft. However, studies are currently underway to improve the airfield, so it may be adequate by the time of the lease sale. Docking facilities, although smaller than Cold Bay, are adequate to serve a couple of supply boats. The harbor is also adequate.

St. Paul is a significantly poorer site than Dutch' Harbor. It has bad ice conditions, poor docking facilities, and it lacks a naturally-sheltered dock site. However, it is significantly closer to the northwest portion of the sale area. It also has a lighted 1,577-meter (5,175-foot) gravel runway sufficient for heavy cargo traffic. The advantage of its proximity, particularly for helicopter support, may override its disadvantages.

4.5 Crude Oil Terminal and LNG Plant Sites

Based on information gathered from USGS Topographic Maps, U.S.C. & G.S. Nautical Charts, regional and local community profiles, F.A.A. publications, geological studies, and biological studies, the following sites were evaluated as potential crude oil terminals or LNG plant sites (Figure 4-l):

- Makushin, Makushin Bay, Unalaska Island
- Unalaska Bay, Unalaska Island
- Akutan Harbor, Akutan Island
- Morzhovai Bay, Alaska Peninsula

- Lost Harbor, Akun Island

- Zapadni Bay, St. George Island

The potential of these sites may depend largely on future land conveyances under the Alaska Native Claims Settlement Act and recent 20-year Federal land withdrawals.

Sites northeast of Unimak Pass, except Morzhovai Bay, are unsuitable because of distance from the sale area and hazardous waterways. Permanent Federal land withdrawals include Unimak Island (part of the Aleutian Islands National Wildlife Refuge) and the northwestern half of the lower 80 kilometers (50 miles) of the Alaska Peninsula (Izembek National Wildlife Range). In addition, the entire southeastern half of the Alaska Peninsula is part of a temporary emergency land withdrawal under Section 204e of the Federal Land Policy and Management Act of 1976 (Alaska Peninsula National Wildlife Range). Although this withdrawal is currently due to expire in November 1981, its status after that date is very much in doubt. Withdrawals as part of the National Wildlife System do not completely preclude use of the lands by industry.

Makushin - Makushin has an ice-free harbor with deep water within 305 meters (1,000 feet) of shore and adequate land for an airstrip and other facilities. Some artificial sheltering may be necessary to protect the site from southwest winds; otherwise, it has no major disadvantages.

Unalaska Bay - The entrance to Dutch Harbor is too shallow (26.8 meters [42 feet]) to accommodate tankers. Captains Bay is deep enough but its entrance is very narrow (130 to 152 meters [400 to 500 feet]), the turning basin is small (only 914 to 1,524 meters [3,000 to 5,000 feet] wide), and there is a shortage of suitable land for facilities. The best land within Unalaska Bay occurs adjacent to Broad Bay where water depths are sufficient within 610 - 914 meters (2,000 - 3,000 feet) of shore, but the shelter here is poor and not easily remedied by artificial means. Wide Bay has the best harbor characteristics, being well sheltered with sufficiently deep water less than 305 meters (1,000 feet) offshore, but its steep topography limits the available land suitable for facilities. A combination of these sites is possible, such as a terminal at Wide Bay and shore facilities at Broad Bay, 3.2 - 6.2 kilometers (2 - 4 miles) away. Airstrip siting throughout the area is a problem. Expansion of the Dutch Harbor airport would solve this problem.

Akutan Harbor - The eastern portion of Akutan Harbor is a good ice-free harbor of sufficient size and depth to accommodate tanker traffic. Shelter is good, but there is a shortage of level land for facilities and an airstrip.

Lost Harbor - Lost Harbor is similar to Akutan Harbor, except that it is smaller. There may not be sufficient land for facilities.

Morzhovoi Bay - This bay has several favorable characteristics: a good harbor with adequate shelter, suitable land for shore facilities, and an airstrip. However, deep water lies 914 - 1,829 meters (3,000 - 6,000 feet) offshore in those areas of the bay that are well protected, and it is roughly 30 percent farther from the central portion of the sale area than other sites considered. Furthermore, it lies within the Alaska Peninsula National Wildlife Range and the Alaska Peninsula National Wildlife Range.

St. George Island - Bathymetry data in the bay is lacking for a thorough assessment of this site, but it appears the bay is sufficiently deep within 305 - 610 meters (1,000 - 2,000 feet) offshore. Artificial shelter would be needed for shore loading of tankers. Adjacent land appears adequate for shore facilities and an airstrip. Sea ice conditions may present a hazard for 4 - 6 months of the year. These disadvantages may be overridden by its proximity to the northwest portion of the sale area.

4.6 Geological Hazards

Geological hazards throughout the area, with the exception of the Pribilof Islands, are high due to seismicity, volcanism, and tsuanamis. All sites will require engineering to withstand earthquakes of magnitudes greater than 7.0. Akutan Harbor has the worst volcanic hazard: The Akutan Volcano has erupted ash six times and lava twice since 1900. Makushin Volcano has erupted ash three times since 1900 and presents a potential hazard to sites in Makushin Bay and Unalaska Bay. Although no major tsunamis have been recorded at the sites considered, an occurrence could cause severe damage. In 1946, a tsunami run-up reached a height of 45.1 meters (115 feet) destroying the Scotch Cape Lighthouse on the southwest end of Unimak Island.

4.7 Biological Sensitivity

Biological sensitivity of the sites is summarized in Table 4-2. The site at Zapadni Bay is probably the most environmentally sensitive as a result of the fur seal rookery and hauling out area at the head of the bay. In addition, thousands of seabirds nest on the cliffs along the northern shoreline. Makushin Bay and Unalaska Bay have considerable fishery resources that could conflict with oil development. Environmental considerations at the other sites could likely be mitigated.

TABLE 4-2

BIOLOGICAL CONS ITERATIONS OF ON- SHORE FACILITY SITES
FOR THE ST. GEORGE BASIN

Sites	Shellfish	Finfish	Marine Mammals[1]	Seabi rds	Comments
Makushin, Makushin Bay, Unalaska Island	Good shrimp producer; varies up to 7 million lbs. Best area on Unalaska Island, good King crab producer; up to 1 million lbs.	Pink salmon-major species, catches can be over 1 million in even years	Sea lion hauling out grounds; Cape Starichkof approximately 100	No seabird colonies in vicinity	Kelp beds located on northside of Bay
Unalaska Bay, Unalaska Island	Some effort for both king and tanner crabs, good shrimp producer	Pink salmon-major species, runs up to 1 million for surrounding bays	No major concentrations of marine mammals	No major seabird colonies in the area	Major fishing port for Bering Sea
Akutan Harbor Akutan Island	Locally fished for king and tanner crab	Locally fished for salmon but no large producing streams	Sea lion hauling out grounds Rootok 1s. 22 km (14 miles) approximately 100	Nearby colony - Akun Head, 12 mi, no estimate of numbers, Rootok Is. 22 km (14 mi.) 100,000 birds	Local fishing port
Morzhovai Bay, Alaska Peninsula	Good king crab producer, 100-250 thousand lbs. annually	Low salmon producer, pink salmon-major species with runs up to 20,000	No major concentration of marine mammals	Largest colony - Amagat Is, 8 km (5 miles) from entrance" 451,000, Egg Island (at entrance) 3,000 birds, Kenmore Head (at entrance) 1,000 birds	Closed to commercial salmon fishing, good waterfowl habitat at head of bay
Lost Harbor, Akun Island	Not major area for fishing: most pot storage	No major fishery	Sea lion hauling out Rootok Is. - 22 km (14 miles) Billings Head - 12 mi. approx. 2,000	Nearest major colony Rooktok Is. 22 km (14 miles), 100,000 birds	Local kelp beds on north shore
Zapadni Bay, St. George Island	No major fishing effort in Bay	No fishery	Fur seal breeding rookeries and hauling out areas 10-20 thousand	Numerous nests, seabirds on northern shore, 100's of thousands	Very vulnerable to disturbance

[1] Marine mammals common, to this region could be sighted at any of these areas (e.g., harbor seal, Dan porpoise, etc.)

5.0 EMPLOYMENT

5.1 Introduction

Previous petroleum development studies by Dames & Moore in the Alaska OCS Socioeconomic Studies Program address the subject of manpower requirements. These studies discuss in general terms the factors that tend to influence labor requirements for construction and operation of OCS petroleum facilities in Alaska. They present definitions of terms used in the analysis of labor force requirements, and they develop a simple computer model that allows estimated manpower levels to be tabulated on a month-by-month basis from the beginning of exploration until abandonment of a commercially productive oil field. The emphasis of the manpower section of the earlier reports, however, is on quantitative estimates of the manpower that would be utilized in each of three different development scenarios.

The present report builds on the previous studies, but it emphasizes the inputs of the estimating process rather than the quantitative outputs for various scenarios. That is, the primary focus in this report is the factors that determine labor force size and productivity, and a probable range of each in an Alaska OCS setting. A quantitative estimate is made for only one (medium case) scenario using the OCS manpower computer model. The reader is referred to Appendix E of Technical Report 49 (Dames & Moore, 1980) for a full definition of the terms used in this report, and for an explanation of the model.

Section 5.2 discusses general factors that influence labor force size and productivity in most OCS activities. Section 5.3 discusses factors that are specific to certain tasks or groups of tasks, and estimates the likely range of manpower that would be required for these tasks in Alaska.

The units of analysis and special assumptions of the OCS employment model for the St. George Basin are specified in Tables 5-1 and 5-2 respectively.

TABLE 5-l

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 construct ion	Base	Assigned	Assigned		1	1.11
	C. Transportation	4. Helicopter for rigs	Wel 1	Same as Task 1	0	5	1	2
		5. Supply/anchor boats for rigs	Wel l	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	?. 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	B	0	80	2	1.5
		10. Shore base	Base	Ass i gned	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

TA8LE 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	Stat ion	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 J & 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 instal-lation 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	(2/52 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, expediters, 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 dril 1 each well divided by the number of months in the dril ling 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.
11	This task includes al 1 subsea ti e-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 mil e/day for 20- to 36-inch pipe; 1.5 mile for 10- to 19-i nch pipe.
16	See Table 5-7.
17	See Table 5-7.
20	See Table 5-7.
21	One helicopter per platform.
22	One helicopter per lay barge spread.
23	Three supply/anchor boats per platform.
24	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 ST. GEORGE BASIN USGS MEAN SCENARIO

Task	
3	Assume required expansion of Dutch Harbor for exploration drilling program requires an average of 100 men/month for 4 months; begins year 1, month 1.
10	Assume construction of a large permanent support base requiring 16 months effort with following monthly employment: 50, 100, 150, 200, 250, 300, 350, 400, 350, 300, 250, 200, 150, 100, 50; begins year 4, month 6.
12	Assume one conventional spread at 1 mile/day; therefore two months in year 7 (begin month 6), two monhs in year 8 (begin month 6), and six months in year 9 (begin month 5)
13	Assume one conventional spread at .75 miles/day; therefore 8 months in year 6 {begin month 3) and 6 months in year 7 (begin month 5).
14	Assume small distance of onshore pipe included in oil terminal construction labor force estimate.
15	Assume pipe coating begins in year 5 (month 6) and lasts for 18 months; therefore pipe is coated and stockpiled prior to use.
16	Assume large oil terminal construction begins year 5 (month 5) and lasts 36 months with the following monthly labor force: 67, 134, 201, 268, 335, 402, 469, 536, 603, 670, 737, 804, 871, 938, 1005, 1072, 1139, 1206, 1206, 1139, 1072, 1005, 938, 871, 804,.737, 670, 603, 536, 469, 402, 335, 268, 201, 134, 67. These estimates assume that no major site preparation problems are involved, and maximum use of prefabrication and modular construction.
17	Assume a very large LNG plant is built over 36 months beginning in year 5 (month 5). Modular construction techniques are used extensively, but size of plant exceeds barge-mount technology. Monthly manpower requirements are: 194, 388, 582, 776, 970, 1164, 1358, 1552, 1746, 1940, 2124, 2329, 2522, 2716, 2910, 3104, 3298, 3500, 3500, 3298, 3104, 2910, 2716, 2522, 2328, 2134, 1940, 1746, 1552, 1358, 1164, 970, 776, 582, 388, 194. Assume no significant site preparation problems.
31	Assume oil production begins in month 10 of each year indicated in development drilling tables.
311	Assume gas production begins in month 8 of each year indicated in development drilling tables.
36	Assume crew size of 55.
37	Assume crew size of 125.

Appendix A, Section VI.1 presents the values and assumptions used in the manpower model to derive the employment estimates for the mean resource estimate presented in Section 7.3. This section shows how the general information in Tables 7-1 and 7-2 were applied to the St. George Basin statistical mean case.

5.2 General Factors Affecting Labor Force Size and Productivity

It is difficult to accurately foresee the manpower requirements of future, hypothetical OCS developments because' many factors can not be predicted. Most importantly, perhaps, is the fact that technology and construction techniques are evolving rapidly. Recent advances in the application of modular construction, for example, are likely to have a significant affect on field construction employment during the development phase.

Also, estimating labor requirements for remote jobs is difficult. Direct labor requirements (laborers and craft workers) are less of a problem than indirect labor requirements (secretarial, clerical, catering, truck drivers, safety and security, pilots, communication personnel, etc.) and on-site management (project owners' staff, project management contractors' staff, execution contractors' staff, quality control, government inspectors, etc.).

Experience with very large projects indicates that the best laid plans can go awry. Most North Sea development programs went off course for one reason or another. The most spectacular example of schedule slippage in the North Sea is construction of the Sullom Voe crude oil marine terminal in the Shetland Islands. This facility was initially projected to have a peak construction labor force of fewer than 800 (Mackay, 1975) and be largely completed by 1977. In early 1979, there were 6,000 men working on the plant (Offshore, 1979). At the present time, the terminal is operating but the oil processing facilities still are not complete. In this case, much of the delay and redesign was caused by additional offshore oil discoveries that demanded more capacity in the facility; but many labor relations, construction, and technical problems also occurred.

In Alaska, the trans-Alaska pipeline project was initially projected to employ a peak work force of 8,300 (Mathematical Sciences Northwest, 1972). By 1975, a work force of 23,000 was reported (Pipeline Industry, 1976). This experience suggests that estimates of the labor required for large projects in frontier areas are (like cost estimates) very general indeed.

These miscalculations reflect the fact that the labor force size on a particular project is influenced by a large number of factors. Manpower necessary for 'completing a task in one setting under a certain set of circumstances is likely to differ substantially from the manpower required to accomplish a similar task in a different setting under a different set of circumstances. Contractors, oil company employees, consultants, and other knowledgeable people interviewed in the course of this study and previous studies have all emphasized that there is no such thing as "typical employment" and that employment levels are a function of many factors. Some of these factors are common to all projects; others are related to the nature of specific tasks.

5.2.1 Schedule

Project completion dates are critically important to manning levels on construction jobs. The more time available to complete the task, the smaller the peak requirements for men and equipment (total project man-months of effort may not differ, however). Also phasing a project so that incremental capacity is added after start-up can allow the construction effort to be spread over a longer period, and thereby reduce peak manpower.

The Claymore production platform in the North Sea presents an excellent example of the effects of schedules on manpower requirements. In this case, a decision was made to accept the deck support frame, and production and drilling modules, in a substantially incomplete state in order to set the components before the winter weather would prevent a lifting operation. Thus, a labor intensive effort offshore was required to complete construction, hook-up and commissioning -- all in hopes of finishing the project earlier than would have been possible if the components were fully built ashore and lifted the following season (Offshore, 1978).

5.2.2 Characteristics of the Labor Force

The skill and productivity of workers determines the amount of labor that a task requires. Availability of skilled craftsmen depends upon the location of the project, the project labor agreement, and the local, national and international demand for the required skills at the time. Pay, work conditions, labor relations and union rules may also affect the quality of the work force.

5.2.3 Union Rules and Project Labor Agreement, Where Applicable

These factors are likely to influence the number of workers required on a job as well as the average skill level of the work force. For example, rigid union rules that limit members to performing narrow, clearly defined tasks result in a larger work force than would otherwise be necessary. A project labor agreement can reduce the overall level of productivity of a work force if, for example, it has strong local hire and minority hire provisions.

Union rules and project labor agreements will also establish length of shifts and rotation of workers on leave. Remote projects, such as development in the Aleutian Islands, probably will have generous rotation allowances for many workers. The rotation factors influence total manpower requirements; not on-site labor requirements.

5.2.4 Contract

There are numerous contract arrangements with various incentive mechanisms that may influence manpower levels. For example, a contractor on a cost-plus fee contract may have significantly less incentive, or even a disincentive, to keep manpower levels to a minimum in contrast to a contractor working under a ump sum contract.

5.2.5. Adequacy of Original Design and Engineering

Field change orders and revisions to equipment specifications that result from incomplete or faulty design and engineering can delay a project for a year or more, especially if there is a narrow "weather window" for construction. Also, delays of this type can result in drastic labor increases to meet the project's original completion deadlines.

5.2.6 Environmental Stipulations

Environmental stipulations can greatly influence construction schedules, operating procedures, design and equipment specifications, and the overall rate of progress of a job. Stipulations, for example, may require construction activity to stop altogether during a certain season because of its potential impact on fish, wildlife, or their habitat. Generally speaking, the more northerly the project location, "the more numerous and stringent environmental stipulations will be.

5.2.7 Operating Environment

The environment in which a facility must be built and operated affects the labor force for both phases of a project. Offshore structures in the Bering Sea, for example, that will contend with sea ice and violent winter storms must be built larger and more elaborately than structures that operate in a temperate zone, such as the Santa Barbara channel.

5.2.8 Location

Location of a facility is a factor in determining its construction and operation manpower requirements. With the exception perhaps of lower Cook Inlet, OCS activities in Alaska will be quite remote from urban centers, industrial infrastructure, and established centers of petroleum service industries. In the Aleutian Islands, platforms are likely to be located long distances from the nearest shore base. This remoteness, combined with the harsh winter environment in Alaska, means that every effort will be made to reduce field manpower because of the expense of transporting, maintaining, and otherwise supporting workers at the site. There will be great financial incentive to use modular construction techniques and prefabrication during construction. Furthermore, shore bases will perform only minimum support functions. Many of the repair functions requiring machine shops and fabrication yards that are performed at shore bases in the Persian Gulf and North Sea will occur at Kenai or outside Alaska at major industrial centers (Japan, Puget Sound shipyards, etc.).

On the other hand, the remoteness and limited seasonal accessibility of the sites in Alaska will require more operations personnel on site than would be the case elsewhere. This is because more mechanical redundancy will be built into the facilities and a wider range of maintenance and repair expertise must be available at the facility around the clock than would be typical of a facility close to these services on shore.

5.3 Estimated Range of Employment and Productivity for Specific Tasks

Field employment created by OCS petroleum development will be a function of the size, design, site conditions, or other characteristics of each particular activity, in addition to the general factors identified above in Section 5.2. This section (1) identifies the specific factors that will influence manpower requirements for individual activities, and (2) estimates a likely range of employment and productivity that can be expected for each activity in the Alaska OCS setting. This information is summarized in Table 5-3. Note that labor force estimates are for on-site labor only. Total employment would include those away from the worksite on leave rotation (Dames & Moore, 1980, Appendix E).

5.3.1 Exploratory Well Drilling

Of all OCS activities, exploration drilling operations are the least variable in manpower requirements. Semi-submersibles and drill ships of the size

TABLE 5-3

ESTIMATES OF LABOR REQUIREMENTS FOR OCS PETROLEUM DEVELOPMENT ACTIVITIES

Activity	Onsite Labor Force Range	Productivity Range	Factors Affecting Labor Force and Productivity
Exploratory Drilling (1;501)	60 - 80/vessel	10,000 ft well 3 - 5 months	geologic conditions weather size of drilling vessel
Geophysical Survey (2;502)	15 - 20	15 - 30 miles/day	extent of existing data weather survey technique
Construction of Exploration Support Base (3)	0 - 200 (peak) 0 - 100 (average)	0 to 6 months	availability of existing facilities site conditions
Gravel Island Construction (301; 19)	175 - 275 (average)	1000m /hr - 1400m/hr/dredge (project average)	size of island depth of water proximity of fill weather construction technique number of suction dredges (summer) or dump trucks, etc. (winter)
Development Drilling (6)	28/rig	10,000 ft well in 1 - 2 months	geologic conditions
Steel platform Installation,	300 - 500 (average)	8 - 14 months	platform size number of piling required type and complexity of deck processing equipment number of development drilling rigs water depth; environment pipeline connections location
Concrete Platform Installation, Hook-up, Commissioning (8)	300- 500 (average)	6 - 12 months	same as above
Shore Treatment Plant (oil or gas) (9)	200- 400 peak 100 - 200 average	6 - 12 months	- plant capacity oil and gas characteristics - site characteristics
Construction of Permanent Support Base (10)			
Small (l-5 platforms)	200 - 300 peak 100- 160 average	6 - 10 months	- size site characteristics - functions
Medium (6 - 10 platforms)	300- 500 peak 160- 265 average	10 - 14 months	
Large (11 plus platforms)	500 - 800 peak	14 - 18 months	
Offshore Loading System Installation (11)	50 - 100 average	2 - 3 months	- size of system - method of crude storage weather

TABLE 5-3 (Continued)

ESTIMATES OF LABOR REQUIREMENTS FOR OCS PETROLEUM DEVELOPMENT ACTIVITIES

Activity	Onsite Labor Force Range	Productivity Range	Factors Affecting Labor Force and Productivity
Offshore Pipeline Construction (12;13)			
Small diameter pipe (250 ft water)	150 - 250/spread	4000 - 8000 ft/day/spred (project average)	diameter & wall thickness of pipe water depth lay barge type & capability
Large diameter pipe (250 ft water)	250 - 350/spread	2500- 4500 ft/ day/spread (project average)	subsea soil conditions weather
Onshore Pipeline Construction (large diameter) (14)	375 - 1000/spread (excludes pump and compressor stations, access roads, material mining, etc)	1000 - 5000/ft/day (project average)	number of spreads terrain, soil access to right-of-way river" crossings above ground installation diameter & wall thickness of pipe weather double or single joints coating method, type environmental stipulations
Pipe Coating & Double Jointing (15)	100 - 350 (average)	60- 200 lengths (40 ft)/day	diameter of pipe type of coating project schedule total throughput
Oil Terminal Construction (16)			
Small (200 MBD)	250- 500 peak 130 - 265 average	10 - 14 months	capacity treatment equipment
Medium (200- 500 MBD)	500 - 1000 peak 265 - 530 average	20 - 36 months	- terrain - water depth
Large (500- 1000 MBD)	1000 - 2500 peak 530 - 1325 average	30 - 48 months	
Very Large (100 plus MBD)	2500- 5000 peak 1325 - 2650 average	40 - 48 months	
LNG Plant Construction (17)			capacity of plant construction technique
Conventional			
Small (500 MMCFD)	350 - 500 peak 190 - 265 average	20 - 30 months	terrain, site conditions
Medium (500- 1000 MMCFD)	500 - 1000 peak 265 - 530 average	20- 36 months	
Large (1000 - 1500 MMCFD)	1000 - 2500 peak 530 - 1325 average	30- 40 months	
Very Large (1500 Plus MMCFD)	2500- 5000 peak 1325 - 2650 average	40 - 48 months	
Modular, Barge Mounted			
Small	100- 300 peak 60 - 160 average	2 - 4 months	
Medium	200- 400 peak 100- 210 average		
Large	300 - 500 peak 160 - 265 average	8 - 16 months	
Shore Base Operations	dependent upon offshore activities		offshore activity location and function of base
Pump/Compressor Station Construction (18)	100 - 400 peak 60 - 200 average	3 - 10 months	plant capacity construction technique terrain, access fuel supply location

TABLE 5-3 (Continued)

ESTIMATES OF LABOR REQUIREMENTS FOR OCS PETROLEUM DEVELOPMENT ACTIVITIES

Activity	Onsite Labor Force Range	Productivity Range	Factors Affecting Labor Force and Productivity
Oil Terminal Operations	35 - 150		size of plant amount of treatment and processing
LNG Operations	40 - 250		size of plant
Oil Platform Operations (31)	50 - 120		deck treatment secondary recovery location
Gas Platform Operations (311)	25-50'		extent of processing and compression on deck location
Well Workover	5 1/2 crew)	fulltime beginning in year 6	- characteristics of producing formation
Scheduled Maintenance and Repair of Platform (seasonal) (33)	14	N/A	age of platform operating environment complexity of deck equipment
Oil Terminal Operations (36)			
Small (200 MBD)	25 - 35	N/A	capacity of plant frequency of loading location treatment and rocessing functions operator's pol ties
Medium (200 - 500 MBD)	75 - 90		
Large (500 - 1000 MBD)	100 - 125		
Very Large (1000 plus MBD)	125 - 175		
LNG Plant Operations (38)		N/A	- Same as Oil Terminal operations
Small (500 MMCFD)	30 - 50		
Medium (500 - 1000 MMCFD)	50 - 70		
Large (10000 - 1500 MMCFD)	80 - 120		
Very Large (1500 plus MMCFD)	200 - 300		

Source: Dames & Moore

NOTES

1. These are the major activities creating OCS-related field employment. They correspond to the tasks utilized in the Dames & Moore OCS employment model ; the number in parenthesis indictes the task number used in the computer model (See Section VI).

2. Onsite labor force is the number of people at the works ite. Definitions of onsite and off site labor are presented in Dames & Moore (1980, pp E-13 ff).

3. Productivity is measured differently for various activities; for construction projects, productivity is the duration of work from start to finish. These estimates assume no major schedule slippage.

4. In addition to these specific factors, general factors are also important.

required in Alaska OCS waters typically carry between 60 and 80 people when working. These people comprise the two drilling crews, the vessel's operating crew, the catering (food service) crew, geologists and representatives of the oil company (or companies) that are drilling the well, weather observers, and oil service industry crews (cement, mud, well logging, etc). A 3,048- to 3,658-meter (10,000- to 12,000-foot) well can be drilled in 2 to 3 months, depending upon subsurface drilling conditions and weather. The offshore population of a large semi-submersible ship operating in the Aleutian Islands would approximate the numbers shown in Table 5-4.

5.3.2 Geophysical Survey

Labor requirements for geophysical surveys after a lease sale depend upon the extent of pre-sale geophysical work that occurred. Some measure of detailed work would be required to fix the exact location of exploratory wells. However," most work is done prior to lease sales by firms working under contract to an oil company or working on speculation (the geophysical survey firm offers the data for sale to interested buyers), A typical offshore geophysical party will number about 15 - 20 people, including the boat crew, although this number will vary with the size of the boat and the survey technique. Productivity is influenced greatly by weather. An average rate of progress might be 16.1 - 48.3 kilometers (10 - 30 miles) per day.

5*3.3 Construction of Shore Base for Exploration

Offshore exploration requires a temporary shore support base to provide the drilling vessel with fresh water, supplies of drilling mud and cement, drill pipe, casing, food, and other supplies. During exploration, oil companies will utilize existing port facilities if at all possible; they will build, modify, or expand facilities only if no existing facilities meet their needs. Thus, for example, a small service base was built at Yakutat to support exploratory drilling in the eastern part of the Gulf of Alaska when use of the existing port of Seward was impractical on a day to day basis. Therefore, the manpower required for this task will depend upon the availability

TABLE 5-4

ESTIMATED POPULATION OF LARGE SEMI-SUBMERSIBLE DRILLING VESSEL, WORKING IN REMOTE LOCATION

CREW	POSITION	NUMBER
Drilling	tool pushers	2
	drillers	2
	derrickmen	2
	floormen	8
	crane operators	2
	roustabouts	8
	rig mechanics	2
	electricians	2
	assistant tool pusher	1
		29
Ship Operation	captain	1
	chief engineer	1
	alternative chief engineer	1
	assistant engineer	2
	radioman	1
	seaman	4
	oiler	1
		11
Catering	chef/manager	1
	night cook/baker	1
	galley hands	5
		7
Diving	dive supervisor	1
	divers	4
	dive tenders	4
		9
Client Representatives		5
		5
Specialty Services	mud engineer	1
	mud logger	2
	electric logger	2
	completion service (cement)	1
	weather observation	2
		8
	TOTAL	69

Source: Dames & Moore

and condition of existing infrastructure. Presumably a construction effort would not exceed 6 months with an average crew of 200 men.

5.3.4 Development Drilling

Drilling development wells from a fixed platform requires roughly the same drill crew (per rig) as does exploratory well drilling. Regular well logging, core sampling, and flow testing are not necessary, and weather is not a factor. A 3,048-meter (10,000-foot) production well might take 50 days to drill and complete in a field that required 4 months for the first exploratory well. Production platforms are designed to accommodate one or two drilling rigs.

5.3.5 Steel Jacket Platform Installation, Hook-up and Commissioning

The many separate tasks that comprise this activity involve different crews for various lengths of time. The platform foundation (jacket) is placed on and attached to the seabed with piles. Modules containing the deck processing equipment are lifted aboard with a derrick barge, and then the modules are connected by crews of pipefitters, welders, and electricians. Finally, connections are made to submarine pipelines.

Time and average offshore crew size for this phase of development work vary widely with several factors. Small platforms in relatively shallow water in the Gulf of Mexico, under good conditions, might be installed in a few months with a total offshore work force of fewer than 200 (Page, 1977). Large platforms in the North Sea, on the other hand, have required substantially larger labor forces. The bulk of manpower requirements on steel platforms is for module hook-up and commissioning. For example, the Thistle platform employed slightly over 600 people for 15 months during hook-up and commissioning (Jumpsen, 1978).

Structures of the size and type required in the Bering Sea, for the field sizes projected, are likely to require an average on-site work force of between 300 - 500 men for 8 - 14 months. The variables are platform size, type and complexity of deck processing equipment, water depth and operating environment, subsea geology, number and complexity of pipeline riser installations, number of production drilling rigs, and distance from shore. Production drilling typically begins before module hook-up is complete.

5.3.6 Concrete Platform Installation, Hook-up and Commissioning

Concrete gravity platforms are immense structures that rest on the seabed without anchor piling. Despite their size, these platforms can be installed in a shorter time than steel platforms because they require no piling and because deck equipment can be installed at the fabrication yard. Nonetheless, offshore hook-up and commissioning of very large concrete platforms can involve a substantial labor force, particularly if the installation of processing equipment is not completed in the yard by the time of the scheduled "tow-out" to location. This was the case with the Statfjord platform, which was moved to location before all equipment was in place. Oil and Gas Journal (1978) reported an offshore work force of 1,200 people on the Statfjord structure.

A major problem associated with the use of concrete gravity structures in the Bering Sea is a suitable site for their construction (Kramer et al., 1978).

5.3.7 Shore Treatment Plant

Raw liquids and gas produced from wells require treatment and conditioning (water and gas separated from oil , gas liquids stripped from the gas stream, impurities removed, etc.) prior to transportation and marketing. If possible, these functions will be performed onshore (as is the case of Cook Inlet offshore crude production, which is treated onshore at Trading Bay and Granite Point). When performed offshore, this function contributes to platform size and operating crew requirements. In St. George Basin, primary treatment would occur offshore.

If treatment occurs onshore in a facility separate from the marine terminal, a separate manpower allocation should be made for construction. This will be a function of the throughput capacity of the plant, the characteristics of the oil and gas stream, and the building site. We estimate a peak labor force of from 200 - 400, and construction lasting from 6 - 12 months. Operating manpower requirements may vary between 20 - 50 people depending upon plant capacity.

5.3.8 Construction of a Shore Base

Only after a decision has been made to develop a field will oil companies begin to invest in permanent shore support facilities. Indeed, construction of a base is the first development project, for it is needed to serve offshore construction, pipelaying, and continued exploration programs. The manpower necessary to build the facility will depend upon its size (number of berths, water depth at quayside, amount of covered and open space, etc.), functions (major repair or minimal "forward" base), location and site characteristics. Construction of a small self-contained base (serving up to 5 medium size platforms) might employ 200 - 300 men (peak), and a large self-contained base (serving a dozen or more platforms) might employ 500 - 800 (peak). Construction could last from 6 - 18 months.

5.3.9 Offshore Loading System Installation

There are various offshore crude oil loading systems. Installation crew size and time depend largely upon the particular design and the capacity of the storage system (if it is separate from the platform structure). The components of the system are towed to the site and fixed to the seafloor. Subsea tie-ins to crude storage containers are required. Bad weather can slow the installation (depending upon the size and weather capability of the derrick barge). We estimate an employment range of 50 - 100 men over a 60 - 90 day period for this task. Operation of these systems does not require significant offshore labor; the tanker crew typically performs the mooring function.

5.3.10 Offshore Pipeline Construction

Crew size and rate of progress for laying offshore pipe of a certain diameter depends upon the equipment used. The current generation of semi-submersible lay barges (SEMAC, Viking Piper, BAR 347, ETPM 1601, for examples) are capable of sustained rates of progress of 1,219.2 - ,1,524 meters (4,000 - 5,000 feet) per day (24 hours) of large diameter pipe. These large lay barges have the ability to continue operations in beam seas of 3 - 3.7 meters (lo - 12 feet), while smaller conventional side lay barges are limited by a beam sea of around 6 feet (weather capability and rates of progress of various lay barges are discussed in Pipeline Industry, 1976a). These vessels carry crews of up to 350 people. They are extremely expensive to mobilize and operate.

The labor force required on conventional offshore lay barges working under good conditions in the Gulf of Mexico is estimate between 200 - 250. An example is shown in Table 5-5. The factors that influence these figures and determine an average rate of progress, in addition to lay barge type and capacity, are pipe diameter and wall thickness, water depth, weather, and subsea soil conditions (Table 5-5). We estimate an overall range of employment for this task of from 250 - 350 people per spread, excluding tug and supply boat crews.

5.3.11 Onshore Pipeline Construction

Onshore pipe" ine construction labor and productivity are very dependent upon the terrain and accessibility of the right-of-way. There is simply no typical pipeline spread. Two estimates of basic manpower requirements for a cross-country buried pipeline in moderate terrain are shown in Table 5-6. Not surprisingly, these differ significantly. However, both sources emphasize that the actual crew size needed for a job depends on conditions specific to the job. On the trans-Alaska pipeline, employment on some spreads exceeded 1,600 (Pipeline Industry, 1976b). In addition to terrain (including soil conditions) and access, significant factors affecting crew size (per spread)

TABLE 5-5

ESTIMATED LABOR REQUIREMENTS FOR OFFSHORE PIPELAYING, MEDIUM DIAMETER PIPE, 100 PERCENT LABOR PRODUCTIVITY, UP TO 250 FEET WATER DEPTH, EXCLUDING TUG AND SUPPLY BOAT CREWS

TASK	CREW SIZE
Lay barge welding and labor	113
Lay barge operation and maintenance	12
Catering	13
Survey crew and work boat	21
Cleaning and testing	50
Dive labor	9
TOTAL	218

Source: Page (1977)

TABLE 5-6

TWO ESTIMATES OF BASIC LABOR REQUIREMENTS
FOR ONSHORE, LARGE DIAMETER PIPELINE CONSTRUCTION SPREAD

Estimate 1[1]

Task	Crew Size
Field Office	23
ROW Clearing	37
ROW Grading	7
Ditching (earth)	20
Ditching (rock)	19
Road Crossing	11
String Pipe	16
Bending Pipe	10
Pipe Crew (alignment and stringer bead)	37
Welding Crew	23
Cleaning and Priming (over-the-ditch)	34
Lower in	23
Tie in	34
Testing	8
Utility Crew	9
Backfill and Clean-up	25
TOTAL	336

Estimate 2[2]

Task	Crew Size
ROW Clearing and Grading	68
Pipe Layout (survey)	9
Stringing Pipe	26
Ditching & Trenching	82
Bending Pipe	16
Aligning & Melding	83
Cleaning and Priming (over ditch)	41
Sand Blasting & Painting above ground pipe	10
Lower in	31
Valve Installation	20
Cleaning & Testing	36
Backfilling	18
Clean-up	43
Utility Operations	38
TOTAL	521

1 International Pipeline Contractors Association, 1972

2 Page, 1977

and productivity are number and type of river crossings, requirement for above ground installation, diameter and wall thickness of pipe, weather, use of single or double-jointed pipe, use of yard coated pipe or over-the-ditch methods, and environmental stipulations. Rates of progress in Alaska might vary from 304.8 - 1,524 meters (1,000 - 5,000 feet) per day (24 hours) per spread for a project average. When estimating total pipeline employment and progress, it is necessary to determine the number of spreads working simultaneously.

5.3.12 Pipecoating and Double Jointing

Labor requirements for a shore based pipecoating and double jointing operation would vary with the total length of pipe processed, the type of coating (concrete, or enamel and fiberglass), and the amount of time available for the work to be accomplished. A field plant would be designed for these parameters. We estimate that a plant used in Alaska for OCS development would be designed to handle between 60 - 200 60.9-meter (40-foot) lengths of pipe per day, employing from 100 - 350 people.

5.3.13 Marine Terminal Construction and Operation

Labor and time required to build a marine terminal depend upon the total capacity of the facility, the extent of crude processing and stabilization required, and the characteristics of the site. Table 5-3 shows estimates of manpower and construction time for terminals of various sizes. Operation of terminals is highly automated. The size of the operating crew varies with the size of the plant. A small terminal (e.g., Drift River) employs about 35 people; a large terminal (Valdez) may have up to 150 people on site.

5.3.14 LNG Plant Construction and Operation

LNG plants that are erected in the field according to conventional petrochemical construction techniques tend to be very labor intensive. Recent advances in the use of prefabricated, modular plant components allow significant reductions in field manpower requirements (Oil and Gas Journal, 1979b). If a prefabricated plant were mounted on barges that were moored offshore or sunk on a prepared bed at the site of operation, field labor requirements could be reduced even further (Offshore, 1978d). Thus, construction technique is an important variable in manpower requirements and installation time for this task. Table 5-3 presents estimates of employment levels and construction times for LNG plants of different sizes and construction methods.

Operational manpower requirements of LNG plants vary (non-arithmetically) with the size of the plant. Very large plants require 'disproportionately larger crews than smaller plants. A small plant (e.g., Union-Marathon in Kenai) requires about 35 people, but a very large plant could require several hundred.

5.3.15 Pump or Compressor Station Construction

If onshore or offshore pipelines are too long for natural reservoir pressure to move gas or oil to treatment plants or terminals, pump stations or compressor stations must be built. Offshore platforms may have to be built to support these facilities if the decks of production platforms are too crowded. Manpower and installation time depend upon the capacity of the plant, its fuel source (several pump stations along the trans-Alaska pipeline have small topping plants that produce turbine fuel for the staions' turbine engines), the terrain, access to the site, etc. Peak employment on the largest Alyeska pump station (Number 1) was about 450 (Pipeline Industry, 1977). We estimate a range of peak construction labor requirements for OCS onshore pump stations from 100 - 400 men, with construction lasting 3 - 10 months. An offshore platform for pumping or compressor equipment would require somewhat less manpower for installation than production platforms in the area.

5.3.16 Platform Operations

The number of permanent operating personnel on oil and gas platforms is a function of the number of wells served by the platform, the extent of separation and treatment, and compressor and pumping on the platform, and secondary recovery operations. For oil platforms the operating manpower (2 shifts) will vary between 50 - 120 men, and for gas platforms between 25 - 50 men.

5.3.17 Well Workover

Producing wells typically require periodic "workovers" during the 15 - 20 years of their active life. Workover operations include the following:

- Repairing mechanical devices, tubing, or casing downhole;
- Opening production from a new zone or deepening a well to reach a new strata;
- Repairing damage to a reservoir; and
- Cleaning out the accumulation of sand or paraffin from the production tubing (Offshore, 1978c).

The type and frequency of workover are unique to each particular field. At one extreme, a well may only need to have a completion assembly re-run once or twice during its life; at the other, a well may require new tubing, casing, stimulation, and other servicing every few years. As workover operations are expensive, only very productive wells can afford elaborate and continuous servicing.

Different workover operations require different periods of time to complete. A new set of production tubing may be rerun in 2 weeks, while a difficult offset well may require a month to be deepened. Note that a platform of

48 wells that required a 30-day operation on each well every 4 years would keep a workover crew busy permanently.

In the OCS employment model we assume that on the average, each platform will require a workover crew 6 months per year or half a crew 12 months per year beginning in the sixth year after production commences. Although a typical offshore workover crew may have as few as six men in the Gulf of Mexico, for example, we estimate a crew size of ten men for Bering Sea platforms.

5.3.18 Platform Maintenance

Maintenance programs for Bering Sea offshore structures are difficult to foresee at this time. Indeed, maintenance requirements of North Sea platforms are just now beginning to emerge. In 1978, an article in Offshore stated: "There is extreme difficulty in making any assessment of the likely future of offshore maintenance and repair work because of the many variables involved and because the industry is on the threshold of new techniques and new technology" (Offshore, 1978). Routine preventative maintenance (checking lubricating oils, greasing valves, replacing pump seals, etc.) is a function of the regular operating crew. Unscheduled, emergency repairs are made when required. Scheduled, annual inspection and repair by maintenance contractors in the summer months is standard practice. This work involves shot blasting and painting damaged or corroded external surfaces, inspection of subsea pipelines and well heads, and checking and calibrating gauges and instrumentation.

Typically, repair contractors with mobile equipment will service more than one platform in the early years of the platform's life. As a platform ages, its repair and maintenance requirements may increase substantially. We estimate that, on the average, among all platforms and over the life of the field, approximately ten men per platform offshore, and four onshore, will be employed in summer maintenance and repair programs beginning in the third year after production begins.

5.3.19 Shore Base Operations

The size of the work force of a supply base depends on the nature and scope of offshore operations, the location of the base, and the functions for which the base was designed. All offshore operations require shore support from a proximate base -- communications, materials handling, and clerical at an minimum. The more remote the site of petroleum development, the more expensive it is to maintain people and equipment. In the Aleutian Islands, shore base functions will probably be quite restricted when compared, for example, with the activities at shore bases on the Scottish mainland at Aberdeen, Peterhead, etc. (see Alaska Consultants, 1976). Thus, while offshore work may require considerable shore employment (it is estimated that the Thistle platform requires shore support of about 200 people), in Alaska much of this onshore support activity will be disturbed between the supply base, Anchorage and industrial centers outside Alaska.

Because shore base employment will fluctuate with the pace and sequence of offshore work, it is likely to have a seasonal pattern. This is true even of the production phase, as annual maintenance work will be a summer activity requiring additional onshore activity.

To estimate shore base employment at a certain time, it is necessary to estimate the onshore support required by each activity occurring offshore, including transportation.(1)

5.3.20 Helicopter and Marine Support

Major offshore activities require transportation service from helicopters, supply boats (usually with heavy anchor-handling capability) and tug boats. The requirements for each depend on distance from shore to offshore operations, the scope of operations, and weather. During the production phase,

---

(1) The estimates of service base employment for the mean resource level in the St. George Basin shown in Table 7-6, Section 7.3 are derived from an estimate for onshore support for each offshore activity. These are shown in Table 7-3).

one aircraft and vessel may be expected to serve one field, which may have several platforms (e. g., in Cook Inlet). However, the further operations are from shore, and the worse the weather conditions, the less likely that a boat or aircraft will serve more than one platform.

Table 5-7 shows the standard crew of tug boats and supply boats. The helicopters most frequently used to support offshore operations, the Skikoirsky SN61, requires two pilots and three mechanics -- five people per aircraft.

Table 5-8 presents an estimate of the number of boats and aircraft required for various offshore operations.

TABLE 5-7

STANDARD CREWS FOR SUPPLY AND TUG BOATS, 100-FOOT CLASS

Boat Type	Personnel	Number
Supply/ Anchor Handling	Captain	1
	1st Mate	1
	Chief Engineer	1
	1st Engineer	1
	Electrician	1
	Oiler	1
	Seaman	4
	Cook	1
TOTAL		11
Tug	Captain	1
	1st Mate	1
	Chief Engineer	1
	1st Engineer	1
	Seaman	4
	Oiler	1
	Cook	1
TOTAL		10

Source: Page, 1977

TABLE 5-8

WORK BOAT AND HELICOPTER SUPPORT FOR OFFSHORE OPERATIONS

Offshore Task	Boats Type	Boats Requirements	Helicopters	Factors Influencing Requirements
Exploratory Drilling	Supply/Anchor	1 - 2	1 - 2	Distance of rig from shore base Size of vessel crew and rotation
Jacket Installation, Hook-up Commissioning	Supply/Anchor	4 - 6	2 - 4	Size of platform distance from shore
	Tug	2 - 4		Requirements will vary during this phase Weather Project schedule Size of offshore population
Pipelaying	Supply/Anchor	2 - 4		Amount of pipe required
	Tug	2 - 4		Concrete coated or uncoated pipe Weather Distance from shore base
Offshore Mooring Installation System	Supply/Anchor	1 - 2		Size of system; complexity of installation
	Tug	1 - 2		Distance from shore base Weather
Platform Operation	Supply/Anchor	1/3 - 1	1/3 - 1	Distance from shore base Meather Size of platform and offshore population Unit agreement

6.0 THE ECONOMICS OF ST. GEORGE BASIN PETROLEUM DEVELOPMENT

6.1 Introduction: Modeling Approach

This chapter presents the results of an economic analysis of OCS oil and gas development in the St. George Basin.

Results for oil development are presented in Section 6.2 and those for gas development are shown 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 in Sections 6.2.9 and 6.3.7. In Sections 6.2.8 and 6.3.6, 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. Section 6.4 discusses the equivalent amortized cost of oil and gas development. Finally, in Section 6.5, the factors affecting the marketability of St. George oil and gas are discussed.

The economic viability of OCS oil and gas fields in the St. George Basin depends on several conditions including reservoir size, depth, location, well productivity, and production method. Since no oil production has taken place and only one well has been drilled in the St. George Basin, the reservoir conditions are uncertain. In the economic analysis, an effort was made to include a wide range of conditions, in order to bracket all reasonable possibilities of the unknown actual conditions in the Basin.

The number of combinations of reservoir characteristics that could be encountered in the St. George Basin is very large. The effects of these variations are demonstrated by defining benchmark or base case conditions for both oil and gas fields that are representative of economically viable reservoir, engineering and locational characteristics. Then these characteristics are systematically varied one at a time.

Attention is also directed to the effect of high world oil prices on economic feasibility. The price used -- $27.50 per barrel (wel l-head value, St. George Basin) -- is about 50 percent higher than the price used in the recent Norton Basin study(1) (Dames & Moore, 1979).

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:(2)

Reservoir Size	100 million barrels
Reservoir Depth	3050 meters (10,000 feet)
Water Depth	107 meters (350 feet)
Initial Productivity (1 P)	2,000 barrels per day per well
Recoverable Reserves Per Acre	60,000 barrels per acre
Distance From Shore	80 kilometers (50 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) Justification for this price is presented in Appendix A, Section V. Because of this high price, reservoirs that would previously have been uneconomic -- under 100 million barrels -- now promise attractive rates of return.

(2) 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.

TABLE 6-1

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

Factor/ Characteristics	Units	Range of Parameter; Modeled
Reservoir Depth	Meters (Feet)	915 (3,000), 1,145 (3,700), 1,525 (5,000), 3,050 (10,000)*
Reservoir Size	Million Barrels	100*, 225, 350, 1000, 2000
Distance From Shore	Kilometers (Miles)	80 (50)*, 160 (100), 240 (150), 320 (200)
Initial Productivity	Barrels per Day	1,000, 2,000*
Water Depth	Meters (Feet)	107 (350)*, 150 (492)
Offshore Loading	Capacity Factor	80 percent**, 70 percent, 60 percent

Source: Dames & Moore

* Indicates the value used in the base case.

** This case includes a portion of graving dock costs.

Ideally the base case conditions would be most representative of the true conditions in the St. George Basin. Unfortunately, these representative conditions are presently unknown. Ranges of reservoir conditions have been only roughly estimated (see Mat"low et al., 1979). Therefore, the base case is selected somewhat arbitrarily, 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 (3,050-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 shallower in the two typical cases modeled and thus involves lower platform cost. Initial well productivity of 2,000 barrels per day is also the more optimistic of the two conditions modeled, but it is more probable than 1,000 barrels per day based on available geologic information. The production system uses a steel platform, at a somewhat higher marginal cost than the gravity platform. The 80-kilometer (50-mile) pipeline to shore is shorter than the more remote areas of the basin would require, but pipeline economics are examined to a distance of 320 kilometers.

In all except the giant field cases (1 - 2 billion barrels), 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.

A capital expenditure of $320 million over 6 years is required to bring the base case field into production. Fourteen producing wells and three injection wel 1s are assumed to allow a peak annual production near 10 percent of recoverable reserves. When costs and revenue streams are discounted to

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

the first year of construction, the net present value at 12 percent is $263.6 million. Internal rate of return (ROR) is 20.2 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 $23.27 per barrel.

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 B. 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.

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, shows the results of varying the depth of the base case reservoir. In column 4 we see that as depth decreases, the number of

---

(1) For explanation of the EAC model, see Appendix A, Section V.

TABLE 6-2

ECONOMIC MODELING RESULTS OF ST. GEORGE BASIN OIL PRODUCTION

ase	2 Reservoir Target Depth	3 Pipeline Distance To Shore/ No. Fields Shari ng Pipe	4 Number of Platforms/ Number of Producing Wells	5 Peak Pro-duction Per Hell/Per Field	6 Undis-counted Capital Investment	7 Reservoir Size - Recoverable Reserves	8 Return On Investment	9 After-Tax Capital cost	10 Equi - valent Amor-ti zed cost - (EAC)
	(Meters)	(Kilometers/ No..)	(No.)	(MBD)	(Million $)	(MMBBL)	(Percent)	($/BBL)	($/BBL)
• Reservoir Depth:									
Base Case	3050	80/2	1/14	2/27	320.0	100	20.2	4.99	23.26
5000 ft.target	1525	"	1/14	"	282.4	"	23.6	4.42	22.59
3750 ft "	1145	"	2/14	"	344.6	"	19.3	5.08	24.18
3000 ft. "	915	"	3/14	"	457.7	"	13.4	6.56	26.38
;. Initial Well Productivity and Water Depth:									
Base Case	3050	80/2	1/14	2/27	320.0	100	20.6	4.99	23.26
Low Pro-ductivity	"	"	1/28	1/27	413.6	"	15.1	5.99	25.57
Deep Water (150 Meters)	"	"	1/14	2/27 ,	360.2	"	19.1	5.47	23.69
:. Reservoir Sizes:									
	3050	80/2	1/7	2/14	200.6	50	14.8	5.62	25.80
Base Case	"	"	1/14	2/27	320.0	100	20.2	4.99	23.26
	"	"	1/28	2/54	599.7	200	24.1	4.55	21.84
	"	"	1/42	2/81	669.4	350	28.0	3.38	19.92
	"	"	4/142	2/273	2244.8	1000	26.8	3.48	20.08
	"	11	8/275	2/ 528	4327.4	2000	23.9	3.47	20.52

(cent inued)

3BL = barrel
MMBBL = million barrels

a

TABLE 6-2 (continued)

ECONOMIC MODELING RESULTS OF ST. GEORGE BASIN OIL PRODUCTION

ase	2 Reservoir Target Depth	3 Pipeline Distance To Shore/ No. Fields Sharing Pipe	4 Number of Platforms/ Number of Producing Wells	5 Peak Production Per Well/Per Field	6 Undiscounted Capital Investment	7 Reservoir Size - Recoverable Reserves	8 Return On Investment	9 After-Tax Capital cost	10 Equivalent Amortized cost - (EAC)
	(Meters)	(Kilometers/ No.)	(140.)	(MBD)	(Million $)	(MMBBL)	(Percent)	($/BBL)	($/BBL)
• Pipeline Distance:									
Base Case	3050	80/2	1/14	2/27	320.0	100	20.2	4.99	23.26
	"	160/2	"	"	342.0	"	19.4	5.30	23.54
	"	240/2	"	"	427.2	"	16.0	6.51	25.03
	"	320/2	"	"	442.2	"	15.5	6.72	25.23
	"	160/1	"	"	402.0	"	17.4	6.17	24.33
	"	240/1	"	"	573.6	"	12.19	8.61	26.94
n	"	320/1	1/40	2/77	1007.2	350	22.0	5.02	21.81
	"	320/1	4/142	2/273	2692.6	1000	22.6	4.37	21.53
• Offshore Loading:									
Base Case	3050	80/2	1/14	2/27	320.0	100	20.2	4.99	23.25
80% Production(1)		"	"	2/22	376.2	"	15.0	6.20	25.59
70% Production	"	"	"	2/19	303.3	"	15.6	5.4'3	25.23
60% Production	"	"	"	2/16	303.3	"	13.1	6.11	26.54
• Associated Gas:									
Base Case	3050	80/2	1/14	2/27	320.0	100	20.2	4.99	23.25
Assoc. Gas	"	"	"	2/27(2)	357.7	100	20.1	5.54(2)	25.19(2)

ource: Dames & Moore, 1980

1)High Platform Cost

2)See text for interpretation of these results.

BL = barrels

MBBL = million barrels

platforms required increases to produce a 100 million barrel field. Equivalent amortized costs (EAC) increase as target depth decreases from 3,050 - 915 meters. At 915 meters (3,000 feet) the capital investment for producing the reservoir is 43 percent more than the base case. Although additional tax write-offs moderate the higher costs substantially, the ROR for the shallow reservoir is 13 percent, close to the 12 percent hurdle rate. Considering that these costs are based on an ideal reservoir shape, this target depth can be regarded as the minimum economic limit.

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 St. George Basin are expected to produce at an initial productivity (1P) of between 1,000 - 5,000 barrels per day per we] 1.

Compared to the base case 1P of 2,000 barrels per day, an otherwise identical field with a 1,000 barrel per day 1P 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 costs are 29 percent higher, as shown in Case B, Table 6-2. Operating costs are 60 percent higher for a low 1P field. Because of these added costs, the EAC cost per barrel is 10 higher, and the ROR is 15.1 percent or 25 percent lower than the base case. Despite the higher costs, low 1P fields are still profitable if they are fairly near shore (i.e., not much more than 80 kilometers) and are deep enough to be produced from one platform.

6.2.4 The Economic Impact of Deeper Water

Increasing the water depth from the base case of 107 meters (350 feet) to 150 meters (492 feet) increases the cost of the platform, and thus raises capital costs by $40 million as shown in Case B, Table 6-2. This increases the EAC only slightly, from $23.26 to $23.69. 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 less significant. In general, water depths likely to be encountered in the St. George Basin will not greatly influence development feasibility except in otherwise marginal situations.

6.2.5 Economic Impact of Alternative Reservoir Sizes

At the base case depth (107 meters), assuming base case oil field conditions, a single platform can reach more than 350 million barrels. However, technical constraints in the ice-covered seas of St. George Basin limit the number of conductor wells to 48. Therefore, 350 million barrels is the maximum reservoir size that can be produced from a single platform if 10 percent of reserves are to be produced at peak (given 2,000 barrel per day 1P wells).(1) To fully develop a 1 billion barrel field, assuming a 3,048-meter (10,000-foot) reservoir, four platforms would be required; eight platforms would be needed for a 2 billion barrel field.

In Table 6-2, Case C, the required number of platforms and wells is shown in column 4. EAC costs decline, and rates of returns increase from field sizes of 50 - 350 million barrels as economies of scale for single platform operations are fully real zeal. For 1 and 2 billion barrel fields, the reserves per platform are roughly equal to the 350 million barrel case. Although pipeline costs for giant fields are amortized over more throughput,

(1) For shallow reservoirs (1,524 meters or less) the numbers of platforms required increase with reservoir size due" to. directional 'drilling limitations. In contrast, for deep reservoirs (e.g. 3,048 meters), it is the technical limitations on the number of wells slots (for the designs proposed for St. George Basin), not directional drilling limitations, that will increase the numbers of platforms with increase in reservoir size. In the case of deep reservoirs and large fields, an operator may have to choose between investment in additional platforms with more wells (i.e., total wells in the field) and higher take-off rate or fewer platforms and a less than optimal take-off rate.

this economy is swamped by the great impact of production phasing. With one new platform started per year, peak production is postponed. As a result, present value of revenues are reduced, resulting in higher cost per barrel. The cost curve, hence, appears to have a traditional U-shape with maximum economies of scale captured at 350 million barrels.

6.2.6 Economic Impact of Alternative Reservoir Location and Pipeline Configurations

The location of fields with respect to distance from shore and distance from other fields is an important determinant of cost of production and ROR. Since the center of the most likely production area is about 240 kilometers (150 miles) from Unalaska Bay (the potential terminal site), long pipelines may be necessary. Although a common pipeline would be somewhat larger in diameter than an unshared pipeline, the total costs to be shared would be only minimally higher than costs for a single platform pipeline. The material costs of a slightly larger pipeline are, almost insignificant compared to the cost of laying the pipe.

Pipelines longer than 160 kilometers (100 miles) require a pumping station to overcome friction losses in the pipeline. This adds considerably to the capital cost of the pipeline, and to operating costs. Such pumping stations would require an additional platform, fuel to run the pumps, maintenance, and operating personnel.

Compared to the base case, an identical field with a half-shared 320-kilometer (200-mile) pipeline has 25 percent higher operating costs and 38 percent higher capital investment. Nonetheless, such a field is economically viable at a 15.5 percent after-tax ROR and an EAC of $25.23 per barrel, only $2.00 per barrel more than the base' case, when the pipeline can be shared.

Even a base case field located 240 kilometers (150 miles) from shore and unable to share a pipeline is economically viable. Despite the increase capital investment, from $320 million to $574 million, such a field would produce a 12.2 percent ROR. This represents the maximum pipeline length that a single 100 million barrel field can economically support. Larger fields can, however, be profitably developed in even more remote locations. A 350 million barrel field producing through an unshared 320-kilometer (200-mile) pipeline returns 22 percent on its $1 billion investment. A 1 billion barrel field under the same conditions has a slightly higher rate of return.

Thus, the long pipeline distances expected in the St. George Basin do not appear to be a constraint to development.

6.2.7 Economic Comparison of Offshore Loading and Pipelines

It should be stated at the outset that the economic modeling of this case should be regarded as preliminary. Unlike the other cases modeled, offshore loading in the Arctic and sub-Artic is beyond the state of current technology. The engineering and operating problems are formidable. Assigning costs with the same level of confidence as in more conventional cases is clearly beyond the scope of this study. Nevertheless, it is important to consider this potential alternative for small remote fields.

In order to load offshore, the platform must be capable of storing a considerable amount of the oil produced; perhaps up to several weeks of production. According to Marlow et al. (1979), "Weather conditions over the St. George Basin are among the world's worst." Sea ice may be present between January and April. Fog is present 40 percent of the time, especially during warmer weather. Single point moorings, through which the oil would be loaded from the platform or storage, are currently designed only for fairly shallow and ice-free conditions. An ice breaking tug would be required to stand by constantly in winter to keep the mooring ice-free and to assist tanker docking. There is insufficient data at present to estimate the amount of weather downtime when tankers would not be able to load. Also, maintenance and repair downtime is unknown. These factors are considered in the design of a platform to estimate storage requirements. With technical and cost constraints on the maximum amount of storage that could be provided on a platform, there may be times when production would have to be curtailed. Given these unknowns, our approach in this assessment of offshore loading system economics has been to evaluate the effects of curtailed production at 80, 70, and 60 percent of capacity.

In consultation with Santa Fe Engineering Services, we made a rough estimate of $30 million per year for the operation, maintenance, and leasing costs of an ice-breaking tanker and tug. Since steel platforms with large storage capacity and undersea storage are beyond the state-of-technology for the sub-arctic, concrete platforms were assumed for this case. Such platforms have been built for use in the North Sea, so accurate unit costs are available. However, while steel platforms can be prefabricated at existing shipyards on the "U.S. west coast and in Japan, concrete platforms would require construction of a new deep water graving dock. While the incremental cost of a concrete "Condeep" platform, even with 1 million barrel storage, is slightly lower than that of a steel platform, it is difficult to allocate the cost of the graving dock. (For this reason all pipeline cases assume steel platforms.) Because of this uncertainty, two offshore loading platform costs were used. In one case only the incremental platform cost was used; in the other, the platform cost was arbitrarily doubled to reflect the amortized cost of the graving dock.

The strategy in modeling the offshore loading case was to determine the minimum average annual percent of peak production that would result in attaining the desired 12 percent after-tax ROR hurdle. As seen in Table 6-2, Case E, an offshore loading system operating at 60 percent of capacity would yield a 13 percent ROR and produce oil with an EAC of $26.54 per barrel. In order to yield a ROR comparable to the 20 percent of the 80-kilometer (50-mile) pipeline base case, production well above 80 percent of peak would be necessary. Given the prevailing conditions in the St. George Basin, it is highly unlikely that such a production rate would be possible.

Given a choice between producing an isolated, 100,000 barrel field 240 kilometers (150 miles) offshore through a pipeline or by offshore loading, the decision becomes more difficult. While the pipeline case produces only a 12.2 percent ROR compared to 13 percent for the offshore loading case, the case in favor of offshore loading is still weak. The additional transit time for the longer run, while not a large part of the total time for a round trip, adds to the unreliability of the system. In addition, the-novelty of the offshore loading system implies greater uncertainty, at any given estimated ROR. Finally, the above costs do not reflect the cost of the graving dock for construction of a concrete gravity structure. Adding these costs, as shown in the high platform cost run, is equivalent to increasing the operating capacity factor by more than 10 percent in order to obtain a given ROR.

In summary, under the stated cost assumptions, offshore loading, while economically feasible, would be less profitable and more risky than pipeline delivery in the St. George Basin.

6.2.8 The Economics Of Producing Gas In Association With Oil

Historically, most gas produced in association with oil has been either flared (wasted) or reinfected to increase the oil productivity rate. Flaring currently is prohibited by Federal law. The advantages of gas reinfection 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.

For modeling purposes, associated gas is produced from a field identical to the base case. One thousand cubic feet of gas is assumed to be produced for each barrel of oil, and the gas decline curve is assumed to follow that of the oil.(1) No additional wells are required to produce the gas since it is a by-product of the oil produced. Equipment to separate the gas and purify

(1) This is a simplifying assumption required by the economic model. It is recognized that associated gas production profile may be different, reflecting complex reservoir dynamics.

it to pipeline quality is assumed to cost $15 million per platform. An 80-kilometer (50-mile) pipeline, half-shared with another identical field, is assumed. Operating costs are assumed to be 10 percent higher than those in the base case.

The results of this model are shown in Table 6-2, Case F. Gas production adds an additional capital cost of $37.7 million. The difference between the EAC for associated "gas and that of the base case is $1.94. Since all other factors are held constant, this means that the gas costs this amount to produce. Since the ROR is virtually equal (20 percent) with and without associated gas, the decision to produce the gas or not would be determined by other than platform optimizing criteria. Ordinarily, the producer will maximize net income as long as return is above hurdle rate.

Because a large part of the incremental cost of associated gas is attributed to pipeline' costs, the economics of associated gas are highly sensitive to the distance from shore and to pipeline sharing options. Any case involving longer distances to shore or unshared gas pipelines would be less economically attractive. On the other hand, associated gas from larger fields would be less expensive, since the gas pipeline costs would be distributed over a greater production.

In addition, the feasibility of producing natural gas depends on the existence of enough gas production from other fields to sustain a terminal for conversion to LNG and to sustain the shipping link to the U.S. west coast. In the absence of this "critical mass" of gas production in the St. George Basin, associated gas production would not be feasible.

6.2.9 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 St. George Basin 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.

6.2.9.1 Oil Price Changes

Increasing oil prices to $45.00 (a 64 percent increase from the base case) increases the ROR dramatically (52 percent). EAC cost also increases by 41.3 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 ROR 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 23 percent increase in the ROR despite an EAC increase of 19 percent.

6.2.9.2 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 ROR on investment to 23.3 percent. A 25 percent increase in these costs reduces ROR to 17.1 percent. Taxes have little influence on these costs, which are incurred in the early years of development. EAC costs

TABLE 6-3

THE SENSITIVITIES OF OIL PRICES AND DEVELOPMENT COSTS ON ST. GEORGE BASIN OIL DEVELOPMENT

		Discounted After-Tax ROR versus Base Case		EAC Oil Cost	
		Percentage Difference	Percentage Change	Cost per Barrel ($)	Percentage Change
	Base Case	20.2		23.26	
1.	Increase oil prices to $45 per barrel	30.9	+ 52	32.87	+ 41.3
2*	Decrease oil prices to $22.50 per barrel	15.9	- 21.2	20.52	- 11,8
3.	Escalate oil prices at 3 percent per year	24.8	+ 22.8	27.75	+ 19.3
4.	Decrease operating and administrative costs by 20 percent	21.6	+ 6.9	22.53	- 3.1
5.	Increase operating and administrative costs by 25 percent	18.4	- 8.9	24.19	+ 4.0
6.	Escalate operating and administrative costs by 3 percent per year	18.9	- 6.4	24.03	+ 3.4
7.	Decrease tangible and intangible costs by 20 percent	23.3	+ 15.3	22.36	- 3.9
8.	Increase tangible and intangible costs by 25 percent	17.1	- 15.3	24.39	+ 4.9

are not as sensitive to these cost changes since the costs are spread over the productive life of the development.

6.2.9.3 Monte Carlo Analysis of Oil Development Economics

Prev ous sections have reported results based on the mid-range values for prices and costs. Repeatedly, however, this report has emphasized that costs for production technology that will be employed in the mid-1980's can only be estimated within a range of values. In this section, Monte Carlo distributions for the after-tax return on investment and EAC costs for the base case scenario are reported to emphasize the uncertainty built into this economic analysis of field development in the St. George Basin. Just as there is a range of values estimated for prices and costs, there is a range of values for the profitability criteria calculated by the model. A Monte Carlo solution to the model estimates the range of outcomes by repeatedly solving the model with random values selected in each solution pass for each of the variables whose values are entered as a range. With 100 solution passes, the Monte Carlo distribution reveals a probable estimate of the worst outcome, best outcome and intermediate results.

In the Monte Carlo solutions below, the spread of prices and costs used in the above sensitivity analysis was used to define a triangular probability distribution for each of the variables. Such a distribution assigns probabilities to all points between the minimum, mean, and maximum values in a linear fashion. The Monte Carlo draws randomly from those distributions.

Table 6-4 and Figure 6-1 show the Monte Carlo results for after-tax ROR based on 100 trails of the base case scenario. The expected value of 22.3 percent is 2 percent higher than the ROR calculated using the mid-range variable values. This difference is due to the inclusion of a maximum oil price of $45 per barrel, well above the mid-range $27.50 price. This price, while high, is by no means implausible since it amounts to a real oil price escalation of 5 percent for 10 years, to 1990 when St. George production can begin. It is interesting to note that the minimum ROR, based on the

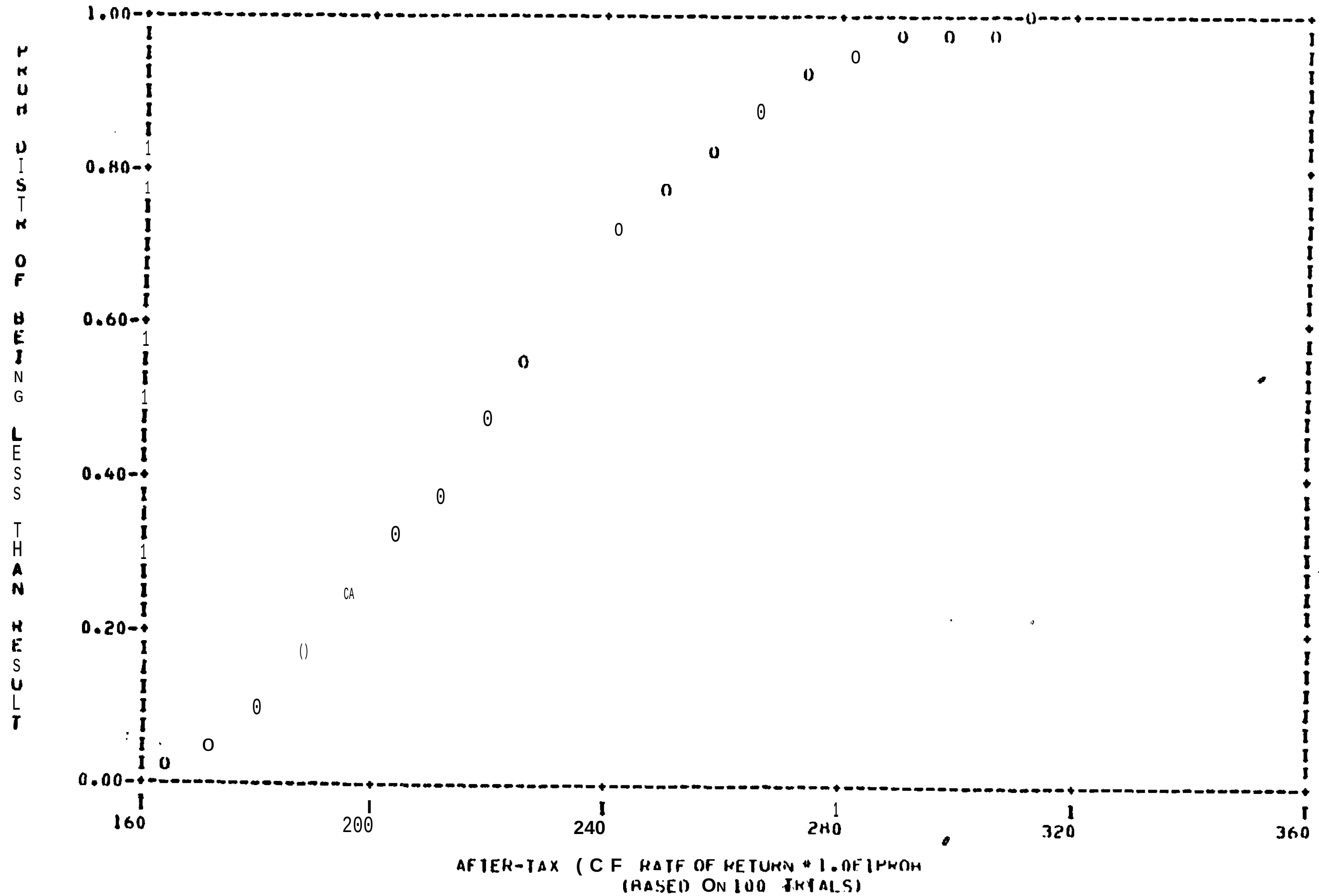
TABLE 6-4

MONTE CARLO RESULTS FOR AFTER-TAX DISCOUNTED
CASH FLOW (DCF) OF OIL FIELD Development

MONTE CARLO RESULTS FOR AFTER-TAX DCF RATE OF RETURN	
Result Value	Prob. of Being Less than Results
16.4480	.020000
17.2291	.060000
18.0102	.090000
18.7912	.180000
19.5723	.240000
20.3533	.330000
21.1344	.380000
21.9154	.480000
22.6965	.540000
23.4775	.630000
24.2586	.730000
25.0396	.780000
25.8207	.820000
26.6018	.870000
27.3828	.920000
28.1639	.960000
28.9449	.970000
29.7260	.970000
30.5070	.980000
31.2881	1.000000
Expected Value =	22.3446
Standard Deviation =	3.4549

FIGURE 6-1

MONTE1: MONTE CARLO ANALYSIS OF SINGLE-VALUED RESULTS OF OIL



combination of the lowest oil price ($22.50) with the highest costs, is 16 percent, well above the 12 percent hurdle rate. As long as the actual values are no more pessimistic than the low ranges estimated, a base ‘case field would be profitable. The most optimistic ROR is in excess of 31 percent. The Monte Carlo EAC shown in Table 6-5 has an expected value of $25.69 per barrel , $2.46 above the single-valued figure. As noted above, high oi l prices tend to raise the EAC because of additional taxes. The minimum EAC is $21.77 and the maximum is $31.73.

6.3 Analytical Results of Non-Associated Gas Development in the St. George Basin

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 6-6.

Most gas-containing reservoirs are in deep formations; therefore, no shallow gas reservoir cases were modeled. Larger reservoirs, while likely to be present, were not modeled since establishing the economic feasibility of smaller fields is sufficient to establish the feasibility of the larger ones. Offshore loading was not considered feasible for gas production.

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 fol owing parameters were assumed in the base case:

TABLE 6-5

MONTE CARLO RESULTS FOR EQUIVALENT AMORTIZED COST OF OIL FIELD DEVELOPMENT

MONTE CARLO RESULTS FOR EQUIV AMORTIZ COST ($/BBL)	
Result Value	Prob. of Being Less than Results
21.7762	.060000
22.2999	.090000
22.8236	.150000
23.3473	.220000
23.8710	.300000
24.3947	.380000
24.9183	.410000
25.4420	.480000
25.9657	.530000
26.4894	.620000
27.0131	.700000
27.5367	.760000
28.0604	.800000
28.5841	.850000
29.1078	.900000
29.6315	.910000
30.1551	.940000
30.6788	.950000
31.2025	.970000
31.7262	1.000000
Expected Value =	25.6931
Standard Deviation =	2.6401

Monte 1: Monte Carlo Analysis of Single-Valued Results of Oil

TABLE 6-6

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

Condition	Units	Range of Parameters Modeled
Reservoir Size	Trillion Cubic Feet	0.5, 0.75, 1.0*
Distance From Shore	Kilometers (Miles) /Share	80 (50)/2*, 160 (100)/2, 240 (150)/2
Initial Productivity Per Well	Million Cubic Feet	10.0, 15.0*
Water Depth	Meters (Feet)	107 (350)*, 150 (500)
Reservoir Depth	Meters (Feet)	3,050 (10,000)

*indicates the value used in the base case.

Reservoir size	1 trillion cubic feet
Initial Productivity	15 million cubic feet per day per wel 1
Recoverable reserves per acre	200 million cubic feet
Production system	Steel platform with half-shared 80-kilometer (50-mile) pipeline to shore
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 Aleutian terminal.(1) Implicit in these economic assessments of individual fields is the assumption that there will be sufficient gas produced from the St. George Basin to sustain an LNG terminal 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 1 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 St. George Basin. Other field conditions represent a favorable bias such as the 80-kilometer (50-mile), shared pipeline, and the 3,050-meter (10,000-foot) reservoir depth. Assuming higher IPs such as the 30 million cubic feet per day suggested by the U.S. Geological Survey (Marlow et al., 1979) would have a major impact on the economics. Therefore, we prefer to assume a conservative upper limit. If development is economic with 15 million cubic feet per day 1P, the impact of a higher 1P is a moot point.

Under these assumptions, a capital investment of $327 million over the first 6 years is necessary for development of the base case field. Twenty-one

(1) For discussion of this assumption, see Appendix A-5.

wells are drilled from the platform to yield a peak flow of 259 million cubic feet per day. The field produces for 13 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 $168 million. Table 6-7 shows ROR on investment to be 16.7 percent. This return, while well above the 12 percent hurdle rate is lower than most of the St. George Basin oil development cases modeled. The EAC gas cost is $1.90 per million cubic feet, well below the $2.22 assumed selling price.

6.3.2 Economic Impact of Alternative Well Productivities

St. George Basin wells are assumed to produce in the range of 10 - 15 million cubic feet per day. Fields with lower 1P wells would require more wells per platform to produce a given size field at a given rate. As seen in Table 6-7, Case A, development of a 10 million cubic feet per day well reservoir would cost $77 million, more than the base case. This results in a ROR of 12.1 percent, just above the 12 percent hurdle rate. The EAC cost per 1,000 cubic feet is barely below the maximum selling price. Fields up to 1.2 trillion cubic feet could produce somewhat more profitably since only a single platform would be needed. Larger fields would require either multiple platforms or a wider well spacing and therefore a longer production period. The economics of the larger fields should be at least as good as the 1 trillion cubic feet field.

6.3.3 Economic Impact of Water Depth

Increasing the water depth at the platform from 107 to 150 meters (350 to 500 feet) causes capital costs to rise $120 million above the base case as shown in Case B. This lowers the ROR to 15.4 percent and raises the EAC cost per 1,000 cubic feet by $0.04. Thus, this case is still economically feasible.

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 ROR 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 6-7 Case C, gas from a 750 billion cubic foot field costs only $0.09 more per 1,000 cubic feet than the gas base case, but yields a ROR 2.4 percent lower than the base case. A field with 500 billion cubic feet of recoverable reserves yields a ROR of only 8 percent, well below the 12 percent hurdle rate. The minimum gas field size for development is slightly under 250 billion cubic feet for the base case assumptions.

6.3.5 Economic Impact of Alternative Pipeline Configurations

As illustrated in Table 6-7, Case D, a shared 160-kilometer (100-mile) pipeline to shore decreases the rate of return by 1.4 percent but only increases EAC costs by $0.05 per 1,000 cubic feet due to offsetting tax effects. A 240-kilometer (150-mile) pipeline requires a compressor station, which increases capital costs 37 percent as well as raising operating costs. Even when those delivery costs are shared with a similar field the ROR would only be 10.4 percent, which is below the 12 percent hurdle rate. An unshared 160-kilometer (100-mile) pipeline (the limit for operation without a compressor station) just makes the hurdle rate. In summary, a 1 trillion cubic foot field would be economic at distances less than 100 kilometers (64 miles) from shore. At greater distances, development economics are unfavorable unless pipeline costs can be shared with more than one other field. Larger fields would support longer pipelines.

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

As shown in Table 6-8, increasing the price received for gas at the shore terminal from $2.22 to $3.60 per 1,000 cubic feet (a 75 percent increase)

Table 6-7

RESULTS OF ECONOMIC MODELING OF GAS PRODUCTION IN THE ST. GEORGE BASIN

1	2	3	4	5	6	7	8	9	10
CASE :	RESERVOIR TARGET DEPTH (Meters)	PIPELINE DISTANCE TO SHORE/NO. OF FIELDS SHARING PIPELINE (Kilometer/No.)	NO. OF PLATFORMS/NUMBER OF PRODUCING WELLS (NO.)	PEAK PRODUCTION PER WELL/PER PLATFORM (MMCFD)	UNDISCOUNTED CAPITAL INVESTMENT $ M)	RESERVOIR SIZE RECOVERABLE RESERVES (TCF)	AFTER -TAX RATE OF RETURN ON INVESTMENT (Percent)	DISCOUNTED AFTER -TAX CAPITAL COST ($/MCF)	EQUIVALENT AMORTIZED COST (E A C) ($/MCF)
Initial Well Productivity (15MMCFO)									
Base Case	3050	80/2	1/18	15/259	327.2	1.0	16.7	0.53	1.98
(10MMCFD)	3050	80/2	1/29	10/278	404.4	1.0	12.1	0.57	2.18
Oeep Water (150 Meters)	3050	80/2	1/18	15/259	356.2	1.0	15.4	0.57	2.02
Reservoir Size (1.0TCF)									
Base Case	3050	80/2	1/18	15/259	327.2	1.0	16.7	0.53	1.98
(0.75TCF)	3050	80/2	1/15	15/216	310.8	0.75	14.3	0.59	2.07
(0.5TCF)	3050	80/2	1/10	15/144	269.0	0.50	8.0	0.78	2.38
Pipeline Distance Base Case	3050	80/2	1/18	15/259	327.2	1.0	16.7	0.53	1.98
160 Kilometer (100 Mile) Shared	3050	160/2	1/18	15/259	368.4	1.0	15.3	0.54	2.03
240 Kilometer (150 Mile) Shared	3050	240/2	1/18	15/259	446.0	1.0	10.4	0.71	2.26
160 Kilometer (100 Mile) Unshared	3050	160/1	1/18	15/259	456.2	1.0	12.6	0.72	

MCF = thousand cubic feet
MMCFD = million cubic feet per day
TCF - trillion cubic feet

TABLE 6-8

THE SENSITIVITY EFFECTS OF GAS PRICE AND DEVELOPMENT CHANGES ON ST. GEORGE BASIN GAS DEVELOPMENT

	Discounted After-Tax ROR versus Base Case		EAC Gas Cost	
	Percent	Percentage Change	Cost per Thousand Cubic Feet ($)	Percentage Change
Base Case	16.7	--	1.98	--
1. Increase gas prices to $3.60 per thousand cubic feet	26.4	57.7	2.73	38.3
2. Decrease gas prices to $1.75 per thousand cubic feet	12.1	28.0	1.72	-13.0
3. Escalate gas prices by 3 percent per year	21.2	26.6	2.32	17.4
4. Decrease operating and administrative costs by 20 percent	18.0	7.5	1.92	- 2.9
5. Increase operating and administrative costs by 25 percent	15.2	- 9.4	2.05	3.6
6. Decrease tangible and intangible capital costs by 20 percent	1907	17.9	1.88	- 4.8
7. Increase tangible and intangible costs by 25 percent	13.7	-17.9	2.10	6.1

raises the rate of return to 26.4 percent, 58 percent higher than the base case. Higher revenues would also cause the EAC to rise 38 percent because of the greater tax liability. Decreasing the gas price to $1.75 per 1,000 cubic feet (a 21 percent decrease) drops the rate of return to 12.1 percent, the economic limit of feasibility. Taxes lower the EAC 12 percent to $1.72, or just below the received price. Escalating relative gas prices by 3 percent per year raises the rate of return to 21 percent, or 27 percent higher 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 1.5 percent in the ROR, while a cost decrease of 20 percent produces an ROR only 1.3 percent higher. EAC cost changes are even less sensitive to operating and administration cost changes.

Decreasing capital costs by 20 percent increases ROR from 16.7 to 19.7 percent. Likewise, increasing capital costs by 25 percent reduces the ROR to 13.7 percent. EAC costs are not so sensitive to those cost changes since the costs are amortized over the life of the field.

6.3.7 Monte Carlo Analysis of Gas Development Economics

The Monte Carlo analysis for gas development follows the procedure used for oil development, as described in Section 6.2.9.3.

The expected rate of return in the Monte Carlo run is 18.5 percent, as seen in Table 6-9. This rate of return is almost 2 percent higher than that calculated using the mid-range values. The Monte Carlo result is preferred methodologically because mid-range values reported in Section 6.3.1 reflect current prices and costs, and the escalation of gas prices with respect to cost is likely.

More significant, however, is the low end of the distribution. As shown in Figure 6-2, which is a graph of the probable distribution of after-tax ROR,

TABLE 6-9

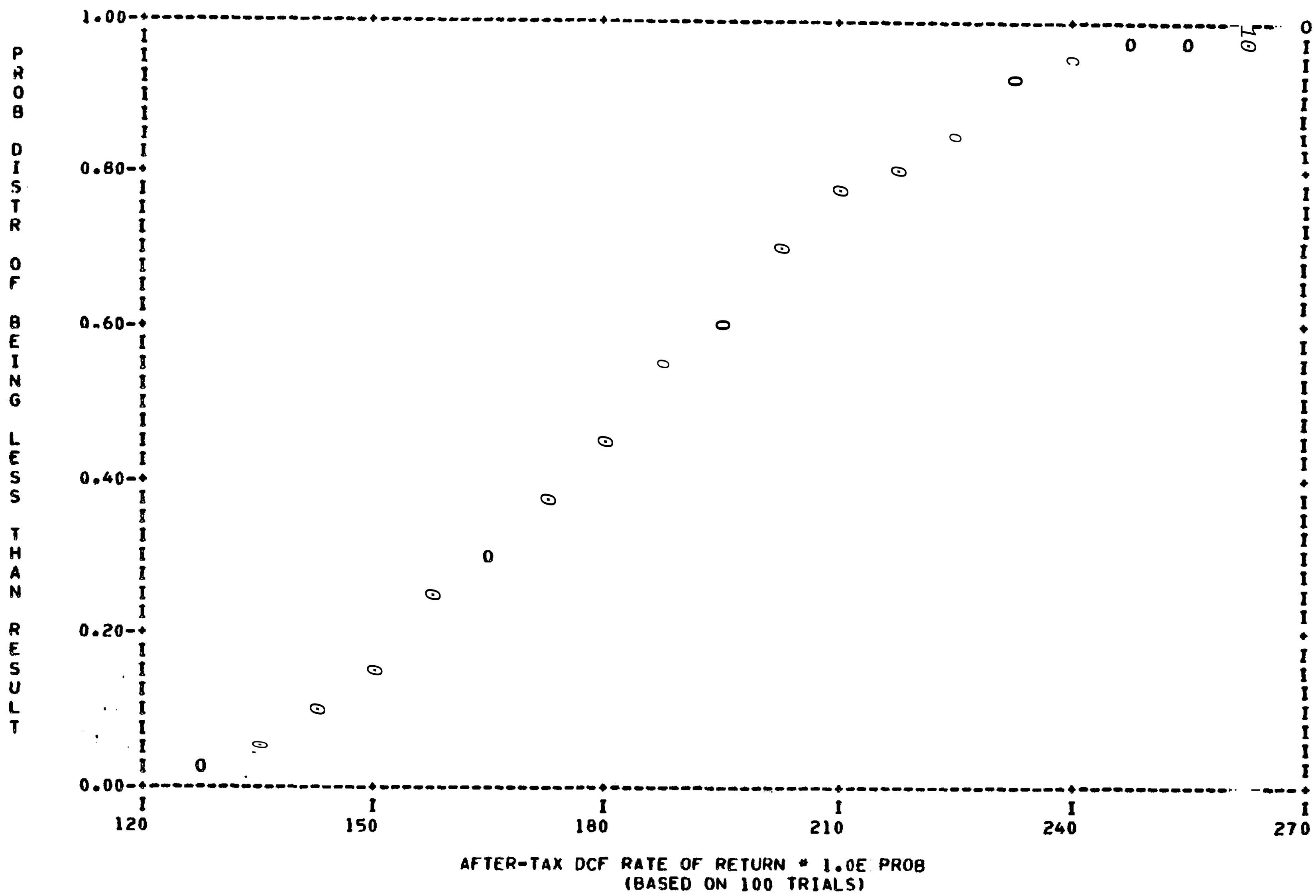
MONTE CARLO RESULTS FOR AFTER-TAX DCF RATE OF RETURN FOR GAS FIELD DEVELOPMENT

MONTE CARLO RESULTS FOR AFTER-TAX DCF RATE OF RETURN	
Result Value	Prob. of Being Less than Results
12.6848	.020000
13.4368	.060000
14.1888	.090000
14.9408	.150000
15.6928	.240000
16.4448	.290000
17.1968	.380000
17.9488	.440000
18.7008	.540000
19.4528	.600000
20.2048	.710000
20.9568	.770000
21.7089	.810000
22.4609	.860000
23.2129	.920000
23.9649	.960000
24.7169	.970000
25.4689	.970000
26.2209	.980000
26.9729	1.000000
Expected Value =	18.4881
Standard Deviation =	3.3017

Monte 2: Monte Carlo Analysis of Single-Valued Results of Gas

FIGURE 6-2

MONTE2: MONTE CARLO ANALYSIS OF SINGLE VALUED RESULTS OF GAS



the most pessimistic assumptions (higher costs and lowest price) still result in a rate of return above the 12 percent hurdle. This indicates that all gas development conditions, as favorable or better than the base case conditions, will be economically feasible.

As seen in Table 6-10, the expected value of the EAC ranges from $1.81 - $2.64 per 1,000 cubic feet with an expected value of $2.15 per 1,000 cubic feet. This expected value is higher than the $1.98 that resulted from the mid-range value computation, again because of the high maximum gas price assumption. A higher price raises the tax paid and hence the EAC.

6.4 Equivalent Amortized Cost of Oil and Gas Development

6.4.1 Oil

The GUESS model, as modified by Dames and Moore, is capable of disaggregating the distinct components comprising development cost on a per barrel, discounted, after-tax basis. Although this information is available for every case run, display of the EAC disaggregate cost is confined to a few representative cases. The EAC for those representative oil cases is shown in Table 6-11.

Development costs are calculated to range between $20.85 - $25.03 per barrel. The range of uncertainty around component capital, operating, and general and administration costs is -20 to +25 percent. However, because of the off-setting effect of taxes the uncertainty range for the sum of the development costs is from -8 to +10 percent.

Transportation costs from Dutch Harbor to the U.S. west coast were estimated to range between $1.88 - $2.95 in 1980 dollars. Adding the mean transport charge of $2.36 to the EAC implies oil can be laid-in to Los Angeles at between $23.88 -$27.39 per barrel.[1]

---

[1] This estimate is based on shipping costs from Valdez to California multiplied by 1.5 to reflect greater shipping distance and greater logistical constraints.

TABLE 6-10

MONTE CARLO ANALYSIS OF EQUIVALENT AMORTIZED
COST FOR GAS FIELD DEVELOPMENT

MONTE CARLO RESULTS FOR EQUIV AMORTIZ COST ($/BBL)	
Result Value	Prob. of Being Less than Results
1.8152	.040000
1.8588	.080000
1.9025	.150000
1.9461	.180000
1.9898	.280000
2.0334	.320000
2.0771	.400000
2.1207	.450000
2.1643	.500000
2.2080	.590000
2.2516	.680000
2.2953	.740000
2.3389	.790000
2.3826	.840000
2.4246	.900000
2.4699	.920000
2.5135	.940000
2.5572	.960000
2.6008	.970000
2.6445	1.000000
Expected Value =	2.1550
Standard Deviation =	.2156

TABLE 6-11

EQUIVALENT AMORTIZED COST OF OIL PRODUCTION AND ASSOCIATED GAS PRODUCTION IN ST. GEORGE BASIN
($ per Barrel - 1980)

Field Size (million barrels)[1]	1000	350	350	100	100		Range of Certainty[3]
Pipeline	Unshared 320 KM	Unshared 320 KM	Half-Shared 240 KM	Half-Shared 240 KM	Half-Shared 80 KM		
Reservoir Depth	3050 M	3050 M	1025 M	3050 M	3050 M		
					Oil	Associated Gas	Percent
Total Capital Charge	6.26	7.09	5.59	9.34	7.14	0.80	-20 to +25
Of which, capital cost at 12 percent	4.37	5.02	3.96	6.51	4.99	0.55	-20 to +25
General and Administrative Expenses	1.31	1.17	1.17	2.98	2.99	0.00	-20 to +25
Operating Costs	3.20	2.02	2.82	4.53	3.79	0.38	-20 to +25
Royalty at 16.67 percent	4.58	4.58	4.58	4.58	4.58	0.37	fixed
Federal Taxes Net of Tax Credits	6.1?	6.14	6.67	3.60	4.76	0.38	Will off-set approx. half of cost change
SUBTOTAL DEVELOPMENT COSTS:	21.52	21.81	20.85	25.03	23.26	1.93	- 8 to +10
Transport to Los Angeles[2]	2.36	2.36	2.36	2.36	2.36	3.50	-20 to +25
TOTAL LAID-IN COST:	23.88	24.17	23.21	27.39	25.62	3.43	- 8 to +10
Allocation of Capital Charge:							
Offshore Production	4.08	3.28	3.29	4.84	4.94	0.72	
Pipeline To Shore	1.16	2.64	1.13	3.17	0.84	0.08	
Terminal	1.02	1.16	1.17	1.31	1.35	0.00	
TOTAL	6.26	7.09	5.59	9.34	7.14	0.80	
Present Barrel Equivalent (PBE)- Million Barrels, Thousand Cubic Feet	303.1	109.2	109.2	36.2	36.2	36.2	

Source: DAMES and MOORE

1 All cases have 2000 barrels per day IP, 108 meter water depth
2 $2.01 transport plus $0.35 terminal charge at Los Angeles.
3 A great deal of uncertainty underlines the original capital and operating cost estimates. Since the royalty rate is fixed, however, and taxes off-set approximately one-half the increase or decrease in cost, the net effect is that there is less uncertainty around the total EAC than around components of costs.

In all but Case 3, the largest component of cost is the capital charge (computed assuming a 12 percent value of money).

Cases 4 and 5 are capital intensive because they are small fields in which the fixed capital investment is allocated over a relative small production. Cases 1 and 2 are capital intensive because a very long pipeline services a single field.

Federal taxes are high for the large fields (Cases 1, 2, and 3) and distinctly lower for the small fields. Since tax credits are distributed over smaller output, royalty payments are the same for all cases. Operating and general and administrative costs reflect economies (and in Case 1, diseconomies) of scale.

The largest share of development costs are attributable to offshore production. The pipe share is proportional to the throughput and pipeline distance. Terminal charges are roughly equal for all cases.

Costs for associated gas are slightly lower than costs for non-associated gas, which are discussed in the next section.

6.4.2 Gas

St. George Basin gas must be converted into LNG at a shore terminal and transported to California in LNG tankers equiped for artic conditions. This is the largest cost component of getting frontier gas to market. The resulting laid-in costs range from $5.80 - $6.12 per 1,000 cubic feet.

Reliable estimates of the cost of LNG conversion and transport are unavailable. Our $3.50 mean cost estimate is derived from our discussion of Norton Sound LNG in Appendix F of the Norton Sound report (Dames & Moore, 1980). Marketability of LNG from St. George Basin at highest conversion and transport costs is discussed in Section 6.5.6. The objective of the economic analysis of gas was to discover the EAC of development. As shown in Table 6-12, the EAC ranges from $2.18 - $2.62.

TABLE 6-12

EQUIVALENT AMORTIZED COST OF GAS PRODUCTION IN
ST. GEORGE BASIN
($ per Million Cubic Feet -1980)

Field Size (billion cubic feet)	1000	1000	500	Range of Uncertainty [1]
Pipeline	80 KM Half-Shared	250 KM Half-Shared	80 KM Half-Shared	
Reservoir Depth	3050	3050	3050	
Initial Productivity (million cubic feet)	10	15	15	(percent)
Total Capital Charge	0.83	1.02	1.13	-20 to +25
Of which, capital cost at 12 percent	0.57	0.71	0.78	-20 to +25
General and Administrative Expenses	0.32	0.30	0.51	-20 to +25
Operating Costs	0.52	0.44	.60	-20 to +25
Royalty at 16.67 percent	0.37	0.37	0.37	Fixed
Federal Taxes Net of Tax Credits	0.15	0.12	0.12	Will offset approx. half of cost exchange
SUBTOTAL DEVELOPMENT COSTS:	2.18	2.26	2.51	- 8 to +10
LNG Convert and Transport	3.50	3.50	3.50	-20 to +25
TOTAL Regasified Cost at Pt. Conception	5.68	5.75	6.07	- 8 to +10
Allocation of Capital Charge:				
Offshore Production	0.73	0.56	0.94	
Pipeline	0.10	0.46	0.19	
TOTAL	0.83	1.02	1.13	
Present Barrel Equivalent (PBE)- billion. cubic feet	357.7	375.2	195.7	

Source: DAMES and MOORE

[1] A great deal of uncertainty underlines the original capital and operating cost estimates. Since the royalty rate is fixed, however, and taxes off-set approximately one-half the increase or decrease in cost, the net effect is that there is less uncertainty around the total EAC than around components of cost.

Apart from conversion to LNG and transportation, the largest development cost is the capital charge. Capital charge is greatest for Case 2", which requires a long pipeline. Operating costs and general and administration costs reflect the economies of scale in operating larger fields. Royalty payments are constant and Federal tax relatively constant in each case.

The distribution of costs between offshore platform and pipeline depends on pipeline length. In all cases, however, offshore platform costs predominate.

6.5 Relationship of St. George Basin Oil and Gas Supplies to U.S. Energy Bal ante

6.5.1 Introduction: The Supply of St. George Oil and Gas

Potential oil and gas supplies from the St. George Basin could be available to the United States no sooner than 1990, if the lease sale is held on 'schedule in 1982. Chapter 7.0 develops the likely supply patterns for the USGS statistical mean resource estimate assuming a high level and rapid exploration and development program. Indeed, the potential supplies are large. Gas could flow at nearly 2 billion cubic feet per day throughout the 1990s. Oil could flow in excess of 500,000 barrels per day throughout most of the 1990s. Hence, development of these offshore resources will entail large onshore developments in the Aleutians or Alaska Peninsula or both.

The following sections highlight the econom c issues concerning marketing potential St. George Basin oil and gas in the United States. In-depth presentation of some of the issues presented in the February 1980 Norton Basin Marketability Study (Dames & Moore, 1980) is not reproduced in this report. The reader is referred to that study.

6.5.2 Background: World Oil Supply and Demand

6.5.2.1 World Oil Production Forecasts

Table 6-13 shows several crude oil production forecasts that recently have appeared in the Oil and Gas Journal, World Oil, government reports, and published company sources. A growing consensus of company forecasts call for world oil production to peak around 1990 and decline thereafter. The average of the various forecasts shown in Table 6-13 reflects the expected trend with a peak near 60 million barrels per day by 1990 and a slow decline thereafter.

Both Exxon and the U.S. Central Intelligence Agency (CIA) have emphasized in recent months that throughout the 1970s new oil discoveries replaced no more than half of production. Prior to 1970, discovery rates were well in excess of production. The CIA has the gloomiest forecast: "Global oil production is peaking and will decline throughout the 1980s . . . The expected decline . . is the result of a rapid exhaustion of conventional crude oil" (Oil and Gas journal, 1980d).

The British Petroleum forecast not only sees the possibility that OPEC may limit production to 30 million barrels per day beyond the mid-1980s, it, like the CIA's forecast, is also very pessimistic about remaining world production capacity. BP assumes that significant new supplies in non-OPEC countries will not be found, and that non-communist world production capacity will peak by 1985 at the latest. Thus, while the average of forecasts in Table 6-13 shows a peak in 1990, BP and the CIA agree that peak world oil production could be sooner and that 1990 and 2000 production levels could be much lower than the average.

6.5.2.2 OPEC'S Continued Importance

The range in the forecasts after 1985 in Table 6-13 is explained by the various company and agency assumptions about OPEC production.

TABLE 6-13

NON-COMMUNIST WORLD CRUDE PRODUCTION FORECASTS(1)
(Million Barrels per Day)

	FORECAST DESCRIPTION	1980	1985	1990	2000
British Petroleum	-OPEC At Max.	--	64	62	52
	-OPEC No Inc.	--	55	52	43
Standard of Indiana	-Base Case	53.8	59	--	--
	-Pessimistic	52.5	55	--	--
Standard of California	-1990 Plateau	53	58	60.5	60
Shell	-Optimistic	--	--	66.5	70
	-Pessimistic	--	--	57	63
Exxon	-1978-Year-End	53	--	57	58
CIA	-Low	53	48	--	--
	-High	--	49	--	--
Michael F. Thiel	-Upper OPEC	57	65	70	--
	-95 Percent OPEC Limit	55	63	67	--
	-Lowest OPEC	47	55	59	--
Average		53	57	61	58

(1) For consistency between forecasts NGL is excluded. NGL is about 5 percent of these production figures.

SOURCES:

1. Oil and Gas Journal, 1979d.
2. Exxon, 1979a.
3. Pocock, Cc., 1979.
4. Thiel, M.F., 1979.
5. Oil and Gas Journal, 1980d.

Political considerations emerging within the Middle East oil producing countries in 1980 suggest that even though proved reserves would allow higher production, OPEC oil during the 1980's probably will not be produced at maximum rates. Thus, the world in the last two decades of the twentieth century will be short of oil due to both political instability and physical resource limitations.

Table 6-14 reveals that OPEC's share of the non-communist world oil production was over 60 percent in 1979. The world will remain dependent on OPEC's oil throughout the remainder of the twentieth century.

"Most industry analysts expect OPEC production to remain about 30 million B/D at least through 1985" (Oil and Gas Journal, 1979d). Many OPEC observers believe there will be little economic incentive to exporting countries to expand production much above 30 million barrels per day after 1985. Incremental production would only increase the OPEC nations' financial assets held in foreign banks and would not benefit their domestic economic growth.

Although Saudia Arabia may increase its productive capacity 1 million barrels per day above its present 9.5 million level, by mid-1980 the CIA expects the Saudis to announce an 8.5 million barrels per day or less production limitation (Oil and Gas Journal, 1980d). Kuwait, which could maintain output at its existing capacity of 2.7 million barrels per day for at. least 50 years, has limited production to 1.5 million barrels per day because it cannot use its oil revenue productively. Similarly, Iraq and Iran will probably limit production to 3 million barrels per day -- enough to meet development needs. So long as the western nations depend on OPEC oil, the OPEC countries will be able to raise prices to increase revenue flows and hold production relatively stable.

6.5.2.3 Sine-Soviet Supply Problems

A CIA forecast (CIA, 1979) contends that the 'potential oil shortage in the western world will be compounded by Soviet Bloc production capacity

TABLE 6-14

WORLD OIL PRODUCTION: 1979[1]

		Million Barrels Per Day	Percent of Non-Communist
Total OECD[2]		14.1	27.5
U*S.	10.3		
Total OPEC		30.8	60.2
Saudi Arabia	9.25		
Iran	3.1		
Total other countries		6.3	12.3
Mexico	1.5		
Total non-communist		51.2	100.0
Sine-Soviet		14.2	
Russia	11.7		
World Total		65.4	

(1) Including Natural Gas Liquids

(2) Organization for Economic Cooperation and Development

Source: Oil and Gas Journal, February 25, 1980 invaded Afghanistan). The world energy picture appears to be quickly changing. Any demand forecast in the uncertain world of 1980 must be viewed as little more than an idea to think about.

Comparing these demand forecasts to the average production forecast in Table 6-13 shows a very tenuous balance in 1985 and 1990. After 1990, as global oil production declines, the gap between demand and supply widens. Demand will have to be met either by increased use of synfuels, alternative energy sources or by increased production from the Middle East -- or not at all if none of these supply alternatives materialize.

6.5.3 United States Energy Situation

6.5.3.1 Demand: A Radical Change in Consumption Patterns

Oil will remain the predominant fuel in the U.S. throughout this century, although its share of total energy will decline. During the 1980s and the 1990s there will be a crude oil shortage. These two decades will be a transition period to coal and nuclear power. Methods will be sought to produce new energy resources on a large scale and integrate them into the existing distribution network in an economic and environmentally compatible way. However, even by year 2000, alternate energy sources will be a very small share of total U.S. energy consumption.

A year ago Shell, Exxon, and Chevron, in independent forecasts, projected 1990 U.S. energy demand to range from 47.6 - 49.9 million barrels per day oil equivalent (O.E.), a narrow range of estimates. They further agreed that crude oil would account for 20 - 21 million barrels per day of this total. 1978 U.S. crude oil demand was 19.2 million barrels per day of a total of 38 million barrels per day O.E. for U.S. energy consumption.

Underlying Shell's, Exxon's, and Chevron's forecasts were real GNP growth rates between 3 - 3.5 percent. Total U.S. energy use growth was expected to fall within 2.0 - 2.25 percent between 1978 and 1990.

Table 6-16 shows our current forecast derived from published and unpublished sources. This is based on a 2.6 percent growth rate for real GNP and requires 1.5 - 1.8 percent growth in total energy use. The 1990 energy forecast has dropped to 43 - 46 million barrels per day O.E., of which oil is 16 - 19 million barrels per day. Most of the increase in energy use will come from coal and nuclear plants whose share of total energy consumption is forecast to increase from 23 percent in 1980 to 42 percent by 2000.

Hydro, geothermal, solar, and other alternatives will not become a significant share of energy consumption during this century. Oil and gas consumption will not decline, or will decline little. Oil, gas, coal and nuclear power together with increased energy efficiency seem to be the critical solutions to our energy supply problems for the remainder of this century.

It is important to realize that this forecast will require a tripling in coal production from 750 million tons last year to 2 billion tons by 2000. During the last 20 years coal production grew 1.5 percent annually. If the U.S. does not increase output to 2 billion tons by 2000, there may be serious shortages of electrical generating capacity.

6.5.3.2 Domestic Oil Production

While U.S. oil consumption growth rates will significantly drop, the fact remains that the domestically produced oil consumed in the 1990s must be developed during the 1980s. The U.S. is currently producing at the rate of approximately 3.75 billion barrels per year. Proved reserves as of January 1, 1979 amounted to 27.8 billion barrels -- an inventory sufficient to last only 7.5 years, through mid-year 1986 at current production rates. Thus , to hold domestic production at current levels for 7.5 years beyond mid-year 1986, additional reserves, at least equal to the total current proved reserves, must be found and developed during this period.

TABLE 6-16

U.S. ENERGY FORECAST: 1980-2000

Million Barrels per Day Oil Equivalent

	1980	1990	2000	Annual Growth Rate 1980-2000 Percent
Hydro, Geothermal, Solar, etc.	1.5	2.0	2.3	2.2
Nuclear	1.4	3.6	5.0	6.6
Coal	7.5	11.3	17.0	4.2
Gas	10.2	10.3	10.8	0.3
Oil	18.0	16.9-19.6	16.7-19.6	(0.4-0.5)
Total	**38.6**	**43.0-46.0**	**51.8-54.8**	**1.5-1.8**

Source: Dames & Moore

In spite of the exploration task facing the U.S. oil industry in the 1980s, most forecasts of domestic oil production for the coming decade predict domestic production near present levels. 1979 production of crude and NGL was 10.3 million barrels per day.

Table 6-17 shows the different sources of oil supplies that will be required to meet forecasted demand. Lower 48 production is shown to be declining throughout the next two decades. The general belief is that this is an irreversible trend. So, too, Prudhoe Bay will begin to decline soon after the mid-1980s. Consequently, America's domestic oil future is tied to two great hopes: (1) new reserves of oil are discovered and produced in a timely manner in the OCS of the United States (most of these new reserves are expected to be found in Alaska), and (2) synthetic oil production increases greatly in the 1990s.

Table 6-17 clearly shows that foreign imports are unlikely to be significantly lower by 1990 than current imports. (Due to the recession and other factors, imports averaged a little over 7 million barrels per day during first quarter 1980.) By 2000, if synfuels increase as anticipated, foreign imports are expected to be lower. This forecast of a decline in foreign oil imports instead of a definite rise represents a significant change from industry projections. Most industry forecasts have maintained consistently that foreign imports are more likely to be higher than lower by 1990 despite increased energy efficiency and slowed energy growth forecasts. Indeed, a May 1980 study by Shell maintains foreign imports will be 9.3 million barrels per day in 1990 (San Francisco Examiner, 1980). It must be remembered, however, that the oil forecasts in Table 6-17 support only a 2.6 percent growth in real GNP. This is only about two-thirds of the U.S. historic average since World War II.

The U.S. as well as much of the rest of the world will remain critically dependent on oil from the Middle East until sometime in the next century when alternative technologies and sources of energy are developed. Minor disruptions in imports will continue to have major economic disruptions.

TABLE 6-17

UNITED STATES OIL SUPPLY FORECAST

Million Barrels per Day Oil Equivalent

	1980	1990	2000
Sources of Oil:			
Lower 48	8.3	6.0 - 7.1	5.6 - 6.1
Alaska - Existing	1.6	1.3	0.4
- New	--	0.5 - 0.9	0.6 - 2.1
Synthetics	--	1.0	4.6
Imports	8.1	7.8 - 9.3	5.5 - 6.5
TOTAL	18.0	16.6 - 19.6	16.7 - 19.7

Sources: Exxon, 1979b.
Dames & Moore.
Department of Energy, 1979.

Alaska's OCS appears to be America's best hope for new oil supplies. The forecast on Table 6-17 is only a rough estimate made by the Department of Energy (DOE) based on gross assumptions. The final 5-year OCS lease schedule EIS contains no additional information for Alaska's potential production in isolation from the rest of the OCS. Neither does another DOE document, "Federal Leasing and Outer Continental Shelf Energy Production Goals" (June 1979).

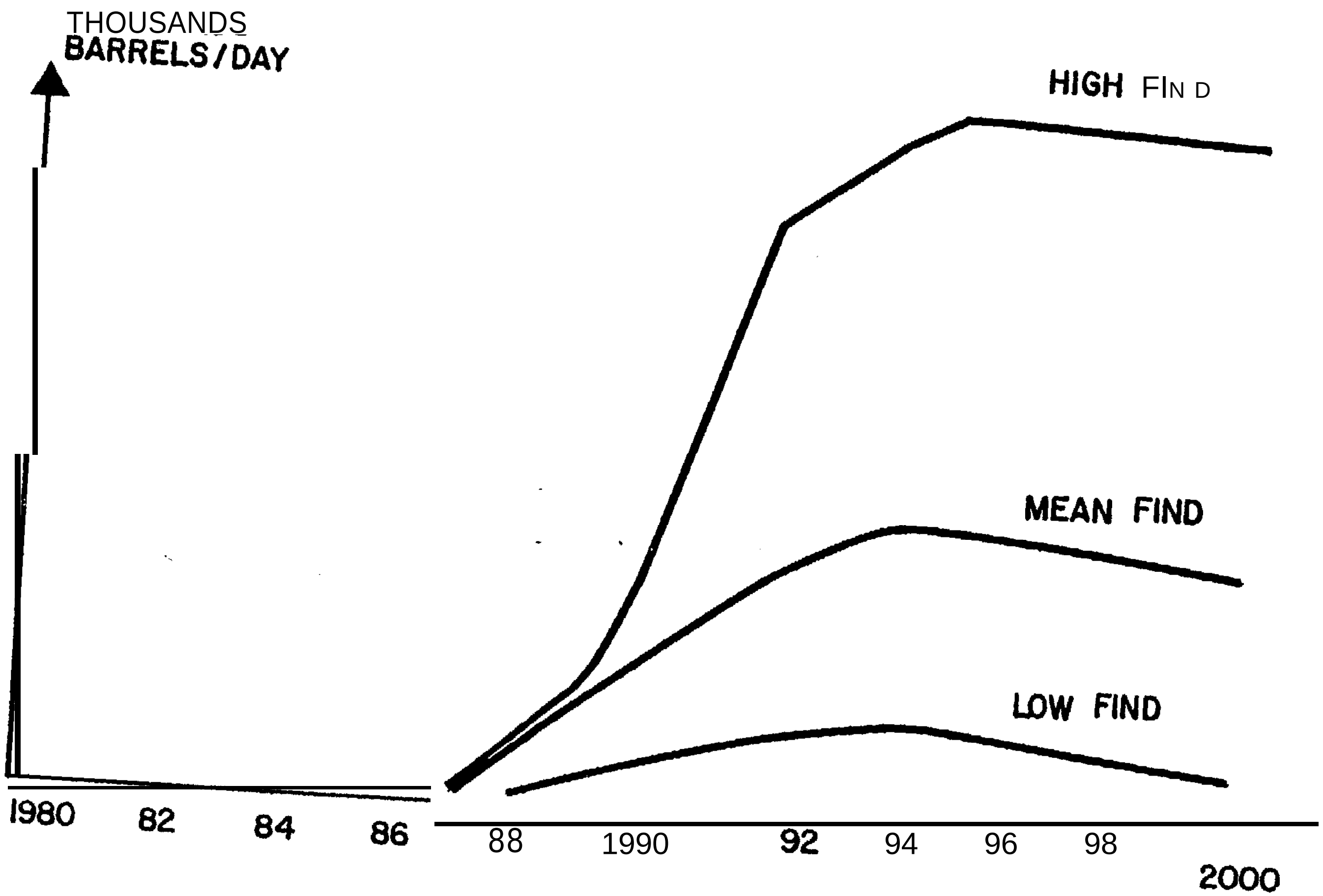
The DOE forecast, together with existing Alaska production shown in Table 6-17, imply a recovery of approximately 12 - 13 billion barrels of oil from Alaska in the next 20 years. Remaining proved reserves in Alaska total about 9 billion recoverable barrels. Latest resource estimates range between 7 - 32 billion barrels (Oil and Gas Journal, 1980c). Hence, a forecast of 12 - 13 billion barrels over the next 20 years may imply too high a recovery rate. In the absence of a better forecast, Table 6-17 adopts the DOE forecast of new Alaska production.

Figure 6-3 shows approximately when new discoveries in the Alaska OCS will become oil supplies to the United States. The time scale is associated with the April 1980 U.S. OCS lease schedule and the long period required to explore, discover, delineate, develop, and produce oil in Alaska's OCS. The earliest that any production could start is 1987 from the Beaufort Sea, assuming that current litigation concerning the sale is soon settled and exploration can commence in the winter of 1980-81.

The horizontal axis has no scale because the potential upper and lower estimates of new supplies are not known. So, too, the shape of the curves only accurately describes the potential step-ups in production. When peak will be reached and how long it can be sustained is unknown. Figure 6-3 reflects the fact that no significant new supplies can be developed before the early to mid-1990s.

FIGURE 4-3

THE TIMING OF POTENTIAL OIL SUPPLIES FROM ALASKA OCS



DAMES & MOORE
APRIL, 1980

6.5.4 Petroleum Administration District V with Special Reference To California

6.5.4.1 PAD V Supply/Demand Balance

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 6-18 shows the District V 1978, 1979, and preliminary first quarter 1980 supply/demand balance for crude oil and petroleum products. The table illustrates several situations about PAD V petroleum flows that were discussed in detail in our February 1980 Bering-Norton marketing study.

Table 6-18 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.

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

TABLE 6-18

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	
Refinery Process Gain	112	115	1?:
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.

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

This situation results from the problem of matching crude supplies with demand slate. 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 hydro-cracking 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 ref· nery 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. By the mid-1990s, when St. George production reaches nearly 700 million barrels per day, Prudhoe Bay production will be down to 70,0 million barrels per day. By then California refineries are expected to be able to handle heavy crudes in the range of 1.25 - 1.5 million barrels per day. Hence, to some extent the quality of potential St. George crude is a moot point.

Table 6-19 shows PAD V demand forecast. The forecast calls for petroleum use to grow at 1.0 percent annually to 1990 and then flatten out. 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.

TABLE 6-19

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

	Actual			Forecast		
DEMANO	1978	1980	1985	1990	1995	2000
Direct V Consumption	2624	2625	2760	2900	3000	3000
Interdistrict Product Exports[5]	136	75	160	125	125	125
Total Demand	2760	2700	2860	3025	3125	3125
SUPPLY						
Alaska Production						
Cook Inlet	137	110	50	25	--	--
Prudhoe Bay	1065	1500	1620	1275	700	370
Subtotal: Alaska	1202	1610	1670	1300	700	370
California Production						
Nest Likely	918.6	1000	1100	1100	1000	950
Maximum	918.6	1000	1400	1400	1300	1200
Minimum	918.6	1000	980	930	850	800
Foreign Imports (Crude & Products)[4]	690	500	330	330	330	330
Interdistrict Product Receipts[5]	167	100	50	50	50	50
Process Gain	112	110	110	120	120	120
Total Supply (Most Likely)[6]	3089.6	3320	3260	2900	2200	1820
Upper and Lower Limit	--	--	3110-3560	2730-3200	2050-2500	1670-2070
Supply Surplus/ (Deficit)[7]	329.6	620	400	(125)	(925)	(1820)
Upper and Lower Limit	--	--	280-700	(295)-175	(625)-(1075)	(1055)-(1455)
Forecast of Potential New Alaska production						
High Case	--	--	350	900	2000	2100
Low Case	--	--	--	500	500	600
St. George Product ion:[9]						
Mean Find				95	690	440

NOTES TO TABLE 6-19

[1]District V consumption is sensitive to supplies of natural gas to District V. This forecast assumes most likely gas supplies. Upper and lower limit demand cases are not shown. Directionally, a single demand case is sufficient to show how potential new Alaska production might supplement expected California and projected Alaska production.

[2]Alaska production is a projection of the known reserves in Cook Inlet and Prudhoe Bay. Prudhoe Bay includes production from the Sadlerochit and Kuparuk fields. No assumed new discoveries are included. Consequently, this is not a forecast; it is a projection.

[3]This is the California Energy Commission most likely and maximum forecast of California production. Standard Oil of California's forecast as shown in CEC's document is shown as the minimum. Standard Oil does not consider this forecast a minimum.

[4]No attempt is made to consider the impact of refinery modification on foreign imports. By 1985 the requirement for foreign Indonesian crude could be much lower if refinery modifications are made to process either incremental North Slope or California crude.

[5]These are light products imported and heavy products exported to balance refineries. Any number of scenarios could be constructed for different cases to project the impact of future refinery modifications on product balance shipments. This is an intermediate case.

[6]This is total supply given the range in forecasts of California production and the projection of Alaska production from proved reserves and an intermediate scenario for products imported and exported to balance refineries.

[7]Supply surpluses represent Alaska crude oil destined for Districts I-IV. Deficits from 1990 represent the potential refinery requirement for new production from new reserves -- or the need for new foreign imports.

[8]This is the range in forecasts of incremental production from new reserves. At year end 1979 these have not yet been discovered. The sum of the projection from known Alaska reserves plus any of these forecasts represents total estimated future Alaska production.

[9]These are taken from Table 7-2.

SOURCES:

Oil Company, 1979.

California Energy Commission, 1979d.

Department of Energy, 1979.

State of Alaska, 1980.

PAD V consumption of petroleum products is sensitive to natural gas supplies. The demand forecast shown in Table 6-19 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. Figure 6-4 shows the low and high demand forecasts.

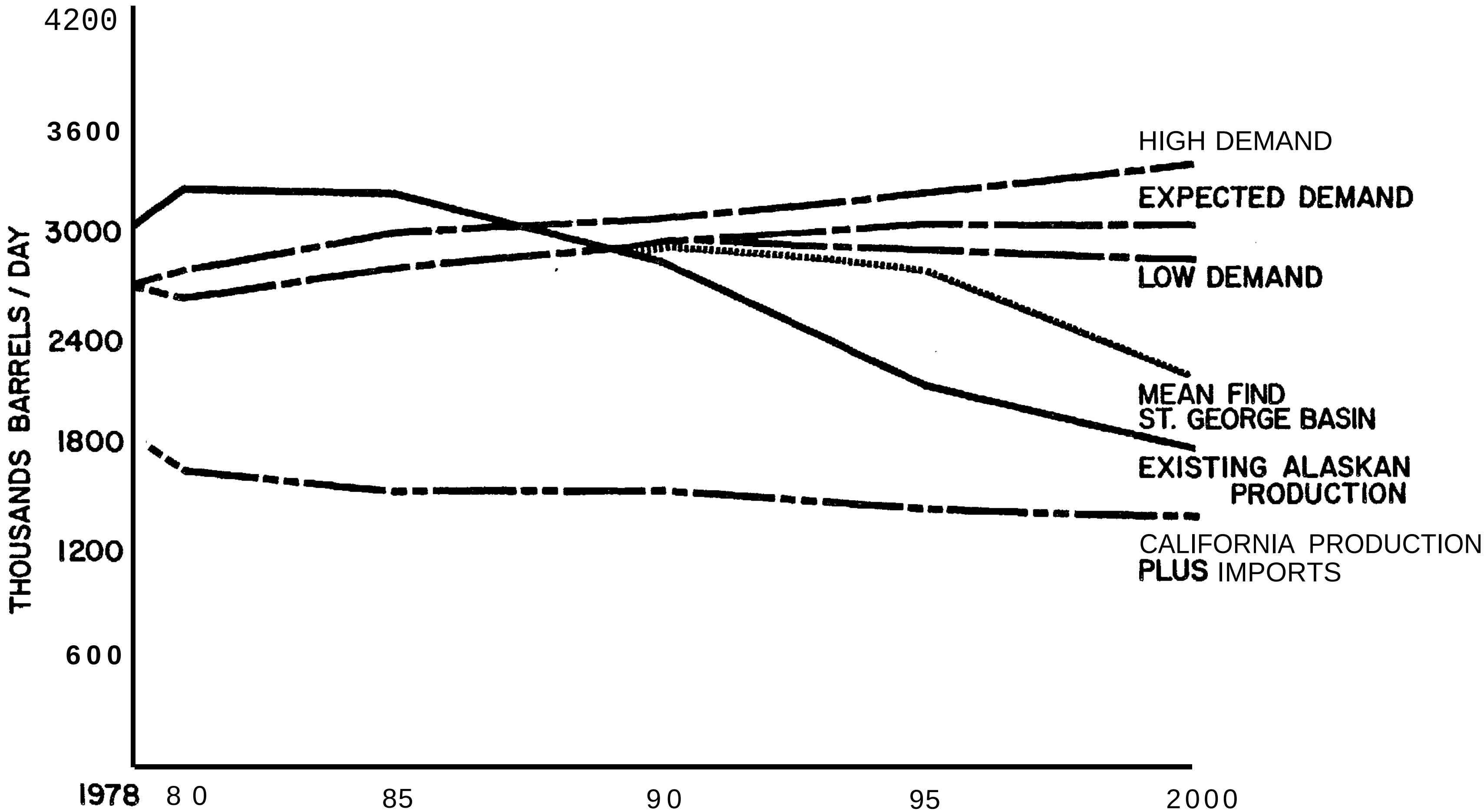
Table 6-19 shows that production from California is expected to peak at 1.1 million barrels per day by the mid-1980s, remain at peak through the early 1990s, and then slowly decline. Some modification of refineries is assumed to reduce, but not eliminate, the requirement for high gravity, low sulfur foreign crude imports.

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 by 1990 and just under 1.8 million 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. The timing depends on whether and when secondary recovery by waterflood begins. When the Prudhoe Bay field starts to decline, the west coast surplus of Alaska crude shown as 600,000 barrels per day in 1980 and 400,000 in 1985 will quickly disappear. By 1990, when St. George begins at 95,000 barrels per day, PAD V will be short 125,000 barrels per day due to declining existing Alaska production. Between 1990 - 2000, the existing Alaska production will decline to create larger deficits than can be offset by discoveries in the St. George Basin, as shown on Figure 6-4. Hence, additional reserves will be required to balance PAD V throughout the last decade of this century. Table 6-17 shows that, after the early 1990s, 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.

FIGURE 6-4

PAD V SUPPLY & DEMAND BALANCE



Source: Dames & Moore

6.5.5 World Oil Price Situation

The International Energy Agency estimates that during the first quarter of 1980, a 1 million barrel per day oil supply surplus existed. Stocks are high in the industrialized nations due to deliberate inventory build-up in 1979, a mild winter, and sluggish economic activity in much of the western world. Consumption has declined somewhat since prices more than doubled in 1979. This surplus could rapidly disappear if Saudia Arabia reduces production from 9.5 million to below 8.5 million barrels per day.

Table 6-20 shows posted prices of selected OPEC crudes. OPEC is on record as saying they want no less than 2 percent per year real price escalation. Until feasible substitutes are available in sufficient quantity to replace oil, the industrialized nations must accept OPEC price increases.

6.5.6 United States Natural' Gas

6.5.6.1 Supply/Demand Balance

Little new information on this subject has become available since the Norton Basin natural gas marketing study was written in late 1979 (Dames & Moore, 1980, Appendix F).

Table 6-21 incorporates two new references that are contradictory. Included are estimates of gas supply forecasts from Exxon's year-end "Energy Outlook" and the Stanford Energy Modeling Forum. The results of the Stanford group are interesting because three of their supply models forecast domestic conventional gas supplies will increase when United States gas is deregulated after 1985. The average of these forecasts is shown as the high-supply forecast on Table 6-21.

The remaining models examined by the Stanford group, however, confirm the American Gas Association (AGA) consensus forecasts that show annual production rates to be falling. The expected supply forecast shown on

TABLE 6-20

SELECTED OPEC CRUDE PRICES

Country	Crude	Gravity	Price			Percent
			Dec 31, 1978	Aug 1, 1979	April, 1980	Increase
Saudi Arabia	Arabian Light	340	12.70	18.00	26.00	105
Iraq	Basrah Light	340	12.66	19.96	27.96	138
Kuwait	Burgan	31°	12.22	19.49	27.50	125
Qater	Dukhan	40°	13.19	21.42	29.40	122
U.A.E.	Murban	39°	13.26	21.56	29.60	123
Venezuela	Centrolago	36.5°	12.90	19.25	28.75	122
Iran	Iranian Light	340	12.81	22.00	35.87	180
Indonesia	Minas	35°	13.55	21.12	30.75	127
Mexico*	Isthmus	34°	13.10	22.60	32.00	144
Algeria	Saharian	49°	14.10	23.50	37.21	163
Nigeria	Bonny Light	37°	14.10	23.47	34.69	146
Libya	Zuetina	40.5°	13.90	23.50	34.72	150

*Not a member of OPEC

Source: _Oil and Gas Journal_, 1979f, 1980b, e.

TABLE 6-21

U.S. SUPPLY/DEMAND BALANCE
(Trillion Cubic Feet per Year)

	1980	1985	1990	2000
DEMAND FORECASTS				
Potential" Gas Demand[1]	26.1	28.7	30.3	--
Economic Gas Demand[2]-Upper Limit	24.3	26.0	27.7	--
Lower Limit	23.9	24.9	25.2	--
Low Gas Demand[3]	22.2	22.5	22.6	--
CONVENTIONAL SUPPLY FORECASTS[4]				
High	19.0	21.5	24.0	24.0
Expected	18.0	16.0	15.0	14.0
Exxon	18.0	--	15.0	11.0
SUPPLY GAP[5]				
Expected Case	6.1	9.5	11.5	--
AGA SUPPLEMENTAL GAS FORECAST[6]	2.5	5.8	8.6	17.2
EXXON SYNTHETICS PLUS IMPORTS FORECAST[7]	1.8	--	3.6	5.9

NOTES TO TABLE 6-21

Sources: American Gas Association, 1979a, b, c.

Oil Company Confidential, 1979.

Exxon, 1979b.

Stanford Energy Modeling Forum, 1980.

[1]Potential demand forecast is the upper limit AGA case if environmental restrictions continue to impede coal use and if federal policy discourages oil imports.

[2]Upper and lower limit demand cases reflect the impact of lower or higher price assumptions on industrial gas use. Other users are not price sensitive within the price ranges assumed.

[3]The low gas forecast is a confidential oil company forecast. They do not consider it a low case.

[4]Most conventional gas supply forecasts agree that production of Lower 48 gas supplies is declining as shown in the expected forecast. At least three gas supply models examined by the Stanford Energy Modeling Forum expect gas production to increase with the increase in gas prices and rapidly increase after 1986 when gas prices are decontrolled. Exxon is the most pessimistic. The Exxon forecast include Alaska North Slope gas as 5 percent of the total for 1990 and a proportionately larger share in 2000.

[5]The supply gap represents a range of demand estimates to be met from supplemental gas supplies. Supply gap equals average economic gas demand less expected gas supplies.

[6]Supplemental gas sources are expected to be mostly LNG, Canadian and Mexican imports and Alaska pipeline gas into the 1990s. By the end of the century new technologies including Devonian shale, geopressured gas, and biomass will make a growing contribution.

[7]Exxon's forecast includes 2.8 trillion cubic feet imports and 3.1 trillion cubic feet synthetic gas in 2000.

Table 6-21 is the average of the results reported in the earlier report and the Stanford results, excluding the three high-supply forecasts of the Stanford Group. The expected supply forecast is a consensus of approximately 15 independent forecasts.

The Exxon forecast is shown as the most pessimistic. Also shown on Table 6-21 is Exxon's supplemental forecast. While Exxon's Energy Outlook" strongly endorses synthetic gas, their forecast of these expensive supplemental gas forms is vastly lower than the AGA's forecast. The AGA may be overly optimistic; in which case the forecasted widening supply gap shown on Table 6-21 is less likely to be offset by new synthetic gas. Hence, the gas demand shown must switch to an alternate fuel (coal's growth as previously discussed will require a herculean development effort to attain forecast goals) or we must assume that conventional supplies will tend toward the upper limit, or we must anticipate that consumers will go without.

6.5.6.2 Alaska OCS Gas Supplies from the St. George Basin

Gas discovered in the St. George Basin must be converted to LNG and shipped to market. A logical domestic point of entry would be Pt. Conception, California.

Potential production from St. George under the mean find discovery profile amounts to nearly 2 billion cubic feet per day[1] beginning in 1990 and extending into the next century (see Table 7-2). This is five times more gas than planned by Southern California Gas Company from the Cook Inlet project. Hence, either the California terminal at Pt. Conception would need to be expanded or the Bering Sea gas would have to go through the Panama Canal to a marketplace.

Table 6-22 compares the potential impact of St. George LNG supplies on the California supply forecast. An additional 2 billion cubic feet per day of

---

[1] Refer to the qualifications and assumptions concerning this high peak gas production profile in Chapter 7,0.

TABLE 6-22

CALIFORNIA NATURAL GAS SUPPLY BY SOURCE
MID-SUPPLY CASE
(Million Cubic Feet per Day)

	1980	1985	1991	2000
California	411	322	285	285
Southwest	2670	2160	1855	1520
Canada - Old	1110	1080	800	--
- New	--	--	--	500
Rocky Mountain	,30	200	285	415
Mexico	--	290	360	360
North Slope	--	--	--	400
Cook Inlet LNG	--	--	400	400
Indonesia LNG	--	250	500	500
SNG	--	--	.-	250
TOTAL	4221	4302	4485	4630
conventional	100%	87%	72%	48%

Source: California Energy Commission, 1979d.

LNG in 1990 and 2000 would radically change anticipated U.S. gas distribution patterns. A likely change would be that southwest gas supplies shown as 1855 and 1,520 million cubic feet per day during the last decade would not flow to California. They would then be available for the rest of the country. This, however, would create a need for a cost-sharing mechanism because Alaska LNG probably would be much more costly than this conventional gas.

In any case, shipping Alaska gas to California is the most economic transportation alternative and existing supply patterns can be reorganized to redistribute gas supplies across the country and achieve an equitable cost structure for all U.S. consumers.

Two billion cubic feet per day of new production would have a big impact on California gas distribution patterns as shown on Table 6-22. On an annual basis this amount of gas is equal to 730 billion cubic feet. This increment would still leave much of the 11.5 trillion cubic feet 1990 supply gap uncovered even including the AGA 8.6 trillion cubic feet supplemental forecast.

6.5.6.3 Marketability of St. George Basin LNG

Natural gas, like oil, will be in short supply in the last decade of this century (when the St. George Basin goes into production). Appendix A, Section IV, pegs the well-head value of St. George gas to No. 2 diesel fuel at the refinery gate in Los Angeles, minus LNG conversion costs and shipping to California. Gas in Los Angeles is worth about $5.70 per 1,000 cubic feet on this basis (see Page A-53). If conversion and shipping costs total $3.50, gas at the well-head can be priced at about $2.20. This is about equal to the EAC of producing gas in St. George and delivering it to an LNG plant on the Aleutian chain.

Consequently, if today it cost $5.00 per 1,000 cubic feet instead of $3.50 to get St. George gas to market, then St. George gas is not economic because, with oil now surplus, the utilities would choose No. 2 diesel at $5.70

instead of LNG at $7.00. However, by 1990 oil supplies will continue to dwindle, and real energy prices will rise. If real oil prices rise 2 percent annually, LNG will be competitive at $7.00 per 1,000 cubic feet in 1980 dollars. The Alaska gas line appears to be moving into development and financial industry sources are assuming that North Slope gas will sell in the $8.00 - $10.00 range. Apparently DOE believes gas demand relative to supply will allow expensive Alaska gas to be competitive by the late 1980s.

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

7.1 Introduction

This chapter presents a hypothetical oil and gas develop ment case for St. George Basin corresponding to the U.S. Geological Survey conditional statistical mean oil and gas resource estimate. Conditional estimates of undiscovered recoverable oil and gas for this basin are (Marlow et al., 1979) :

	Probability		Statistical
	95 percent	5 percent	Mean
Oil (billions of barrels)	0.8	6.4	2.7
Gas (trillions of cubic feet)	4.5	18.6	10.3

For the purposes of formulating a development case, natural gas resources (2.7 tri 11 ion cubic feet) have been assumed to be about 60 percent non-associated and 40 percent associated (Marlow et al., 1979).

Table 7-1 shows the assumed fields, their reserves, and location and the 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 built, and their construction and operation schedules.

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

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 Shore Terminal (2) Kilometers (Miles) Oil	Pipeline Distance to Shore Terminal (2) Kilometers (Miles) Gas	Timing Discov…
1000	2000	Northwest	3,048	10,000	Steel platform(s) with shared pipeline to shore terminal	4/5	140	2000	10	2.74	548	125	410	314 (195)	274 (170)	19
250	250	Northwest	1,524	5,000	" "	2/5	36	"	"	68.5	68.5	115	377	36a (229)	299 (186)	19
500	1 000	Southeast	3,048	10,000	" "	2/5	70	"	"	137	274	130	427	277 (172)	195 (121)	19
--	3000	Northwest	3,048	10,000	" "	2/5	56	"	"	--	518	135	443	-- --	274 (170)	19
200	--	Northwest	1,524	5,000	" "	2/5	28	"	"	54.8	--	145	476	383 (238)	-- --	19
500	500	Northwest	1,524	5,000	" "	4/5	72	"	"	137	137	110	361	345 (215)	306 (190)	19
--	2000	Southeast	3,048	10,000	" "	1/5	37	"	"	--	345	115	377	-- --	198 (123)	19
250	250	Southeast	1,524	5,000	" "	2/5	36	"	"	68.5	68.5	110	361	245 (152)	187 (116)	19
--	1 300	Southeast	3,048	10,000	" "	1/5	24	"	"	--	230	120	394	-- --	163 (101)	19

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

NOTES: (1) All fields share two trunk pipelines - one oil, one gas - to Aleutian terminal sites
(2) Distance represents spur plus trunk line
(3) Trunk line diameters -- oil 30-36 inches, gas 30-36 inches
(4) Terminal Sites: (a) crude terminal - Unalaska Bay, (b) LNG plant -- Akun Island

Source: Dames & Moore

TABLE 7-2

HYPOTHETICAL PETROLEUM DEVELOPMENT CASE FOR ST. GEORGE BASIN[1]

Calendar Year	Year After Lease Sale	Exploration and Delineation Wells (2)		Exploration Rigs Operating	Commercial Discoveries		Offshore Production Platforms (3)	Intermediate Pump/Compressor Platforms (4)	Development Wells (5)	Pipeline Construction Kilometers (Miles Per Year								Production (6)	
										Offshore				onshore					
										Oil		Gas		Oil		Gas		Oil	Gas
		Exploration	Delineation		Oil	Gas				Trunk	p. r	Trunk	Spur	Trunk	Spur	Trunk	Spur		
1983	1	6		2															
1984	2	12		4	2														
1985	3	10	5	5	2	1													
19S6	4	10	8	6	1	1													
1987	5	12	6	6	1	1				149 (90)		129 (80)							
1988	6	14	4	6						161 (100)	54 (33.5)	137 (85)	45 (28)	8 (5)		8 [5]			
I 9tJ9	7	6		2			4	2	9		88 (55)							35	%6
1990	8	2					5		69		96 (60)		173 (108)					88	138
1991	9						4		122									143	312
1992	10						4		140									197	518
1993	11						2		I 30									241	664
1994	12						1		79									253	746
1995	13								24									253	775
1996	14								1									245	768
199?	15																	221	732
1998	16																	186	686
1999	17																	161	644
2000	18																	135	605
2001	19																	115	574
2002	20																	97	547
2003	21																	83	525
2004	22																	66	768
200s	23																	52	379
2006	24																	37	281
2001	25																	15	204
2008	26																		140
2009	27																		108
2010	28																		85
2011	29																		66
2012	30																		52
2013	31																		41
2014	32																		32
2015	33																		26
2016	34																		20
2017																			12
2018																			9
2019																			4
2020	38																		
2021	39																		
2022	40																		
2023	41																		
2024	42																		
TOTALS		72	23	31	6	3	20	2	514	310 (190)	238 (1483)	266(165)	2113 (136)	8 (5)		8(5)		2,623	10,223

NOTE S TO 7-2

NOTES: 1. The assumpt ions 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 d probability in St. George Basin.

3! Hybrid Steel jacket/upper Cook Inlet design.

4. One intermediate pump slat ion and one intermediate compressor station required due to length of trunk pipelines.

5. Includes non-producing wells for f njection of water or gas at a rat 10 of l :5 to producers.

b. Total resource corresponding to U.S. Geological Survey estimate not produced due to appl teat ion of economic limit to product ion f lows . To exhaust reserves corresponding to assumed field size (i .e. beyond economic l imi t) makes the field longer by 2 to 4 years.

7. Includes associated gas from oil fields. Forty percent of gas resource of basin is assumed to be associated.

TABLE 7-3

MAJOR SHORE FACILITIES CONSTRUCTION
START-UP AND SHUT-DOWN DATES

Facility	Year After Lease Sale		
	Construction	Start-Up Date[1]	Shut-Down Date[2]
Unalaska Oil Terminal	5-7	8	26
Akun Island Plant	5-7	8	38

(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

six years of 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 siting 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

Despite the long pipeline distances to suitable shore terminal sites, the technical and economic results of this study indicate that a development strategy involving steel platforms (hybrid upper Cook Inlet/steel jacket design) with pipelines to terminal sites in the Aleutians is feasible. The development option specified in Tables 7-2 and 7-3 involves two clusters of oil and gas fields, located in the northwestern and southwestern portions of the sale area, respectively. The fields share two large diameter trunk pipelines (one oil, one gas) that connect with an oil terminal and large LNG plant located in the Aleutian Islands. Five of the six oil fields produce associated gas to a pipeline shared with the three non-associated gas fields.

---

(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 equipment requirements and production (including peak production 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 optional economic recovery of oil or gas and infrastructure sharing arrangements.

Two reservoir depths have been assumed in the development case specifications -- 1,524 and 3,048 meters (5,000 and 10,000 feet). Initial well productivities of 2,000 barrels per day and 10 million cubic feet per day along with optimal recovery rates and related numbers and spacing of development wells are assumed. Oil and gas production both commence in 1990 and terminate in 2008 and 2020, respectively. Production of significant amounts of associated gas in shorter-lived oil fields contributes to the sharp peak and large volume of gas production in the mid-1990's.

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. The assumptions upon which these estimates are based are shown in Tables 5-1 and 5-2.

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.

Table 7-4

USGS STATISTICAL MEAN OIL AND GAS RESOURCE DEVELOPMENT CASE
07/15/80

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	1452.	156.	0.	0.	846.	168.	0.	2298.	324.	2622.
2	2904.	312.	0.	0.	1692.	336.	0.	4596.	648.	5244.
3	3630.	390.	0.	0.	2115.	420.	0.	5745.	810.	6555.
4	4356.	468.	0.	1400.	2538.	504.	0.	6894.	2372.	9266.
5	4356.	468.	0.	12821.	2538.	504.	0.	6894.	13793.	20687.
6	4356.	468.	2000.	46592.	3010.	800.	0.	9366.	47860.	57226.
7	1452.	156.	10000.	33886.	2778.	1204.	0.	14230.	35246.	49476.
8	2932.	280.	12700.	3685.	3783.	2034.	750.	19415.	6749.	26164.
9	10470.	920.	18300.	1575.	5715.	4009.	3000.	34485.	9504.	43989.
10	20372.	1720.	13920.	1198.	5134.	3768.	3000.	39426.	9686.	49112.
11	26758.	2162.	8160.	794.	3938.	3348.	3000.	38856.	9304.	48160.
12	27664.	2076.	4500.	565.	3151.	3067.	3000.	35315.	8708.	44023.
13	22822.	1434.	1660.	379.	2487.	2802.	3000.	26969.	7615.	34584.
14	18045.	852.	840.	336.	2304.	2736.	3000.	21189.	6924.	28113.
15	15906.	588.	880.	352.	2304.	2736.	3000.	19090.	6676.	25766.
16	16114.	576.	880.	352.	2304.	2736.	3000.	19298.	6664.	25962.
17	16314.	576.	880.	352.	2304.	2736.	3000.	19498.	6664.	26162.
18	16419.	576.	880.	352.	2304.	2736.	3000.	19603.	6664.	26267.
19	16464.	576.	880.	352.	2304.	2736.	3000.	19648.	6664.	26312.
20	16464.	576.	880.	352.	2304.	2736.	3000.	19648.	6664.	26312.
21	16002.	564.	880.	352.	2268.	2706.	3000.	19150.	6622.	25772.
22	14154.	516.	800.	320.	2124.	2586.	3000.	17078.	6422.	23500.
23	12768.	480.	720.	288.	2016.	2496.	3000.	15504.	6264.	21768.
24	12306.	468.	720.	288.	1980.	2466.	3000.	15006.	6222.	21228.
25	9996.	408.	640.	256.	1800.	2316.	3000.	12436.	5980.	18416.
26	6762.	324.	480.	192.	1548.	2106.	3000.	8790.	5622.	14412.
27	4452.	264.	400.	160.	1260.	1599.	3000.	6112.	5023.	11135.
28	1680.	192.	200.	80.	720.	348.	3000.	2600.	3620.	6220.
29	1680.	192.	200.	80.	720.	348.	3000.	2600.	3620.	6220.
30	1680.	192.	200.	80.	720.	348.	3000.	2600.	3620.	6220.

Table 7-5

USGS STA 5 CAL MEAN OIL AND GAS RESOURCE DEVELOPMENT CASE
07/15/80

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

YEAR AFTER LEASE SALE	JANUARY OFFSHORE		JANUARY ONSHORE		JANUARY TOTAL	JULY OFFSHORE		JULY ONSHORE		JULY TOTAL	PEAK	
	ONSITE	OFFSITE	ONSITE	OFFSITE		ONSITE	OFFSITE	ONSITE	OFFSITE		MONTH	TOTAL
1	180.	146.	26.	10.	362.	203.	149.	28.	10.	390.	5	417.
2	360.	292.	52.	20.	724.	406.	297.	56.	20.	779.	5	807.
3	450.	365.	65.	25.	905.	519.	373.	71.	25.	987.	5	987.
4	540.	438.	78.	30.	1086.	632.	448.	186.	41.	1307.	12	1475.
5	540.	438.	478.	74.	1530.	632.	448.	1194.	152.	2426.	12	3598.
6	540.	438.	2602.	308.	3888.	941.	728.	4248.	512.	6429.	10	7197.
7	180.	146.	4202.	469.	4997.	2238.	2016.	2998.	460.	7712.	6	8001.
8	848.	752.	1181.	175.	2956.	2468.	2224.	409.	170.	5271.	10	5645.
9	2311.	2105.	717.	512.	5645.	3509.	3234.	901.	567.	8211.	10	9036.
10	3522.	3258.	873.	569.	8222.	3466.	3281.	833.	520.	8100.	10	8610.
11	3596.	3393.	843.	543.	8375.	3376.	3252.	803.	506.	7937.	1	8375.
12	3220.	3084.	761.	507.	7572.	3103.	3007.	771.	509.	7390.	1	7572.
13	2661.	2559.	677.	488.	6385.	2248.	2185.	667.	499.	5599.	1	6385.
14	1810.	1744.	562.	465.	4581.	1908.	1842.	634.	507.	4891.	8	4901.
15	1611.	1545.	538.	465.	4159.	1719.	1653.	614.	509.	4495.	8	4515.
16	1529.	1463.	526.	465.	3983.	1749.	1683.	614.	509.	4555.	8	4565.
17	1549.	1483.	526.	465.	4023.	1769.	1703.	614.	509.	4595.	6	4595.
18	1559.	1493.	526.	465.	4043.	1779.	1713.	614.	509.	4615.	6	4615.
19	1564.	1498.	526.	465.	4053.	1784.	1718.	614.	509.	4625.	6	4625.
20	1564.	1498.	526.	465.	4053.	1784.	1718.	614.	509.	4625.	6	4625.
21	1564.	1498.	526.	465.	4053.	1784.	1718.	614.	509.	4625.	6	4625.
22	1398.	1338.	512.	456.	3704.	1598.	1538.	592.	496.	4224.	6	4224.
23	1232.	1178.	498.	447.	3355.	1412.	1358.	570.	483.	3823.	6	3823.
24	1232.	1178.	[illegible]	447.	3355.	1412.	1358.	570.	483.	3823.	6	3823.
25	1066.	1018.	484.	438.	3006.	1226.	1178.	548.	470.	3422.	6	3422.
26	734.	698.	452.	420.	2304.	854.	818.	504.	444.	2620.	6	2620.
27	568.	538.	442.	411.	1959.	668.	638.	482.	431.	2219.	6	2219.
28	200.	185.	298.	274.	957.	250.	235.	315.	288.	1088.	6	1088.
29	200.	185.	298.	274.	957.	250.	235.	315.	288.	1088.	6	1088.
30	200.	185.	298.	274.	957.	250.	235.	315.	288.	1088.	6	1088.

Table 7-6

USGS STATISTICAL MEAN OIL AND GAS RESOURCE DEVELOPMENT CASE
07/15/80

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	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.
2	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.
3	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.
4	ONSITE	612.	360.	1400.	0.	0.	0.	0.	0.	0.	0.	324.	4032.	0.	0.	0.	2538.
	OFFSITE	0.	360.	154.	0.	0.	0.	0.	0.	0.	0.	0.	4032.	0.	0.	0.	1269.
5	ONSITE	612.	360.	2200.	225.	0.	2412.	6984.	0.	0.	0.	324.	4032.	0.	0.	0.	2539.
	OFFSITE	0.	360.	242.	135.	0.	265.	768.	0.	0.	0.	0.	4032.	0.	0.	0.	1269.
6	ONSITE	1146.	400.	0.	925.	0.	11390.	32497.	0.	0.	0.	324.	4032.	0.	0.	2000.	3010.
	OFFSITE	220.	400.	0.	212.	0.	1253.	3630.	0.	0.	0.	0.	4032.	0.	0.	2000.	1505.
7	ONSITE	2100.	260.	0.	0.	0.	8442.	24444.	0.	0.	0.	108.	1344.	0.	6600.	3400.	2778.
	OFFSITE	780.	260.	0.	0.	0.	929.	2689.	0.	0.	0.	0.	1344.	0.	6600.	3400.	1389.
8	ONSITE	2786.	273.	0.	0.	0.	670.	1940.	0.	330.	750.	36.	448.	2538.	12300.	400.	3693.
	OFFSITE	993.	273.	0.	0.	0.	74.	213.	0.	330.	750.	0.	448.	2538.	12300.	400.	1847.
9	ONSITE	4753.	431.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	10980.	17100.	1200.	5205.
	OFFSITE	1565.	431.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	10980.	17100.	1200.	2603.
10	ONSITE	4876.	490.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	21212.	13800.	0.	4414.
	OFFSITE	1430.	490.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	21212.	13800.	0.	2207.
11	ONSITE	4466.	519.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	27838.	7800.	0.	3214.
	OFFSITE	1207.	518.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	27838.	7800.	0.	1607.
12	ONSITE	3855.	533.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	28984.	3900.	0.	2431.
	OFFSITE	1070.	533.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	28984.	3900.	0.	1216.
13	ONSITE	2770.	525.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	24302.	900.	0.	1767.
	OFFSITE	929.	525.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	24302.	900.	0.	884.
14	ONSITE	2074.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	19605.	0.	0.	1584.
	OFFSITE	900.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	19605.	0.	0.	792.
15	ONSITE	1822.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17506.	0.	0.	1584.
	OFFSITE	964.	524.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17506.	0.	0.	792.

** SEE ATTACHED KEY OF ACTIVITIES

Table 7-6 (con't)

USGS STA S AL MEAN OIL AND GAS RESOURCE D VELOPMENT CASE
07/15/80

YEARLY MANPOWER REQUIREMENTS BY AC V TY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	1816.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17714.	0.	0.	1584.
	OFFSITE	908.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17714.	0.	0.	792.
17	ONSITE	1816.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17914.	0.	0.	1584.
	OFFSITE	908.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17914.	0.	0.	792.
18	ONSITE	1816.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	18019.	0.	0.	1584.
	OFFSITE	908.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	18019.	0.	0.	792.
19	ONSITE	1816.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	18064.	0.	0.	1584.
	OFFSITE	908.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	18064.	0.	0.	792.
20	ONSITE	1816.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	18064.	0.	0.	1584.
	OFFSITE	908.	528.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	18064.	0.	0.	792.
21	ONSITE	1786.	516.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17602.	0.	0.	1548.
	OFFSITE	893.	516.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	17602.	0.	0.	774.
22	ONSITE	1634.	468.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	15674.	0.	0.	1404.
	OFFSITE	817.	468.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	15674.	0.	0.	702.
23	ONSITE	512.	432.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	14208.	0.	0.	1296.
	OFFSITE	756.	432.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	14208.	0.	0.	648.
24	ONSITE	1482.	420.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	13746.	0.	0.	1260.
	OFFSITE	741.	420.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	13746.	0.	0.	630.
25	ONSITE	300.	360.	.	.	0.	0.	0.	0.	1320.	3000.	0.	0.	11356.	0.	0.	980.
	OFFSITE	650.	360.	.	.	0.	0.	0.	0.	1320.	3000.	0.	0.	11356.	0.	0.	490.
26	ONSITE	1026.	276.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	7962.	0.	0.	828.
	OFFSITE	513.	276.	0.	0.	0.	0.	0.	0.	1320.	3000.	0.	0.	7962.	0.	0.	414.
27	ONSITE	823.	210.	0.	0.	0.	0.	0.	0.	990.	3000.	0.	0.	5482.	0.	0.	630.
	OFFSITE	412.	210.	0.	0.	0.	0.	0.	0.	990.	3000.	0.	0.	5482.	0.	0.	315.
28	ONSITE	500.	120.	0.	0.	0.	0.	0.	0.	0.	3000.	0.	0.	2240.	0.	0.	360.
	OFFSITE	250.	120.	0.	0.	0.	0.	0.	0.	0.	3000.	0.	0.	2240.	0.	0.	180.
29	ONSITE	500.	120.	0.	0.	0.	0.	0.	0.	0.	3000.	0.	0.	2240.	0.	0.	360.
	OFFSITE	250.	120.	0.	0.	0.	0.	0.	0.	0.	3000.	0.	0.	2240.	0.	0.	180.
30	ONSITE	500.	120.	0.	0.	0.	0.	0.	0.	0.	3000.	0.	0.	2240.	0.	0.	360.
	OFFSITE	250.	120.	0.	0.	0.	0.	0.	0.	0.	3000.	0.	0.	2240.	0.	0.	180.

Table 7-7

USGS STATISTICAL MEAN OIL AND GAS RESOURCE DEVELOPMENT CASE
07/15/80

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) F	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	2298.	324.	2622.	4065.	444.	4509.	339.	37.	376.
2	4596.	648.	5244.	8130.	888.	9018.	678.	74.	752.
3	5745.	810.	6555.	10163.	1110.	11273.	847.	93.	940.
4	6894.	2372.	9266.	12195.	2886.	15081.	1017.	241.	1257.
5	6894.	13793.	20687.	12195.	15563.	27758.	1017.	1297.	2314.
6	9366.	47860.	57226.	16903.	53574.	70477.	1409.	4465.	5874.
7	14230.	35246.	49476.	26963.	39903.	66866.	2247.	3326.	5573.
8	19415.	6749.	26164.	36948.	9382.	46330.	3079.	782.	3861.
9	34485.	9504.	43989.	66368.	15840.	82207.	5531.	1320.	6851.
10	39426.	9686.	49112.	76645.	15926.	92571.	6388.	1328.	7715.
11	36856.	9304.	46160.	76103.	15349.	91452.	6342.	1280.	7621.
12	35315.	8708.	44023.	69415.	14631.	84045.	5785.	1220.	7004.
13	26969.	7615.	34584.	53055.	13389.	66444.	4422.	1116.	5537.
14	21189.	6924.	28113.	41586.	12672.	54258.	3466.	1056.	4522.
15	19090.	6676.	25766.	37388.	12432.	49820.	3116.	1036.	4152.
16	19298.	6664.	25962.	37804.	12420.	50224.	3151.	1035.	4186.
17	19498.	6664.	26162.	38204.	12420.	50624.	3184.	1035.	4219.
18	19603.	6664.	26267.	38414.	12420.	50834.	3202.	1035.	4237.
19	19648.	6664.	26312.	38504.	12420.	50924.	3209.	1035.	4244.
20	19648.	6664.	26312.	38504.	12420.	50924.	3209.	1035.	4244.
21	19150.	6622.	25772.	37526.	12351.	49877.	3128.	1030.	4157.
22	17078.	6422.	23500.	33454.	12027.	45481.	2788.	1003.	3791.
23	15504.	6264.	21768.	30360.	11772.	42132.	2530.	981.	3511.
24	15006.	6222.	21228.	29382.	11703.	41085.	2449.	976.	3424.
25	12436.	[illegible]	[illegible]	24332.	11310.	35642.	2028.	943.	2971.
26	8790.	5622.	14412.	17166.	10731.	27897.	1431.	895.	2325.
27	6112.	5023.	11135.	11909.	9635.	21544.	993.	803.	1796.
28	2600.	3620.	6220.	5020.	6990.	12010.	419.	583.	1001.
29	2600.	3620.	6220.	5020.	6990.	12010.	419.	583.	1001.
30	2600.	3620.	6220.	5020.	6990.	12010.	419.	583.	1001.

** OTAL ICLUDES ONST AND OFFSITE

TABLE 7-8

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

Exploration Start-Up

Exploration commences 6 months after the lease sale (i.e., summer 1983); all schedules cited in this report relate to 1983 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

10 months.

Decision to Develop

The decision to develop is made 24 months after discovery.

NOTES : (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)

Platform Fabrication and Installation

Steel platforms in all water depths are fabricated and installed within 36 months of the decision to develop. 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 1,524-meter (5,000-foot) reservoirs and 60 days (6 per rig per year) for 3,048-meter (10,000-foot) reservoirs.

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 (see items 31 and 311 in Table 5-2).

Reservoir Depth

Oil -- 1,524 and 3,048 meters (5,000 and 10,000 feet)
Gas -- 3,048 meters (10,000 feet)

TABLE 7-8 (continued)

Initial Well Productivity

Oil -- 2,000 barrels per day
Gas -- 10 million cubic feet per day

Allocation of Gas Resource Between Associated and Non-Associated

Associated -- 40 percent; non-associated -- 60 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 36 months.

LNG Plant Construction

LNG plant design and construction takes 36 months.

REFERENCES

Alaska Consultants, Inc., 1976. Service Bases for Offshore Oil Development. Prepared for the Div. of Community Planning, Dept. of Community and Regional Affairs, State of Alaska, July 1976.

Allcock, L.G., 1978. Oil and Gas Transport and Storage - The Competing Systems, in A Guide to North Sea Oil and Gas Technology. Proceedings of the Institute of Petroleum 1977 Annual Conference, London, England. Published by Heyden & Son, Ltd., 1977, pp. 99-103.

American Gas Association, 1979a. The Future for Gas Energy in the United States.

American Gas Association, 1979b. A Forecast of the Economic Demand for Gas Energy in the U.S. through 1990. February 1979.

American Gas Association, 1979c. Comparison of Conventional Natural Gas Supply Forecasts. September 1979.

Antonakis, J., 1975. Steel vs. Concrete Platforms, Part 11. Petroleum Engineer, November 1975, pp. 11-17.

Arctic Institute of North America, 1973. Arctic Marine Commerce Study. Report prepared by the Arctic Institute of North America for Maritime Administration, U.S. Department of Commerce, August 1973.

Arctic Environmental Information and Data Center, 1974. The Bristol Bay Environment, A Background Study of Available Knowledge.

Arps, J.J., et al., 1967. A Statistical Study of Recovery Efficiency. Report by the API Subcommittee on Recovery Efficiency, API Bulletin D14.

Arps, J.J., et al.; 1968. Reasons for Differences in Recovery Efficiency. SPE Paper No. 2068.

Arthur D. Little, Inc., 1976. Outer Continental Shelf Oil and Gas Costs and Production Volume: Their Impact on the Nation's Energy Balance to 1990. Washington, U.S. Department of Interior, Bureau of Land Management, Contract No. 08550-CTS-75, July 1976.

Birks, D.J., 1978. Field Appraisal in Understanding North Sea Oil Operations, Prospects and Policy. Bank of Scotland Information Service and Institute of Petroleum. Collected papers of seminar, pp. 6-8.

Bonner & Moore Associates, Inc., 1980. 1985 California Oil Scenario Study. Ad Hoc Industry and Government Study, March 1980.

Brewer, W. A., Jr. , et al. , 1977. Climate Atlas of the Outer Continental Shelf Water and Coastal Regions of Alaska, Volume II, Bering Sea; Arctic Environmental Information and Data Center, University of Alaska.

California Energy Commission, 1979a. Energy Choices for California . . . Looking Ahead. March 1979.

California Energy Commission, 1979b. California's Energy Demand, 1978 - 2000: A Preliminary Assessment. August 1979.

California Energy Commission, 1979c. California's Energy Challenge: The Next 20 Years. November 1979.

California Energy Commission, 1979d. Fuel Price & Supply Projections, 1980 - 2000. November 1979.

California Energy Commission, 1979e. Energy Futures for California, Two Scenarios, 1978 - 2000. November 1979.

CIA, 1979. The World Oil Market in the Years Ahead, in Oil and Gas Journal, August 1979.

Cook Inlet Pipeline Company, 1978. Written Communication, October 1978.

Dames & Moore, 1974. Detailed Environmental Analysis, Proposed LNG Project. Report Prepared for Pacific Alaska LNG Company, Los Angeles, California.

Dames & Moore, 1979a. Northern Gulf of Alaska Petroleum Development Scenarios. Alaska OCS Socioeconomic Studies Program, Technical Report No. 29, Report prepared for the Bureau of Land Management, Alaska OCS Office, February 1979.

Dames & Moore, 1979b. Western Gulf of Alaska Petroleum Development Scenarios. Alaska OCS Socioeconomic Studies Program, Technical Report No. 35, Report prepared for the Bureau of Land Management, Alaska OCS Office, February 1979.

Dames & Moore, 1979c. Lower Cook Inlet and Shelikof Strait Petroleum Development Scenarios. Alaska OCS Socioeconomic Studies Program, Technical Report No. 43, Report prepared for the Bureau of Land Management, Alaska OCS Office, July 1979.

Dames & Moore, 1980. Norton Basin OCS Lease Sale No. 57 Petroleum Development Scenarios. Alaska OCS Socioeconomic Studies Program, Technical Report No. 57, Report prepared for the Bureau of Land Management, Alaska OCS Office, February 1980.

Department of Energy, 1979. Petroleum Supply Alternatives for the Northern Tier and Inland States Through the Year 2000. October 31, 1979.

Diver, J.J., W. Hart, and G.A. Graham, 1976. Reservoir Management at McArthur River. Petroleum Engineer, December 1976, pp. 38-52.

Duggan, P.D., 1978. Shore Terminals - Oil, in A Guide to North Sea Oil and Gas Technology. Proceedings of the Institute of Petroleum 1977 Annual Conference, London, Heyden & Son, Ltd.

Engineering Computer Opteconomics, 1977. An Assessment of Marine Transportation Costs Related to Potential Port Sites in Alaska. Report prepared for the Federal-State Land Use Planning Commission for Alaska, August 1977.

Exxon, 1979a. World Energy Outlook, December 1979.

Exxon, 1979b. Energy Outlook, 1980 - 2000. December 1979.

Ford Foundation, 1979. Energy: The Next Twenty Years, An Overview. Report by a Study Group, Hans H. Landsberg, Chairman. Cambridge: Ballinger Publishing Co.

Gardner, J.V., and T.L. Vallier, 1977. Map Showing Types and Distribution of Faults Interpreted from Seismic Profiles in the Saint George Basin Region, Southern Bering Sea. U.S. Geological Survey Open-File Report OF 77-591.

Gardner, J.V., et al., 1979. Sedimentology and Geochemistry of Surface Sediments and the Distribution of Faults and Potentially Unstable Sediments, St. George Basin Region of the Outer Continental Shelf, Southern Bering Sea. U.S. Geological Survey Open-File Report OF 79-1562.

Global Marine Engineering Co., 1977. A Preliminary Feasibility Study of a Tanker Transportation System Serving the Northwest Coast of Alaska. Report prepared for the U.S. Department of Commerce, Maritime Administration, Office of Commercial Development.

Goodfel low, R., 1977. Underwater Engineering. Petroleum Publishing Co., Tulsa, Oklahoma, 1977.

Gruy Federal, Inc., 1977. pricing Effects on Frontier Oil Production. Report to FEA, June 20, 1977.

Hancock, M.V., E.I. White, and M.C. Hay, 1978. Design, Fabrication and Installation of the Ninian Field Southern Platform. Proceedings of the 10th Annual Offshore Technology Conference, Houston, Texas, May 8-11, 1978. Paper No. OTC 3148.

Howe, C.W., 1979. Natural Resource Economics. John Wiley & Sons, 1979.

Jumpsen, T., 1978. Taywood-Santa Fe Ltd., Personal Communication, May 23.

Kalter, R.J., W.E. Tyner, and D.W. Hughes, 1975. Alternative Energy Leasing Strategies for the Outer Continental Shelf. Report prepared by Cornell University for National Science Foundation, Report No. PB-253 315.

Kennedy, J.L., 1976. Billion Dollar Plus Forties Project in Full Swing, in Offshore Platforms and Pipelining. The Petroleum Publishing Company, Tulsa, Oklahoma, 1976, pp. 7-10.

Kramer, L.S., U.C. Clark, and G.J. Cannelos, 1978. Planning for Offshore Oil Development, Gulf of Alaska OCS Handbook. Prepared by Alaska Department of Community and Regional Affairs, Division of Community Planning.

Lisitsyn, A.P., 1969. Recent Sedimentation in the Bering Sea. Academy of Sciences of the USSR (in Russian, 1966); Translated by Israel program for Scientific Translations.

Mackay, G.A., 1975. North Sea Study Occasional Papers, No. 4 -- Prospects for the Shetland Economy. University of Aberdeen.

Mansvelt Beck, F.W., and K.M. Wiig, 1977. The Economics of Offshore Oil and Gas Supplies. Lexington Books, Lexington, Massachusetts.

Mathematical Sciences Northwest, 1972. A Study of the Economic and Sociological Impacts of Construction and Initial Operation of the Trans-Alaska Pipeline. Bellevue, Washington.

Marlow, M.S., et al"., 1976. Preliminary Report on the Regional Geology, Oil and Gas Potential and Environmental Hazards of the Bering Sea Shelf South of St. Lawrence Island, Alaska. U.S. Geological Survey Open-File Report OF 76-785.

Marlow, M.S., et al., 1979. Resource Report for Proposed OCS Lease Sale No. 70, St. George Basin, Shelf Area, Alaska. U.S. Geological Survey Open-File Report OF 79-1650.

Meyers, H., R.J. Brazee, L.L. Coffman, and S.R. Lessig, 1976. An Analysis of Earthquake Intensities and Recurrence Rates In and Near Alaska. NOAA Technical Memorandum EDS NGSDC-3, 101 pp.

National Petroleum Council, 1975. Ocean Petroleum Resources. Report prepared by National Petroleum Council for U.S. Department of the Interior, March 1975.

New England River Basin Commission (NERBC), 1976. Offshore Facilities Related to Offshore Oil and Gas Development. Boston, Massachusetts.

Ocean Industry, 1978. Trends in Subsea Production Systems. July 1978, pp. 19-20.

Offshore, 1978a. The Maintenance of Offshore Structures. February 1978, pp. 32-35.

Offshore, 1978b. Claymore Field Sets North Sea Record Despite a Barrel Full of Postponements. March 1978, pp. 102-106.

Offshore, 1978c. No Slack for Offshore Workover Industry. May 1978, pp. 338-344.

Offshore, 1978d. A Floating Alternative in LNG Plants. December 1978.

Offshore, 1979. Sullom Voe Project Has Long Way to Go. February 1979.

Offshore, 1980. Clearing the Way for Workovers. March 1980, pp. 156-158.

Oil and Gas Journal, 1978. Projects Pushed During North Sea Weather Window. October 16, 1978.

Oil and Gas Journal, 1979a. California Ponders Ways to Match Crude, Refining. April 16, 1979, pp. 27-30.

Oil and Gas Journal, 1979b. Modules Speed Construction at Cactus. August 20, 1979, pp. 114-118.

Oil and Gas Journal, 1979c. CIA: Global Oil Supply Outlook Poor. September 1979, pp. 50-51.

Oil and Gas Journal, 1979d. Oil in the Eighties: Tight Supply, Soaring Capital Outlays. November 12, 1979, pp. 163-169.

Oil and Gas Journal, 1979e. U.S. Petroleum Industry Will Face Monumental Task in Next Decade. November 12, 1979, pp. 170-184.

Oil and Gas Journal, 1979f. Action by OPEC Further Disarrays Crude Prices. December 24, 1979, p. 22.

Oil and Gas Journal, 1980a. Newsletter, January 7, 1980, p. 9.

Oil and Gas Journal, 1980b. OPEC Members Settling on Crude Prices. January 7, 1980, p. 39.

Oil and Gas Journal, 1980c. Offshore Oil. Gas Estimates Rise Only for Alaska. March 17, 1980, p. 88.

Oil and Gas Journal, 1980d. CIA See Global Oil Production Peaking. April 28, 1980.

Oil and Gas Journal, 1980e. Outlook for Stable Prices Jolted by Iranian Dispute. April 28, 1980, p. 43.

Oil Company (Confidential), 1979. World Energy Outlook, 1979 - 1990. July 1979.

Page, J.S., 1977. Cost Estimating Manual for Pipelines and Marine Structures. Gulf Publishing Company, Houston.

Penick, D.P., and W.B. Thrasher, 1977. Mobil's Design Considerations for North Sea Oil/Gas Separation Facilities. Petroleum Engineer, October 1977, pp. 22-34.

Pipeline Industry, 1976a. North Sea Pipe Laybarges: A Performance Evaluation. July 1976, pp. 44-48.

Pipeline Industry, 1976b. Second Year Progress Report: Trans-Alaska Pipeline. August 1976, pp. 25-118.

Pipeline Industry, 1977. Trans-Alaska Pipeline Goes On-Stream. August 1977, p. 55.

Popcock, C.C., 1979. Prospects for Oil & Gas: A Look Ahead to Year 2000, in World Oil, October 1979, pp. 107-111.

Potocsky, G.J., 1975. Alaskan Area 15- and 30-Day Ice Forecasting Guide, Naval Oceanographic Office.

Ralstan, T.D., 1977. Ice Force Design Considerations for Conical Offshore Structures. Proceedings of the Fourth International Conference on Port and ocean Engineering Under Arctic Conditions, St. Johns. Newfoundland. September 26-30, 1977. pp. 741-752.

San Francisco Examiner, 1980. Shell Says We'll Still Be Over a Barrel in 1990. May 6, 1980.

State of Alaska, 1977. Statistical Report, Department of Natural Resources, Division of Oil and Gas.

State of Alaska, 1980. Petroleum Production Revenue Forecast, Quarterly Report, March 1980. Department of Revenue.

Shell Oil Co., 1978. Written Communication. D.L. Lilly, Division Mechanical Engineer, Western Division.

Stanford Energy Modeling Forum, 1980. U.S. Oil & Gas Supply Summary. February 1980.

Stobaugh, R., 1979. After the Peak: The Threat of Imported Oil, in Energy Future, Report of the Energy Project at the Harvard Business School, R. Stobaugh and D. Yergin, Editors. New York: Random House.

Stokely, E., and R. Zeckhauser, 1978. A Primer for Policy Analysis. Norton & Company, 1978.

Sullom Voe Environmental Advisory Group, 1976. Oil Terminal at Sullom Voe Environmental Impact Assessment. Thuleprint, Ltd., Sandwick, Shetland.

Thiel, M.F., 1979. World Oil & OPEC: The Razor's Edge. World Oil,'October 1979, pp. 123-133.

Trainer, W., J.R. Scott, and W.J. Cairns, 1976. Design and Construction of Marine Terminal for North Sea Oil in Orkney, Scotland. Proceedings of the 8th Annual Offshore Technology Conference, Houston, Texas, May 3-6, 1976, Paper No. OTC 2712, pp. 1067-1080.

United States Coast Pilot, 1979. Pacific and Arctic Coasts of Alaska: Cape Spencer to Beaufort Sea, 9th Edition.

Vallier, T.L., and J.V. Gardner, 1977. Maps Showing Types and Distribution of Faults Interpreted from Seismic Profiles in the St. George Basin Region, Southern Bering Sea. U.S. Geological Survey Open-File Report OF 77-591.

Visser, R. C., 1969. Platform Design and Construction in Cook Inlet, Alaska. Journal of Petroleum Technology, V. 21, No. 4, pp. 411-420.

Wood, Mackenzie & Company, 1978. North Sea Report. Wood, Mackenzie & Company, Edinburgh, Scotland.

APPENDICES

APPENDIX A

METHODOLOGY AND ANALYTICAL ASSUMPTIONS

I. METHODOLOGY

Figure A-1 illustrates the methodology for this study and shows the relationship between the petroleum technology, manpower, and economic models that comprise the three major components of the study. The first part of this appendix describes the study methodology and the second part explains the reservoir, production, economic, and technical assumptions of its analysis.

1.1 Assessment of Environmental Forces and Operating Conditions

The first task of this study developed the necessary data to assess the environmental forces and operating conditions in the St. George Basin. These data were used to identify exploration, production, and transportation options that may be used to develop the petroleum resources of the basin. The purposes of this analysis were to: (1) bracket the environmental parameters such as design wave and ice loading that would affect the design of structures, and (2) identify hypothetical discovery locations that have representative combinations of environmental constraints (water depth, sea ice, etc.) and distance to shore terminals. The analysis of environmental constraints also focused on those conditions such as ice coverage and storm frequency that determine the summer weather window for exploratory drilling, offshore construction operations, the transportation strategy of field development, and the logistical problems of resupply.

The final part of this analysis involved an assessment of the biologic constraints on offshore petroleum activities and the siting of onshore petroleum facilities.

a

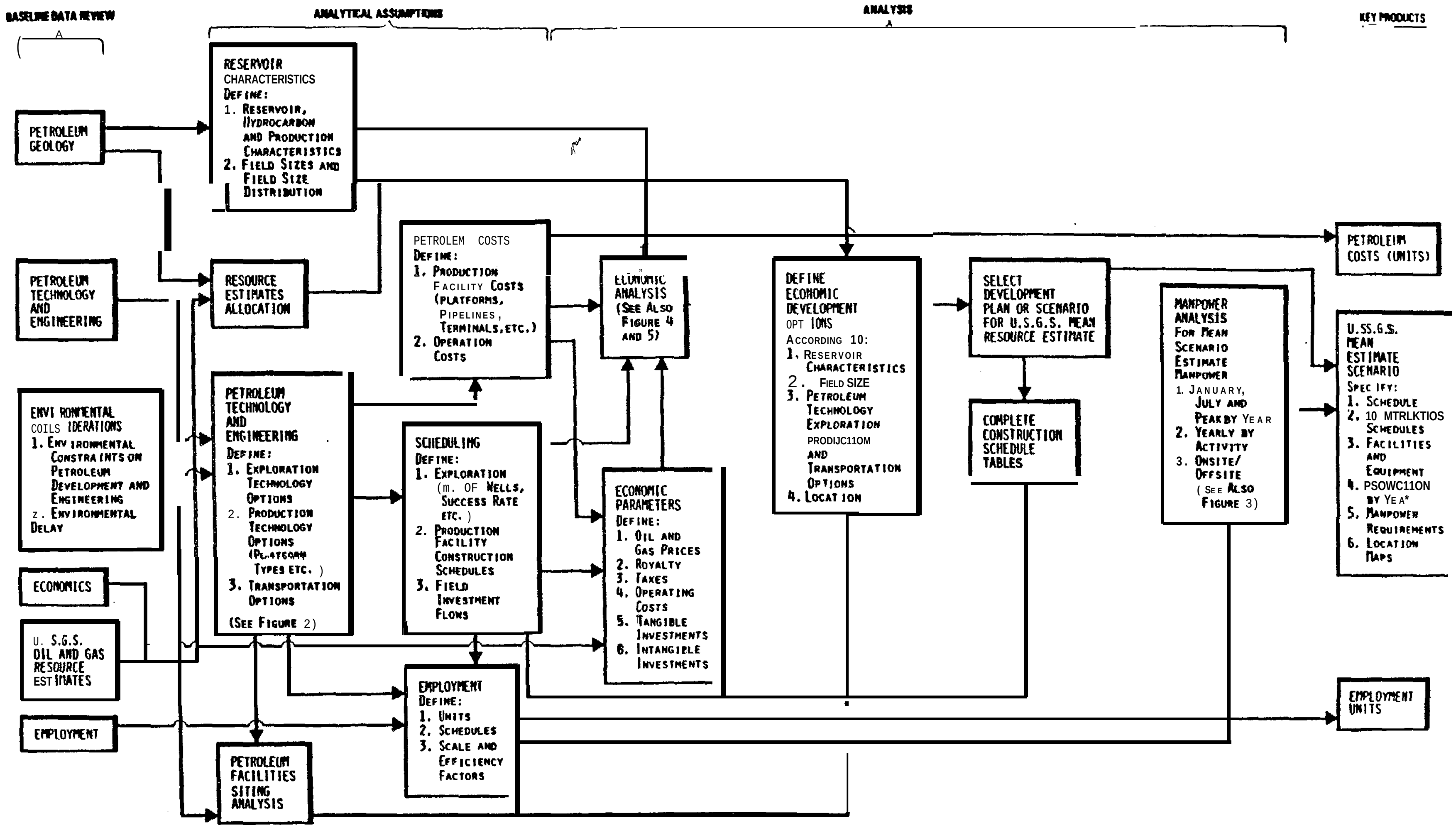


FIGURE A-1 LOGIC AND DATA FLOW OF DAMES & MOORE OCS PETROLEUM DEVELOPMENT MODEL

1.2 Major Facilities and Their Siting

To a large degree, the major shore facility requirements for petroleum development in the St. George Basin depend upon the production options identified in the technology assessment and the assumed location and distribution of fields. The facilities siting analysis was conducted concurrently with the petroleum technology review to assess the field development and transportation options for economic analysis and for specification of a hypothetical development case. For each representative discovery location, technically and economically feasible crude oil terminal, LNG plant, and support base sites were identified.

A three-phase approach was adopted in this investigation:

1. The technical criteria for facilities siting such as land and navigation requirements were defined for various petroleum facilities.

2. The principal oceanographic, geologic, and geomorphic characteristics of the coastlines adjacent to the lease sale area that relate to the feasibility of facility siting were identified and evaluated. Essentially, the approach considered the regional, sub-regional, and site-specific characteristics. This resulted in the identification of a number of sites that fulfill the technical requirements identified in the siting analysis.

3. Data on marine and terrestrial biology, natural resources (fisheries, etc.), and land status were synthesized to establish the environmental sensitivity of the technically feasible sites.

1.3 Petroleum Geology Assessment

Formulation of the reservoir and production assumptions was based upon an independent assessment of the petroleum geology in the lease sale basin using publicly available geologic and geophysical data. (We did not develop independent oil and gas resources estimates.) The data base included the U.S. Geological Survey resource report for the lease sale area and other USGS open-file geology reports and geophysical data. The petroleum geology analysis also reviewed analog basins to make reasonable extrapolations when geologic data were lacking.

A set of reservoir and production assumptions was formulated to: (1) develop engineering equipment specifications, (2) provide production specifications for the economic analysis, and (3) formulate a hypothetical development case corresponding to the U.S. Geological Survey statistical mean resource estimate.

1.4 Technology Assessment

Data regarding environmental constraints (in maps and tabular form) and selected facility sites were submitted to our marine engineers (Santa Fe Engineering Services Co.) to assess feasible field development strategies and their individual components (platforms, pipelines, process equipment, etc.) Brian Watt Associates, Inc. provided estimates of anticipated ice forces. Cost ranges for these individual field development components (Appendix B) were estimated to form the basis of the economic analysis. The technology assessment also provided important assumptions on exploration, construction, production, and operation scheduling that drove the economic analysis (schedule of investment and revenue flows) and formulated a hypothetical development case.

The technology assessment was designed to accomplish the following:

- To identify the principal factors of the petroleum facilities that are cost sensitive, such as water depth for platforms, number of well slots on a platform, production throughput of platform process equipment, throughput of LNG plant or crude oil terminal, etc.

- To identify "building block" unit costs of field development components such as platforms, process equipment, pipelines, terminals, wells, etc., that can be "mixed and matched" to 'provide different field development strategies, and accommodate different assumed reservoir characteristics, field sizes, and field locations.

A set of cases was formulated for the economic analysis that comprised the following elements:

- Reservoir characteristics

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

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

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

These cases were structured to evaluate a number of development issues related to field development economics such as the effects of reservoir depth and long pipelines.

1.5 Economic Analysis

The economic model and methodology are described in Section IV of this appendix. This section briefly defines the principal roles of the economic analysis in the study. These are:

1. To identify the production system that is most economic for a given lease sale area and discovery location;

2. To identify the general reservoir characteristics that would justify development of a given field;

3. To identify a minimum field size for development in relation to various physical characteristics and **economic** assumptions associated with different lease sale areas;

4. To identify the minimum required price of crude oil to justify development of a given field;

5. To identify the economic effects of the location of a field and development; and

6. To identify the relationship between economic assumptions (prices, costs, discount rate, federal policy variables) and field development.

This analysis led to a technologically feasible and economically realistic hypothetical development option **for the** U.S. Geological Survey statistical mean oil and gas resource estimate.

1.6 Manpower Analysis

The employment analysis in this project had two objectives. The primary objective was to **discuss likely manpower requirements** for the major activities associated with OCS petroleum activity in the lease sale area. The secondary objective was to estimate employment requirements for the statistical mean USGS resource case in the lease sale area. The first objective must be met before the second can be accomplished, as “per unit” values are the basis for estimating total employment levels. However, whereas previous Alaska OCS petroleum development projects have emphasized manpower estimates for each of three or four petroleum development scenarios in the lease sale area under study, this project emphasized the components, or "per unit" estimates utilized for areawide employment forecasts.

A bewildering amount of detail is created by disaggregating the petroleum development process into its many component tasks, and then specifying manpower levels and characteristics for each task. It is quite possible for many exploration, development, and production tasks to be underway simultaneously, each having a different beginning date and duration, different rotation factor, and different proportions of onshore and offshore workers.

Because of this complexity, Dames & Moore developed a compute rmanpowermodel to calculate manpower estimates. This model is based on the disaggregation of the entire scope of OCS petroleum activity into 38 separate tasks. The model identifies employment by industry (mining, construction, transportation, manufacturing) for each month of each year; total employment, on site, off site, onshore and offshore employment; and peak employment in each year. Also, the model calculates an employment estimate for 16 general activities.

Figure A-2 shows the steps Dames & Moore follows in developing and utilizing the OCS Manpower Model. The first step is a data search, which leads in Step 2 to the identification of tasks and assignment of manpower values to each task on the basis of industry practice. Site-specific conditions and detailed petroleum development plans of lease areas are examined to determine if all the necessary tasks have been included in the program. (For example, it was necessary to add construction of gravel islands to the list of tasks in the Norton Sound scenarios.) Also, the site and development plans are studied to determine if modifications are needed to the manpower values that have already been assigned to existing tasks. In St. George Basin, for example, offshore loading may be a possibility. These facilities may be larger, stronger and more complex than those that have been built in less harsh environments. Therefore, construction of offshore loading facilities may require greater effort. A modification to the computer program may be

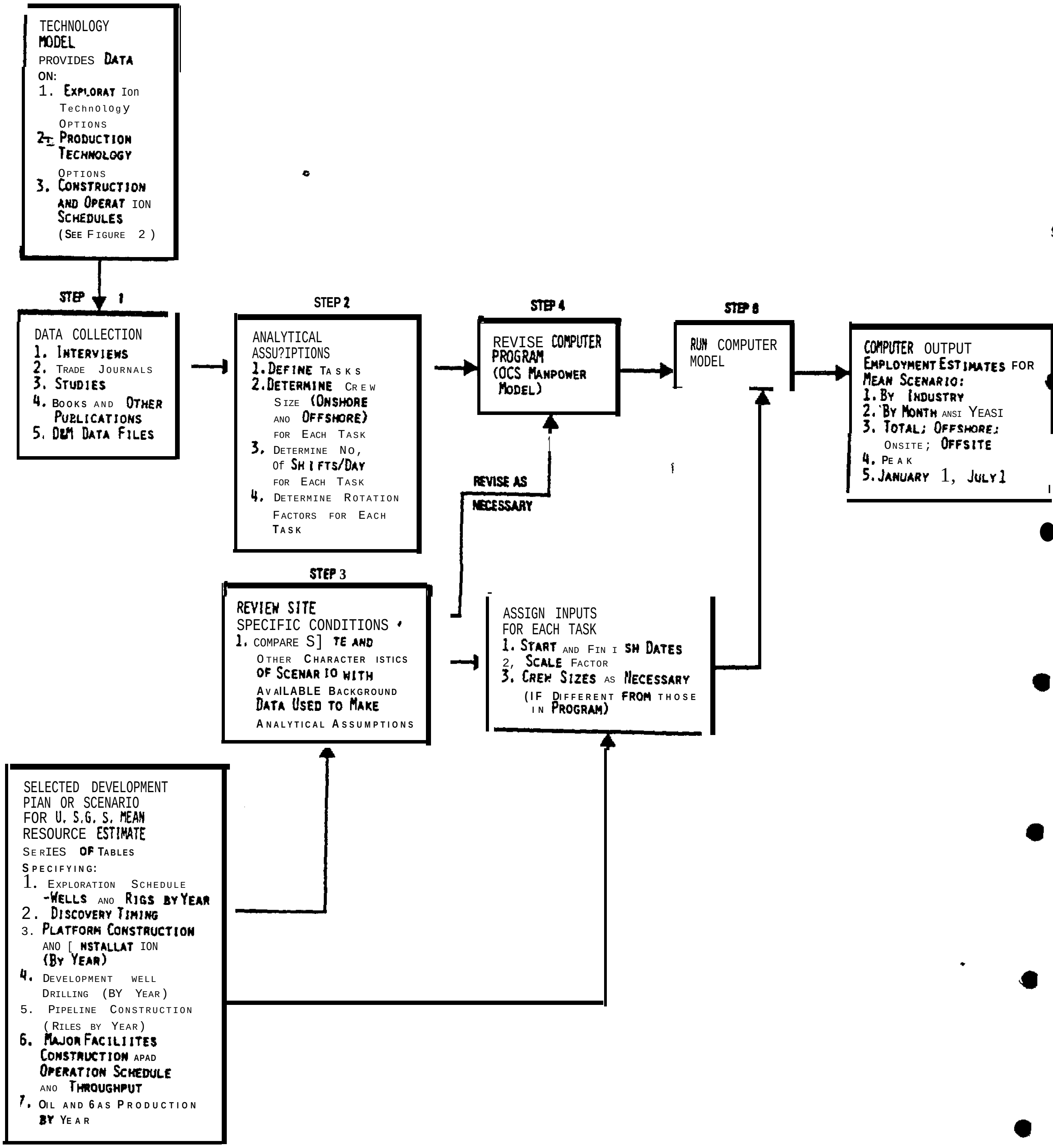


FIGURE A-2 **DAMES & MOORE OCS MANPOWER MODEL** appropriate (if the modification cannot be accomplished satisfactorily by application of a scale factor). These program modifications occur in Step 3. At this point in the process, unit manpower estimates are available. The description and specification of these unit manpower requirements constituted the primary objective of the employment analysis.

While background, information about the tasks and employment factors are being researched, an economically and technologically feasible development option (including number of wel 1s, platforms, facilities, construction schedule, etc.), based upon the mean oil and gas case for each basin, is prepared (see Figure A-I-1). From this detailed information, inputs are prepared for each task that include start and finish dates, scale factors, and crew sizes if these are not already in the program. This is step 5 on Figure A-2.

In Step 6,, the computer calculates monthly employment estimates for the USGS mean resource estimate for each lease sale.

More detailed information about the Dames & Moore OCS Manpower Model is presented in Appendix E of our final Norton Sound scenarios report (Dames & Moore, 1980), which begins with a definition of terms.

1.7 Hypothetical Development Case for the United States Geological Survey Statistical Mean Oil and Gas Resource Estimate

The results of technology, economic, and manpower analyses were brought together and applied to form a hypothetical development case corresponding to the U.S. Geological Survey statistical mean oil and gas resource estimate (see Marlow et al., 1979). The following analytical steps were taken in formulating the hypothetical development case:

1. Select the number of field sizes corresponding in aggregate to the U.S. Geological Survey resource;

2. Define reservoir characteristics for each field consistent with the petroleum geology assessment and related assumptions;

3. Develop discovery, exploration, and delineation schedules for the assumed fields in the 5-year tenure of the leases consistent with a historical discovery success rate for-other OCS areas;

4 Match engineering and equipment requirements to the assumed reservoir and locational characteristics of each field;

5. Construct field development schedules consistent with the engineering specifications and various scheduling assumptions (Appendix B);

6. Define a production schedule based upon the field construction schedule and assumed reservoir characteristics;

7. Estimate the employment required to explore, develop, and operate the fields (see Section 1.6); and

8. Aggregate production from each field into an overall basin-wide production schedule.

The hypothetical development case is then shown on a set of tables that include the following:

- Field sizes and their annual and peak production
- Location of fields (including water depth)
- Type and number of platforms for each field
- Number of exploration wells

- Number of development wells per platform and field
- Pipeline size and length
- Intermediate pumps or compressor stations
- Scheduling of exploration, construction, and operations.

II. PETROLEUM GEOLOGY, RESERVOIR, AND PRODUCTION ASSUMPTIONS

11.1 Introduction

This section reviews the petroleum geology of the St. George Basin 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 overemphasized that there is insufficient geologic, geophysical, and drilling data to make predictions with a high degree of certainty on reservoir characteristics in St. George Basin. Our approach in this study was to explore the economic and engineering impacts of diverse geologic and reservoir characteristics. That diversity, however, should fall within the range of conditions indicated by the available data and data from producing basins with similar geologic settings.

11.2 Summary of St. George Basin Petroleum Geology

11.2.1 Regional Framework

The St. George Basin is an elongate Tertiary sedimentary depression located on the Bering Sea continental shelf between the Pribilof Islands and the Alaska Peninsula. The basin is a long (322 kilometers or 200 miles}, narrow (32 - 48 kilometers or 20 - 30 miles) structural graben whose long axis strikes northwest, parallel to the continental margin of the southern Bering Sea.

Situated beneath the peneplained Bering Sea Shelf, the St. George Basin is filled with more than 10,000 meters (33,000 feet) of Tertiary sediments ranging in age from Eocene to Recent. These sediments are cut by a series of normal faults that parallel the basin axis. Offset along these faults increases with depth, indicating that movement was continuous throughout much of Tertiary time.

Basement rocks beneath the St. George Basin are part of an assemblage of Mesozoic eugeosynclinal rocks that extends from southern Alaska to eastern Siberia beneath the Bering Sea margin and outer shelf. A parallel belt of plutonic and volcanic rocks of late Mesozoic and earliest Tertiary age also lies beneath the inner Bering Sea Shelf.

The northern part of the Bering Sea Shelf is underlain by a broad basement high called the Nunivak Arch. This deeply eroded arch served as part of the sediment source, principally the early Tertiary sediments, for the Bering Sea Basins. It is believed that during upper Tertiary time, the Yukon River flowed southwesterly over this now submerged arch and contributed much of the Miocene and Pliocene sediment source to these basins.

The oldest exposed rocks at the western end of the Alaska Peninsula are Upper Jurassic siltstones and sandstones of the Naknek Formation. The westernmost exposures of these rocks are 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 Bristol Bay Basin from the St. George Basin.

The outcrop and subsurface geology of the Alaska Peninsula and Koryak region of the U.S.S.R. provide important clues with which to decipher the age of formation of the Bering Sea basins and the character of the sediments contained in these offshore basins. Nine wells drilled along the northern coast of the Alaska Peninsula relate directly to the offshore Bering Sea Basins. Although all of these wells were abandoned as dry holes, shows of oil and gas were recorded. In addition, Soviet drilling in the Anadyr Basin resulted in the discovery of non-commercial gas from Miocene sands.

11.2.2 Structure

Regional common depth point (CDP) marine seismic data shot by the USGS reveal basin symmetry and structures that are representative of the St'. George Basin. The seismic line is a southwest-northwest line oriented normal to the axis of the St. George Basin and shows the graben-like symmetry of this basin. Tertiary strata that infill the basin are essentially unfolded. The St. George Basin was formed from a downfaulted block and is a silled basin. In such a closed basin, ocean circulation is restricted, oxygen is not replenished in the water, and organic matter can be preserved in a manner favorable for hydrocarbon generation.

Within the acoustic basement, a number of dipping reflectors, which strongly diverge from the overlying and relatively undisturbed Tertiary reflecting strata, indicate that the Mesozoic "basement" includes folded sediments much like that on the Alaska Peninsula and eastern Siberia.

Deformation of the layered Tertiary sequence is mainly by normal faults that dip basinward, and appear to be related to offsets in the acoustic basement. Offset along the faults is visible at or near the ocean floor, and increases with depth, implying that the faults are growth features.

There are several moderate-sized prospective basement highs located deep within the basin, draped by overlying basalt sediments.

We believe that the structural highs located at the edges of these offshore basins offer the best potential for housing large hydrocarbon accumulations. These hinge line features are "basement" highs draped by the Tertiary sediments. However, of the several observed on the seismic lines, the prospective Tertiary section is relatively thin, less than 1,524 meters (5,000 feet) thick, but the basin edge location provides uninterrupted drainage to these structures from large basinal fetch areas. Many of the world's giant oil and gas fields are similarly located along basin hinge lines.

11.2.3 Stratigraphy

Knowledge of the subsurface stratigraphy of the St. George Basin is essentially limited to the only offshore test well drilled on the shelf, the Arco COST #1 (lat. 55° 32′ 41″ N, long. 166° 57′ 20″ W)[1]. The well was located on a sharp magnetic anomaly, and required only 90 days to drill to a total depth of 4,196 meters (13,766 feet). Although the data from this well are being kept confidential, the relatively fast drilling rate (about the same as the drilling rates of the onshore test wells drilled on the Alaska Peninsula) strongly indicates only moderately indurated sediments.

The COST well reportedly bottomed in Eocene volcanic rocks. Based on the stratigraphic relationships of the Tertiary outcrop geology onshore in the Alaska Peninsula and on the Koryak Peninsula, it seems probable that the major part of the unfolded basin. fill of the St. George Basin is comprised of an interbedded sequence of Pliocene and Miocene sand and shale, and the deeper parts of the graben are believed to contain Oligocene and Eocene sediments.

A series of samples were dredged by the USGS from the Bering Sea continental slope. Many of the dredged Miocene and Pliocene rocks consist of highly porous diatomaceous siltstone and sandstone and, if the textures and lithologies of these outcrops are partly representative of age-equivalent units within the St. George Basin, adequate reservoir rocks may be anticipated at least in the upper part of the sequence.

In the absence of actual subsurface well data, the seismic lines that cross the St. George Basin provide important clues about the stratigraphy of this basin. A visual feature common to all lines is the division of the basin fill above acoustic basement into two different reflective sequences; an upper strongly-reflective sequence of probable Pliocene to Recent age in which

---

[1] COST = Continental Offshore Stratigraphic Test

there appears to be reflections with rather long lateral continuity, and a . lower, weakly-reflective sequence, of probable Eocene and Oligocene age, in which the seismic reflections are mainly discontinuous and short.

Previous experience in evaluating seismic data from other Tertiary basins around the Pacific rim indicates that in the St. George Basin the upper strongly-reflective sequence probably represents interbedded sandstones and shales, and the lower weakly-reflective sequence probably represents predominantly shaly rocks. This hypothesis would seem to fit the Tertiary stratigraphic succession in the subsurface of the onshore Alaska Peninsula. Here, the upper Tertiary Miocene Bear Lake Formation is composed of an interbedded sand and shale sequence, whereas the lower Tertiary Oligocene Stepovak and Eocene Tolstoi formations are made up primarily of finer-grained sediments. Similar stratigraphic relationships exist in the onshore Anadyr and Khatyrka basins of the U.S.S.R.

Based on regional paleogeologic evidence, porous elastic units should be common within the upper strongly-reflective sequence. This sequence probably accumulated at a rate closely matching that of basin subsidence, which since the middle Tertiary has averaged between 150 - 300m/10^6 years. The area of rapid accumulation is near the mouths of major Alaska rivers (e.g., Yukon and Kuskokwim) and, during the Miocene and Pliocene, the outer Bering Shelf was periodically swept by marine transgressions and regressions. These factors favor the deposition of coarse neritic elastic and deltaic sequences, and, therefore, the likely presence of reservoir sands in the Miocene and Pliocene section.

It also seems likely that some coarse conglomeratic beds would be present in the Oligocene-Eocene sequence within the deeper parts of the graben, where coarse debris from the upthrown basin margins were being eroded and deposited into the sinking graben areas.

11.2.4 Reservoir Rocks

The rocks that have the greatest reservoir potential for oil and gas in the offshore St. George Basin are considered to be sandstone units of the middle to late Miocene Bear Lake Formation. Sand percentages within the Bear Lake, in the eight subsurface penetrations on the Alaska Peninsula, range from 33 - 67. The greatest amount of net sand is 1,330 meters (4,362 feet) (67 percent), which was encountered in the Pan Am Hoodoo Lake #1 (See 21-T 50 S-R76W). Bear Lake sands exhibit very good reservoir qualities in most of the Alaska Peninsula test wells. In the deepest penetration, Gulf Sandy River #1 (See 10 -T 46S - R 70W), sonic and density log derived porosities of 25 - 27 percent were calculated from sands at a depth of 3,200 - 3,231 meters (10,500 - 10,600 feet). Sidewall core permeabilities as high as 1,165 millidarcys (mdcys) were recorded at 1,995 meters (6,545 feet) in the Gulf Port Heiden #1 (See 20 - T 37S - R59W). The Bear Lake sands are both marine and non-marine, and age equivalent sands should be present in the offshore St. George Basin.

Shows of oil and gas were recorded on the mud log in the basal Bear Lake sands in the Gulf Sandy River #1.

Sandstones in the older Tertiary formations on the Alaska Peninsula, namely the Oligocene Stepovak and Eocene Tolstoi, contain a very low percentage of good reservoir quality sands. The low porosity and permeability are a function of a combination of factors, principally the abundance of volcanic detritus including matrix clay, and the relatively dense nature and high degree of induration.

A comparison of average porosity versus depth for producing reservoirs in California shows a rapid loss of porosity with depth below 3,962 meters (13,000 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, and it follows that good reservoir quality sands in the St. George Basin below 3,962 meters (13,000 feet) probably are not likely to be encountered.

11.2.5 Source Rocks

Source rock analysis of the Alaska Peninsula wells indicates that, in general, the Miocene Bear Lake has abundant organic carbon but is immature and the kerogen is predominantly woody with a minor amount of amorphous sapropel. Bear Lake 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 in the formation. The Bear Lake, therefore, would most likely be gas prone on the Alaska Peninsula.

The most favorable source rocks examined were the Eocene Tolstoi in the Pan Am Hoodoo Lake #2 (See 35 - T 50S - R 76W). This unit was high in total organic carbon content, was within the oil generating range, and exhibited a modest vitrinite reflectance.

In the offshore St. George Basin, it is believed that the Pliocene and Miocene shales will probably be light-colored with a poor source rock potential due to their open marine depositional environment. However, the Oligocene and Eocene shales within the deep St. George graben should be darker-colored, contain a higher percentage of organic matter, and serve as adequate source rocks. As stated earlier, this deeper portion of the St. George Basin was a closed, silled basin during the early Tertiary when ocean circulation was restricted, and where organic matter could have been preserved in a manner favorable for hydrocarbon generation.

The Tertiary Khatyrka and Anadyr Basins of eastern Siberia are very similar in age, structural style, and stratigraphy to the offshore Bering Sea basins. Source rock data from the Russian basins compares quite closely with that derived from the Alaska Peninsula.

Eocene, Oligocene, and lower Miocene shales in the Khatyrka Basin all have sufficient organic matter and thermal maturity to qualify them as adequate source rocks.

The middle and upper Miocene rocks, however, have a low content of organic matter and are thermally immature.

11.2.6 Comparison to Other Pacific Margin Basins

As noted by the U.S. Geological Survey resource report for St. George Basin (Marlow et al., 1979), only very qualified analogies can be shown with other Pacific margin basins. Nevertheless, some comments about possible common features are appropriate.

Although the Pacific rim Tertiary basins are relatively numerous and may have high oil recoveries per sediment volume, the small number of "giant" oil fields within such basins means that they contain only a small part of total world reserves. It is, therefore, not reasonable to expect multi-billion barrel reserve oil fields in the St. George Basin.

A significant criterion that must be considered in the tectonic evolution of the St. George Basin is the timing of the structural growth as it relates to time of deposition of the host reservoir beds. Generally, in the productive Pacific Tertiary basins, early structural growth, or development of synchronous "highs," is essential for entrapment of large hydrocarbon accumulations. Early structural growth can be demonstrated seismically in the St. George Basin.

The St. George Basin covers an area of about 12,173 square kilometers (4,700 square miles) , which is about the same as the productive Ventura Basin of California. Based on our analysis of the seismic data, trap density in the St. George Basin, however, appears to be very 10W, with only about 10 basement block-faulted structures evident on the available seismic lines. It must be stated, however, that insufficient seismic coverage was available to map closure on these features, and it is probable that there may be more structures than the limited seismic coverage indicates.

Low trap density does tend to increase chances for very large fill-up and thus very large oil and gas fields, assuming the presence of favorable source and reservoir rocks. Unfortunately, there is no reliable means to rationally estimate the percent fill-up of St. George Basin structures. However, based on data from other Pacific margin basins, fill-up in excess of 50 percent would be the exception in the St. George Basin, with 15 - 30 percent being more in the range of probability.

11.2.7 Traps

Three distinct traps may occur in the St. George Basin: (1) basement highs located at the margins of the deep graben, and whose axes parallel the deep basin axis; (2) basement highs within the deep graben; and (3) fault closures against, the steep basin walls. It is our belief that the first offers the best chance for large oil and gas accumulations if closures can be seismicly demonstrated over these features. The basement highs located near the bottom of the graben are probably too deep to have reservoir beds with the necessary high porosity and permeabilities. Fault closures against the steep basin walls probably would exhibit low porosity and permeability due to the great depths of potential reservoirs.

11.3 Assumptions

11.3.1 Initial Production Rate

11.3.1.1 Oil

Initial well production rate is used in the economic analysis as an index of reservoir performance in the absence of specific data about reservoir characteristics (pay thickness, porosity, permeability, drive mechanism, etc.). The initial productivity per well influences the numbers of wells that have to be drilled to efficiently drain a, reservoir. Assuming standard well spacing (80 - 160 acres) and the maximum number of wells that can be drilled from a single platform (dictated by the reservoir depth and well spring limitations), the peak throughput on an individual platform can be estimated using the initial well productivity assumption.

To make assumptions about potential reservoir performance in the St. George Basin as simplified by the initial well productivity index, we need to make a qualitative assessment of a number of geologic clues such as the depth of prospective reservoirs (obtained from geophysical records), reservoir rock permeability and porosity (derived from well data), probable reservoir rock thickness (obtained from well log data), and production characteristics from analog basins, in this case the Pacific margin basins.

Initial well productivities that should be assumed for wells located on hinge-line structures at the basin margins are probably no more than 1,000 barrels per day. This is due to the shallow depth of the reservoirs (less than 1,524 meters or 5,000 feet), with resultant lower pressures, and therefore, lower productivities. As a result of these anticipated lower pressures at shallow depths, wells will have to be placed on pump at an early date.

Higher initial well productivities of 1,000 - 2,000 barrels per day can be assumed for those productive reservoirs that may be encountered within the deeper portions of the St. George graben, principally at depths ranging from 1,524 - 3,048 meters (5,000 - 10,000 feet). At these depths, the most favorable ratio of porosity, permeability, and pressure is anticipated to occur. Much of the flush oil production in Tertiary basins around the Pacific rim occurs within this depth range.

For those basement structures located deep within the St. George graben, i.e., between 3,968 and 5,182 meters (13,000 and 17,000 feet), initial well productivities may be less than 1,000 barrels per day. Although high pressures can be expected at these depths, porosity and permeabilities generally will be low, which will reduce well performance significantly. The low porosity and permeability at these depths is typical for arkosic and volcaniclastic sands in Pacific Margin Tertiary basins.

In this study we evaluated well productivities of 1,000 and 2,000 barrels per day in combination with reservoir depth, numbers of wells, and recovery rates. As noted in previous studies, these values are consistent with the general ranges of reservoir performance for many of the Pacific Margin Tertiary basins including Cook Inlet. As a analog, upper Cook Inlet initial well productivities have averaged 1,000 - 2,000 barrels per day, although some wells have produced at significantly higher rates, notably in the McArthur River field (see Diveret al., 1976). In 1977, with production from Cook Inlet oil fields in decline, wells were averaging 159 - 1,530 barrels per day (State of Alaska, 1977).

Within certain technical and economic constraints, the number of wells and their spacing can be varied, depending upon the initial well productivity, to optimize the recovery or take-off rate. There are trade-offs between the investment in additional wells, and the increased revenue streams from a higher offtake rate. (Increasing the number of wel 1s will decrease the well spacing). In general, the deeper the reservoir the more expensive are the development wells and the longer the drilling time. Thus , it is more advantageous to increase the number of wells in shallow reservoirs (1,524 meters or less) to overcome low initial well productivities than it is for deeper reservoirs.

In this study, we have set the number of wells at these two 1P rates to obtain a recovery rate that produces about 10 percent of total assumed reserves in the peak years of production. Our production profile, which assumes secondary recovery, produces approximately 45 percent of reserves during peak production prior to the onset of decline (see also discussion of recoverable reserves, Section 11.3.3, and production profile, Section 11.3.4).

11.3.1.2 Non-Associated Gas

Initial productivity per well for non-associated gas is essentially unknown at this time. Geochemical data on shale well samples are needed to determine the ability of a given potential source rock unit to generate oil and/or gas. This critical information (which undoubtedly is available from the COST well record) is not available to us at this time. For economic sensitivity testing, we will evaluate gas well productivities ranging from 5 - 15 million cubic feet per day.

11.3.2 Reservoir Depth

The geophysical records indicate that reservoir depths may range from very shallow, 914 - 1,524 meters (3,000 - 5,000 feet), to medium to deep, 1,524 - 3,048 meters (5,000 - 10,000 feet), and to very deep, 3,962 - 5,182 meters (13,000 - 17,000 feet). We therefore assumed reservoir depths of 917 meters (3,000 feet), 1,524 meters (5,000 feet), and 3,048 meters (10,000 feet). Analysis of the USGS seismic data covering the St. George basin provides the control for the reservoir depth assumptions.

The most common reservoir depths should be shallow, where prospective sediments are draped over the shallow "basement" highs located at the margins of the basin. Intermediate reservoir depths can be expected within possible fault closures that may exist along the walls of the basin margin. Deep objectives will be limited to drapes over on a few basement highs located deep within the St. George graben axis.

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

II.3.3 Recoverable Reserves

An assessment of recoverable reserves in a virgin basin such as St. George is very speculative. As stated earlier, the Miocene Bear Lake equivalent sands offer the best reservoir objectives in the St. George Basin, if these sands are present. The porosity and permeability of these sands, as encountered in wells and outcrop on the Alaska Peninsula, compare closely with porosities and permeabilities of similar Teritiary sands in productive Pacific Margin basins that have recovery factors averaging 200 barrels per acre foot. Assuming a recovery factor of 200 barrels per acre foot and net pay thicknesses of 100 and 300 feet, recoverable reserves per acre can generally be bracketed between 20,000 and 60,000 barrels for primary recovery.

The lower porosity sands anticipated in the deeper portion of the basin below 3,048 meters (10,000 feet) may only have recovery factors of about 100 barrels per acre foot.

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

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

In this study, we assumed primary recovery between 20,000 and 60,000 barrels per acre and primary plus secondary recovery of 30,000 - 90,000 barrels per acre. Table A-3 shows maximum recovery per platform for various reservoir depths for these recoverable reserves. We emphasized 60,000 barrels per acre in the economic analysis. To optimise recovery, we have also assumed that a secondary recovery program (e.g., water injection) is initiated early in the development schedule. The field development plan would incorporate secondary recovery in the platform and process equipment design since retrofitting for a secondary recovery program could be exceedingly expensive.

11.3.3.1 Technical Discussion

A brief technical overview of estimated recoverable reserves will demonstrate the complexity of the problem and the requirement for much more detailed reservoir data than are presently available for the St. George Basin.

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

- Oil gravity
- Oil viscosity
- Gas volubility in the oil
- Relative permeability
- Reservoir pressure
- Connate water saturation
- Presence of a gas cap, its size, and method of expansion

- Fluid production rate
- Pressure drop in the reservoir
- Structural configuration of the reservoir

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

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

- Porosity
- Water saturation
- Oil information volume factor
- Permeability
- Oil and water viscosities
- Initial and abandonment pressures

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

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

11.3.4 Production Profiles

11.3.4.1 Oil

The three basic production profile assumptions are: (1) about 40 - 50 percent of the reserves are captured during peak production prior to the onset of decline, (2) about 10 percent of total reserves are captured each year of peak production, and (3) decline is exponential at approximately 10 - 15 percent per year.

The timing of production start-up and build-up to peak is governed by the number of development wells, the reservoir depth (rate of well completion), . and numbers of rigs (one or two) operating in the platform. Typically, production commences in the fifth year after the decision to develop, and peaks (depending upon well completion rate, numbers of wells, and field size) from 6 - 9 years after decision to develop.

11.3.4.2 Associated Gas

While recognizing the complex reservoir dynamics related to the production of associated gas, the economic model requires the analytical simplification of a constant ratio of associated gas to oil production at the assumed gas-oil ratio (GOR). Thus, an initial GOR of 1,000 standard cubic feet of gas per barrel of oil, for example, is maintained thoughout the life of the field.

11.3.4.3 Non-Associated Gas

The principal production assumptions concerning non-associated gas production are: (?) about 75 percent of the reserves are captured during peak production(1), and (2) decline is exponential at approximately 10 - 15 percent per year. The factors affecting production timing are essentially

(1)Note this is essentially a plateau in the production profile where gas is produced at constant rate for a number of years (i.e., production at "peak" is essentially "flat").

the same as those for oil; the main difference is that peak gas production generally occurs earlier because fewer wells are required. Typically, gas field production commences in the fifth year after the decision to develop and peak commences in the seventh or eighth year.

11.3.5 Field Size and Distribution

Three types of traps of economic importance may be present in St. George Basin. These are:

1. Potential sand reservoirs draped over pre-Tertiary basement horsts;

2. Fault closures against the steep graben walls; and

3. Stratigraphic traps of buttressing sand units against pre-Tertiary basement highs.

All three potential traps are visible on the 10 USGS seismic lines that cross the St. George Basin. Eleven structurally positive axes were noted on the 10 seismic lines. It must be emphasized, however, that insufficient seismic data are available to determine if closures exist on these axes. Also, it appears likely that several of the positive axes are part of the same anticlinal feature, so that in reality, there may only be six or seven or less separate anticlinal "basement" highs.

An unknown number of fault closures may exist in the basin. These include potential closures against the steep basin walls and potential fault closures that may exist within the St. George graben. Rollover anticlines on the downthrown sides, like the Gulf Coast, were noted rarely on a few seismic lines.

Potential stratigraphic traps of buttressing sands against pre-Tertiary basement highs are visible particularly on the north sides of the basin margin highs located near the north rim of the basin.

Sufficient seismic data was not available to determine area of closure, which is necessary to determine field size.

Assuming that offshore St. George Basin traps will be hydrocarbon bearing, and assuming seismic data were available to identify structures and estimate the areas of closure, etc., the all important economic problem would be the prediction of percent fill-up. The approach used to predict fill-up would be an analogy based on statistical comparisons with known productive Pacific Margin basins. It should be emphasized, however, that any analogical approach to prediction of petroleum resources is extremely hazardous. 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.

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

The field sizes selected for economic screening were 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.

The field sizes evaluated in this study, therefore, ranged from 50 million" barrels to 2 billion barrels for oil and 500 billion cubic feet to 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 rather than the actual field size distribution.

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

An assumption about the allocation of the U.S. Geological Survey gas resource estimates between associated and non-associated is not critical to our economic analysis because we 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 Alaska offshore frontier areas, non-associated gas resources, in many locations, are less economic than the same amount of associated gas. This is because the incremental investment to produce associated gas (with oil the primary product) is less than the total development costs for a non-associated gas field with the same recoverable reserves. In addition, the allocation of the total basin gas resource estimate between associated and non-associated affects the facilities and equipment requirements to develop offshore fields. If most of the gas was non-associated, located in separate fields from oil, then 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 mean gas estimates, we followed the USGS assumption about the allocation of the gas resource between associated and non-associated for the statistical mean resource estimate of 60 percent non-associated/ 40 percent associated (Marlow et al., 1979).

The U.S. Geological Survey estimates do not specify any ratio of associated to non-associated gas reserves and no such ratio is implicit in their estimates. It should be noted that U.S. historic production data indicates that 80 percent of U.S. gas resources is non-associated.

To evaluate the economics of associated gas production, we assumed a GOR of 1,000 standard cubic feet per barrel.

III. TECHNOLOGY AND TECHNICAL ASSUMPTIONS

111.1 Introduction

This section outlines the technical and technology assumptions behind the economic analysis, the principal aim of which was to evaluate the relationships among the engineering strategies that may be adopted to develop St. George Basin oil and gas resources, and the minimum field sizes required to justify each technology as a function of geologic conditions in the sale area.

111.2 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 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 gravity platforms with shared or unshared pipeline to shore LNG plant --non-associated gas production,
- Single or multiple steel platforms with shared oil and gas pipelines to shore terminals--oil and associated gas production; and
- Single gravity platform with single anchor leg mooring offshore loading system and shuttle tankers to an Aleutian transshipment terminal.

a

111.3 Pipeline Distances and Transportation Options

Table A-1 shows representative pipeline distances from different parts of the sale area to (1) Unalaska Bay, (2) St. Paul Island, and (3) St. George Island. Pipeline distances to be costed and screened in the economic analysis are consistent. Distances from potential discovery sites to the potential shore terminal sites are described in Chapter 4.0. Based on these distances, the following pipeline distances were selected for economic evaluation: 80 kilometers (50 miles), 160 kilometers (100 miles), 241 kilometers (150 miles), and 322 kilometers (200 miles).

With the exception of lower Cook Inlet Sale GO, where pipelines from Shelikof Strait to Kenai Peninsula were considered (Dames & Moore 1979c), potential offshore pipeline distances from St. George Basin discoveries to possible terminal sites are generally longer than those anticipated for other lease sale areas (Kodiak, northern Gulf of Alaska, Norton Sound, and Beaufort Sea lease sales). For much of the sale area, pipeline distances are comparable to, or longer than, many of the North Sea trunk lines that are supported by very large reserves. The economics of pipelining are, therefore, critical in determining the economic feasibility of deve'oping St. George Basin oil and gas resources.

111.4 Other Technical Assumptions

111.4.1 Well Spacing

111.4.1.1 General Considerations and Oil

Well spacings consistent with industry practice, reflecting maximum efficiency rates, and varying as a function of initial well productivity, recoverable reserves per acre, reservoir depth. and numbers of wells are implicit in Table A-2. Table A-3 indicates the maximum number of production wells that can be housed on platform for well spacings of 80 and 160 acres. Based on industry practices in the upper Cook Inlet, well spacing for the

TABLE A-1

REPRESENTATIVE DISTANCES IN KILOMETERS (MILES) FROM THE

ST. GEORGE BASIN LEASE SALE AREA TO POSSIBLE SHORE FACILITY SITES

HYPOTHETICAL DISCOVERY LOCATION

POSSIBLE SHORE FACILITY SITES	SOUTHEAST Lat. 55° 00′ N Long. 166° 12′ W	CENTRAL Lat. 55° 46′ N Long. 166° 53′ W	NORTHWEST Lat. 56° 40′ N Long. 168° 30′ W
UNALASKA BAY	121 (75)	209 (130)	323 (201)
ST. PAUL ISLAND	346 (215)	259 (161)	121 (75)
ST. GEORGE ISLAND	274 (170)	188 (117)	61 (38)

SOURCE: Dames and Moore calculation

TABLE A-2

MAXIMUM NO. OF PRODUCTION WELLS HOUSED ON A PLATFORM FOR DIFFERENT RESERVOIR DEPTHS (ASSUMING 80 AND 160 ACRE WELL SPACING)

Depth of Reservoir		Theoretical Maximum No. of Wells	
Meters	Feet	80-acre spacing	160-acre spacing
762	2,500*	2	1
1,525	5,000*	31	16
2,286	7,500	94	47
3,050	10,000*	N/A	95

Notes: (1) Also see Table A-3 and Figure 3-7

(2) Assumes maximum angle of deviation to be 60 degrees

N/A = probably not applicable due to technical limitations

* Resevoir depths evaluated in this study; assumes 80 and 160-acre well spacing:

TABLE A-3

MAXIMUM AREA REACHED WITH
DEVIATED WELLS FROM A PLATFORM

Depth of Reservoir		Maximum Area Produced[1,2]			Maximum Recovery Per Platform (million barrels)[4]		
Meters	Feet	Sq. Miles	Acres	Hectares	@ 30,000 bbl/acre	@ 60,000 bbl/acre	@ 90,000 bbl/acre
7623	2,500*	0.25	162	66	4.9	9.7	14.6
1,525	5,000*	3.9	2,510	1,016	75.3	150.6	225.9
2,286	7,500	11.7	7,503	3,036	225.1	450.2	675.3
3,050	10,000*	23.8	15,226	6,162	456.8	913.6	1,370.3
3,812	12,500	40.0	25,654	10,382	769.6	1,539.2	2,308.9
4,575	15,000	60.6	38,786	15,697	1,163.6	2.327.2	3,490.7

Notes:

1. Maximum angle of deviation assumed to be 60 degrees with a kick off point at a depth of 152-meters (500 feet)
2. See directional drilling chart Figure 3-7
3. For shallow reservoirs, the area of coverage is very sensitive to the depth of the kick off point
4. Assumes secondary recovery

* Reservoir depths evaluated in this study.

Source: Dames & Moore

St. George Basin oil fields could range between 80 - 160 acres per well depending on initial well productivity, recoverable reserves per acre, and numbers of wells and reservoir depth. In shallow reservoirs with low 1P, wells spacing may be as low as 40 acres. The oil wells in McArthur River field in upper Cook Inlet, for example, are now complete with 80-acre spacing. Although the original spacing was 160 acres, this was reduced by in-filling as field development proceeded. At Prudhoe Bay, production is currently coming from wells on 160-acre spacing (individual well flow rates average 7,000 barrels per day but vary from 2,000 - 23,000 barrels per day). Ultimate well spacing at Prudhoe Bay may be 80 acres, although the actual reservoir management strategy will depend upon future reservoir performance. A reasonable assumption, therefore, is that standard industry well spacing between 80 and 160 acres will be adopted for St. George Basin oil fields; oil fields may be developed initially on a 160-acre spacing but, subsequently, reduced by in-filling to 80-acre spacing. Therefore, based on reservoir depths, initial well productivity, and recoverable reserves per acre, there will have to be enough wells to:

- Produce about 10 percent of reserves each year for peak production at a spacing generally between 80 and 160 acres.

- Allow exhaustion of recoverable reserves within 20 - 25 years.

111.4.1.2 <u>Non-Associated Gas</u>

As noted in previous scenario studios, well spacing in Alaska frontier areas is likely to be set by the market demand for gas, rather than by industry desire to maximize recovery. Consistent with reservoir engineering and petroleum geology, well spacing up to 1,200 acres may allow sufficient gas production to run potential LNG capacity. Well spacing in the usual U.S. range of 160 - 320 acres may have little relevance to gas producers in the St. George Basin if there is a limited market for gas. The onshore Kenai gas field in upper Cook Inlet, however, which has long-term contracts with both domestic and industrial users in the Cook Inlet area, is currently developed with wells on a 320-acre spacing. Some other Cook Inlet fields are producing below capacity or are shut-in.

111.4.1.3 Well Allowances

A certain number of wells in a field are non-producing wells. These wells may be (1) water injection wells required as part of a secondary recovery program, (2) abandoned wells, and (3) gas injection wells drilled either as part of a pressure maintenance program or because there was no market for associated gas. As in previous studies, we have assumed that well allowances will be one in five wells. This is consistent with experience in producing fields although the ratio may be as high as 1:3. In our analysis we have assumed early initiation of a secondary recovery program. However, it should be emphasized that the number of non-producing wells will vary considerably with reservoir characteristics and reservoir management program. Well allowances are factored into the economic and manpower analyses.

111.4.2 Well Completion Rates

111.4.2.1 Exploration Wells

As indicated in the petroleum geology review, the depth to basement varies considerably across the area from less than 1,524 meters (5,000 feet) on the flanks of the basin to over 10,000 meters (33,000 feet) in the central graben. Prospective reservoirs probably lie at depths ranging from less than 1,524 meters (5,000 feet) to about 7,572 meters (15,000 feet). Within the graben, therefore, the depths of exploratory wells are likely to be medium to deep but only shallow on the structures on the flanks of the basin. Consequently, other factors apart, there will be considerable variation in the completion schedules of exploratory wells. Based upon drilling experience in the other OCS areas, medium to deep exploratory wells can be expected to take 3 to 5 months to drill. Very deep wells of 4,572 - 5,486 meters (15,000 to 18,000 feet) may take over 6 months to complete. Actual schedules will vary according to geologic conditions, testing requirements and technical difficulties. For the purposes of manpower estimation and analytical simplification, we have assumed that exploratory and delineation drilling averages 4 months per well.

111.4.2.2 Development Wells

Potential reservoir depths range from 917 - 4,572 meters (3,000 - 15,000 feet). Since most of the development wells will be drilled directionally from platforms, their actual length (measured depth) will be greater. Directional wells drilled into the Sadlerochit reservoir (2,348 - 2,773 meters or 8,000 - 9,000 feet) at Prudhoe Bay take an average of 30 days to drill. For shallow reservoirs (about 917 meters or 3,000 feet) we will assume a 20-day completion schedule, 60 days for deep reservoirs (3,098 meters or 10,000 feet), and 30 days for intermediate depth reservoirs (1,524 meters or 5,000 feet). Wells drilled from offshore platforms may be drilled on the batch principal.

IV. ECONOMIC ANALYSIS

IV.1 The Objective of the Economic Analysis

The objective of the economic analysis is:

(1) To evaluate the relationships among the likely oil and gas production technologies suitable for conditions in the St. George Basin and the minimum field sizes required to justify each technology as a function of geologic conditions in different parts of the basin; and

(2) To calculate the costs per barrel or per 1,000 cubic feet of development and transportation of oil and gas fields under various technological, geologic and locational considerations.

The analysis will focus on the engineering technology required to produce reserves under the difficult conditions of the St. George Basin and will emphasize the risk due to the uncertainties in the cost of that technology, reservoir conditions, and future market value of the resource. Sensitivity and Monte Carlo procedures will be used to allow for the uncertainty in the costs of technology and in the price of the oil and gas, as well as the uncertainty in the reservoir conditions that affect the recoverability of oil and gas resources.

A model has been formulated that allows determination of either: (a) the minimum field size to justify development under several oil and gas production technologies, or (b) the minimum required price to justify development given a field size and a selected production technology.

The model is a standard discount. cash flow algorithm designed to handle uncertainty among key variables and driven by the investment and revenue streams associated with a selected oil and gas production technology given reservoir conditions. The model explicitly allows an examination of the effects of various financial pol icy variables on minimum field size and minimum required wel 1 head price. The essential profitability criteria calculated by the model are: (a) the net present value (NPV) of the net after tax investment and revenue flows given a discount rate, or value of money, and (b) the internal rate of return, which equates the value of all cash flows when discounted back to the initial time period.

In general, the model calculates discounted cash flows (investment outflows and revenue inflows) from production with different production systems at different water depths, reservoir target depths, distances to shore, and transportation options to examine how these different physical characteristics affect the decision to develop a field in the OCS.

Attention is focused on the engineering technology required to produce oil and gas under the difficult conditions in the Bering Sea and the risk due to the uncertainties in the cost of that technology. Sensitivity and Monte Carlo procedures will be used in the analysis to allow for the uncertainty in the costs of technology as well as the uncertainty in the price of the oil and gas.

By excluding exploration costs and bonus payments, and the time lag from bonus payment to discovery, the model assumes discovery costs are sunk and answers these important questions:

(1) What are the optimum development strategies for discovered fields in the lease sale area?

(2) What is the minimum field size required to justify development from the time of discovery for a selected production technology and development option?

"Sunk" exploration costs (seismic and geophysical , dry hole expenditures, and lease bonuses) must be covered by successful discoveries. The solution assumes that these costs, and the time period for exploration (neither of which are small), are covered by the firm's earnings from its successful portfolio of exploration investments.

In order to calculate the cost per barrel of oil or per 1,000 cubic feet of gas, Dames & Moore has developed the equivalent amortized cost model (EAC Model). This model will be used to develop unit costs for each economically feasible field. The EAC Model is described more fully in Section IV-2.

In the following sect ens, the model, its assumpt ens, and their implications are discussed.

IV.2 The Model and the Solution Process

IV.2.1 The Model

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

(Equat on No. 1) NPV = [[Price x Production x (l-Royalty) - Operation Costs] . (l-Tax) + [Tax Credits] - [Tangible Investments + Intangible Costs]] x PV

where:	NPV	= net present value of producing a certain field with specified technology over a given period
	Pv	
	Price	= well head price escalating over time
	Production	= annual production uniquely associated with a given field size, a selected production technology, and a number of wells
	Royal ty	= royalty rate
	Operating Cost	= annual operations cost, including general administration costs and escalated costs over the life of the project
	Tax	= corporate income tax rate

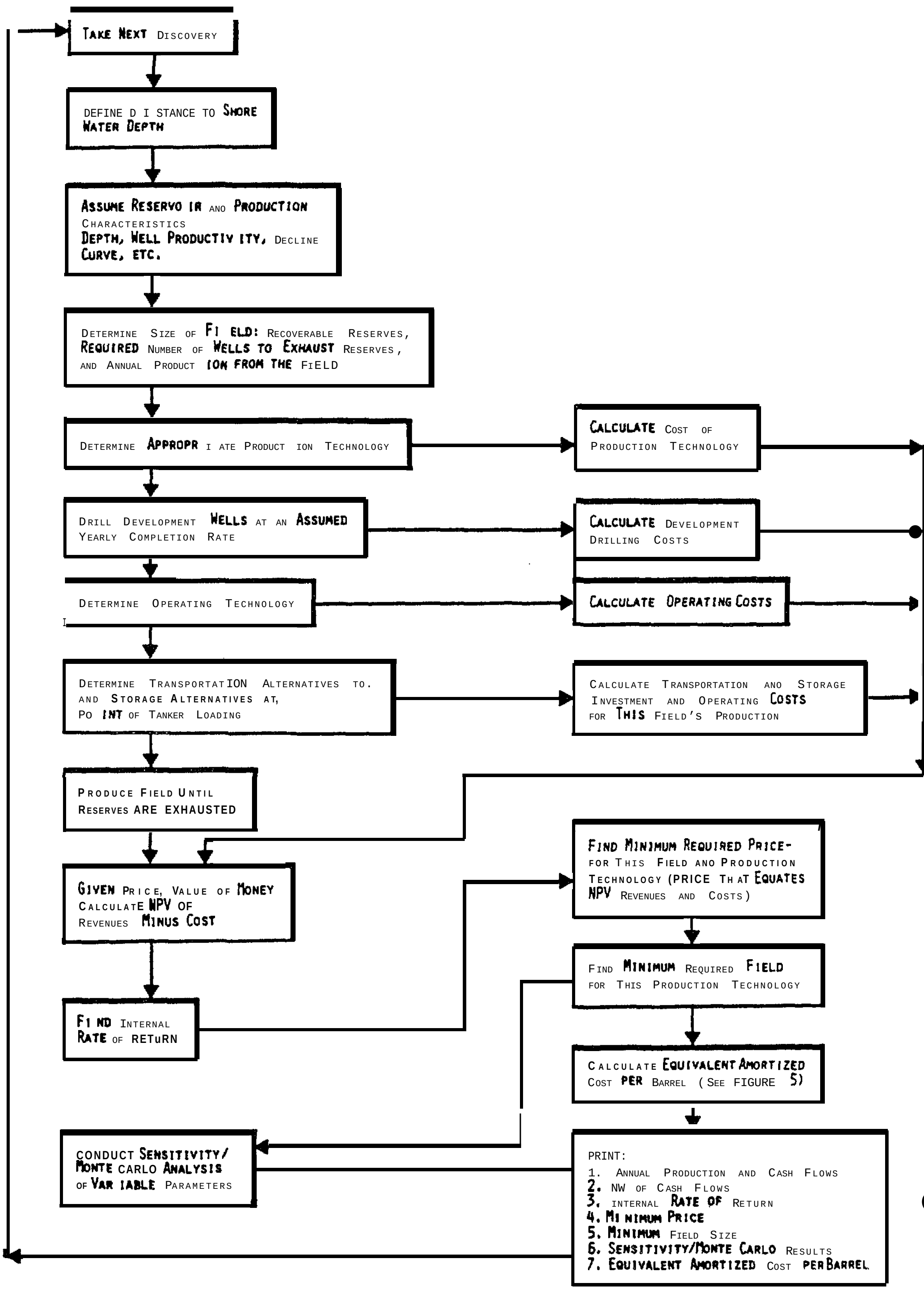
Tax Credits	=	the sum of investment tax credits (ITC) plus depreciation tax credits (DTC) plus intangible drilling costs tax credits (IDC)
Tangible Investments	=	development investments escalated over the investment period and depreciated over the production life of the field
Intangible Investments	=	development expenditures escalated over the investment period and expensed for tax purposes

The model does not include a term for salvage of equipment at the end of production. The assumption is made that the cost of removing all equipment and returning the producing area to its pre-development environmental conditions to meet State and Federal regulations would be as much as the salvage value of the equipment.

The logic and data flow for the discounted cash flow analysis is diagramed on Figure A-3.

The cost flows developed in the economic evaluation model are supplied to EAC Model to calculate the equivalent amortized cost per barrel of oil or thousand cubic feet of gas for each feasible field. The cost categories include:

1. Total capital charges on total capital invested including:
   a) Capital recovery
   b) Capital earnings
2. Operating costs including:
   a) General and administrative expenses
   b) Development operating costs
3. Royal ty
4. Federal taxes net of all tax credits



NOTE: THE ECONOMIC DATA FLOW AS ILLUSTRATE IN THIS FIGURE ASSUMES EXCLUSION OF EXPLORATION COSTS IN THE ANALYSIS

FIGURE A-3 LOGIC AND DATA FLOW FOR DISCOUNT CASH FLOW ANALYSIS OF OFFSHORE FIELD DEVELOPMENT

The model calculates the present barrel equivalent (PBE) of production to arrive at the per barrel total and component costs. Calculations based on the EAC cost of capital and on the assumed costs of facilities permit investment flows to be disaggregate into individual facility costs of: (1) offshore production, (2) onshore terminal , and (3) pipelines.

The EAC Model will be used to calculate the equivalent amortized total and component costs per barrel of oil or per 1,000 cubic feet of gas on a present barrel equivalent basis for all development options for each field. Transportation costs to market from the St. George Basin will be specified and shown on a comparable unit basis. Total unit costs of producing oil and gas resources and delivering them to market will be calculated.

Figure A-4 shows the flows between the economic analysis model and the EAC Model and indicates the inputs and outputs of each model. Figure A-4 also shows how the resource marketability relates to the total unit cost of production calculation. The potential markets will determine the transportation options and attendant transportation costs.

IV.2.2 Solution

Equation No. 1 can be solved deterministically if values for the critical variables are known with reasonable certainty. But single values for the independent variables on the right-hand side of Equation No. 1 are not known. The technologies that are being considered for parts of the Alaska OCS have not been tested or cost-estimated in the United States. Thus, the model is designed to handle upper, lower, and mid-range values for the critical variables of Equation No. 1,

The model can be solved for a given field size and given reservoir conditions, prices, and a selected technology for the rate of return that will drive the NPV of production to zero. Sensitivity analysis can be used to

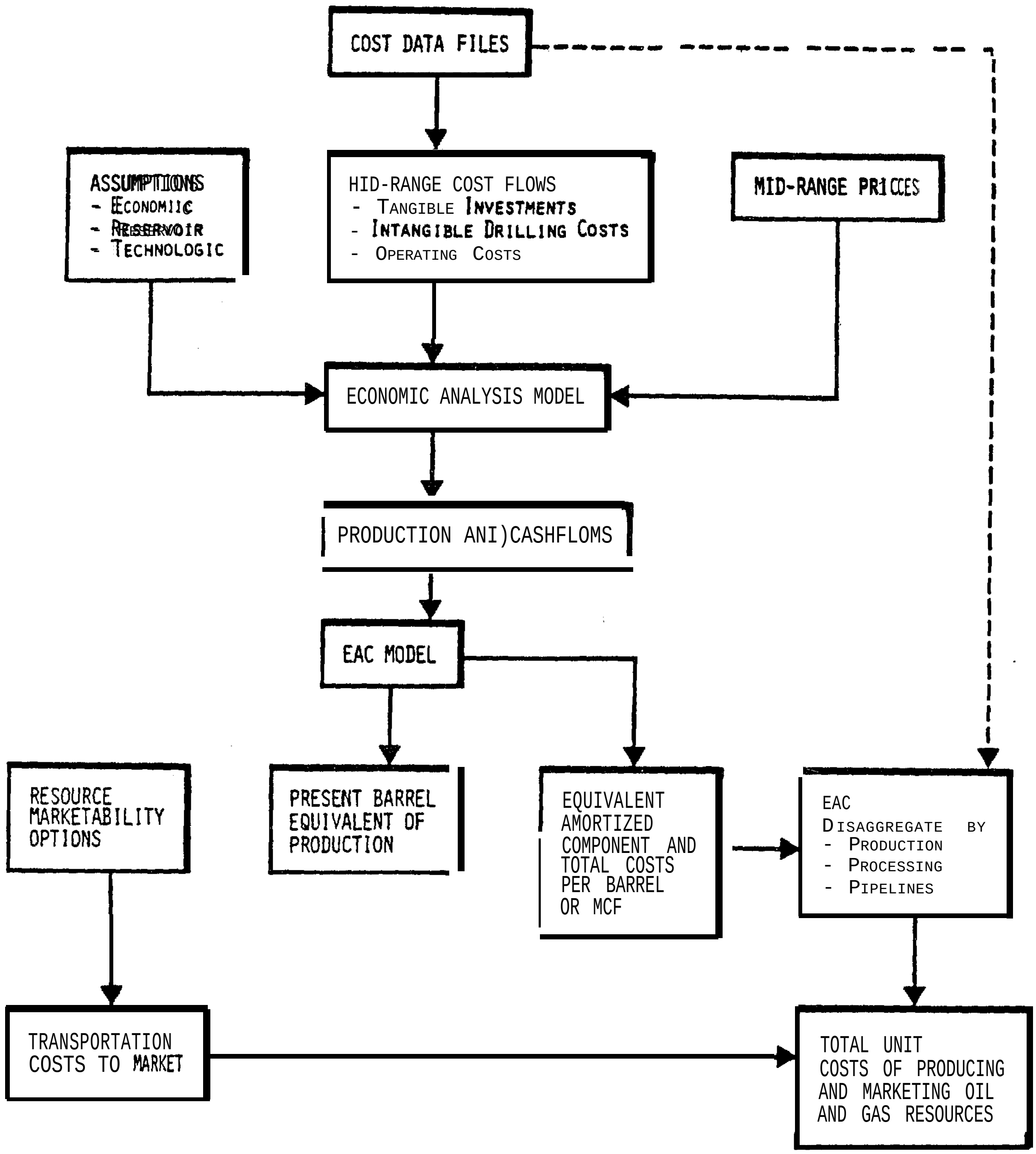


FIGURE A-4

UNIT COSTS OF PRODUCTKIN AND DAMES & MOORE EAC MODEL

show how the previously calculated rate of return changes with different values for:

- Crude oil and gas prices
- Operating costs
- Tangible investment costs
- Intangible drilling costs
- Taxes, royalty payments, and royalty schemes

Iterative solutions of Equation No. 1, given prices and a selected technology, can be used to determine the minimum size field to justify development at various values of money. Sensitivity' analysis to show how changes in the values for prices and costs or their relative rates of inflation change minimum economic field size.

Both sensitivity analysis and Monte Carlo simulation are used in the solution process of Equation No. 1. Both techniques are designed to handle uncertainty among the input variables and both give a measure of the spread of potential outcomes.

Sensitivity analysis facilitates the answer to those important "what if" policy questions. Monte Carlo simulation goes a step further and yields a measure of the potential riskiness of the final outcome in the form of a sampling distribution of the probability of the outcome -- but at a dramatic increase in computational cost.

IV.2.3 Issues Analysis: Field Development Problems

The economic analysis will be focused to identify, first, the preferred development options given locational and environmental constraints and, second, the extent to which the range of constraints improve or reduce the economic viability of the preferred development options. The development options appear to entail a range of steel jacket hybrid platforms and gravity structures suitable for ice, bottom soil, and seismicity conditions, together with pipeline-to-shore options or offshore loading.

IV.3 The Assumptions

IV.3.1 The Time Values of Money

The discounted cash flow model, which forms the basis of the economic feasibility analysis, is designed to reflect the time value of cash flows. The present value discount rate term (PV in Equation No.1, Section V.2.1) has a profound influence on the outcome of this model. Present value discounting is necessary because of three largely independent factors:

1. The buying power of current revenues decreases over time because of inflation;

2. The investor must pay a real cost for borrowed capital, or must forego other investment opportunities; and

3. The risk of some ventures may increase progressively.

In consultation with BLM economists and major oil company analysts, Dames & Moore has adopted an 8 - 12 percent discount rate to bracket the after-tax real rate of return that winning bidders will be willing to accept to develop a field. This rate takes into account the opportunity cost of capital (historically about 3 percent), and risk (Factors 2 and 3 above), but does not include the effects of inflation. Economists such as Howe (1979) and Stokely and Zeckhausers (1978) have suggested' discount rates of 6-3/8 percent and 7.5 - 10 percent, respectively. These factors refer to public investment decisions. As Howe points out, the social and private discount rates do not necessarily coincide because the former may reflect the government's responsibility to protect future interests. Private firms do not make decisions on this basis, and since the economic behavior modeled here is of the private sector, the social discount rate is not relevant. Furthermore, the 6-3/8 percent figure used in Howe is based on a risk-free rate of return. In ventures as risky as OCS development in an environment as hostile as St. George Basin, a risk premium of at least 5 percent and more likely 9 percent is easily justified. The economic analysis will stress a 12 percent discount rate, as the hurdle rate sufficient to induce private investment.

As can be seen in Table A-4, the real prices of oil and gas relative to the Gross National Product (GNP) deflator have not followed a distinct pattern in the past two decades. The rapid petroleum price increase (which roughly doubled in the past year) and the high general inflation rate offer no discernible basis for protecting future prices and costs. For this reason, the analysis of St. George Basin development continues as in past studies to use constant (1980) dollar prices and costs. Under this assumption, Factor 1 above, correction for inflation, is not needed. All product prices and development costs are held at the assumed 1980 levels throughout the life of the investment. Inflation is a "wash" and return on investments refers only to real returns to capital investment. For the life of the development, however, sensitivity analyses are presented to show the effects of increasing and decreasing relative costs and prices by constant factors. In addition, the effects of inflating the costs and prices by 3 percent per year are also presented.

IV.3.2 The Relationship Between Inflation, Gas and Oil Prices, and Development

IV.3.2.1 Oil Prices

In order to estimate the value of oil from St. George Basin, the current (January 1980) price of the most common imported oils at gulf and west coast ports was determined. Assuming imported oil remains available, crude from the St. George Basin must be competitive with these laid-in prices. Thus, the laid-in value of Alaska oil can be calculated by subtracting shipping

Table A-4

REAL PRICE CHANGES FOR OIL, GAS AND OIL FIELD MACHINERY

Year	Crude Oil Prices[1] (¢ MMBTU)	Natural Gas Prices[1] (¢MMBTU)	Oil Field Machinery And Tools[2] (Cost Index 1974 = 100)	GNP Deflator Index (1974 = 100)
	(1972 dollars)	(1972 dollars)		
1960	72.3	19.7		61.0
1965	64.0	20.3		65.6
1970	57.0	18.2		79.1
1972	58.5	18.1		86.2
1973	63.4	20.0		91.2
1974	102.1	25.6	100	100
1975	104.0	34.3	124.4	109.6
1976	105.6	42.5	137.9	115.2
1977	104.4	57.7	149.9	122.1
1978	101.6	59.2	164.5	131.1
1979	135.9	78.1	187.8	142.6
Average Annual Real and Inflationary Growth Rates (%)				
1960-72	-1.7	-0.7		2.9
1960-79	3.4	17.2		4.57
1972-79	12.8	23.2	-	7.5
1974-79	5.9	25.0	13.4	7.4

1 Source - US Statistical Abstract 1979, Table 1007 for data through 1978. 1979 data adapted from BLS Producer Price indices 1531 and 1191.

2 BLS Producer Price Index 1191.

costs, terminal fees, and quality differentials from the imported oil prices. These calculations are presented on Table A-5.

An average of the laid-in values in Table A-5 is $27.44. On this basis, a mid-range price of $27.50 is used for the economic analysis. In addition to the mid-range, upper and lower prices of $45 and $22.50 are used to bracket the real price changes that may occur during the productive life of the basin. Since relative price increases for oil are more plausible than decreases, the range is not symmetric, but emphasizes price increases. In addition, the effects of a 3 percent annual oil price escalation are explored.

IV.3.2.2 Natural Gas Prices

The natural gas production of the St. George Basin will not come on-line before "United States gas prices are decontrolled in 1985. Since gas is a clean burning, easily transportable fuel, ready to use in its unrefined state, there is no reason to assume that its final laid-in price per BTU will be less than the price of diesel oil. There is, however, the expense of converting the gas to LNG for transportation to the west coast and the cost of reconstituting the LNG to pipeline gas at the destination port.

Based on these assumptions, a hypothetical current (1980) but deregulated end-of-pipeline valve for gas can be calculated as follows:

Value of diesel (refinery gate, at west coast)	$32.00/BBL
Equivalent value/MMBTU (1 BBL = 5.7 MMBTU)	5.61
Equivalent value/MCF (1 MCF= 1.02 MMBTU)	5.72
Less liquefaction cost at Dutch Harbor	-2.20
Less shipping cost Dutch Harbor to west coast	-1.20
Less terminal charges at west coast	-0.10
End-of-pipeline value of Dutch Harbor N.G.	$ 2.22

Source': Based on Pacific Alaska LNG Co. cost estimations inflated to 1980 dollars.

TABLE A-5

LAID-IN VALUE OF ALASKA OIL BASED ON WORLD OIL PRICES

Oil Type	Origin	Oil Price Jan., 1980 $/BBL[1]	Shipping to Refinery at	cost of Shipping[2]	Laid-In Cost/BBL at Refinery	Shipping cost Dutch Harbor to Refinery[3]	Terminal Fee Plus quality Differential[4]	Laid-In Value
Arabian Light	Saudi Arabia	26.00	U.S. Gulf Coast	$2.49	$28.49	-$4.81	- 0.85	$22.83
Bonney Light	Nigeria	34.48	U.S. Gulf Coast	1.91	36.39	- 4.81	- 0.85	30.73
Isthmus	Mexico	32.00	U.S. Gulf Coast	0.45	32.45	- 4.81	-0.85	26.29
Minas	Indonesia	30.75	California	1*50	32.25	- 2.01	-0.85	29.39

[1]Source: Oil & Gas Journal, 1980a, p. 39

[2]PIW January 21, 1979, p.9. Shipping Prices for December, 1979

[3]Based on shipping cost from Valdez to U.S. refinery (PIW, December 24, 1979, p. 10) multiplied by 1.5 to reflect greater distance and difficult of shipping from Dutch Harbor.

[4]Quality differential is assumed to be -$.50/BBL, and terminal cost = $0.35

On the basis of this calculation, a mid-range price of gas of $2.22 is used in this analysis. In order to indicate the effects of uncertainty of this price on gas development in the St. George Basin, sensitivity analyses using prices of $1.75 and $3.50 are presented. As with oil prices, this range is asymmetric to reflect the greater likelihood of relative gas price increases versus declines. In addition, the effects of a 3 percent annual gas price escalation are analyzed.

IV.3.3 Effective Income Tax Rate and Royalty Rate

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

Royalty is assumed to be 16-2/3 percent of the value of production. In consultation with BLM economists, their judgment was adopted that future royalty schemes would not change the outcome of this analysis substantially.

IV.3.4 Tax Credits, Depreciation, and Depletion

Investment tax credits of 10 percent apply to tangible investments. Depreciations 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 for development decision analysis.

IV.3.5 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 and intangible investment costs varies with the component parts of offshore development. In consultation with Santa Fe Engineering, Dames & Moore has determined that approximately 50 percent of the offshore investment costs are tangible. Thus a 50/50 split between tangible and intangible offshore development costs is used in this analysis.

IV.3.6 Investment Schedules

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

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

Both tangible and intangible investment costs are entered into the model as lower, mid-range, and upper limits reflecting the cost ranges specified in Appendix B. The model yields a base case solution on the mid-range investment level along with sensitivity tests at the upper and lower limits. In some cases, Monte Carlo analysis is conducted over these range of values.

APPENDIX B

FIELD DEVELOPMENT COMPONENT COSTS AND SCHEDULES

1. 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 St. George Basin. 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.

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

TABLE B-1

COST ESTIMATES OF INSTALLED PLATFORMS

Platform Type	Water Depth		Cost ($ Millions 1980)	
	Meters	Feet	Low	High
Steel 32 wells	107	351	65.0	78.0
Gravity 32 wells	107	351	60.0	72.0
Steel 48 wells	150	492	89.0	106.8
Gravity 48 wells	150	492	83.0	99.6

Notes:

1. The water depths reflect the range anticipated in the lease sale area.

2. The cost of a construction site for the gravity structure is not included in these estimates. This cost could significantly increase the cost of the platforms.

3. 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, setdown and pile driving.

4. The above estimates do not include any allowance for the installationor 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 either type of platform being considered.

2. The above cost estimates include installation, hook-up, and commissioning. It is assumed that module installation would be concurrent with platform installation, thus avoiding a second mobilization and demobilization of the equipment.

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 either type of platform being considered.

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

Source: Santa Fe Engineering Services Co.

TABLE B-4

ESTIMATES OF DEVELOPMENT WELL COSTS

Well Type	Reservoir Depth Meters	Feet	Cost ($ Millions 1980) Low	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 St. George Basin.

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 transpiration 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

ESTIMATES OF MARINE PIPELINE COSTS

Diameter (Inches)	Average Cost per Mile ($ 1980) Low	High
30 - 39	1,700,000	2,500,000
20 - 29	1,300,000	1,600,000
10 - 19	900,000	1,200,000
less than 10	650,000	820,000

Notes:
1. See text for discuss” on of cost sensitivities related to offshore pipelines.

2. The above cost per mile is based on an overall average pipeline length of 160 meters (100 miles) and average water depth of 122 meters (400 feet).

3. The above costs assume no pipeline insulation or burial. One shore approach and one platform riser per line are included.

Source: Santa Fe Engineering Services Co.

TABLE B-6

ESTIMATES OF ONSHORE PIPELINE COSTS

Diameter (Inches)	Average Cost per Mile ($ 1980) Low	High
30 - 39	1,800,000	2,200,000
20 - 29	1,400,000	1,700,000
10 - 19	1,000,000	1,300,000
less than 10	900,000	1,000,000

Notes : 1. The above costs per mile are based on typical assumed project length of 32 - 64 kilometers (20 - 40 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 not assumed any river or mountain crossings.

4. We have assumed acceptable camp and associated facilities would be available in the area.

Source: Santa Fe Engineering Services Co.

TABLE B-7A

ESTIMATES OF OFFSHORE LOADING SYSTEM COSTS

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

TABLE B-7B

OFFSHORE LOADING BUOY/MOORING SYSTEM
ANNUAL OPERATING COST ESTIMATES

System	Cost ($ Millions)
One Platform plus SALM	35

Source: Santa Fe Engineering Service Co.

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 $1,800 to $3,000 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*
8 Platform Field, Well-Terminal	-	-	250*

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

Sources: 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.

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.

111.1 Platform Fabrication and Installation (Table B-1)

Cost estimates are presented for two types of platforms -- a Cook Inlet steel jacket hybrid and a concrete gravity structure -- in water depths that are representative of the shallow and deep portions of the high interest areas of St. George Basin.

In addition to the water depth for steel platforms, factors such as design deck load and number of well slots also affect cost. To increase cost sensitivity, we have presented estimates for a range of conductor wells from 32 - 48. Fewer than 32 probably may be difficult to justify economically, while greater than 48 becomes a design constraint for these platforms. For this general estimate, we feel that the difference in cost estimates is not that great between platforms containing 32 and 48 conductors. In estimating platform costs, process equipment specifications could have been considered as a more appropriate size/deck load index. This is true in many cases. However, for the platforms and various design criteria considered, the deck load does not appear to be a design criteria principal factor.

111.2 Platform Process Equipment (Table B-2)

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 little difference in cost related to the decision to produce or reinject associated gas, for the range of figures and type of construction we have assumed, the major cost is equipment installation, not the cost of hardware.

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 reinfected into the reservoir to maintain pressure and to prolong the flowing life of the well. Further, the reinfection of associated gas is the only viable solution to the flaring ban imposed upon producing fields if natural gas production is not economically feasible.

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, pipelines and the increased equipment requirements for gas processing, are usually insufficient to affect dramatically the platform costs.

In the economic analysis, we have evaluated the economics of associated gas production assuming field(s) with high GOR (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. Also, more space will also be required for equipment. However, given the platform designs considered, this would have little effect on overall installed platorm costs.

III.3 Marine Pipelines (Table B-5)

The costs presented in Table B-5 are for a 100-kilometer (62-mile) project that would be a representative distance from the central portion of the lease sale area to an Aleutian Island terminal. If the line was approximately 80 kilometers (50 miles) long, the cost could be increased by approximately 20 percent per mile. If the pipeline was 322 kilometers (200 miles) long, the cost could be decreased by approximately 10 percent per mile. If the pipeline were buried, the cost would increase by approximately 25 - 35 percent per mile. The costs in Table B-5 assume an average depth of 122 meters (400 feet). If the average depth were 91 or 152 meters (300 or 500 feet), the above costs would be affected by a factor of approximately 10 percent, plus or minus.

III.4 Onshore Pipelines

Onshore pipelines would be required to take production from offshore pipeline landfalls to terminal sites located on one of the Aleutian Islands or on the Alaska Peninsula. While the onshore *lines* would be relatively short for the facility sites located in the Aleutians, longer onshore lines, 50 kilometers (30 miles) or greater, would probably be required for the Alaska Peninsula sites since these are located on the Pacific Ocean side of the peninsula. 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 engineering in permafrost, remote location, 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 transferred 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-n. The schedules of capital *cost* expenditures are based upon typical development schedules in other offshore areas modified for the environmental conditions of St. George Basin assuming certain assumptions on field construction schedules (see discussion below).

TABLE B-n

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)
I'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 -- 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 (100-300MBD)	10	30	30	30		

Source: Dames & Moore

V. EXPLORATION AND FIELD DEVELOPMENT SCHEDULES

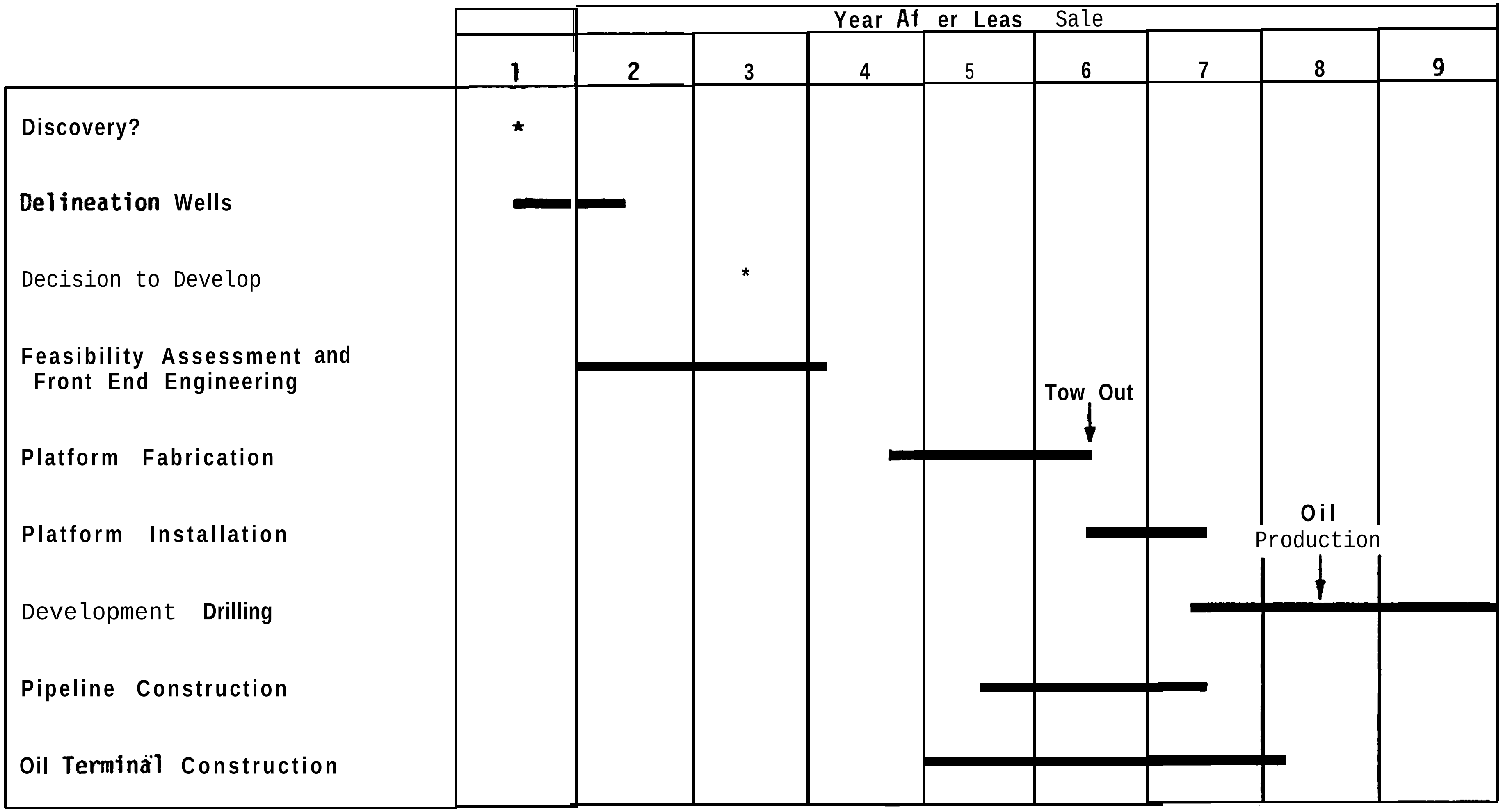
This appendix also discusses the assumptions made in defining the exploration and field development schedules contained in the development option for the U.S. Geological Survey statistical mean resource estimate (Chapter 7.0). These schedules are basic inputs into the economic analysis (scheduling of 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-1 illustrates the field development schedule for a medium-sized oil field involving a single steel platform, pipeline to shore, and shore terminal in a non-ice, 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-2) 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-1

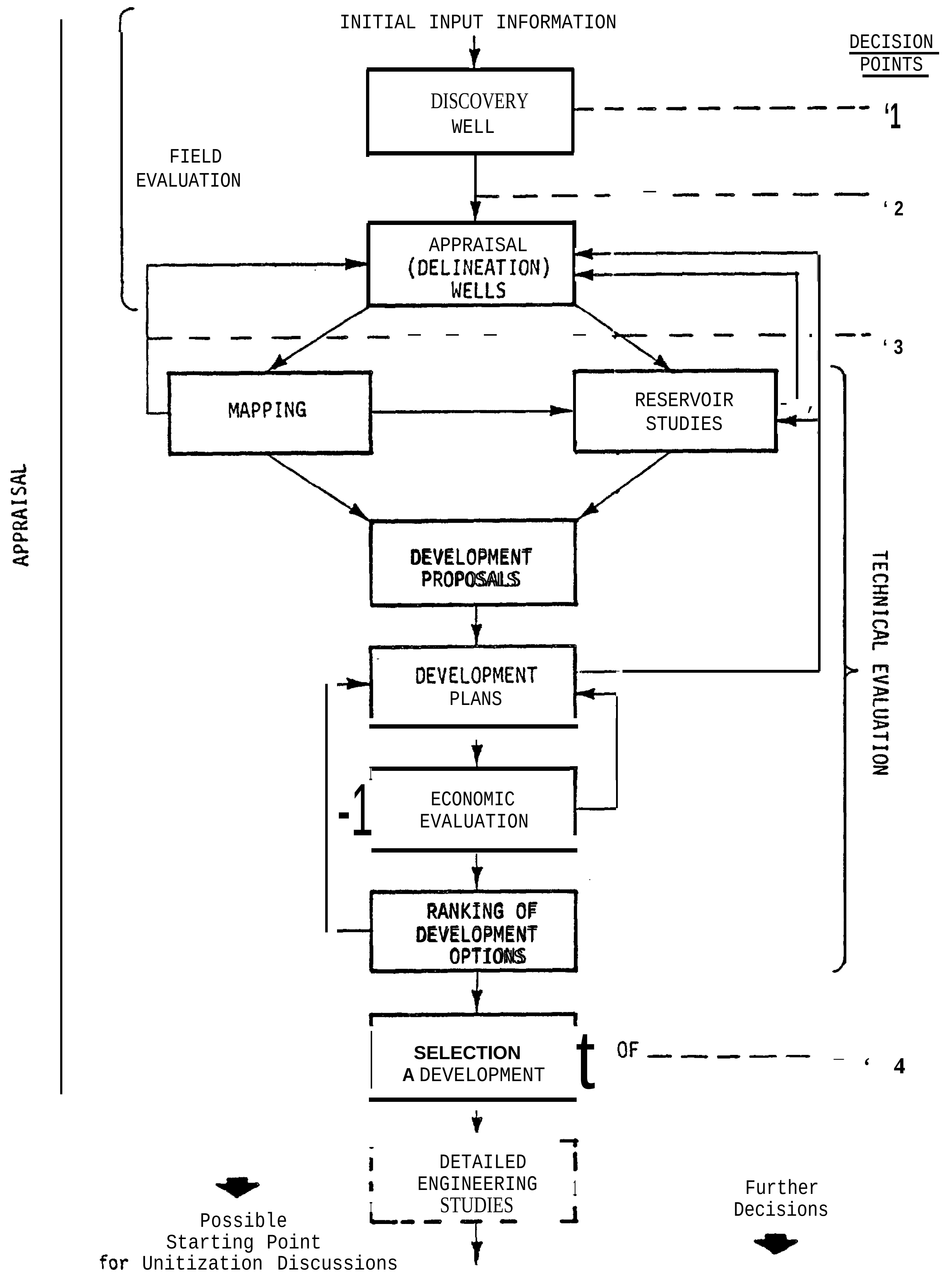
EXAMPLE OF MEDIUM-SIZED FIELD COMPLETION SCHEDULE
SINGLE STEEL PLATFORM, OIL PIPELINE TO SHORE, SHORE TERMINAL[2]
IN NON-ICE-INFESTED ENVIRONMENT



Source: Dames & Moore

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



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 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 to 12 months after tow-out on steel jacket platforms. Development wells may be drilled using the "batch" approach whereby a group of wells are drilled in sequence to the surface casing depths, then drilled to the 13-3/8-inch setting depth, etc. (Kennedy, 1976). The batch approach not only improves drilling efficiency but also improves material-supply scheduling. On large platforms, two drill rigs may be used for development well drilling, thus accelerating the production schedule. One rig may be removed after completion of all the development wells, leaving the other rig for drilling injection wells and workover.

e

V.1 St. George Basin 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 St. George Basin, 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 6 months after the lease sale (i.e., summer 1983); all schedules cited in this report relate to 1983 as year 1.

- An average completion rate of 4 months per exploration/delineation well is assumed with an average total well depth of 3,048 - 3,692 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 platforms in all water depths are fabricated and installed within 36 months of the decision to develop and gravity platforms within 48 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 and gravity platform tow-out and emplacement are 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 (2,500-foot) reservoirs, 30 days per well (12 per rig per year) for 1,524-meter (5 ,000-foot) reservoirs, and 60 days (6 per rig per year) for 3,048-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.