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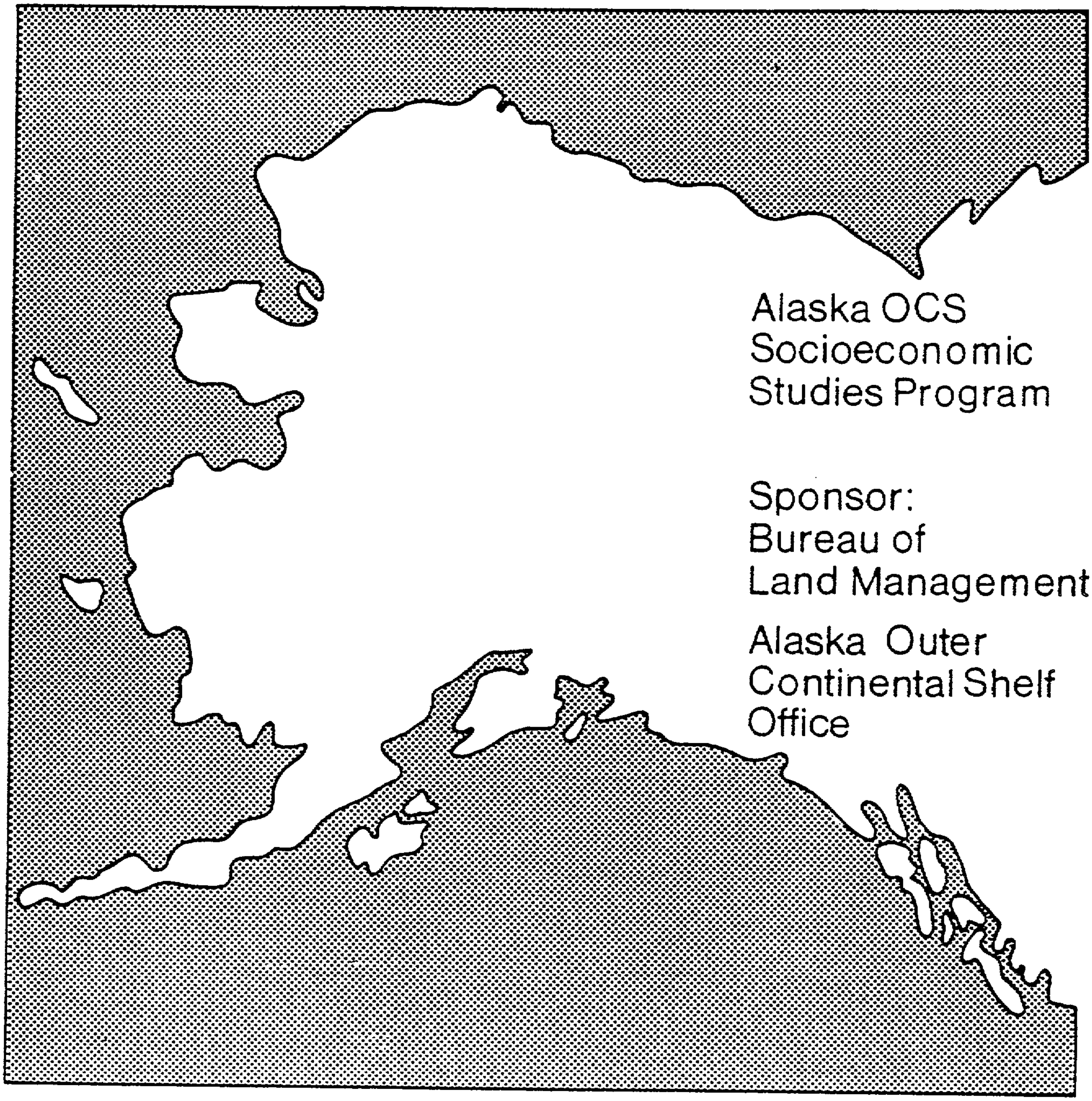

Alaska OCS Socioeconomic Studies Program

Sponsor:
Bureau of Land Management
Alaska Outer Continental Shelf Office

Western Gulf of Alaska Petroleum Development Scenarios

The United States Department of the Interior was designated by the Outer Continental Shelf (OCS) Lands Act of 1953 to carry out the majority of the Act's provisions for administering the mineral leasing and development of offshore areas of the United States under federal jurisdiction. Within the Department, the Bureau of Land Management (BLM) has the responsibility to meet requirements of the National Environmental Policy Act of 1969 (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.

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 analysis addresses the differing effects among various geographic units: the State of Alaska as a whole, the several regions within which oil and gas development is likely to take place, and within these regions, the various communities.

The overall research method is multidisciplinary in nature and is based on the preparation of three research components. In the first research component, the internal nature, structure, and essential processes of these various geographic units and interactions among them are documented. In the second research component, alternative sets of assumptions regarding the location, nature, and timing of future OCS petroleum development events and related activities are prepared. In the third research component, future oil and gas development events are translated into quantities and forces acting on the various geographic units. The predicted consequences of these events are evaluated in relation to present goals, values, and expectations.

In general, program products are sequentially arranged in accordance with BLM's proposed OCS lease sale schedule, so that information is timely to decision making. In addition to making reports available through the National Technical Information Service, the BLM is providing an information service 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. 35

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
WESTERN GULF OF ALASKA
PETROLEUM DEVELOPMENT SCENARIOS

FINAL REPORT

Prepared for

BUREAU OF LAND MANAGEMENT
ALASKA OUTER CONTINENTAL SHELF OFFICE

Prepared by

DAMES & MOORE

February 1979

Contract No. AA550-CT6-61,
Task 9BA

Job No. 8699-016-20

NOTICES

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

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

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

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
Western Gulf of Alaska
Petroleum Development Scenarios
Final Report

Prepared by

DAMES & MOORE

February 1979

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1.0 INTRODUCTION

1.1 Purpose

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

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

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

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

1.2 Scope

The petroleum development scenarios formulated in this report are for the proposed Western Gulf of Alaska (Kodiak) OCS lease sale No. 46, currently scheduled for the autumn of 1980. This is a first generation lease sale following an earlier Gulf of Alaska OCS lease sale (No. 39) in the northern gulf held in April of 1976; the sale will also follow a second generation lease sale for the Northern Gulf of Alaska (No. 55) scheduled for June 1980.

The study area considered in this investigation (Figure l-l) is that defined in the draft environmental impact statement for the Western Gulf of Alaska, lease sale No. 46 (U.S. Department of the Interior, 1976, Appendix I). This area comprises 564 blocks or tracts (13 million hectares; 3.2 million acres) of the outer continental shelf located east of Kodiak, Afognak and Trinity Islands with a distance to shore ranging from 4.8 to 185 kilometers (3 to 115 miles). The tracts are located in water depths that range from approximately 35 to 300 meters (115 to 984 feet). Most of the area lies within the 200 meter (650-foot) isobath and a substantial proportion of that area is located in water depths ranging from 30 to 100 meters (98.4 to 328 feet).

The U.S. Geological Survey resource estimates that are used in this study are as follows (Von Huene et al., 1976):

	95 Percent Probability	5 Percent Probability	Statistical Mean
Oil (billions of barrels)	0	1.2	0.2
Gas (trillions of cubic feet)	0	3.5	0,7

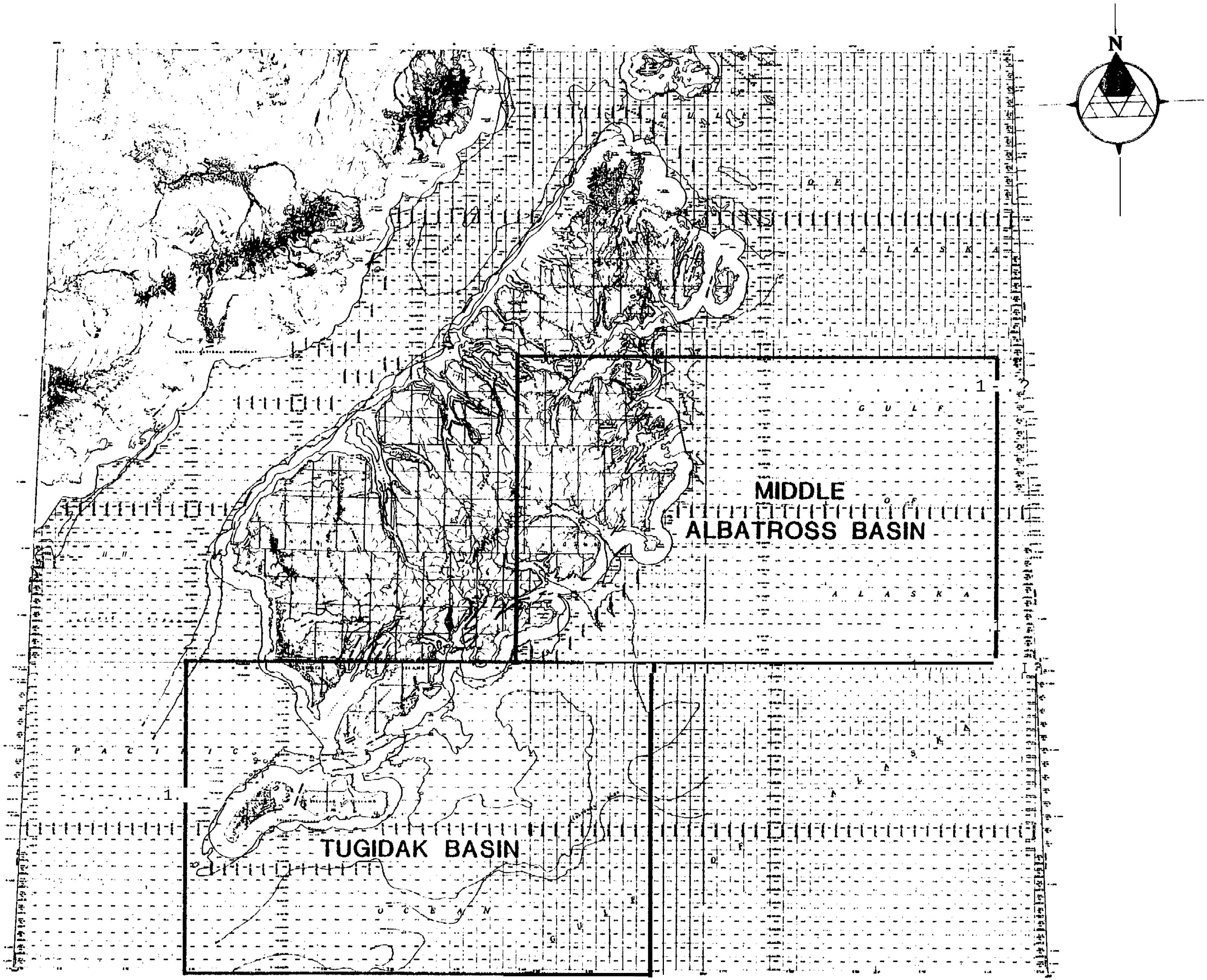


FIGURE 1-1

WESTERN GULF OF ALASKA, LOCATION OF STUDY AREA

This study details scenarios for the five percent, statistical mean and 95 percent probability levels of the U.S.G.S. resource estimates. In addition, a scenario specifying exploration only is detailed. Since the 95 percent probability level identifies no commercial resources, the exploration only and 95 percent cases are essentially one and the same. Therefore, this study formulates three scenarios corresponding to the five percent, statistical mean resource levels and/or no commercial discoveries resulting in exploration only,

1.3 Methodology

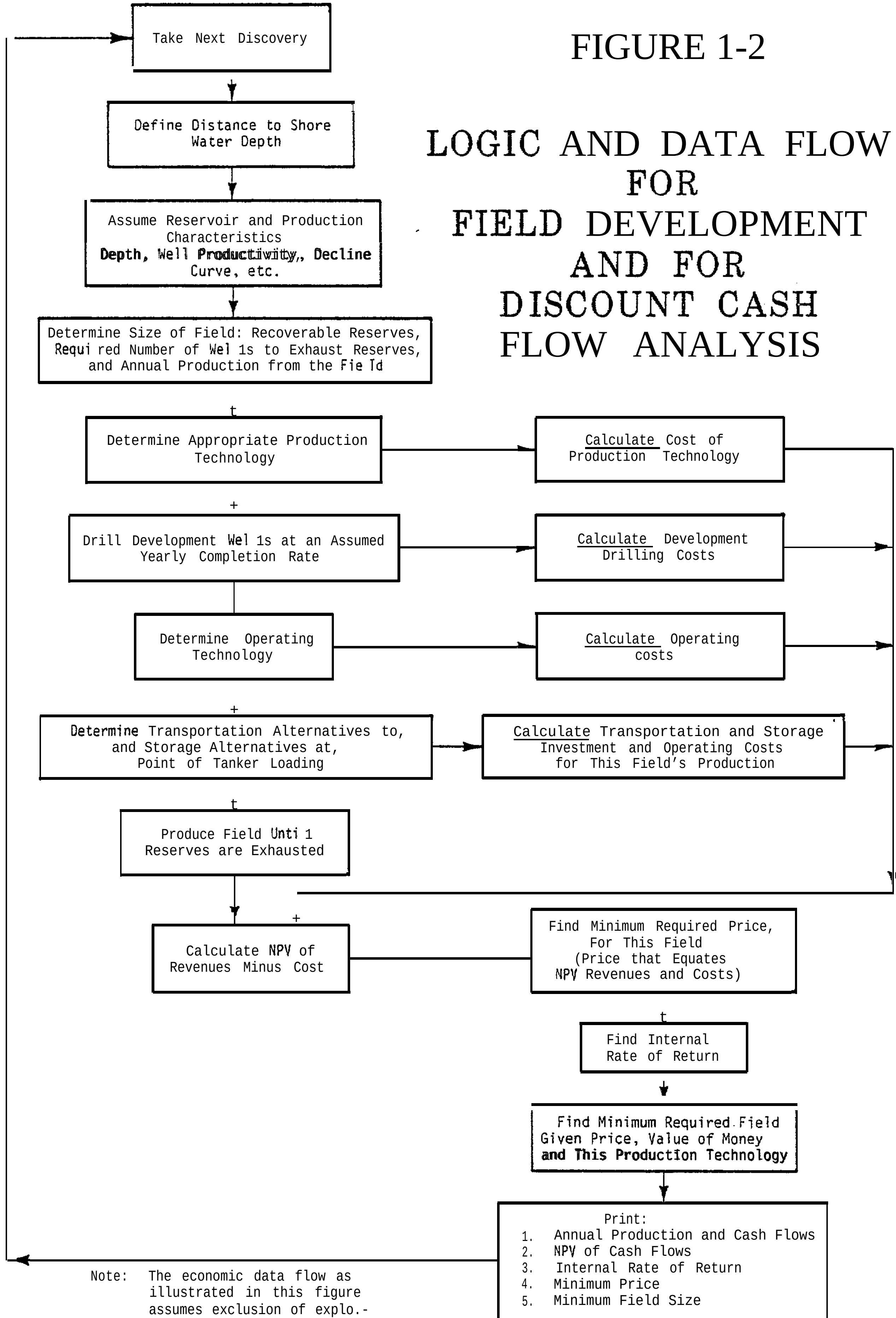
The logic and data flow of this study, centering around the economic analysis are illustrated in Figure 1-2.

The construction of petroleum development scenarios commences with allocation of the U.S.G.S. resource estimates between several sub-basins of the Kodiak Tertiary Province and the formulation of a set of reservoir, hydrocarbon and production assumptions, as described in Chapter 3.0, which include basic analytical assumptions necessary to conduct the economic analysis. The petroleum geology of the western Gulf of Alaska, including allocation of the resource, is discussed in Appendix A.

A review of existing and imminent petroleum exploration, development and transportation technologies in similar operating environments is made in Chapter 4.0 in order to construct a technology model which identifies a number of production system options to be screened in the economic analysis. An integral part of this review is the identification of petroleum development and operating costs which are the basic input in the economic analysis; these cost estimates are presented in Appendix B. The scheduling of field development construction activities is also a product of the technology review and provides the basic input for the analysis of manpower requirements both in terms of the individual petroleum facility/activity components, as described in Chapter 5.0, and the total scenario manpower estimates, as detailed in Chapter 9.0.

FIGURE 1-2

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



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

The oceanographic, geologic and environmental conditions that may present engineering constraints to petroleum developments are also reviewed in Chapter 4.0.

Chapter 6.0 examines the siting criteria and potential sites for onshore petroleum facilities such as oil terminals, LNG plants and staging areas along the Kodiak shoreline. The purpose of this assessment is to provide locational criteria for scenario facility siting.

The objective of the economic analysis is to evaluate the relationships among several likely oil and gas production technologies suitable for conditions in the Gulf of Alaska and the minimum field sizes required to justify each technology at various water depths. The model calculates the net present value of developing certain field sizes with a given technology appropriate for a selected water depth and distance from shore. The water depth and distance to shore values selected for input into the model are representative ranges anticipated in the lease areas. Field sizes selected for economic screening are consistent with the resource estimates and allocations; test cases using raw cost data were run prior to the full analysis to establish the range of parameters for input to the economic analysis (e.g. the smallest field size to be considered). The methodology and assumptions of the economic model and analysis are described in detail in Appendix C. The results of the economic analysis are presented in Chapter 7.0.

Although the economic analysis defines those cases which are uneconomic (under the assumptions defined in Chapter 3.0 and Appendix C), there still remain an infinite number of permutations of field size, production technologies and discovery locations which are demonstrated to be economic. Chapter 8.0 describes the assumptions and method utilized to reduce the number of cases to a set of skeletal scenarios from which a scenario at each resource level (five percent, statistical mean, no commercial resources) can be selected. The main basis for identification of the skeletal scenarios is variation in potential for onshore development, which is a function of such factors as field size, field distribution, location, and production technology.

The selection of skeletal scenarios to be described in detail (one scenario for each resource level) was conducted by staff of the Bureau of Land Management, Alaska OCS Office.

The detailed (selected) scenarios are described according to environmental setting, development scheduling, facility equipment and manpower requirements. Although these scenarios are in essence hypothetical developments, they have been formulated to provide reasonable and representative predictions, given the available data base, on the course of possible petroleum development in the Gulf of Alaska given the potential resource base identified by the U.S.G.S.

It is recognized that some of the findings may be controversial. Predictions on frontier petroleum economics are often educated guesses. The history of petroleum economics during this decade - the quadrupling of world oil prices following the 1973 Arab oil embargo, the significant escalation in offshore petroleum development costs in the mid-1970's and the rapid advancements of offshore petroleum technologies (such as witnessed in the North Sea) - all confirm this unpredictability.

Review of economic studies of OCS petroleum development and other published data through the 1970's reveals, that estimates that at the time were reasonable economic predictions, now are apparent underestimates of petroleum development costs.

This study is based on extensive literature review and contacts with industry and government personnel involved in offshore petroleum development.[1] Special emphasis in the data gathering has been placed on as-

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(1) The data collection portion of this study was funded under a separate contract. Results of that work are presented in Alaska OCS Socioeconomic Studies Program Task 9AGA: Technical Memorandum Number One: Annotated Bibliography, Dames & Moore, 1978a, prepared for the Bureau of Land Management, Alaska OCS Office. Data too late for inclusion in that bibliography and the data that have become available subsequent to completion of Task 9AGA are referenced in this report. Contrasts in the data base between the Beaufort Sea (see Dames & Moore, 1978b) and the Gulf of Alaska and their analytical implications are discussed in the Task 9AGA report and further discussed, where appropriate, in this report.

sessing petroleum industry opinions on petroleum economics and technology. Information on the North Sea experience has been utilized extensively in this report since in terms of operating environment it is similar in many ways to the Gulf of Alaska. Use of the North Sea experience has to be qualified, however, with the knowledge of contrasts in such areas as seismicity, geology and geography.

This study was conducted concurrently with a similar study of the northern Gulf of Alaska second generation OCS lease sale (No, 55). The data collection, analytical procedures and economic screening parameter selection were structured to be applicable, when appropriate, to both studies. The economic analysis, for example, encompasses anticipated conditions in both areas; when contrasts exist that affect the analysis, they are noted in the text.

This report begins with a summary of findings under the headings of selected petroleum development scenarios, manpower and employment, resource economics, technology, and petroleum geology.

2.0 SUMMARY OF FINDINGS

2.1 Selected Petroleum Development Scenarios

Three scenarios are detailed describing exploration only (no commercial resources), a high find case corresponding to the five percent probability resource level estimate of the U.S. Geological Survey and a medium find case corresponding to the statistical mean resource level estimate. At the direction of BLM staff, the five percent resource scenario rather than considering oil and gas resources together, detailed separate scenarios for oil and gas production to explore the possibility that the Kodiak Tertiary Province may be gas prone, yielding only natural gas.

The principal resource assumption affecting the scenario development is that 80 percent of the oil and gas resources are located in the Albatross Basin and the remaining 20 percent in the Tugidak Basin. The Albatross Basin resources are assumed to be located beneath the central Albatross Bank offshore of Kodiak Island.

2.1.1 Exploration Only Scenario

The exploration only scenario postulates that 17 exploration wells are drilled over a three year period following the lease sale with only non-commercial finds (Table 2-l). Exploration is centered on the Albatross Bank with lesser interest shown in the Tugidak Basin.

The U.S. Geological Survey resource estimate corresponding to the 95 percent probability that there is at least that resource present is zero. This is because, in frontier areas such as the Kodiak shelf lacking in geologic data, a marginal or conditional factor is applied to the resource estimate which specifies the chance of no commercial oil or gas. The U.S. Geological Survey estimates that the probability of no commercial oil or gas is 60 percent. Thus, any probability estimate greater than 60 percent implicitly means no commercial resources.

TABLE 2-1

EXPLORATION ONLY SCENARIO

Basin	YEAR AFTER LEASE SALE 1		2		3	
	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells
Albatross	2	4.8	2	4.8	1	1.4
Tugidak	1	2.4	1	2.4	1	1.2
Portlock	--	--	--	--	--	--
TOTALS	3	7.2	3	7.2	2	2.6

TOTAL WELLS = 17

The principal exploration base is postulated to be Seward (as was the case during the exploration program following lease sale no. 36 in the northern Gulf of Alaska) with Kodiak and Homer performing minor roles.

2.1.2 Five Percent Probability Resource Level Scenario - Oil Only

The major characteristics of this scenario are shown in Table 2-2. This scenario represents a high find case of oil resource discovery but with only a 1 in 20 chance that that amount of resource will be discovered. The total reserves discovered and developed are:

	Oil (mmbbl)	Gas - Associated (Bcf)
Albatross Basin	950	560
Tugidak Basin	250	140

The associated gas reserves are too small to be economic and are used to power the platforms with the remainder reinfected.

Three fields are discovered within 48 kilometers (30 miles) of each other on the middle Albatross Bank in water depths of 61 to 91 meters (200 to 300 feet). The fields share a pipeline to an oil terminal on the north shore of Ugak Bay on the east coast of Kodiak Island.

A single field with reserves of about 250 million barrels is discovered in the Tugidak Basin. An offshore loading production system employing a single steel platform with no storage capability loading to tankers via an SPM is selected to develop this field.

2.1.3 Five Percent Probability Resource Level Scenario - Non-Associated Gas Only

The major characteristics of this scenario are shown on Table 2-3. This scenario assumes discoveries of non-associated gas only. The total resources discovered are:

TABLE 2-2

5% PROBABILITY RESOURCE LEVEL SCENARIO
OIL AND ASSOCIATED GAS PRODUCTION ONLY

Basin	Field Size		Production System	Platforms	Number of Production Wells	Peak Production		Water Depth		Distance to Shore Terminal[2]		Pipeline Diameter (inches)	
	Oil (MMBBL)	Gas[4] (BCF)		No./Type[1]		Oil (MB/D)	Gas (MMCF/D)	meters	feet	kilometers	miles	Oil	Gas
Albatross	500	--	Steel platforms with shared trunkline to shore	2S	80	192	--	61-91	200-300	32-56	20-35	--	--
Group 1	250	--	Steel platform with shared trunkline to shore	1S	80	192	--	61-91	200-300	32-56	20-35	8-30[3]	--
	200	--	Steel platform with shared trunkline to shore	1S	40	96	--	61-91	200-300	32-56	20-35	--	--
Tugidak	250	--	Steel platform with no storage, offshore loading	1S	40	65	--	61-91	200-300	--	--	--	--
Portlock	--	--	--	--	--	--	--	--	--	--	--	--	--

[1] S = Steel , C = Concrete

[2] Shore terminal for Albatross is Ugak Bay area.

[3] Group 1 fields share a pipeline to Ugak Bay: peak throughput, 384 MB/D.

[4] A low gas-oil ratio or non-commercial associated gas is implicit - associated gas is assumed to be used as platform fuel and reinfected (see text).

TABLE 2-3

5% PROBABILITY RESOURCE LEVEL SCENARIO
NON-ASSOCIATED GAS ONLY

Basin	Field Size Oil (MMBBL)	Field Size Gas (BCF)	Production System	Platforms No. /Type[1]	Number of Production Wells	Peak Production Oil (MB/D)	Peak Production Gas (MMCF/D)	Water Depth meters	Water Depth feet	Distance to Shore Terminal[2] kilometers	Distance to Shore Terminal[2] miles	Pipeline Diameter (inches) Oil	Pipeline Diameter (inches) Gas
Albatross	--	1200	Steel platform with shared gas pipeline to shore	1S	8	--	192	61-91	200-300	32-56	20-35	--	16-18
		800	Steel platform with shared gas pipeline to shore	1S	8	--	192	61-91	200-300	32-56	20-35	--	--
		800	Steel platform with shared gas pipeline to shone	1S	8	--	192	61-91	200-300	32-56	20-35	--	--
Tugidak	--	700	Not produced - uneconomic	--	--	--	--	--	--	--	--	--	--

[1] S = Steel, C = Concrete

[2] Ugak Island area.

Basin	Non-Associated Gas (Bcf)
Albatross	2,800
Tugidak	700

The gas resources in the Tugidak Basin, even though they are found in one field, prove to be uneconomic and are not developed.

The Albatross reserves consist of three fields located within 48 kilometers (30 miles) of each other on the middle Albatross Bank in water depths of 61 to 91 meters (200 to 300 feet) about 80.5 kilometers (50 miles) southeast of Kodiak. The fields share a trunk pipeline to an LNG plant designed to process its anticipated peak production of nearly 600 mmcfd located on the north shore of Ugak Bay. The liquefied gas is exported to the lower 48 by a fleet of three LNG tankers. Field construction support bases are located at Seward and Kodiak.

2.1.4 Statistical Mean Probability Resource Level Scenario

The major characteristics of this scenario are presented in Table 2-4. This scenario represents a medium find case of resource discovery. The total reserves discovered and developed are: (1)

	Oil (MMbbl)	Associated Gas (bcf)	Non-Associated Gas (bcf)
Albatross Basin	160	--	--

The only commercial discovery made is located on the middle Albatross Bank about 80.5 kilometers (50 miles) southeast of the city of Kodiak in a water depth of about 61 meters (200 feet). The reserves (160 mmbbl)

(1) The oil and gas resources of the western Gulf of Alaska as estimated by the U.S. Geological Survey at the statistical mean level (200 mmbbl oil, 700 bcf gas) when allocated 80 percent to the Albatross Basin, 20 percent to the Tugidak Basin result in one economic oil field in the Albatross Basin. The remainder of the oil and all the gas are uneconomic and cannot be produced under the technological and economic assumptions of this analysis. Furthermore, to be economic all the oil would have to be found in a single field as indicated in this scenario.

TABLE 2-4

STATISTICAL MEAN RESOURCE LEVEL SCENARIO
OIL AND ASSOCIATED GAS PRODUCTION

Basin	Field Size Oil (MMBBL)	Field Size Gas[3] (BCF)	Production System	Platforms No./Type[1]	Number of Production Wells	Peak Production Oil (MB/D)	Peak Production Gas (MMCF/D)	Water Depth meters	Water Depth feet	Distance to Shore Terminal[2] kilometers	Distance to Shore Terminal[2] miles	Pipeline Diameter (inches) Oil	Pipeline Diameter (inches) Gas
Albatross	160	--	Steel platform with no storage offshore loading	1S	40	65	--	61	200	--	--	--	--
Tugidak	--	--	--	--	--	--	--	--	--	--	--	--	--
Portlock	--	--	--	--	--	--	--	--	--	--	--	--	--

[1] S = Steel, C = Concrete

[2] Ugak Bay area

[3] A low gas-oil ratio or non-commercial associated gas is implicit - associated gas is assumed to be used as platform fuel and reinfected.

Note: The oil and gas resources of the western Gulf of Alaska as estimated by the U. S.G. S. at the statistical mean level (200 mmbbl oil, 700 bcf gas), when allocated 20 percent to the Tugidak Basin, 80 percent to the Albatross, and 0 percent to the Portlock Basin, result in one economic oil field in the Albatross Basin. The remainder of the oil is uneconomic and cannot be produced under the technological conditions as assumptions of this analysis.

are insufficient to justify a pipeline to shore and shore terminal. An offshore loading system using an SPM and "dedicated" tankers, A single steel platform without storage capacity is selected; the increased production afforded by storage is not deerned to offset the incremental investment in a storage buoy,

Kodiak is used as the construction support base and field operation center. The single steel platform and topside modules are fabricated on the U.S. West Coast and transported to Alaska by barge.

2.2 Employment

Tables 2-5 through 2-8 present summaries of manpower requirements for the four scenarios. Figures 2-1 through 2-4 show graphically the annual monthly average manpower requirements (estimates of actual peak employment for each year are presented in Section 9.0).[1] Maximum manpower demand created by the five percent oil scenario occurs in year 7 when a total of 33,323 man-months of labor are consumed by exploration and development activity. The average monthly manpower requirement in year 7 is 2,777 people. On-site labor consumption in year 7 is 21,228 man-months (this is the amount of direct labor input required by the various tasks, excluding time off by crews).

The five percent gas scenario requires about 12 percent fewer man-months of employment in its peak year of work than the five percent oil scenario. Maximum manpower demand in the five percent gas scenario occurs in year 5, when a total of 29,460 man-months are consumed. The average monthly manpower requirement in year 5 is 2,455 people. On-site labor consumption in year 5 is 18,665, although 20,297 on-site man-months of labor are required in year 4 (this is because onshore construction employment is greater in year 4 than year 5, offshore construction is greater in year 5 than year 4, and onshore construction is virtually all on-site labor while offshore construction has a large off-site component).

(1) Project peak month of employment may not occur in the same year as project peak year of employment.

TABLE 2-5

SUMMARY OF MANPOWER REQU IREMENTS FOR ALL INDUSTRIES - EXPLORAT ION ONLY SCENARIO
ONS I TE AND TOTAL

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL (MAN-MONTHS)			TOTAL LABOR FORCE (MONTHLY AVERAGE)		
	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL
1	3127.	482.	3609.	5611.	662.	6273.	468.	56.	523.
2	3127.	482.	3609.	5611.	662.	6273.	468.	56.	523.
3	1059.	162.	1221.	1887.	222.	2109.	158.	19.	176.

TABLE 2-6

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES - 5 PERCENT PROBABILITY RESOURCE LEVEL SCENARIO OIL ONLY
ONSITE AND TOTAL

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL MAN-MONTHS)			TOTAL LABOR FORCE (MONTHLY AVERAGE)		
	OFFSHORE	ONSHORE	TOTAL	OF SHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL
1	870.	134.	1004.	1560.	184.	1744.	130.	16.	146.
2	2118.	324.	2442.	3774.	444.	4218.	315.	37.	352.
3	2118.	324.	2442.	3774.	444.	4218.	315.	37.	352.
4	4211.	646.	4857.	7523.	886.	8409.	627.	74.	701.
5	3152.	6112.	9264.	5636.	6911.	12547.	470.	576.	1046.
6	5471.	4658.	10129.	10204.	5242.	15446.	851.	437.	1288.
7	12171.	9057.	21228.	23295.	10028.	33323.	1942.	836.	2777.
8	13620.	3948.	17568.	26326.	5239.	31565.	2194.	437.	2631.
9	13594.	2614.	16208.	26479.	3822.	30301.	2207.	319.	2526.
10	13013.	2477.	15490.	25492.	3735.	29227.	2125.	312.	2435.
11	11340.	2223.	13563.	22350.	3506.	25856.	1863.	293.	2155.
12	11760.	2268.	14028.	23160.	3576.	26736.	1930.	298.	2224.
13	10656.	2220.	12876.	20952.	3528.	24480.	1746.	294.	2040.
14	8448.	2124.	10572.	16536.	3432.	19968.	1378.	286.	1664.
15	7344.	2076.	9420.	14328.	3384.	17712.	1194.	282.	1476.
16	6240.	2028.	8268.	12120.	3336.	15456.	1010.	278.	1288.
17	6240.	2028.	8268.	12120.	3336.	15456.	1010.	278.	1288.
18	6240.	2028.	8268.	12120.	3336.	15456.	1010.	278.	1288.
19	6240.	2028.	8268.	12120.	3336.	15456.	1010.	278.	1288.
20	6240.	2028.	8268.	12120.	3336.	15456.	1010.	278.	1288.
21	5412.	1869.	7281.	10506.	3142.	13648.	876.	262.	1138.
22	4992.	1824.	6816.	9696.	3072.	12768.	808.	256.	1064.
23	3336.	1506.	4842.	6468.	2684.	9152.	539.	224.	763.
24	2496.	408.	2904.	4848.	528.	5376.	404.	44.	448.
25	1668.	249.	1917.	3234.	334.	3568.	270.	28.	298.
26	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
27	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
28	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
29	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
30	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.

TABLE 2-7

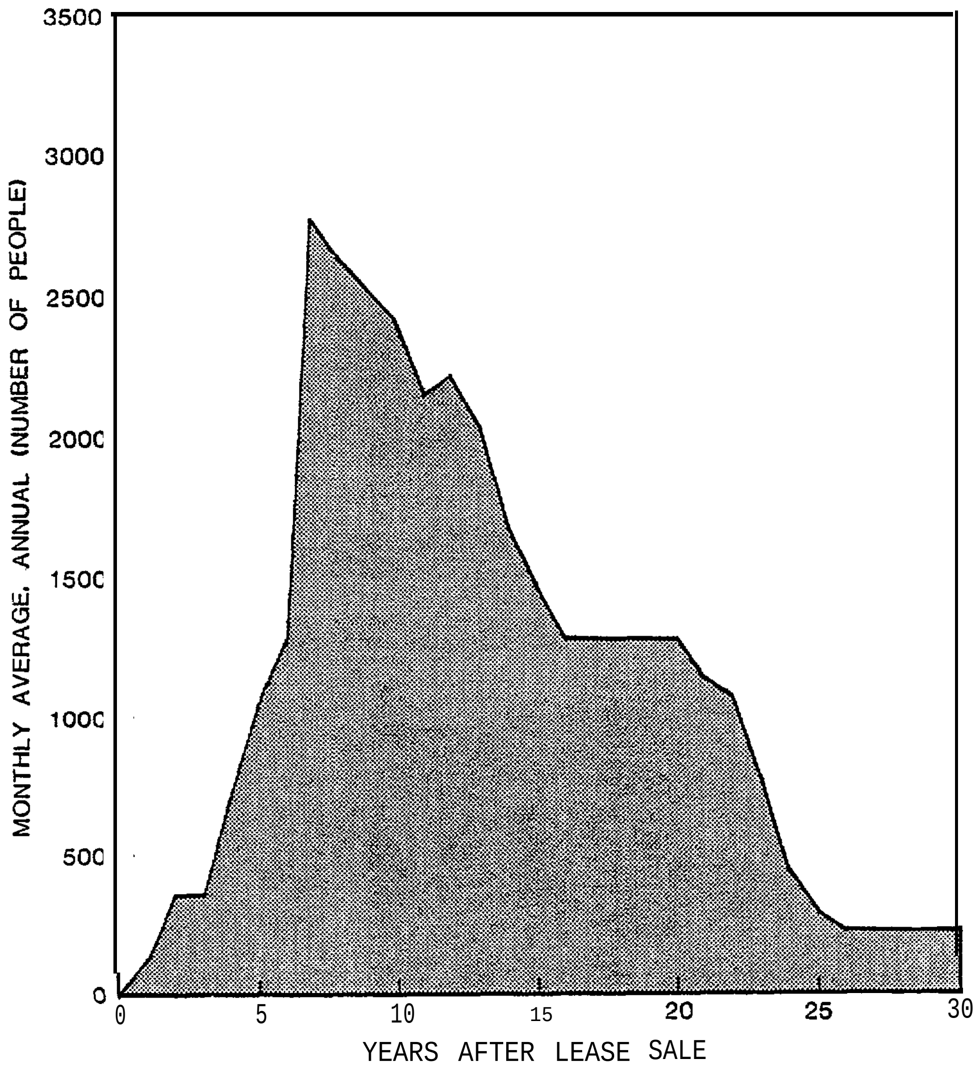
SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES - 5 PERCENT PROBABILITY RESOURCE LEVEL SCENARIO - GAS ONLY
ONSITE AND TOTAL

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL LABOR FORCE (MONTHLY AVERAGE) OFFSHORE	TOTAL LABOR FORCE (MONTHLY AVERAGE) ONSHORE	TOTAL LABOR FORCE (MONTHLY AVERAGE) TOTAL
1	1034.	160.	1194.	1862.	220.	2082.	156.	19.	1/4.
2	2nd.	324.	2442.	3774.	444.	4218.	315.	37.	352.
3	2118.	8192.	103IO.	3774.	9177.	12951.	315.	765.	1080.
4	7539.	12758.	20297.	13928.	14318.	28245.	1161.	1194.	2354.
5	11~(-in.	7297.	18066.	21207.	8253.	29460.	1768.	688.	2455.
b	8916.	2120.	11036.	16764.	3087.	19851.	1397.	258.	1655.
7	6140.	1469.	7608.	11806.	2339.	14144.	984.	195.	1179.
8	3696.	1116.	4812.	7248.	1956.	9204.	604.	163.	767.
9	2688.	1008.	3696 .	5232.	1848.	7080.	436.	154.	590.
10	2016.	936.	2952.	3888.	1776.	5664.	324.	148.	472.
11	2256.	1032.	3288.	4368.	1872.	6240.	364 .	156.	520.
12	2496.	1128.	36,24.	4848 .	1968.	6816.	404.	164.	568.
13	2736.	1224.	3960.	5328.	2064.	7392.	444.	172.	616.
14	2736.	1224.	3960 .	5328.	2004.	7392.	444.	172.	616.
15	2736.	1224.	3960.	5328.	2064.	7392.	444.	172.	616.
16	2736.	1224.	3960.	5328.	2064.	7392.	444.	172.	616.
17	2736.	1224.	3960.	5328.	2064.	7392.	444.	172.	616.
18	3240.	1278.	4518.	6300.	2148.	8448.	525.	1/9.	704.
19	3744.	1332.	5076.	7272.	2232.	9504.	b06.	186.	79.2.
20	3744.	1332.	5076.	7272.	2232.	9504.	60b.	186.	792.
21	3744.	133,?.	5076.	7272.	2232.	9504.	606.	186.	792.
22	3000.	1182.	4182.	5820.	2052.	7872.	485.	171.	656.
23	2256.	1032.	3288.	4368.	1872.	6240.	3b4 .	156.	520.
24	2256.	1032.	3288.	4368.	1872.	6.?40.	364.	156.	520.
25	2256.	1032.	3288.	4368.	1872.	6240.	364.	156.	520.
26	2256.	31?.	2568.	4368.	432.	4800.	364.	36.	400.

TABLE 2-8

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES - STATISTICAL MEAN RESOURCE LEVEL SCENARIO
ONSITE AND TOTAL

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL LABOR FORCE (MONTHLY AVERAGE) OFFSHORE	TOTAL LABOR FORCE (MONTHLY AVERAGE) ONSHORE	TOTAL LABOR FORCE (MONTHLY AVERAGE) TOTAL
1	2093.	322.	2415.	3749.	442.	4191.	313.	37.	350.
2	2118.	324.	2442.	3774.	444.	4218.	315.	37.	352.
3	1059.	162.	1221.	1887.	222.	2109.	158.	19.	176.
4	0.	5628.	5628.	0.	6247.	6247.	0.	521.	521.
5	2625.	352.	2977.	4973.	387.	5360.	415.	33.	447.
6	5194.	634.	5828.	10045.	668.	0713.	837.	56.	893.
7	1848.	198.	2046.	3660.	228.	3888.	305.	19.	324.
8	2352.	252.	2604.	4632.	312.	4944.	386.	26.	412.
9	2352.	252.	2604.	4632.	312.	4944.	386.	26.	412.
10	2352.	252.	2604.	4632.	312.	4944.	386.	26.	412.
11	1568.	168.	1736.	3064.	228.	3292.	256.	19.	275.
12	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
13	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
14	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
15	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
16	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
17	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
18	1248.	204.	1452.	2424.	264.	2688.	202.	22.	224.
19	1128.	156.	1284.	2184.	216.	2400.	182.	16.	200.
20	0.	0.	0.	0.	0.	0.	0.	0.	0.

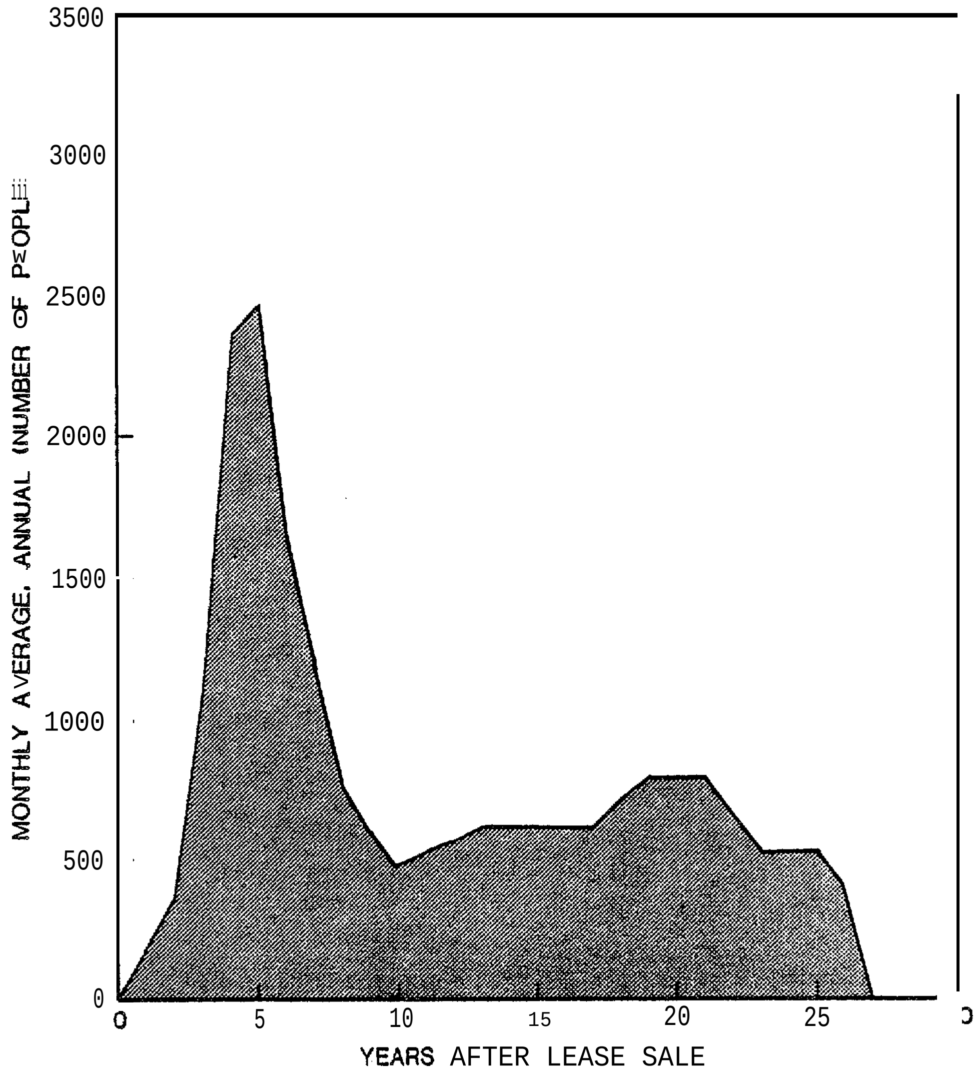


SOURCE: DAMES & MOORE

NOTE: ANNUAL PEAK LABOR FORCE REQUIREMENTS EXCEED THESE AVERAGES; REFER TO TABLES IN SECTION 9.0

FIGURE 2-1

MANPOWER REQUIREMENTS,
MONTHLY AVERAGE NUMBER OF PEOPLE PER YEAR,
KODIAK 5% OIL SCENARIO

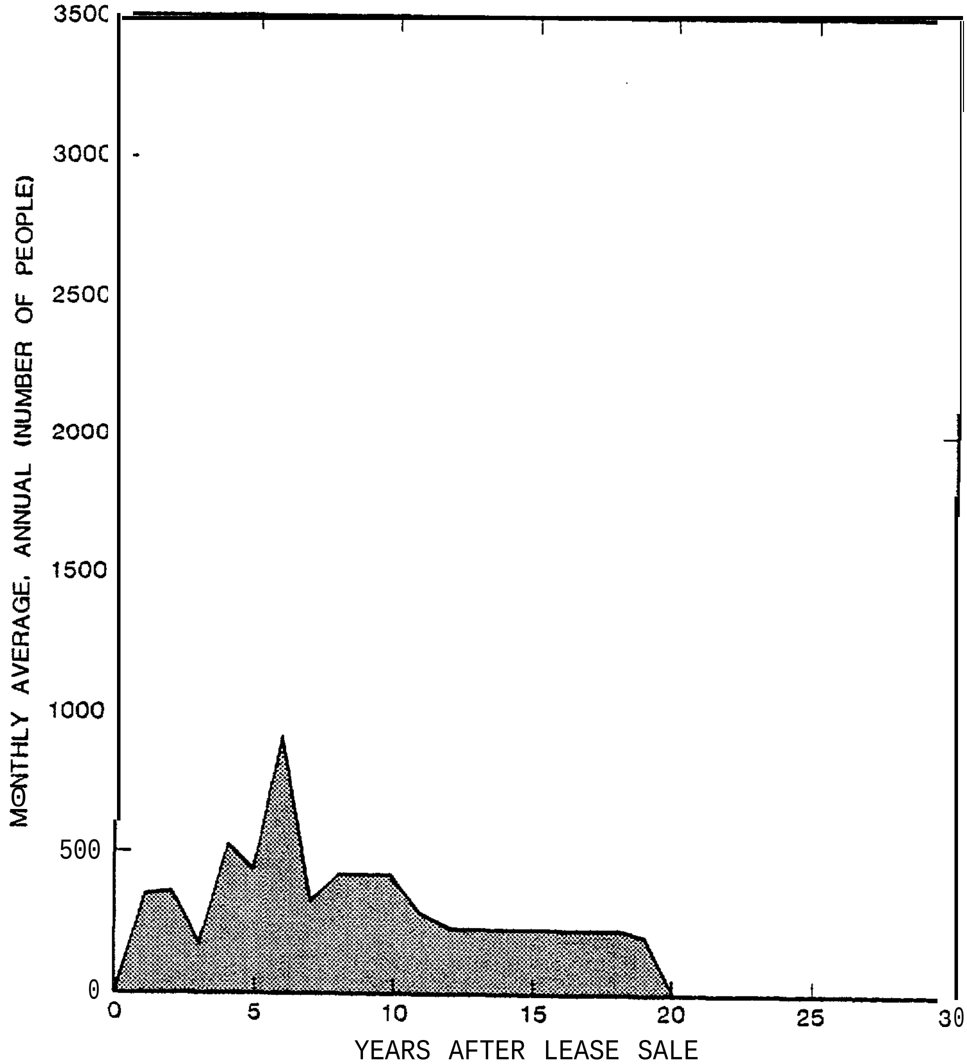


SOURCE: DAMES & MOORE

NOTE: ANNUAL PEAK LABOR FORCE REQUIREMENTS EXCEED THESE AVERAGES: REFER TO TABLES IN SECTION 9.0

FIGURE 2-2

MANPOWER REQUIREMENTS,
MONTHLY AVERAGE NUMBER OF PEOPLE PER YEAR,
KODIAK 5% GAS SCENARIO

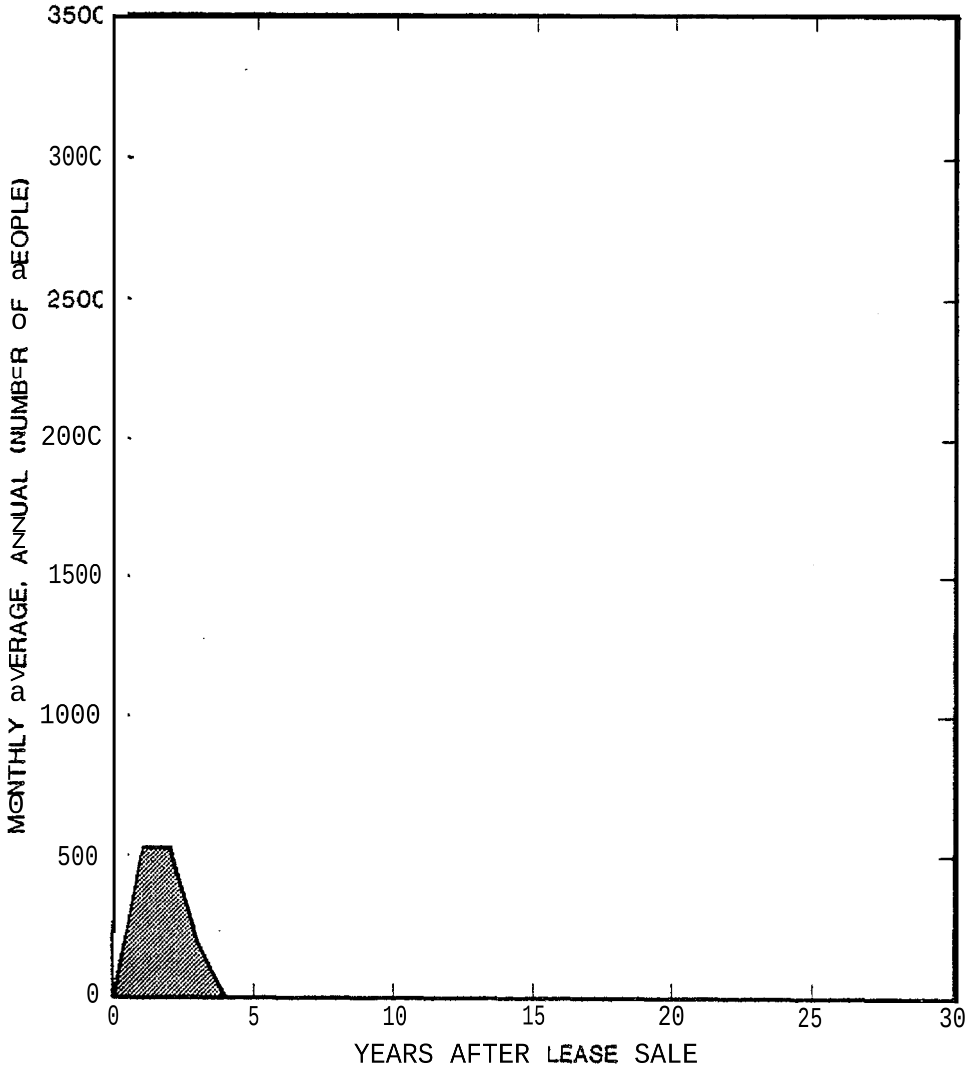


SOURCE: DAMES & MOORE

NOTE: ANNUAL PEAK LABOR FORCE REQUIREMENTS EXCEED THESE AVERAGES; REFER TO TABLES IN SECTION 9.0

FIGURE 2-3

MANPOWER REQUIREMENTS,
MONTHLY AVERAGE NUMBER OF PEOPLE PER YEAR,
KODIAK STATISTICAL MEAN SCENARIO



SOURCE: DAMES & MOORE

NOTE: ANNUAL PEAK LABOR FORCE REQUIREMENTS EXCEED THESE AVERAGES; REFER TO TABLES IN SECTION 9.0

FIGURE 2-4

MANPOWER REQUIREMENTS,
MONTHLY AVERAGE NUMBER OF PEOPLE PER YEAR,
KODIAK 95% SCENARIO
EXPLORATION ONLY

The statistical mean scenario generates a relatively small labor force because it involves few onshore facilities (the field development plan calls for a single platform and offshore loading, no shore terminal, and gas is not commercial). Maximum manpower demand created by this scenario occurs in year 6 when a total of 10,713 man-months of labor are consumed. The average monthly manpower requirement in year 6 is only 839 people. On-site labor consumption in year 6 is 5,828 man-months.

2.3 Resource Economics

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

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

Two vital pieces of information are estimated in this analysis:

- The minimum economic field size to justify development of a known field with a selected technology in the Gulf of Alaska.

- The minimum required price to justify development of a field in the Gulf of Alaska.

Both are very sensitive to water depth, and to the value of money used to discount cash flows. At water depths of 30.5 meters (100 feet), 91 meters (300 feet), and 183 meters (600 feet), the calculated minimum prices and field sizes are bracketed between 10 percent and 15 percent discount rates.

The essential findings of this report are summarized below. The single value calculations below are the mid-range values. The upper and lower limits are discussed in Section 7.4.6 and the assumptions are detailed in Section III, Appendix C,

- No oil field smaller than 110 MMbbl at 10 percent value of money is economic in the Gulf of Alaska with any production system tested in 91 meters (300 feet) of water. At 15 percent value of money the minimum field size is 215 MMbbl. Fewer than one percent of oil fields discovered in the U.S. are larger than 100 MMbbl. Of 5,374 fields discovered in the U.S. since 1970, only nine exceeded either 50 MMbbl or 300 Bcf (Oil and Gas Journal, July 13, 1978, p. 33).

- In 183 meters (600 feet) of water no oil production system with the price of oil at $12.00 is economic in the Gulf of Alaska no matter how large the discovered field -- under the assumptions of this analysis, including 2500 B/D initial well production rate -- if the operator requires a 15 percent return on his investment.

- An initial well productivity higher than 2500 B/D is required to earn the 15 percent hurdle rate in 183 meters (600 feet) of water in the Gulf of Alaska. Assuming 7500 B/D initial well productivity the minimum field size for development is 320 million barrels.

- The minimum sized gas field for development ranges between 0.5 and 0.65 Tcf in 91 meters (300 feet) of water at discount rates between 10 percent and 15 percent.

- In 183 meters (600 feet) of water the minimum size gas field for development ranges between 0.7 and 1.75 Tcf at discount rates between 10 percent and 15 percent.

- The economics of developing a single field favor a single steel platform with a pipeline to a shore terminal over off-shore loading if the cost of the shore terminal is shared among producers of several fields in the Gulf of Alaska.

- Offshore loading systems without storage capacity are much less economic than either systems with storage or systems which will allow a pipeline to a shared shore terminal.

- The economic results are not very sensitive to the distance to shore that a pipeline must travel because its share of development cost is relatively small.

- Under the assumptions of the mode"l , and assuming technical considerations related to reservoir thickness and depth not limiting, the decision to develop a field with two platforms requires a field with recoverable reserves greater than 500 MMbbl . The decision to add a third platform requires a field larger than 1.0 billion barrels. These field sizes represent those required to optimize the investment rather than the minimum field size for development. Smaller fields allow the minimum hurdle rate with two or three platforms. If technical considerations do not require the additional platform to reach the reservoir, the rate of return is higher with one or two instead of two or three platforms.

- If reservoir thickness or depth dictate development with two platforms of a field smaller than 500 MMbbl, the operator would have to be willing to accept a rate of return lower than 15 percent.

- The minimum required price in 1978 dollars to justify development of the most economic system identified in this report for fields smaller than 500 MMbbl -- the single steel platform with a pipeline to a shared shore terminal -- varies with field size, water depth and value of money.

	Water Depth			
	91 Meters (300 Ft.)		183 Meters (600 Ft.)	
Field Size	10%	15%	10%	15%
200 MMbbl	$10.00	$14.00	$15.00	>$20.00
350 MMbbl	$ 7,00	$10.00	$11.00	$16.00

- The minimum required price to justify development of a non-associated gas field varies with field size, water depth and value of money.

	Water Depth			
	91 Meters (300 Ft.)		183 Meters (600 Ft.)	
Field Size	10%	15%	10%	15%
1.0 Tcf/12 wells	$1.50	$2.10	$2.40	>$2.75
2.0 Tcf/16 wells	$0.75	$1.15	$1.70	$2.45

2.4 Technology

Review of current and imminent petroleum technologies indicates that the North Sea to some extent serves as a technology model although there are important environmental contrasts. While oceanographic and meteorologic conditions are similar in the North Sea and Gulf of Alaska (some what more severe storm conditions can be anticipated in the gulf), there are significant contrasts in geology which are particularly important with respect to the feasibility and design of fixed platforms and pipelines. The Gulf of Alaska lies in one of the most seismically active zones in the world and there are extensive areas of potential unstable bottom soils and soils with low bearing capacities. (See chapter 4 for a specific discussion of geologic hazards.) These factors pose design problems for both steel jacket and concrete gravity platforms, the principal types of platforms employed to data in the North Sea. Both platform types can be designed to withstand earthquake loadings but the application of concrete platforms is especially restricted by soil conditions (Watt, Boaz and Dowrick, 1978). In the North Sea where seismic risk is minor, seismic loading is not required in platform design.

One of the advantages of the concrete platform has been its storage capability, which significantly improves the economics of offshore loading of crude. An offshore loading system is favored in situations where a pipeline to shore and marine terminal can not be economically justified -- generally where a field is distant from shore and isolated from other fields (with which it could possibly share pipelines and terminals). Offshore storage capability can also be provided by a permanently moored tanker (of uncertain feasibility in the Gulf of Alaska). Storage capability has also been incorporated in a number of proposed “hybrid” platform designs, such as the steel gravity platform, semi-submersible concrete (Condrill) platform and loading/mooring/storage (LMS) platform. Offshore storage may also be provided by steel and concrete storage/loading buoys separate from the drilling/production platform.

To develop marginal fields and fields in deeper water (other factors being equal, for a given field size the deeper the water the greater the field development costs using a fixed platform)” a number of floating or compliant platform designs have been proposed. These designs have, in part, been necessitated by the fact that fixed steel or concrete platforms are reaching their limit of economic feasibility (under current economic conditions) at 183 meters (600 feet) water depth in storm-stressed environments such as the North Sea. In less severe operating environments fixed steel platforms have been installed in water depths greater than 183 meters (600 feet), e.g. Exxon’s Hondo platform in 260 meters (848 feet) of water in the Santa Barbara channel and Shell’s Cognac platform in 313 meters (1,025 feet) of water in the Gulf of Mexico. The floating and compliant platform designs include the guyed tower, articulated tower, tension leg platform and a variety of semi-submersible structures (including converted exploration rigs); the latter two designs are floating structures. Rather than resist environmental loading of waves etc. these platforms are designed to accommodate, to a lesser or greater extent, these forces. Floating and compliant structures require less materials (e.g. steel) to construct, and less offshore construction time. Floating systems involving subsea completed wells can reduce field development time and speed return on investment. For Gulf of Alaska fields, floating systems would also be favored in areas where soil conditions do not favor fixed platforms.

Undoubtedly, the trends in offshore petroleum development in the 1980's, as operations move into deeper waters and marginal fields need to be produced, will include increasing use of hybrid, compliant and floating platform designs and subsea completed wells. To improve the economics of those systems which do not produce into pipelines, offshore storage facilities will be required; probably semi-submersible or buoy structures. Steel jacket platforms and to a lesser extent concrete platforms will still have a major role, at least in waters of less than 183 to 305 meters (600 to 1,000 feet). The trend in design of these structures will (and has been) reduction of weight and material requirements such as steel.

In predicting the production technologies that may be used in Gulf of Alaska petroleum development in the 1980's, the petroleum technology review (Chapter 4.0) has to consider the geography of the Gulf of Alaska, in particular two important considerations:

- The Gulf of Alaska is isolated from petroleum markets and transportation systems (pipelines etc.); most if not all petroleum production will be shipped to the lower 48 states;

- Most potential discovery sites (within the study area) are located less than 50 miles from shore; production through pipelines to shore, other factors being equal, is favored especially if a number of fields are sufficiently close together to share pipeline and shore terminal development costs.

In the selection of production systems for costing and economic screening, it is important to note that the available cost data base (see Appendix B) mainly pertains to conventional fixed platforms with pipeline-to-shore or offshore loading production systems, and there is little or no cost data on the various hybrid and floating/compliant platform systems summarized above. This has, in part, influenced the production systems selected for economic screening. The economic screening has identified those field sizes and locations where more cost effective technologies must be developed to develop such “marginal” fields.

The production systems selected for economic screening are systems currently used in the North Sea which, to various degrees, may have application in the Gulf of Alaska (see detailed discussion of their selection in Section 4.5 of Chapter 4.0). These are:

- Floating production platform with maximum of 20 producing wells (subsea completions). Limited to 65 percent production due to no storage. Offshore loading with-single point mooring. No water depth limitation.

- Single steel jacket platform, limited to 65 percent production due to no storage and inaccessibility of pipeline. Offshore loading with single point mooring. Water depths: 30.5 to 183 meters (100 to 600 feet).[1]

- Single steel jacket platform. Storage buoy allows full production equal to 96 percent of capacity. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single steel jacket platform. Pipeline to shore terminal shared with other producing fields allows full production equal to 96 percent of capacity. Water depths: 30.5 to 183 meters (100 to 600 feet).

(1) Water depth ranges specified are those screened in economic analysis of each system.

- Concrete platform. Storage allows full production equal to 96 percent of capacity. Offshore loading with single point mooring. Water depths: 91 to 183 meters (300 to 600 feet).

- Concrete platform as part of a multi-platform field. Pipeline to shore terminal allows full production equal to 96 percent of capacity. Water depths: 91 to 183 meters (300 to 600 feet).

- Multiple steel jacket platforms. Pipeline to shore terminal allows full production equal to 96 percent of capacity. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single or multiple steel platforms. Gas pipeline to shore, gas converted to LNG. Water depths: 30.5 to 183 meters (100 to 600 feet).

The systems specified above have all been used in the North Sea and are believed to be applicable (with suitable modification), to various degrees, for use in the Gulf of Alaska. While no steel jacket platform system producing direct to tankers in the North Sea to date has had sufficient storage capability to produce full-time at maximum rates (Shell's Brent field SPAR buoy with 300,000 bbl capacity comes closest to this), it has been assumed that offshore storage technology by the 1980's will provide sufficient storage capability in conjunction with production from a steel jacket platform to allow full-time or maximum production.

In the scenarios selected for detailed description (Chapter 9.0), the production systems specified involve fixed platforms with some production to shore via pipeline and some oil production loaded directly to tankers offshore. The offshore loading systems include both platforms with and without storage capacity; for those with storage capacity a steel platform and adjacent storage buoy or concrete platform with internal storage have been indicated. There is insufficient data on bottom geology to properly assess problems relating to the feasibility of concrete platforms or similar gravity hybrids in the Gulf of Alaska except to identify active slump areas which obviously pose problems for fixed platforms, pipelines and subsea equipment. In terms of various industry viewpoints, concrete platforms have evolved from a cost effective alternative to steel platforms to a less favored and more expensive option. Nevertheless, concrete platforms or similar hybrids may have a role in Gulf of Alaska petroleum development and the scenario specifications reflect the same.

2.5 Petroleum Geology and Resource Estimates

The basis of the resource estimates used in this study for development of petroleum scenarios are the U.S. Geological Survey estimates of undiscovered oil and gas resources (Von Huene et al., 1976). These are:

	95 Percent Probability	5 Percent Probability	Statistical Mean
Oil (billions of barrels)	0	1.2	0.2
Gas (trillions of barrels)	0	3.5	0.7

By definition these resources are economically developable with current or imminently available technology (Miller et al., 1975). Allocation of the resources has been based upon an estimate that 80 percent will be located in the Albatross Basin and the remaining 20 percent in the Tugidak Basin.

There is no producing field analog or sufficient geologic data to establish with any certainty assumptions on reservoir and hydrocarbon characteristics of possible western Gulf of Alaska discoveries although some geologists have suggested that the Cook Inlet province may be an analog. However, as described in Chapter 3.0 and Appendix A, a set of reservoir, hydrocarbon and production assumptions have been defined. These include:

- Average reservoir depth -- 2,286 meters (7,500 feet) oil; 3,810 meters (12,5(10 feet) gas.

- Recoverable reserves per acre -- 20,000 and 50,000 bbl.

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

- Individual well productivity -- oil - 2,500 barrels per day; gas - 25 million cubic feet per day.

- Gas resource -- scenarios were developed for oil production only (associated gas was assumed to be used as platform fuel and reinfected) and, at the direction of BLM staff, a scenario assuming only discoveries of non-associated gas since the possibility exists that the western Gulf of Alaska Tertiary Province may be gas prone.

- No.gas-oil ratio assumed (see bullet above).

- No assumption was made on the physical properties of the oil.

3.0 PETROLEUM GEOLOGY AND RESOURCE ESTIMATES

3.1 U.S. Geological Survey Resource Estimates

The basis of the resource estimates used for development of petroleum scenarios in this study is the U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources of the western Gulf of Alaska Kodiak Tertiary Province. These estimates apply to an area measuring approximately 600 kilometers by 100 kilometers located east of the Kodiak group of islands between 56°N and 60"N latitude. Water depths in the area are generally less than 200 meters (650 feet). The most current estimates are presented in U.S. Geological Survey Open-File Report 76-325 (Von Huene et al., 1976). These are:

	95 Percent Probability	5 Percent Probability	Statistical Mean
Oil (billions of barrels}	0	1.2	0.2
Gas (trillions of cubic feet)	0	3.5	0.7

The U.S. Geological Survey estimates that there is a 95 percent probability that at least the lower value of resource will be discovered, but only a five percent (1 chance in 20) that the high estimate will be discovered. The statistical mean as given above is defined as the arithmetic mean of the low, high and most likely estimate.

In the case of frontier areas lacking in detailed geologic information such as the Gulf of Alaska, a marginal or conditional factor is applied which specifies a chance of no commercial occurrence of oil or gas. For the western Gulf of Alaska, the U.S. Geological Survey estimates that the probability of no commercial oil or gas is 60 percent. Consequently, the 95 percent probability resource level is zero.

Studies conducted by or for the Bureau of Land Management, relating to OCS development, such as the environmental impact statements prepared prior to the OCS lease sales and this study, are mandated to use the U.S. Geological Survey resource estimates.

The study area taken for this report is the area of the proposed lease tracts listed in the environmental impact statement for the Kodiak lease sale (U.S. Department of the Interior, 1976). This area is not coincident with that of the U.S. Geological Survey estimates (above) which is not precisely defined. Because the resource estimate area is ill-defined, no proration of the resource estimate on an area basis has been attempted. Nevertheless, it is believed that the area of hydrocarbon potential as defined by the U.S. Geological Survey and the area of high industry interest and proposed tracts are broadly coincident. Therefore, the U.S. Geological Survey estimates as published in Open-File Report 76-325 were not changed for this study.

3.2 Allocation of the U.S. Geological Survey Resource Estimates

In the development of petroleum scenarios it is necessary to allocate the oil and gas resources estimated by the U.S. Geological Survey among the three geologic basins of the Kodiak Tertiary Province as described in the report. Secondly, within each basin the resources need to be distributed according to field sizes (in total adding up to the basin estimate). To bring geographic and geologic specifity into the analysis, the individual fields should be located where possible in known geologic structures of sufficient size to accommodate all the oil at a reasonable range of recoverable reserves per acre. Unfortunately, this has not been possible in this analysis due to the paucity of available geologic data.

An independent petroleum geology assessment was conducted to allocate the U.S. Geological Survey estimated resources and, if possible, identify prospects (structures) and information on probable reservoir and hydrocarbon characteristics. The results of this assessment are presented in Appendix A. As indicated in Appendix A, 80 percent of the estimated resources have been allocated to the Albatross basin and 20 percent to the Tugidak basin; no commercial oil and gas resources are believed to be present in the Portlock basin (see Table 3-1).

3.3 Reservoir Characteristics and Assumptions

In an economic analysis of offshore petroleum development it is important to know some basic characteristics on the quality of the hydrocarbon stream and the probable production performance of the reservoir. Listed below are some of the hydrocarbon and reservoir characteristics required by the economic analysis:

- Reservoir depth;
- Recoverable reserves per acre - barrels of oil or cubic feet of gas;
- Well spacing;
- Individual peak well productivity - oil (bd), gas (mmcfd);
- Allocation of gas resources between associated and non-associated;
- Gas-oil ratio (GOR);
- Oil physical properties.

There is very little published data available to either make assumptions on these parameters or establish a range of values. The petroleum geology review (Appendix A) involved review of the published literature and geophysical records; the publically available geophysical lines were unfortunately too widely spaced to identify specific prospects. In contrast to the northern Gulf of Alaska, the Kodiak Tertiary Province lacks a producing field analog in the same basin such as the Katalla field in the northern Gulf of Alaska or onshore drilling history with a number of oil and/or gas "shows". However, the U.S. Geological Survey has noted that the most nearly analogous basins are considered to be the adjoining Eastern Gulf of Alaska Tertiary Province and westernmost Oregon-!dashington, including the offshore (Von Huene et al., 1976,

TABLE 3-1

ALLOCATION OF U.S. GEOLOGICAL SURVEY RESOURCE ESTIMATES[1] BY BASIN -- WESTERN GULF OF ALASKA (KODIAK)

Basin	Percentage of Total Resource[2]	Estimated Reserves			
		Five Percent Probability		Statistical Mean Probability	
		Oil (Bbbl)	Gas (tcf)	Oil (Bbbl)	Gas (tcf)
Albatross	80	0.96	2.8	0.16	0.56
Tugidak	20	0.24	0.70	0.04	0.14
Portlock	--	--	--	--	--
Totals		1.2	3.5	0.20	0.70

[1]U.S. Geological Survey Open-File Report 76-325 (Von Huene et al., 1976).

[2]Based on assumption, see text.

p. 25).[1] Consequently, the reservoir/hydrocarbon assumptions made for the Kodiak Tertiary Province are similar to those adopted for the north Gulf of Alaska. Although detailed data on reservoir and hydrocarbon characteristics does not permit specificity in the economic analysis, the economic methodology is flexible enough to accommodate a range of values. The economic analysis can explore the effects of variation of such parameters as well productivity and thus detect key economic sensitivities produced by contrasts in reservoir/hydrocarbon characteristics.

Assumptions on reservoir and hydrocarbon characteristics are discussed in detail in Appendix C. They will only be briefly summarized here; reference to the appropriate sections in Appendix C is given.

3.3.1 Reservoir Depth

Reservoir depths are fixed by assumption in this analysis. There is insufficient geologic data to identify ranges of reservoir depths that may be encountered in western Gulf of Alaska fields. Medium depth reservoirs about 2,286 meters (7,500 feet) are assumed for oil fields. Gas fields are assumed to be deeper -- 3,810 meters (12,500 feet) average depth. The 2,286-meter (7,500-foot) reservoir depth corresponds approximately to the average depth of the deepest oil producing horizons in U.S. giant fields (Moody, Mooney and Spivak, 1970). Upper Cook Inlet oil field reservoirs by comparison range in depth from 1,280 to 4,511 meters (4,200 feet to 14,800 feet); the major producing pools are, however, located between 1,829 and 3,353 meters (6,000 and 11,000 feet). The Prudhoe Bay Sadlerochit reservoir lies at a depth of approximately 2,682 meters (8,800 feet).

(In the scenario analysis reservoir depth is a parameter which relates to the proportion of reservoir that can generally be drained by directional wells from a single platform and to the well completion site which

(1) In the review comments of the draft report, some geologists suggested that the western Gulf of Alaska Tertiary province may be analogous to the Cook Inlet province.

affects production timing and drilling employment; the development well completion rates used in this study are 45 days for oil wells and 90 days for the deeper non-associated gas wells. Reservoir depth also affects the number of platforms that may be required to develop a field for a given field size and reservoir characteristics.)

3.3.2 Recoverable Reserves Per Acre and Well Spacing

The use of recoverable reserves per acre as a reservoir parameter along with well spacing are discussed in Section IV.2, Appendix C. Lower and upper values of 20,000 and 50,000 barrels per acre have been assumed in this study. In this study, well spacing (consistent with ranges experienced in known producing areas) is a parameter which varies according to the recoverable reserves per acre and well productivity.

3.3.3 Individual Well Productivity

As explained in Section IV.1 .1.2 of Appendix C, individual well productivity (peak) per well is assumed to be 2,500 bpd for oil and 25 mmcfd for gas.

3.3.4 Allocation of Gas Resource Estimate Between Associated and Non-Associated

The U.S. Geological Survey resource estimates for natural gas (see Miller et al., 1975 and Von Huene et al., 1976) do not allocate the gas between associated and non-associated. The estimates are applicable to the total gas resource, both associated and non-associated. Estimation of the oil and gas resources by the U.S. Geological Survey are made in two separate iterations by the U.S. Geological Survey using analogs from producing basins (Scott, personal communication, 1978).

In this study, unlike that conducted for the northern Gulf of Alaska, no assumption on the allocation of the gas resource between associated and non-associated was applied. This is because in the selection of scenarios for detailing (Chapter 8.0), the decision was made by BLM staff to evaluate an oil-only and gas-only scenario at the five percent probability resource level. In the northern Gulf of Alaska study, however, following the assumption made in a report by Kalter, Tyner and Hughes (1975), using U.S. historic production data, the assumption was made that 20 Percent of the gas is associated and 80 percent non-associated.

3.3.5 Gas-Oil Ratio

There is no available data to provide a firm basis on which an assumption can be made on the gas-oil ratio (GOR) in hypothetical Gulf of Alaska reservoirs. GOR can vary considerably from field to field in the same basin and between different reservoirs in the same geologic horizon. However, as noted in Section 3.3.4 (above), there was no requirement to specify the allocation of gas between non-associated and associated gas. Similarly, no GOR is specified in the scenario development for the Kodiak OCS. Associated gas in the oil scenarios is assumed to be used as platform fuel and reinfected.

3.3.6 Production Characteristics

Production characteristics including decline curves assumed for the economic analysis are discussed in Section IV of Appendix C.

3.3.7 Oil Physical Properties

No analog is available for the type of oil that may be produced from offshore Kodiak fields. In the northern Gulf of Alaska, however, there was one analog for the type of oil that may be produced. This was oil produced from the shallow Katalla field. Katalla oil was light gravity, from 41.5° to 45.9° API, had a paraffin base and no sulphur content (see Appendix A).

No assumption is made in this study on the quality of oil that may be found in the western Gulf of Alaska. Qualitative differences in crudes and their accommodation in the economic analysis are discussed in Section 111.3 of Appendix C.

3.4 Additional Onshore Reserves

No petroleum potential is assumed onshore for the Kodiak group of islands.

4.0 TECHNOLOGY

The economic analysis of future petroleum development in the Gulf of Alaska requires a technological framework. The technology utilized in offshore exploration, development and production relates to the economics of resource development, potential onshore and offshore impacts, and the manpower/employment requirements. Reasonable predictions on the technology, that may be utilized to develop Gulf of Alaska resources, serves as the principal component of this study.

This chapter reviews the technology of offshore petroleum development, especially that utilized in comparable operating environments, and relates that technology to the particular engineering constraints (design considerations) of the Gulf of Alaska (oceanography, geology, etc.). The approach taken in this chapter is to first review the individual components of offshore petroleum production systems (platforms, etc.). Second, 'the particular engineering constraints of the Gulf of Alaska environment are discussed and related to the design considerations of offshore production technology. The chapter is concluded with a discussion on the selection of production systems linking the individual system components described previously. The discussion reviews the development planning considerations, particularly the transportation options, which an operator has to evaluate upon discovery of an apparently commercial oil or gas field.

4.1 Petroleum Technology in Comparable Operating Environments

Exploration and production of offshore oil and gas resources has essentially been a post-World War II development commencing in the late 1940's in the Gulf of Mexico. The first specifically designed steel structure for offshore oil production, for example, was installed in the Gulf of Mexico in 1947 (Geer, 1976). Gulf of Mexico petroleum development has provided the technology base from which offshore petroleum development has progressed into diverse (and often harsher) operating environments.

Until the mid-1970's offshore petroleum development in the United States had been confined to the Gulf of Mexico, southern California and upper Cook Inlet. Recent and planned OCS lease sales have extended areas available for exploration into deeper waters and more severe operating environments. These areas include the Gulf of Alaska, Lower Cook Inlet, and Beaufort Sea in Alaska, and mid-Atlantic and North Atlantic regions in the lower '48. Outside the United States the major areas of offshore petroleum activity have been the North Sea (southern North Sea in the late 60's, central and northern North Sea in the 19701s), the Far East, West Africa, Brazil and Australia. In terms of the numbers of exploration rigs operating, the principal areas of exploration activity in the late 1970's are (in order) North America, the North Sea, the Far East and Latin America.

Trends in offshore petroleum exploration and production have been to deeper and more hostile waters. Exploration capabilities are now common in water depths of 305 to 457 meters (1,000 to 1,500 feet), and the present record for drilling in deep water is about 1,067 meters (3,500 feet) (Hammett, 1977; Geer, 1976). Production operations (typically conducted in shallower waters than exploration capabilities at a given point in time) have progressed to 259 meters (850 feet) water depth in southern California (Exxon's Hondo platform in the Santa Barbara channel) and 312 meters (1,025 feet) in the Gulf of Mexico with Shell's Cognac field platform. In the North Sea, fixed platforms have been installed to depths of 162 meters (530 feet).

In terms of severity of operating conditions and water depth ranges, the North Sea development provides the closest analog to the Gulf of Alaska. Consequently, this technology review draws extensively on North Sea literature and the economic analysis (see Appendix B) uses much North Sea cost data. The principal similarities and contrasts between the Gulf of Alaska and the North Sea are listed below.

Similarities:

- Water depths of the currently or soon-to-be leased areas range from 61 to 183 meters (200 to 600 feet) in both areas.

- The design waves are of similar magnitude -- 100 year return wave in the northern North Sea is about 30.5 meters (100 feet) and 36.6 meters (120 feet) in the Gulf of Alaska.

- Climatic conditions and storm frequencies are similar.

Contrasts:

- The Gulf of Alaska is a seismically active region; the North Sea is not.

- Bottom soil conditions and submarine slope stability are generally less favorable to bottom-founded structures in the Gulf of Alaska.

- The Gulf of Alaska is far removed from major industrial/ manufacturing centers of North America; the North Sea lies close to the major industrial centers of Europe.

- The Gulf of Alaska is far removed from the markets for oil and gas whereas the North Sea fields are adjacent to the major consumers.

4.2 Production Technology

4.2.1 Platforms

The platform is the principal component of offshore oil and gas production. Depending upon reservoir characteristics, environmental conditions (water depths, etc.) and economics, offshore platforms may serve as an Integrated drilling and production unit, or as a single function facility (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 the use of integrated drilling/production units; this has been the trend in the North Sea.

Piled steel jacket structures have been the dominant platform type since offshore oil and gas production commenced in the Gulf of Mexico in the late 1940's. 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 which 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. Such designs have been necessitated by the increasing costs of "conventional" platforms with increasing water depths and, concomitantly, the need to develop "marginal" fields. At the same time designs which minimize the amount of offshore construction work effect cost savings and may speed field development resulting in earlier production, and cash flow to the operator.

4.2.1.1 Steel Jacket Platforms

Description

The steel jacket is the substructure of offshore steel platforms. The term is often used loosely to refer to the whole platform which in typical North Sea designs comprises four major structural elements: the modularized topside facilities, the module support frame, the jacket substructure and pile foundation.

The jacket consists of a space frame type structure fabricated from tubular members of varying diameters and wall thicknesses welded together at modal points, termed joints. In deep water situations the platform piling are commonly grouped in clusters at each of the jacket corners. The piles are driven through large diameter tubulars known as pile sleeves. When the piles have been driven to their desired depth, they are grouted to the jacket by filling the annulus between the sleeve and piling with cement. The pile sleeves are in turn attached to large tubular structural elements called "bottle legs" located at the lower section of the main jacket legs.

In addition to the above structural elements, the jacket structure may also incorporate a "launch truss" which may be an integral component with the jacket framework or an additional framework attached to the jacket frame. The "launch truss" is a primary structural element which enables the jacket to be loaded onto a launch barge and launched at the offshore location.

To achieve a desirable horizontal floating altitude after launch and to ensure jacket clearance from the sea floor during rotation to the up-right position, auxiliary buoyancy tanks may be attached to the jacket during fabrication onshore. Compartmentalization of tubular members combined with a system of valves and piping in the jacket legs is used for remotely controlled ballasting and deballasting of selected members in order to upright the jacket on the sea floor.

In some cases a self-floating tower design is selected rather than a barge-launched jacket. The self-floating tower is towed to the site under its own buoyancy; two of the platforms four legs are large diameter floating legs. The advantages of the self-floating, design include: no reliance is placed on barge equipment; time consuming lifting and fitting of deck support trusses is not needed; and no fitting and retrieval of supplementary buoyancy tanks is required. The self-floating tower design was selected for the Ninian Southern, Brent A and Thistle platforms in the North Sea (see Hancock, White and Hay, 1978; Praught and Clifford, 1978; Offshore, September 1976, p. 129-137; Ocean Industry, May, 1976, p. 94).

To appreciate the size of some steel jacket deep water drilling/production platforms, Table 4-1 presents some statistics on platforms recently installed in the North Sea and United States.

The platforms described in Table 4-1 are currently the largest steel jacket drilling/production platforms in the world and are located in water depths in excess of 137 meters (450 feet). They represent the current state-of-the-art in conventional steel jacket piled structures.

TABLE 4-1

SPECIFICATIONS ON SOME DEEP WATER
STEEL JACKET DRILLING/PRODUCTION PLATFORMS

Platform/Field	Water Depth Meters (feet)	Jacket Height Meters (feet)	Overall Height Meters (feet)	Jacket[1] Weight (tons)	Base Dimension Meters (feet)	Well slots	Installation Date	Remarks
Ninian Southern, North Sea (1)	141 (463)	167 (547)	..	18,000	75 x 75 (246 x246)	42	1977	Self-floating design
Thistle, North Sea (2)	161 (530)	185 (606)	295[2] (968)	26,000	82 X 82 (270 X 270)	60	1976	Self-floating design
Hondo, Santa Barbara, California (3)	259 (850)	264 (865)	288 (945)	12,000	52 X 72 (170 x 235)	28	1976	Constructed in two sections, barged to site, sections re-connected prior to uprighting.
Cognac, Gulf of Mexico (4)	311 (1020)	317 (1040)	386 (1265)	33,000	116 x 122 (380 x 400)	62	1977-1978	Jacket constructed in three sections, based installed horizontally, middle and top sections will be installed by up-righting.

References: (1) Praught and Clifford, 1978. Hancock, White and Hay, 1978.
(2) McNally, 1977a.
(3) Bardgette, 1978; Bardgette and Irick, 1977; Deflache, et al., 1977.
(4) McNally, 1976b.

[1]Excluding Piles.
[2]To top of flare tower.

Fabrication and Installation

Depending on the size and complexity of the platform design, onshore fabrication of the steel jacket will take from 12 to 24 months in a graving dock. Generally, the jacket will be constructed on its side. The module support frame will be fabricated at the same time as the jacket to be ready to set on the jacket as soon as the jacket is securely piled to the sea floor. If the jacket is to be launched from a barge, it will be pushed or pulled into the launch barge, using hydraulic jacks and winches. For transportation on the barge to the offshore site, transpiration tie downs or braces are fitted between selected points in the jacket and barge and welded to each. These tie downs ensure stability during transportation to the offshore site.

In the case of a self-floating design, the graving dock is flooded and the platform towed out. Bouyancy requirements and tow-out stability are a major design consideration in this type of platform (Praught and Clifford, 1978). An advantage in favor of the self-floating design is that the jacket can carry built-in deck trusses complete with skid beams, thereby eliminating the usual installation of deck trusses offshore. Primary piling clustered in guides around the legs may be transported in place with the jacket.

Emplacement of the barge-transported jacket at the site involves ballasting of the barge to the correct draught and launch angle. The jacket is then launched by pushing or pulling using hydraulic jacks and/or winches. The jacket moves along runners on the barge, eventually sliding under its own momentum, increasing its trim angle, and lowering the barge. Once in the water in a predetermined floating attitude, parallel to the water surface, the jacket is towed to the emplacement position and uprighted by sequential ballasting of the jacket. Auxillary buoyancy tanks are cut loose and initial pile driving is commenced with one pile placed at each corner of the jacket.

Early commencement of piling is critical since the platform is most vunerable to storm damage while unpiled. The platforms on-bottom stability while unpiled and during the piling program will be analyzed in the design to determine the required jacket ballasting to give stability consistent with allowable bearing pressures. The expected frequency and probability of storm waves during the piling season will be assessed. In steel jacket platform design, there is a trade-off between the amount of piling required for the platform to withstand a fifty-year storm and a jacket design sufficient to withstand a storm prior to completion of piling (Alcock, personal communication, 1978).

Emplacement techniques for steel jacket platforms will vary according to the platform design and size. After launch from the barge, upending and final placement of the jacket may be aided by a derrick barge; jacket rotation is controlled by both sequential ballasting and manuevering by the derrick barge. This system was used for the installation of 3,500 ton Auk field jacket in the North Sea (Ocean Industry, August, 1974) and is only feasible for relatively small jackets.

A three phase upending procedure was used for the self-floating Ninian Southern jacket (Praught and Clifford, 1978). This involved a first rotation brought about by flooding the bottom compartments of the flotation legs which brings a rapid pitch rotation that is arrested by immersion of the upper smaller diameter legs in the water; a second rotation, more gradual, is achieved by flooding the smaller diameter legs until the tower is vertical with a predetermined clearance from the sea floor; landing in the sea floor is accomplished by sequential or simultaneous flooding of all legs after final positioning over the target areas.

For very large platforms in deep water such as the Hondo and Cognac platforms, it is not feasible to transport the whole jacket to the offshore location in one section. The Hondo platform is unique in that it was fabricated in two sections, designed to be joined at sea (Bardgette, 1978; Bardgette and Irick, 1977). After launch of the upper and lower jacket sections, the sections were joined together in the horizontal position by winching with connection assisted by four stabilizing cones located on the four external jacket legs. Positive connection for each of the eight legs of the upper jacket to its counterpart in the lower jacket was effected by specially-designed, hydraulically actuated coup-Iers-hydroflanges. Upon coupling of the legs, the compartments at the hydroflanges were dewatered, and welding together of the hydroflange units was conducted from inside the legs. The completed jacket was towed to the installation site and upended by sequential ballasting of leg compartments.

The 317 meter (1040-foot) Cognac jacket was constructed in three sections (McNally, 1977a). A base section 116 meters (380 feet) by 122 meters (400 feet) by 53 meters (175 feet) high, weighing 14,000 tons was barged to the site standing upright and lowered to the sea-floor by two derrick barges. The mid-section [86 meters (282 feet) by 95 meters (310 feet) by 96 meters (315 feet) high, weighing 8,000 tons] and top section [78 meters (257 feet) by 96 meters (254 feet) by 162 meters (530 feet) high, weighing 11,176 metric tons (11,000 tons)] were barged on their sides, launched and rotated to the upright position.

A piling program for a large steel jacket platform may require 30 to 50 1 arge diameter (102 to 152 centimeters or 40 to 60-inch in diameter) piles driven (or inserted into pre-drilled holes)as much as 305 meters (?000 feet) into the sea floor. The Cognac platform for example, used 61 to 204 centimeters (24 to 80 inch) piles. Piling may be installed by pile driving hammers operated from an adjacent derrick barge or from a temporary work deck on top of the jacket, A modular work deck on the North Sea Thistle platform, for example, was used to support pile driving equipment (in addition to that on an adjacent work barge) to speed up the piling program (McNally, 1977b). Piling may take from 3 to 6 months on large steel jacket platforms.

If the module support frame was not set on the jacket prior to tow-out, then upon completion of piling, the frame is set upon the jacket legs and the frame columns welded to previously trimmed and bevel led jacket legs. Modularized top side facilities are then placed on the jacket by a derrick barge. The modules weighing up to 1,500 tons, may comprise up to three deck levels and total up to 20, depending on the throughput, functions and processing requirements of the platform (see Section 4.5). Module placement and platform commissioning may take 3 to 6 months. About one year will have elapsed from installation of the, platform to platform commissioning.

4.2.1.2 Concrete Gravity Platforms

Utilization of concrete for marine structures is not a recent innovation.[1] Use of marine gravity structures, which depend primarily on their weight to resist vertical and horizontal loads, is, however, a recent innovation. One of the first concrete gravity structures was the Kish Bank Lighthouse installed off the entrance to Dublin Harbor in 1965 (Young, Kraft and Focht, 1976). The first oil storage gravity structure was constructed in 1966 for Tenneco Oil Company and installed in 131 feet of water in the Gulf of Mexico.

The use of concrete gravity structures for drilling and production platforms was pioneered in the North Sea. The first structure in the North Sea was the Ekofisk oil storage tank designed by the French company C. G. Doris. The Ekofisk tank was designed to provide storage for one million barrels of crude oil as buffer storage when offshore loading was not possible (and, more recently, when the Ekofisk pipeline was inoperative during repairs). Specifications of the Ekofisk structure, which was installed in the summer of 1973, are given in Table 4-2. The structure located in 70 meters (230 feet) of water comprises nine cellular storage tanks surrounded by a perforated JarIan breakwater which reduces wave forces and provides protection against impact by ships (Harris, 1978; Clausen et al., 1976; Ocean Industry, August, 1973).

The success of the Ekofisk storage tank stimulated development of concrete gravity drilling and production platforms. The advantages of

(1) For a state-of-the-art review of the use of concrete for floating structures, the reader is referenced to a volume of papers, Concrete Afloat (The Concrete Society, 1977).

TABLE 4-2

SPECIFICATIONS OF ‘SOME NORTH SEA CONCRETE PLATFORMS

Platform	Functions	Design	Water Depth Meters (feet)	Installation Date	Height Meters (feet)	Storage Capacity (bbl)	Col Umms	Deck Weight tons (inc. Equip.)	ase Cross Section Meters (feet)	Well Capacity	Comments
Ekofisk[1]	Oil Storage Production	G.G. Doris	70 (230)	1973	90 (295)	1,000,000	N/A	--	91 (300)	N/A	Additional deck: and processing equipment not incorporated in original design have been successfully accumulated.
Beryl 'A'[2]	Drilling/ Production	Condeep	118 (388)	1975	199 (653)	900,000	3	20,000	87 (285)	40	
Brent 'B'[3]	Drilling/ Production	Condeep	140 (460)	1976		1,000,000	3	--	87 (285)	38	
Cormorant 'A'[4]	Drilling/ Production/ Pump Station Gathering Center	Seatank	152 (498)	1978	172 (564)	1,000,000	4	--	98 (320)	36	
Ninian Central[5]	Drilling/ Production	Howard Doris	140 (460)	1978	168 (550)		1	37,000	--	40	
Dunlin[6]	Drilling/ Product ion	Andoc	154 (505)	1977	--	820$000	4	20,000	104 (340)	48	

Source: [1]Clavsental ., 1976; Ocean Industry, August, 1973.
[2]Werenskiold, 1977; Carlson and Vindvik, 1977; Foss, 1974.
[3]Werenskiold, 1977; Carlson and Vindvik, 1977; Eide and Larsen, 1976; Eide, Larsen and Me. , 1977; Foss, 1974.
[4]Demington, 1977.
[5]World Oil, July, 1978; Buckman, 1977.
[6]Foss, 1974; Ocean Industry, August, 1976.

concrete platforms include:

- Storage capability -- the platform provides buffer storage so that production can continue when transshipment (tanker or pipeline) is restricted;

- Float-out with deck in place -- since concrete platforms are towed out vertically the deck and modules can be installed onshore. This reduces the amount of offshore construction work and reduces the time for hook-up and commissioning.

- Reduction in offshore operations -- a concrete platform does not require piling, deck installation, etc., all of which reduce offshore construction time.

- Capability for high deck loads.

- Protected access to the seabed -- risers are located within the concrete shaft(s), in a dry environment protected from wave action and corrosion problems (for a discussion on the special problems of drilling from a concrete platform see Bew, 1978).

Specifications of some North Sea concrete platforms are given in Table 4-2. More detailed descriptions of three platforms of the Seatank design, including concrete quantities, are given in Table 4-3.

Designs

Several different concrete platform designs have been employed in the North Sea by different constructors. To a greater or lesser extent these designs have several common elements. The typical concrete gravity platform consists of a base caisson comprising a number of interconnected cells or cylinders, one or more (up to four) of which extend upwards as towers. The towers support a steel deck. Two types of deck have been utilized -- the standard module type and an integrated type.

TABLE 4-3

SPECIFICATIONS OF "SEATANK" CONCRETE PLATFORMS

Platform and Client	Seamac I Elf/Aquitaine	Seamac II Shell/Esso	Seamac III Shell/Esso
North Sea Location	Frigg	Brent C	Cormorant A
Water Depth (mean)	104 m	140 m	152 m
Dimensions			
Caisson plan area	72 m^2	91 m^2	100 m^2
Caisson height	42 m	57 m	56 m
Number of towers	2	4	4
External diameter on top of towers	9 m	9 m	9.5 m
External diameter on bottom of towers	14 m	15 m	16 m
Overall platform height (sea bed to top of towers)	126 m	165 m	172 m
Deck area	2750 m^2	4000 m^2	4250 m^2
Storage capacity, barrels	Nil	660000	1000000
Concrete quantities			
Stage 1. Float-out			
Caisson wall height	13 m	13 m	15 m
Volume, including base slab	15100 m^3	25500 m^3	29700 m^3
Weight, t	39400	66600	77600
Stage 2. Roof level			
Full caisson height	29 m	39.5 m	40 m
Volume, including roof	51400 m^3	73600 m^3	89400 m^3
Weight, t	130500	192700	234000
Stage 3. Towers			
Volume	3500 m^3	8700 m^3	12000 m^3
Weight, t	9100	22800	31400
Total volume of concrete	70000 m^3	107800 m^3	131000 m^3
Total weight, including reinforcement, t	179000	282000	343000
Steel reinforcement and stressing			
Weight, t	5800	11400	13930

Source: Derrington, 1976.

The standard module deck consists of a steel frame supporting the modules; the integrated deck comprises a compact unit in which production equipment is installed within the deck supporting frame. The cellular caisson provides the required buoyancy during construction and towing, and oil storage and ballasting when installed.

The base of the platform may be equipped with steel skirts, which penetrate the sea floor when the platform is ballasted down. The purpose of the skirts is: (1) to improve foundation stability, (2) reduce scour or erosion, and (3) divide the base into compartments for grouting.

Design Considerations

All platform designs stem from the operator's basic requirements and the dictates of the operating environment. The major factors include (Harris, 1978):

- Platform location.
- Number of wells and their spacing.
- Operational deck load.
- Soil conditions.
- Riser and J tubes, numbers and directions.
- Operating environment -- wave height, wave spectra (periods), currents, wind strengths, water depths, temperature extremes.

In addition, for concrete platforms:

- Float-out deck load.
- Storage volume required -- oil density, temperature, loading rate, discharge rate.

Soil conditions are one of the most important considerations in the design and feasibility assessment of gravity structures. This is because a gravity structure, unlike a piled steel jacket, depends upon a single or multiple concrete mat bearing on an unprepared sea floor to provide foundation stability against the maximum environmental loads imposed on the structure. Since a concrete platform is constructed from the base upwards commencing with the mat, there is little or no opportunity to change mat design during construction. Therefore, detailed site soil investigations and foundation design have to be completed before construction starts. The foundation design has to satisfy the following criteria:

- No sliding under the design storm.
- Permissible bearing pressure.
- No uplift.

The main concern is the risk of foundation failure. Potential failure modes include sliding between the base of the structure and the soil, deep-seated bearing capacity failure, progressive failure caused by softening along the rim of the base and liquefaction of sand. A major factor also to be considered in the foundation analysis is the influence of cyclic loading on the stress-strain-strength characteristics of the foundation soils. In the case of loose and medium dense sands the potential for total loss of shear strength due to increase in pore water pressure (liquefaction) has to be evaluated. For technical discussions on foundation design considerations for gravity structures and related site soil investigations, the reader is referred to papers by Young, Kraft and Focht (1976); Pool (1976); Hitchings, Bradshaw and Labiosa (1976); Milling (1976); and Garrison and Bea (1977). In the Gulf of Alaska, seismicity and slope instability will be major foundation and structural design considerations. These are discussed in Section 4.4.2.

In the North Sea selection of concrete gravity structures has been favored by the bottom geology. Large areas of the North Sea are underlain by dense over-consolidated glacial tills and dense sand substratum characterized by little or no relief (Milling, 1976).

The cost and availability of steel and concrete are also factors in the selection of concrete vs. steel platforms in the North Sea. The Norwegians have favored concrete platforms in part because they lack a large steel manufacturing industry although the steel requirements of concrete platforms are still significant, e.g. Statfjord A platform required 12,000 tons of reinforcing steel and 2,600 tons of posttensioning steel cables (Carlson and Vindvick, 1977).

Concrete platforms have mainly been designed for water depths greater than 91 meters (300 feet). In water depths less than 91 meters (300 feet), economics are felt to favor steel platforms (Enright, 1976). Concrete gravity platforms have, however, been constructed for shallow water fields. In Brazil, the Urbana field, located in water depths of 12 to 14 meters (40 to 45 feet) off the coast of Rio Grande do Norte is being developed with concrete platforms (France, 1976). The typical drilling/production platform consists of 42 cylindrical shells forming a rectangular box-shaped unit (with no legs or towers) measuring 43 meters (140 feet) wide by 53 meters (174 feet) long and 26 meters (85 feet) high. The 20 peripheral cells hold ballast and the remainder provide storage for up to 145,000 bbl of crude. Two decks accommodate processing equipment, drilling equipment and living quarters. Construction, which is taking place at the Aratu naval base, commences with drydock construction, followed by inshore completion of the cellular base.

The economics of concrete platforms, like steel jacket platforms, become problematic as the 183 meter (600-foot) water depth is approached in storm-stressed environments and this more than any other factor may prove to be the limiting criterion in their adoption.

Fabrication

North Sea concrete platforms have been fabricated in Norwegian fjords, the west coast of Scotland and the Netherlands. Their design and construction techniques require a deepwater sheltered location with about 46 meters (150 feet) of water for the intermediate phase of construction and as much as 213 meters (700 feet) of water for final testing and deck assembly. Land requirements, however, are less than that required for fabrication of steel jacket platforms varying from 7.3 to 34 hectares (18 to85 acres) depending upon the number of dry basins. Fabrication site location is also influenced by tow-out requirements and route to the installation site. The completed platform will draw up 40 meters (130 feet) of water when towed-out partially ballasted.

Fabrication of concrete platforms is conducted in three phases:

- dry dock;
- wet dock;
- deck and equipment installation.

Initial construction commences in a dry basin excavated on the shore to between 8.5 and 10 meters (28 and 33 feet) below sea level. An earthen dike reinforced by temporary sheet piling keeps the basin dry. In this basin the base slab is constructed with pre-cast skirt units (if required by the design) placed first followed by the base slab. Slipforming of the cellular caisson follows. When the caisson walls have reached a level sufficient to provide adequate freeboard for wet dock construction, the basin is flooded by removal of the sea wall and the base is towed-out for wet dock construction. At the wet dock site the floating caisson is anchored to the sea floor. Slipforming of the remaining portion of the caisson continues afloat until their full height (about 30 to 40 meters, or 100 to 130 feet, for example, in the Sea Tank designs) is attained. The roof of each caisson comprising a series of domes or cones is fabricated through concreting using steel tressils and wooden forms. In construction of the Ninian Central platform pre-cast slabs and dome sections, fabricated onshore, were used to complete cell closure (Buckman, 1977). Prior to closing the cells or caissons, permanent ballast such as crushed iron ore is placed in the bottom of the storage cells and concreted over. Slipforming of the towers or columns may begin simultaneously with roof construction. Slipforming progress of about 300 centimeters (118 inches) per day has been reported for tower construction (Derrington, 1976; Carlsen and Vindvik, 1977). Platform concrete requirements are given in Table 4-3.

When the towers are completed, the structure is ready for mating with the steel deck. This may require towing the structure to a deeper water location because the deck mating operation requires almost full ballasting of the structure to within a few meters of the top of the towers. The deck may be mated either by floating it over the submerged shafts (with the deck elevated above two barges, one either side of the platform) or by lifting the deck using crane ships or derrick barges. If the deck is of the integrated design, most of the equipment will be in place at "float over" (e.g. Beryl "A" platform). Designs such as the Ninian Central platform and the Sea Tank platforms do not use the integrated deck; equipment modules are loaded onto the deck by derrick barge.

When the module placement and inshore hook-up work are complete, the platform is deballasted to its design towing draft. A detailed survey of the towing route has been conducted and holding areas identified. With a suitable weather window forecasted, the platform will be towed out by five or six tugs with a combined capacity of 70,000 to 80,000 hp (Werenskiold, 1977; Cranfield, 1978). In good weather the towing speed will be about 2.5 knots.

Platform installation is a delicate maneuver. The platform is gradually deballasted on approach to the site. For example, clearance under the base of Frigg TCP-2 was reduced to 0.2 meters during the last 300 meters (984 feet) of the approach and to zero for the last 100 meters (328 feet) (Ocean Industry, August, 1977). Once located over the target, water ballasting is continued and dowels extending three to four meters below the base penetrate the soil to provide initial stability, followed by the skirts. Finally, the voids beneath the slab are grouted. Some remarkable accuracies in concrete platform positioning have been recorded for North Sea concrete platforms (Table 4-4). For more detailed descriptions of concrete platfrom fabrication the reader is referred to Derrington (1976) who discusses construction of McAlpine/Sea Tank designs and Carlsen and Vindvik (1977) who discuss construction of the Condeep , platforms. Concrete platform installation is described in detail by Eide, Larsen and Mo (1977) and Eide and Larsen (1976).

TABLE 4-4

PLACING ACCURACIES OF CONCRETE STRUCTURES
IN THE NORTH SEA

Client	Structure	Distance Off Target	Angle
Phillips	Ekofisk Tank	19m	2.1°
Mobil	Beryl A	32m	
Shell/Esso	Brent B	25m	1°
Total	Frigg CDP1	14m	0.6°
Shell/Esso	Brent O	8m	
Mobil/Statoil	Statfjord A	10m	
Elf	Frigg TP1	7m	
Total	Frigg MCP01	7m	0.1°
Elf	Frigg TCP2	1.9m	

Source: Harris (1978)

Application to the Western Gulf of Alaska

The application of concrete gravity structures to the Western Gulf of Alaska is uncertain especially with the lack of detailed geologic data on soil conditions. One of their principal advantages -- payload in place at tow-out with a reduction in offshore construction time -- is particularly suited to the short summer weather window of the Gulf of Alaska. Their storage capability may also be an asset in the Gulf of Alaska where there is a lack of suitable shore terminal sites (in the northern gulf) and where most production will be exported to the lower 48. Both of these factors may favor offshore loading of oil although there are many other factors involved in the selection of production system (see Section 4.5).

In addition to the problem of areas with questionable foundation suitability", the Gulf of Alaska has a high earthquake risk (see Section 4.4.2 for a discussion of geology and geologic hazards), A preliminary analysis on the response of concrete gravity platforms to earthquake excitations for the Gulf of Alaska was conducted by Watt, Boaz and Dowrick (1978) who concluded that "... Concrete gravity platforms appear feasible for earthquake regions in water depths ranging from 100 to 200 meters (328 to 656 feet) (p. 232)". They investigated the foundation response of soils in the stiffness range of firm to very hard based on the assumption that suitable foundation conditions are present in the Gulf of Alaska. Weak links in the structural design were identified and possible design modifications were presented in their paper.

The available data indicates that bottom geology in the Gulf of Alaska (within the study area) ranges from soft pro-delta sediments, unsuitable for foundation of gravity structures, to (possibly) over-consolidated glacial moraine deposits probably suitable for such structures. Large slide areas mapped at a number of locations on the continental shelf and upper continental slope from the Malaspina Glacier southwest to Albatross Bank off Kodiak Island are also unsuitable sites for locating gravity platforms.

Suitable sites for the construction of concrete gravity platforms exist at several locations along the shores of the Gulf of Alaska (see Chapter 6.0). In addition, several companies are known to have interest in concrete platform construction in the Puget Sound area. Whether or not towing of a concrete gravity platform or similar hybrid from Puget Sound to the Gulf of Alaska (over 1,609 kilometers or 1,000 miles) is feasible in terms of insurance risk is debatable.

Possible towing routes within the Inside Passage, which would minimize exposure to the stormy North Pacific Ocean for a portion of the journey, have not been assessed. Draft clearance and lateral clearance for the platform, and maneuvering room for the towing fleet have to be considered. In the North Sea, concrete platforms constructed on the west coast of Scotland have been towed as much as 1,046 kilometers (650 miles) although a portion of the journey has been in sheltered waters. The first sites for concrete platform construction in the North Sea were, however, in the nearest suitably deep water of the Norwegian fjords.

4.2.1.3 Concrete Hybrids

A number of concrete platform designs evolved from those first used in the North Sea have been proposed which may have Gulf of Alaska application.

Semi-submersible floating concrete platform termed "Condrill" and "Conprod" have been designed by a Norwegian contractor (Kure, 1977). The advantages of such floating platforms include:

- Moderate capital expenditures enabling marginal fields to be exploited.

- Field development time from discovery to production is reduced by about three years thereby speeding return on investment.

- Continental shelf areas beyond the technical or economic reach of conventional systems can be developed by floating concrete platforms combined with subsea completion.

"Condrill" consists of a submerged substructure formed by several contiguous vertical cells, nine of which project above sea level to support a deck structure. An open-ended central cell permits drilling and production access for risers, etc. Condrill has a displacement of 100,000 tons and has storage capacity for up to 260,000 bbl of crude. Condrill is secured on-site by a conventional mooring system.

As a specialized version of "Condrill", "Conprod" is a floating production platform with a storage capacity of 500,000 bbl and capability to handle up to 100,000 b/d production. Conprod has a caisson substructure unit composed of nineteen vertical cells. Seven of the cells including an open-ended central cell project above sea level to carry the deck. The deck structure is composed of 12 concrete box ginders and can carry up to 20,000 tons of production equipment. The platform is used in conjunction with subsea completed wells, either satellite single wells or multi-well clusters, which are produced through risers in the central open cell. Conprod is kept on location by a twelve leg mooring system. The platform is designed to operate in water depths up to 1,600 feet.

A second generation of Condeep platforms has been designed for a variety of offshore environments including a version for earthquake-prone areas (Ocean Industry, May, 1976). Few details are available on this earthquake resistant version of the Condeep series; the platform is designed to operate in water depths of 30 to 200 meters (98 to 656 feet) and is suitable in areas of both poor soil conditions and high seismic activity.

4.2.1.4 Tension-Leg Platform

The tension-leg platform (TLP) production system has been developed in response for the need to develop marginal fields in deep water (Falkner and Franks, 1978; Kypke, 1975; Le Blanc, 1978). The TLP System includes a floating platform, a multi-well sea floor template and individual production risers. Produced crude would be processed on the platform transferred to shore through a subsea pipeline or a single point mooring (SPM) tanker system. To provide buffer storage in the SPM/tanker system, an undersea storage tank could be included.

The TLP platform appears similar to a conventional semi-submersible rig. It uses an excess of buoyancy to apply tension to a vertically oriented, transversely flexible mooring system. The mooring system consists of a number of large diameter wire ropes attached to dead weight anchors. The effect of this mooring system is to eliminate heave while permitting limited horizontal motion of the platform.

A prototype TLP, triangular in shape, 40 meters (130 feet) on each side, and 20 meters (66 feet) in height from deck to lower horizontal pontoon, has been successfully tested off the coast of California in 61 meters (200 feet) of water (Horton, 1975). The prototype, "Deep Oil X-l", could be envisaged as about a one-third scale model of a large drilling and production platform (110 meters or 360 feet on a side).

Preliminary economic evaluations on the TLP system have been made (Kypke, 1976). Other factors assumed constant, the cost of the platform is relatively insensitive to water depth. Installation costs will increase with water depth but not significantly. The TLP becomes competitive with and surpasses performance and cost standards for other systems in varying water depths. For example, in a severe environment such as the North Sea the TLP may break-even with conventional piled jacket structures in water depth range as low as 122 to 152 meters (400 to 500 feet). In a less severe environment such as the Gulf of Mexico, the break-even point would be in the 183 to 213 meter (600 to 700-foot) water depth range. If environmental factors such as seismicity or unsuitable soil conditions, which affect the economics of conventional bottom-founded structures, are introduced, the depth of water at which TLP systems are competitive decreases.

In comparison with the conventional moored semi-submersible platform (e. g. North Sea Argyll field), the advantages of a TLP production system are cited to be (Falkner and Franks, 1978, p. 2080):

- Risers remain connected in all weather conditions.

  Hazards involved with riser disconnect, handling and re-connect are avoided.

  Production efficiency is improved because downtime due to weather related riser handling operations is eliminated.

- The need for conventional, heavy, long-stroke riser tensioners is eliminated.

  Lower initial capital investment.

- Quasi static conditions of the riser pipe with respect to the process piping on the platform permits the use of steel connecting pipes or swivel joints.

  No flexible hoses to replace periodically.

  Greater security in case of fire.

- Multiple riser systems do not become overly complex.

- TLP features a more efficient pound of payload per pound of platform.

  This advantage increases with increasing water depth.

There are some limitations and disadvantages to the TLP production system. These include:

- Deck load limitations restrict the amount of process and other equipment that can be installed. It is also unlikely that drilling and production can be done at the same time.

- The TLP system involves subsea wells which have significant maintenance requirements and related high costs.

- Significant maintenance and repair of the vertical tensioned cables may be required.

- The competitive advantage in water depths of 400 to 600 feet is not clearly demonstrated; an operator may have to be prepared to absorb some high front end R&D costs with feasibility of the system in deeper waters clearly demonstrated before he is prepared to commit to this innovative system.

Possible introduction and successful operation of the TLP system in the North Sea to develop one of the marginal fields, will undoubtedly influence production system selection in U.S. offshore areas.

4.2.1.5 Guyed Tower

The guyed tower is a compliant platform that has been developed and tested by Exxon Production Research (Taylor, 1975; Pierce, 1976; Finn, 1976; Power et al., 1978; Finn and Young, 1978).

The guyed tower is a bottom-founded structure which differs in two important ways from conventional steel jacket platforms (Finn and Young, 1978): (1) the guyed tower uses a guyline and clump weight system to dissipate the wave energy and a spud can foundation to transfer gravity loads to the soil, and (2) because the sway period is greater than the design wave period, the principal structural inertial forces always oppose the principal wave forces instead of adding to the total load as occurs on conventional platforms. As a result, the guyed tower is believed to offer economic alternative to conventional platforms in the water depth range of 183 to 610 meters (600 to 2,000 feet).

Exxon’s prototype is designed for 457 meters (1,500 feet) of water in the North Sea. The guyed tower is a trussed structure with four legs spaced 30 meters (100 feet apart from five to eight feet in diameter.

The truss supports a deck which has a capacity for 24 wells which run from the deck through guides on the tower and through sleeves provided in the tower base or spud can. The deck would have two levels, 46 meters (?50 feet) on a side, and would support a 7,500 ton payload.

The tower base is supported on a blunt-nosed, truss-reinforced stiffened shell termed a spud can which on installation is forced into the bottom soils by adding drilling mud to the spud can cavity.

The 457 meter (1,500-foot) tower will be guyed by twenty 8.9 centimeter (3-1/2 inch) bridge strands placed symmetrically around the structure. Each guyline is secured at the deck of the platform by two wedge type cable grips (Lucker clamps) placed in series to form a hydraulic jacking unit.

The guylines run down the legs to fairleads located about 15 meters (50 feet) below the water. From the fairleads the guylines run at a 60 degree angle to clump weights on the sea floor. The clump weights are in turn held horizontally by anchor lines which extend a water depth or more to a drag-type anchor such as the BOSS anchor. The clump weight guying system has several advantages. First, with clump weights the guylines can be shorter than with conventional catenary lines while still maintaining horizontal pull on the anchors. Second, the clump weight system permits the guylines to be held essentially in a taut line condition. Consequently, for smaller wave forces, anticipated in typical operational sea states, the tower would stand stationary, moving only a few inches in even 10 to 20-foot waves. However, during the passage of large amplitude long period storm waves the tower becomes compliant and the clump weights are permitted to lift off the sea bottom resulting in a softening of the guying system. Deck offset during passage of storm waves, 50 feet or greater, would be on the order of 12 to 15 meter (40 to 50 feet).

The guyed tower is technically feasible in water depths of 183 to 610 meters (600 to 2,000 feet). The amount of structural steel required at a given water depth is significantly less than that required for a conventional steel jacket platform. Assuming that installed cost is related to steel tonnage, it can be concluded that the installed costs of a guyed tower increase only moderately from 183 to 610 meters (600 feet to 2,000 feet) water depth (Finn, 1976). Beyond 610 Meters (2,000 feet), however, the guyed tower probably becomes uneconomical because a rapid increase in structural steel is necessitated by large increase in tower cross section required to maintain a low resonance free flex and period.

In water depths less than 183 meters (600 feet) the guyed tower, as presently designed, has several technical limitations which would require substantial alteration of the design. The angle of tower tilt due to wave forces increases as water depth decrease. As a result flexural stresses in the conductors at the mudline for most soil conditions decreases the load carrying capacity of the spud can.

A one-fifth scale structure, selected in order to model a 30 meter (100-foot) North Sea design wave with 6 meter (20-foot) winter storm waves in the Gulf of Mexico, was installed in 89 meter (293 feet) of water in the Gulf of Mexico in 1975 (Powers et al., 1978; Finn and Young, 1978). The test tower had a 6 meter (20-foot) square frame with four 41 centimeter (16-inch) diameter legs and was held on eight line guying system (twelve during hurricane season). The test guyed tower was operated successfully performing close to theoretical predictions of dynamic response behavior.

The guyed tower concept has not as yet been selected in any field development plans in the North Sea or elsewhere.

4.2.1.6 Floating Production Systems

Hamilton Brothers' North Sea Argyll field has been successfully developed using a floating production system (Hammet et al., 1977; Gordy and Thomas, 1976; Elwes and Johnson, 1976). The field has been developed using subsea wells which produce through a production riser to a production platform, the converted semi-submersible drill rig "Transworld 58".

The produced crude after processing on the platform is shipped back down a riser to a single point mooring (SPM) and tanker.

Principal factors in the decision-to-develop using a floating production facility included:

- The complex geology of the fractured dolomite reservoir made predictions on reservoir performance and ultimate recoverable reserves very difficult. A temporary test production facility was required for extended reservoir testing prior to making a major investment for a fixed platform facility.

- At the same time, the production test would yield sufficient revenue to assure profitable initial operation of the field. Furthermore, the field development time is reduced using a floating system (vs. conventional fixed platform) thereby speeding return on investment.

The Argyll field, located in 79 meters (260 feet) of water in the central North Sea, was discovered in August 1971. Drill stem testing indicated individual well productivity of 10,000 bpd and a low gas-oil ratio in the range of 150 to 300 scf/bbl.

Production comes from four subsea completions located from 1,030 to 2,258 meters (3,378 to 7,408 feet) away from the moored platform. The wells are connected by submarine flowlines to a subsea manifold and then through individual 10-centimeter (4-inch) diameter lines in a production riser assembly up to an oil/gas separation plant mounted on the deck of the semi-submersible platform. The crude is degassed and pumped back down to the sea bed through a 25-centimeter (10-inch) central riser member and then through a 2,286 meter (7,500-foot) long, 25-centimeter (10-inch) submarine line. The 25 centimeter (10-inch) line is, in turn, connected by a pipeline end manifold to a 30 centimeter (12-inch) submarine hose which interfaces to a single buoy mooring. Crude is conveyed from the single buoy mooring to the export tanker via a tapering floating hose.

The floating platform is a converted semi-submersible rig (Transworld 58) from which the drilling equipment has been removed. Production equipment comprises a standard two-stage gas/oil separator train designed for a maximum throughput of 70,000 bpd. Separated gas is flared. The platform has limited water treatment capability which is used to handle produced water.

The field is served by a two tanker shuttle. Using a 50,000 deadweight ton tanker with a 400,000 bbl capacity, the loading cycle is about 10 days. The tankers have been modified for self-mooring and bow loading. A field maintenance boat is used to assist in the single buoy mooring operation.

During the first year of operations overall field downtime was 32.4 percent. By the end of the second year downtime was anticipated to level out at 20 percent. The majority of the downtime has been created by the tanker loading system; during the first year of operation (1975-76) mechanical failure, repair and maintenance of the SPM accounted for 13.5 percent of the downtime. The maximum weather criteria for connecting or disconnecting the tanker due to weather is as follows:

	Maximum Wind	Maximum Wave
Tanker Begin Mooring	30 kt.	4m (12 ft.)
Tanker Prepare Disconnect	40 kt.	6 m (20 ft.)
Tanker Disconnect	48 kt.	8 m (25 ft.)

Because there is no storage on the platform, field shut-in is required when the tanker disconnects for any reason. Major downtime and field shut-in has occurred twice since production started in the Argyll field. In 1976 the mooring system failed in a major storm resulting in one month's downtime. Cracks in the structural members of the rig necessitated platform repair onshore in 1977 resulting in three months lost production.

The operators of the Argyll field note that larger fields can also be developed using converted semi-submersible rigs and subsea completions.

Existing rigs such as the SEDCO H class or SEDCO 700 class have the deck capacity for separation, injection equipment etc. to handle 80,000 and 160,000 bpd, respectively. A second North Sea field, Buchan, to be developed using a floating production system (converted semi-submersible rig) is scheduled to start production in 1979.

In the United States, flaring of gas will probably not be permitted. Reinfection equipment for gas will be required adding to the deck load.

The economics of the floating system would be significantly improved with the provision of storage in a permanently moved VLCC (very large crude carrier).

The floating production system significantly reduces the time between discovery and production start-up. In the case of the Argyll field, for example, only 52 months elapsed from decision-to-develop to first production. Some or all of the subsea wells may be drilled and completed by a conventional drill rig prior to installation and hook-up of t'he production platform.

4.3 Engineering Constraints to Petroleum Development

4.3.1 Oceanography

Past experience has taught the petroleum industry that safety and cost effectiveness are enhanced with increased knowledge of a potential operating area. When activities begin, two decisions that will have adverse effects can be made. Facilities and operations may either be underdesigned, resulting in the jeopardizing of safety, or designs may be overly conservative, which would probably result in a severe reduction of profitability. Decision makers almost always opt for the conservative approach; errors tend toward conservatism and higher costs rather than intentionally sacrificing safety.

From the industry's point of view, much is known about environmental conditions in the Gulf of Alaska. Relative to other frontier areas of the world, the Western Gulf has been more extensively studied prior to start-up activities. Probably the best data are in the hands of the various oil companies, in a proprietary status. One of the sources of sea state information is from a joint industry sponsored project monitored by Marathon Oil Company called the Gulf of Alaska Wind and Wave Measurement Program (GAWWMP). Data collection for this project began in 1974, and the information will probably be released in 1980.

Most of the data that are available originate from two basic sources:

- Data from buoys that are not strategically located near the present areas of interest.

- Observations from military, survey, or merchant vessels and ships of opportunity.

Information from the latter source is necessarily biased toward "fair weather" observations. Quite naturally, ships tend to avoid foul weather,

The Fleet Numerical Weather Central (FNWC) has compiled much of the meteorological data from the Gulf of Alaska. These are being used as input to hindcasting models which generate theoretical wave climates. FNWC should complete this project within a few months, thus making available much needed wind and wave information.

With these few qualifying remarks, the following is a description of the general marine environment in the Gulf of Alaska. This description emphasizes the proposed operating areas of the Western Gulf of Alaska. Where appropriate, and if the data are available, both operating and extreme conditions will be described. These differ in that the operational environment represents the conditions that may impact on routine day-to-day activities. Extreme conditions, on the other hand, are events that have a very low probability of occuring within the proposed life of the structure or operation. They are quite near the most forceful situation nature ought to produce.

4.3.1.1 Bathymetry

The dominant topographic feature of the Gulf of Alaska is the Aleutian Trench with a central depth in excess of 6,400 meters (20,998 feet). The width of the continental shelf ranges from approximately 200 kilometers (124 miles) off the Kenai Peninsula and south coast of Kodiak to about 20 kilometers (12.4 miles) directly off the coast north of Sitka. The continental slope approaches a steepness of seven degrees midway between Yakutat and Sitka. Adjacent to the Kenai Peninsula it is less steep, being slightly greater than two degrees.

Most of the western Gulf of Alaska is on the continental shelf, whose width exceeds 200 kilometers (124 miles) off the Kenai Peninsula. A dearth of detailed bathymetric information exists for this part of the North Pacific. Navigation charts produced by the National Ocean Survey (NOS Chart No. 16013) indicate that the shelf consists of plateau-1 ike features dissected by troughs, portions of which reach depths of 400 meters. These troughs may have been produced by subaerial erosional processes (AEIDC/ISEGR, 1974). Several banks rise above the shelf and have been fairly well delineated, especially off the coast of the Kodiak Island complex. Southeast of Kennedy Entrance and northeast of Afognak Island is the Portlock Bank. It rises from a surrounding shelf depth of approximately 180 meters (591 feet) to a depth of 50 meters (164 feet). A portion of the northern lease area is located on this bank. To the southwest lies the Albatross Bank. Its relief is similar to that of the Portlock Bank.

Albatross Bank consists essentially of three separate banks divided by two troughs. The northern-most bank of this complex is called the Marmot Bank in the AEIDC/ISEGR (1974, Figure 7) report. Most of the western Gulf lease area is located on the Albatross system. Water depths within the lease areas do not normally exceed 100 meters (328 feet). Should significant reserves be found on the northernmost bank of the Albatross group water depths of 150 meters (492 feet) or more may have to be crossed to make a pipeline landfall.

At their shoreward terminus the troughs bifurcate, finally ending in many of the deep bays that are situated along the coastlines of the Kodiak Island complex.

To the south of Kodiak Island the Aleutian Trench lies adjacent to a continually narrowing continental shelf. The bank and trough topography continues along the entire shelf off the southeastern coast of the Alaskan Peninsula. This is well south of the proposed lease sale area for the western gulf.

4.3.1.2 General Circulation and Currents

The oceanography of this area is predominately the result of large-scale oceanic circulation. In the North Pacific this circulation forms the northward and then eastward flowing Kuroshio Current. Near latitude 42″N and longitude 170°E it is joined by the Oyashio Current, which flows southward out of the Bering Sea. ‘ Together they form the Subarctic Current, which represents the northern limit of the North Pacific Gyre. As this current approaches the southeastern coast of Alaska it separates. The major portion flows southward along the west coast of Canada and the U.S. A portion also flows north, becoming the Alaska Current. This current tends to be heavily influenced by bottom topography, with trajectories that generally parallel the bottom contours. Sustained surface speeds in excess of one knot are not uncommon for this area. This is especially true of the currents that tend southwestward along the Alaska Peninsula. There they take on the form of a typical western boundary current.

The Gulf of Alaska during the winter is influenced by a rather permanent low pressure region over the Aleutian Islands. (In the summer the dominant meteorological feature is the North Pacific High.) The cyclonic motion around the low reinforces the general counterclockwise circulation in the Gulf. This pattern produces a net onshore transport of surface water, producing a zone of coastal convergence.

Circulation near shore is also affected by the presence of islands and bays as well as local freshwater inflows. NOAA has recently been studying circulation patterns within Cook Inlet and Prince William Sound. Results of these studies have not yet become available.

The Alaska Current continues on its generally westerly heading along the Aleutian Islands. Some of the transport is northward between the islands flowing into the Bering Sea. The remainder completes the Gyre and rejoins the Kuroshio and Oyashio current system to begin the trek around the Gulf once more.

Currents in the proposed lease areas can be modified by both storms and tides. Thus attention should be paid to the total current regime. A joint industry study monitored by Exxon was performed for the Gulf of Alaska Operators Committee (GAOC) in 1971. (This study was revised in 1973.) This study attempted to define extreme and operating conditions for all parameters described in that report, including currents. The investigators strongly point out the probable conservatism built into their results on ocean current-s. They indicate that 25 percent of the year surface currents will exceed one knot and that extreme surface currents may be in excess of three knots. Unfortunately, the return period associated with the extreme value was not given.

4.3.1.3 Tides

Tidal ranges in the Gulf of Alaska do not greatly exceed three meters (9.8 feet) (Searby, 1969). Tides are of the mixed type, resulting in two unequal highs and lows per day. No separate measurements of tidal currents within the open Gulf have been made.

The Gulf of Alaska Group Oceanographic Survey Technical Committee (1973) report has computed the maximum total water level rise which represents the combination of astronomical and storm tide. For a 100-year value the total rise may approach six meters (19.7 feet).

4.3.1.4 Waves

The Climatic Atlas issued by the Bureau of Land Management - OCSEAP (1 977) is a summary of much of the known environmental data on the Gulf of Alaska. Many of the parameters including wind and wave information are obtained from ship observations. The following information was compiled from this source:

- Waves equal to or exceeding 3.7 meters (12.1 feet) can be expected 40 to 50 days per year in the Western Gulf.

- Waves equaling or exceeding 6.1 meters (20 feet) can be anticipated 10 days per year in the lease area.

As pointed out, these data are ship observations. Consequently, they are not statistically reliable estimators of the annual extreme wave heights. Based on the information that follows, and more recent studies, the values presented above grossly underestimate the overall state of the sea; much more severe conditions can be anticipated during any typical year.

The GAOC (1973) report probably represents a more reliable source of data. In this study waves were hindcast from atmospheric pressure charts compiled by the U.S. Weather Bureau. A site near Middleton Island was used as a representative deepwater area, beyond the direct influence of land.

These statistics were based on six years of generated wave heights taken from the 23-year base period from 1945 to 1968. These six years were selected as they appeared to be representative of mild, average, and stormy years. The geographic sensitivity around the Gulf of Alaska was checked and spatial variations were found to be less than five percent. This is a particularly significant finding in that it means the wave climate near Middleton Island is extremely similar to that in the Western Gulf.

This study also reported that wave direction was predominantly from the south during the summer while coming from the east about 10 to 15 percent of the time. During the winter waves come from the east about 25 percent and from the south 60 percent of the time.

The GAOC study used the then best available wave forecasting model to generate the respective sea states, This model has been revised and improvements have been incorporated. Information for the general operating conditions are not available; however, an interesting comparison can be made between the two versions of the model in the area of maximum design waves. The results of this comparison can be used to speculate on the operating conditions published in the GAOC report. Augustine et al. (1 978) computed Gulf of Alaska wave statistics for the 13-year period from 1964 to 1977, using the revised wave model. They determined that extreme wave conditions there were more severe than for either the North Atlantic or the North Sea, though not as severe as some previous studies had suggested (Freeman and Gujnoch, 1976). For the area around Middleton Island they found the 100-year wave to be 35 meters (115 feet). The GAOC report, on the other hand, determined the wave with this recurrence interval to be 27 meters (90 feet). If this difference can be totally explained by recent improvement in wave forecasting techniques, then the general operating wave climate determined in the GAOC study similarly must be revised upward,

4.3.1.5 Surface Icing

Freezing spray often found in the Gulf of Alaska can produce surface icing on vessels which can seriously affect their stability (Searby, 1969). The data on this potential hazard is rather limited and, consequently, the magnitude of the problem cannot be assessed. It is known that surface icing on the deck, hull and superstructure of fishing vessels has required that they be abandoned. It is doubtful that the rigidity of fixed structures nor the stability of "semis" could be significantly altered. On the other hand, supply boat activities, and operations that require mobility on deck, such as pipelaying might be affected.

4.3.1.6 Tsunamis

A tsunami is a long, shallow-water wave that may have a length measured in kilometers and an associated height of just a few centimeters. Tsunamis generally occur as a result of seismic activity that produces large volume changes on the sea floor, They can travel thousands of kilometers with little energy attenuation. Because of the active tectonic zone that rims the North Pacific, tsunamis frequently occur in this part of the ocean. Their extreme lengths and subtle heights create a benign sea wave in deep water. However, shoaling has a pronounced effect on these high energy waves. Upon entering shallower water the length of a tsunami decreases as its height increases, concentrating its energy over a reduced wavelength. Depending on the size of the wave and the bathymetry, this energy can be destructively dissipated over a relatively short area. This wave generally appears as an extreme tide of short duration typical of those that spawned as a result of the 1964 Great Alaska Earthquake. The area with the greatest potential of sustaining damage is confined to the area immediately adjacent to the shoreline, where flooding is the primary hazard. Though potentially dangerous alone, a tsunami can be even more hazardous when superimposed upon a high astronomical tide.

In restricted bodies of water, large waves can also be generated locally by earth slumps and snowslides. These waves, because of their extreme heights and short periods, are potentially very destructive. Miller (1960) has reported such a wave as a result of a landslide following a 1958 earthquake. The report states that the wave crest topped a vertical distance of 518 meters (1,700 feet) above Lituya Bay, Alaska.

The threat of damage by tsunamis should be considered in planning shore-based facilities, drilling in shallow, restricted waters, or in making a landfall with a pipeline.

4.3.1.7 Fog

Viability is often restricted by fog. Certain sections of the Gulf of

Alaska may have fog in excess of five percent of the year. Reasonable visibility is essential for certain operations, especially those involving supply and work boats. The problem will increase during periods of active fishing within the Western Gulf of Alaska. Fog is prevalent in the North Sea especially during the fall, but data has not been found that specifically relate fog to potential hazards in the marine petroleum industry. Obviously prudent seamanship may require a reduction in vessel speed and signals indicating the presence of not only vessel underway but also of fixed and floating structures.

4.3.1.8 Environmental Restrictions

The crucial environmental parameter in practically all offshore operations is the sea state, or wave height. Sea states can have impacts that manifest in several ways. The most obvious concern is the design-wave height. This is generally the maximum wave height likely to occur during a specified period of time -- generally 50 or 100 years. Most North Sea structures are built to withstand the 100-year wave. It should be borne in mind that a sizeable margin of error, or safety factor, is necessarily built in. There is a relatively small difference between the 50- and 100-year waves. The decisions to use one or the other can depend on the expected design life of the structure, requirements for certification, and design philosophy. The last criterion is based on the amount of damage the owners are willing to accept. It is generally assumed that the design wave will not cause complete failure. The decision must also depend on the amount of confidence the company has in their simulation of wave forces for given wave conditions.

Aside from the maximum design criteria, wave conditions must also be considered for their effect on day-to-day operations. Facilities, though designed to survive certain design values, are forced to limit or even cease operating under much less hostile conditions. Obviously, profits decrease as the amount of time that key activities have to be curtailed increases. It is therefore important to know the “normal” expected conditions so that decisions regarding the type of equipment and operations can correctly be made.

A third factor directly affected by sea state is the long-term structural response. This is the fatigue life and must be considered over the design life of the structure. It is influenced by both the number and the force of waves. It becomes increasingly more important as water depth increases -- that is, as structures become more compliant. Therefore, it is also necessary to consider the anticipated wave climate for the duration of the proposed life of the structure. Ultimately, most failures occur due to this accumulative effect rather than literally being destroyed by a single wave. The effect, though so crucial in design, is difficult to assess and is not considered in the following discussion.

Fixed drilling and production platforms are either piled, steel-jacketed types or gravity structures. Operations are seldom stopped or wells shut in on either unless waves approach the design case. An added consideration in the space-frame types is the placement of the deck section. Since vertical wave slamming can cause considerable damage, there must be a sufficient air gap between the deck and water surface to bring the deck above the zone of potential damage.

Additionally, an assessment of the relative merits of these systems should include consideration of where the fabrication yard will be. Thousand mile tows, or more, are becoming fairly routine on steel-jacketed platforms, thereby obviating the requirement for local construction. Gravity platforms, on the other hand, are less stable under tow. For the 1600 kilometer plus tow from the U.S. West Coast, insurance risk may be excessive, to the extent of precluding out-of-state construction.

The North Sea experience has resulted in the development of giant semi-submersibles that can remain on station for all but the most severe conditions. Drilling suspensions due to weather would probably only be minimal. Resupplying these vessels and handling their anchors could prove to be the limiting weather factors for semi-submersibles operating in the Gulf of Alaska.

Some of the newer pipelay barges are also capable of operating in hostile seas (significant wave heights approaching six meters [19.7 feet]). This could permit pipeline construction from early April almost continuously through September. Table 4-5 summarizes the limiting wave conditions for specific offshore related operations. Currents and water depths should not hamper pipeline operations with one possible exception. Maximum tidal currents may be sufficiently strong to produce substantial scouring in certain areas around Kodiak -- especially in the inter-island straits on the southern end of the large island. Extra heavy cement coating may be required on the pipe in these areas.

There are several other production concepts which have either been tested under less hostile climatic conditions (tension-leg-platform and guyed tower) or which are still not much beyond the conceptual stage (concrete semi-submersible platforms) , There is little economic data on these systems which are designed to develop "marginal" fields or fields in water depths in excess of 183 meters (600 feet).

The environment existing in the North Sea is similar in most respects to that in the Western Gulf of Alaska. Based on what has been learned in European waters and the availability of equipment designed especially for such hostile regions, it is doubtful that environmental restrictions will severely limit operations in the Western Gulf of Alaska.

4.3.2 Geohazards

4.3.2.1 Introduction

The Gulf of Alaska is an extremely high level tectonic area which accounts for approximately seven percent of the annual worldwide release of earthquake energy. It also is the most seismically active region in the United States, apart from the Aleutian Islands. Major earthquakes that could create serious potential hazards to installations on the continental shelf or along the Gulf"of Alaska coast may occur in the future (Plafker, et al., 1978). Among these hazards are ground shaking, fault displacement, tectonic warping, and ground failure. In addition

TABLE 4-5

CRITICAL WAVE CONDITIONS FOR SELECTED OFFSHORE OPERATIONAL

Operation	Wave Heights[2] Meters	Feet
Offshore Loading		
SBM		
Mooring	‘2.4-3.7	8-12
Operating	3.7-4.3	12-14
SPAR		
Mooring	3.7-4.0	12-13
Operating	5.5-6.1	18-20
Resupplying Pipeline Barge	2.4-3.0	8-10
Resupplying Semi-drilling Vessel	2.4-3.7	8-12
Anchor Handling on Semi	2.4±	8±
Pipelaying From Semi-Type Barge	4.6	15[4]

[1] Data supplied by Shell Oil Company, 1978.
[2] Heights equal significant wave heights (maximum height is approximately 1.8 times significant),
[3] With dedicated tankers and with suspended hose.
[4] Such as SEMAC 1.

to the following discussion of seismic hazards other environmental threats will be considered in this section, as they pertain to design criteria for offshore petroleum exploration. These hazards include slumping and slope stability, gas charged sediments, liquefaction, and rapid sedimentation.

4.3.2.2 Seismicity

Earthquakes in the Gulf of Alaska region are primarily caused by sporadic slippage of the Pacific Ocean crust (Pacific Plate) as it is thrust northward towards the Aleutian Islands and Alaska Plate. Most earthquakes in the Gulf of Alaska originate at depths of less than 50 kilometers (31 miles) and the foci generally deepen towards the mainland (Plafker, Bruns, and Page, 1975). Since 1898, there have been nineteen earthquakes with a magnitude of 7.0, on the Richter scale, or larger. The most recent was in 1964 (8.5 Richter magnitude) and was the largest earthquake ever recorded. There have also been approximately 60 earthquakes in the Gulf of Alaska region with a Richter magnitude of 6.0 or greater (Plafker, Bruns, and Page, 1975) (See Table 4-6).

Earthquake reoccurrence intervals within the Gulf of Alaska vary in magnitude between a maximum average reoccurrence of about 800 years and a minimum interval of 33 years. It is therefore reasonable to assume that a major earthquake will occur within the lifetime of an oil producing installation (Von Heune et al., 1975).

An earthquake results in energy, in the form of seismic waves, traveling through the earth's crust, away from the source (focus). Part of this energy is transmitted to structures through the soil/foundation contact. As earthquake ground motion (intensity) increases, the amount of energy transmitted to a structure is restricted by the ability of foundation elements and soils to transmit energy to the structure. This is in contrast to wave current action which increases the amount of transmitted load unlimitedly. The potential force effects developed by severe ground motion on platforms are very different from those caused by intense wave and current action. The potential effects of an earth-

TABLE 4-6

Earthquakes In and Near the Gulf of Alaska Tertiary Province.
Alaska, 1899 Through 1973.

[Includes earthquakes of magnitudes 6.0 or greater whose epicenters 1 ie between 55" and 62° North latitude and between 136" and 154° West long itude.]

Day	Date Month	Year	Origin Time Hr/Mi n GMT	Latitude (Degrees N)	Longitude (Degrees 'W)	Depth (Kilometers)	
4	09	99	22	60.00	142.00	0	8.30
10	09	99	1704	60.00	140.00	0	7.80
10	09	99	2140	60.00	140.00	0	8.60
9	10	00	1228	60.00	142.00	25	8.30
15	05	08	831	59.00	141.00	0	7.00
19	09	09	2100	60.00	150.00	0	7.40
22	09	11	501	60.50	149.00	60	6.90
31	01	12	2011	61.00	147.50	80	7.25
7	06	12	955	59.00	153.00	0	6.40
10	06	12	1606	59.00	153.00	0	7.00
5	12	12	1227	57.50	154.00	90	7.00
7	07	20	1841	61.00	140.00	0	6.00
24	10	27	1559	57.50	137.00	0	7.10
21	06	28	1627	60.00	146.50	0	7.00
24	12	31	340	60.00	152.00	100	6.25
14	09	32	843	61.00	148.00	50	6.25
4	01	33	359	61.00	148.00	0	6.25
27	04	33	236	61.25	150.75	0	7.00
13	06	33	2219	61.00	151.00	0	6.25
19	06	33	1847	61.25	150.50	0	6.00
4	05	34	436	61.25	147.50	80	7.20
14	05	34	2212	57.75	152.25	60	6.50
2	06	34	1645	61.25	147.00	0	6.25
18	06	34	913	60.50	151.00	80	6.75
2	08	34	713	61.50	147.50	0	6.00
11	10	40	753	59.50	152.00	0	6.00
1	04	41	1040	56.00	153.50	0	6.50
30	07	41	151	61.00	151.00	0	6.25
5	12	42	1428	59.50	152.00	100	6.50
3	11	'43	1432	61.75	151.00	0	7.30
3	02	44	1214	60.50	137.50	0	6.50
3	11	45	2209	58.50	151.00	50	6.75
12	01	46	2025	59.25	147.25	50	7.20
27	09	49	1530	59.75	149.00	50	7.10
31	10	49	139	56.00	136.00		6.25
25	06	51	1612	61.10	150.10	12:	6.25
9	03	52	2000	59.50	136.00	0	6.00
29	11	52	2346	56.30	153.80	0	6.90
15	06	53	1747	56.30	153.80	0	6.50
3	10	54	1118	60.50	151.00	100	6.70
19	07	55	2352	56.50	153.00	0	6.00
26	07	55	404	56.50	153.00	0	6.00
27	07	55	1819	56.50	153.00	0	6.25
10	04	57	1130	55.96	153.86	0	7.10
24	01	58	2317	60.00	152.00	60	6.38
10	07	58	615	58.36	136.34	0	7.90
24	09	58	344	59.50	143.50	0	6.25
19	04	59	1503	58.00	152.50	0	6.25
26	12	59	1819	59.74	151.38	0	6.25
1	09	60	1537	56.30	153.70	24	6.13
20	01	61	1709	56.60	152.30	46	6.38
31	01	61	48	56.00	153.90	26	6.38
10	05	62	3	62.00	150.10	72	6.00
12	05	63	2008	57.30	154.00	60	6.10
24	06	63	426	59.50	151.70	52	6.80
28	03	64	336	61.00	147.80	33	8.50
28	03	64	454	59.80	149.40	25	6.10
28	03	64	643	58.30	151.30	25	6.10
28	03	64	710	58.80	149.50	20	6.10
28	03	64	901	56.50	152.00	20	6.00
28	03	64	1035	57.20	152.40	33	6.10
28	03	64	1220	56.50	154.00	25	6.10
28	03	64	1447	60.40	146.50	10	6.10
28	03	64	1449	60.40	147.10	10	6.10
28	03	64	2029	59.80	148.70	40	6.60
30	03	64	709	59.90	145.70	15	6.00
3	04	64	2233	61.60	147.60	40	6.20
20	04	64	1156	61.40	147.30	30	6.60
21	04	64	501	61.50	147.40	40	6.00
4	09	65	1432	58.20	152.70	10	6.20
22	12	65	1941	58.40	153.10	51	6.50
23	04	68	2029	58.70	150.00	23	6.30
15	11	68	7	58.33	150.37	26	6.38
17	12	68	1202	60.17	152.84	86	6.50
24	11	69	2251	56.20	153.56	33	6.00
16	01	70	805	60.31	152.72	91	6.00
11	03	70	2238	57.46	153.92	29	6.50
11	04	70	405	59.71	142.74	7	6.20
16	04	70	533	59.77	142.60	7	6.80
19	04	70	115	59.64	142.83	20	6.00
18	08	70	1752	60.70	145.38	16	6.00
1	07	73	1333	57.84	137.33	33	6.70
3	07	73	1659	57.98	138.02	33	6.40

Primary Sources of Oata:

1. Table 2 in Seismicity of Alaska, in Wood, F. J., cd. , 1966, Operational phases of the Coast and Geodetic Survey program in Alaska for the period March 27 to December 31, 1964, v. 1 of the Prince Wi 11 i am Sound, Alaska, earthquake of 1964 and aftershocks; U.S. Coast and Geodetic Survey, 236 p.

2. [u. S.] National Oceanic and Atmospheric Administration, Earthquake data file, 1900-1973, National Oceanic and Atmospheric Administration Environmental Oata Service.

Source: Plafker, Bruns, and Page, 1975.

quake on a platform or structure depends greatly on the particular characteristics of the structure elements and the local soils that act to convey energy to the structure (Bea, 1978). Without detailed soils data, effects on platforms placed within the Western Gulf of Alaska area are impossible to predict.

Damage sustained on Kodiak Island, due to direct shaking during the 1964 earthquake was relatively minimal because Kodiak Island is predominantly underlain by competent bedrock. However, Kodiak (seaward side) did sustain extensive damage from a tsunami generated by the earthquake. The 1964 earthquake and resulting tsunamis resulted in 114 people killed and over $300 million of damage throughout the Gulf of Alaska region (Plafker, Bruns, and Page, 1975; Von Huene et al., 1976).

Damage to a platform drilling on the Western Gulf of Alaska OCS, due to seismicity, is likely to be greatest in areas underlain by thick accumulations of saturated unconsolidated sediments. Therefore, design criteria will vary according to, among other things, bottom type.

4.3.2.3 Faulting and Tectonic Deformation

Relatively minimal data is available pertaining to fault systems in the Western Gulf of Alaska. An active fault zone offshore does exist along a zone from Montague Island to the Kodiak Island group, and extends southeast along the coast of Kodiak Island. Tectonic deformation occurs along lines of weak strata often associated with a fault zone, and much of the shelf area southeast of Kodiak Island is believed to be highly deformed.

Large-scale vertical movements and displacement of land, relative to sea level, are known to have occurred during at least three major earthquakes in the Gulf of Alaska. The 1899 earthquake located near Yakutat Bay caused complex patterns of tectonic warping and tilting over an area of about 1,500 square kilometers (580 square miles). A right lateral slip of up to seven meters (23 feet) on the Fairweather fault in the northeastern Gulf of Alaska is attributed to the 1958 Lituya Bay earthquake. The 1964 Prince William Sound earthquake caused dip-slip displacement of 20 meters (66 feet) or more on a segment of the Aleutian Arc mega thrust system of at least 800 kilometers (500 miles). Major deformation affected a minimum area of 200,000 square kilometers (77,000 square miles) (Plafker et al., 1978). Surface deformation in the Gulf of Alaska region caused landward tilting. The maximum uplift was about 15 meters (49.2 feet) and maximum subsidence of about 2.5 meters (8.2 feet). It is assumed that this indicates the probable magnitude of vertical displacement that could accompany a major event (Plafker, Bruns, and Page, 1975).

Tectonic deformation can produce various problems to offshore petroleum exploration. Tectonic uplift can elevate docks and processing facilities above water to an undesirable and/or non-workable position. Uplift can cause navigation channels to become unsafe or require recharting or dredging. On the other hand, subsidence can deepen channels and improve navigation. An example of the latter is Pamplona Ridge in the Northeast Gulf of Alaska. According to historic navigation logs and journals from around 1779, Pamplona Ridge was charted as a dangerous rocky shoal 10 leagues (5.2 kilometers [3.2 nautical miles]) off the Alaskan Coast. There are several reports that tend to verify the existence of Pamplona Shoal . However, recent coast and geodetic surveys in the area show no rock mass protruding from the water, in fact seismic profiles show a searidge, assumed to be Pamplona Ridge, some 122 meters (400 feet) below sea level. It is unlikely that such a change in elevation could have occurred in a short period of time. The foundering probably occurred gradually, perhaps in connection with events such as tremors and earthquakes in 1788, the eruption of Mt. Wrangell in 1819, and the earthquakes of 1847 in the Gulf of Alaska and 1899 in Yakutat Bay (Jordan, 1958). It is possible that fault displacement and/or tectonic deformation could cause damage to offshore production platforms. Damage to a platform placed on a fault could be extensive if movement occurred along the fault.

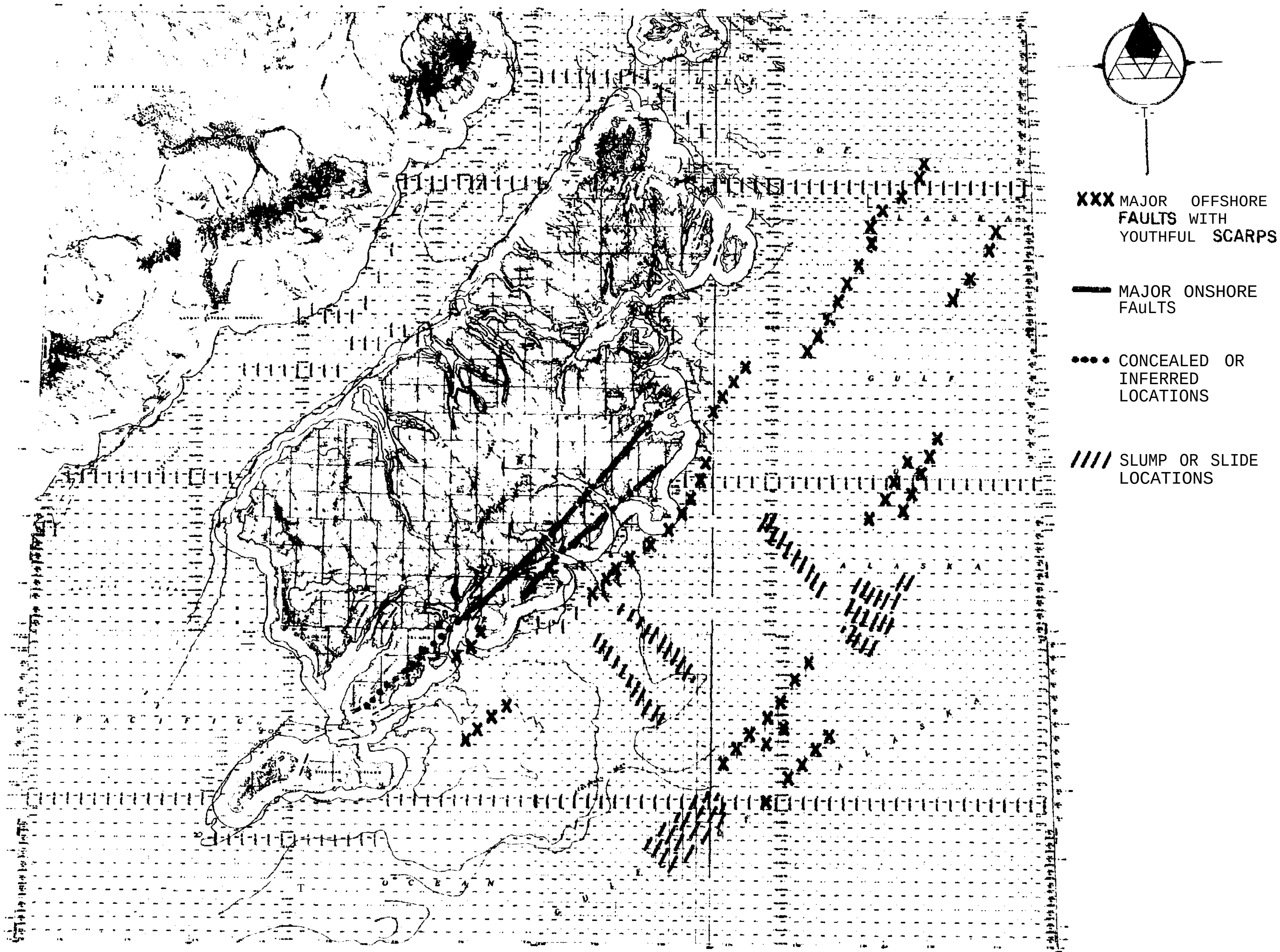

XXX MAJOR OFFSHORE FAULTS WITH YOUTHFUL SCARPS
MAJOR ONSHORE FAULTS
CONCEALED OR INFERRED LOCATIONS
//// SLUMP OR SLIDE LOCATIONS
G U L F
A L A S K A
P A C I F I C
O C E A N
KILOMETERS

FIGURE 4 - 1

4.3.2.4 Submarine Slides and Slumps

The uppermost continental slope, off Kodiak Island, from Southern Albatross Bank to Portlock Bank includes two broad areas where slides and slumps have occurred. Within this area there is evidence for active near surface folding which results in slope steepening. (See Figure 4-l).

Submarine slope failure is characterized as being much larger and occurring on flatter slopes than sub-aerial slides. Some slides and slumps within the Gulf of Alaska extend more than 90 kilometers (56 miles) over areas of up to 1,080 square meters (417 square miles) and show offsets on headwall scarps of 5 to 20 meters (16 to 66 feet) (Plafker et al., 1978).

Evidence of slide and slumps show as disrupted sediments and irregular topography on seismic profiles. Bottom samples of slump sediment consist of low strength, poorly sorted clayey silt." Some slump blocks show progressive failure caused by lateral extension or stretching of sedimentary units at the base of slump blocks, possibly caused by intense ground shaking from the 1964 or other earthquakes.

Potential slide or slump zones can be delineated on the basis of thickness of Holocene sediments (greater than 82 meters [25 meters]), relative slope steepness (one degree to eight degrees) and pore pressure. S1 ides occur in regions with high rates of sedimentation where the lag between accumulation and consolidation causes excess pore pressure. Triggering events include major storms (wave loading) and major seismic accelerations is important in depths of less than 150 meters (492 feet) (Hampton, Bouma, and Carlson, 1978).

There are four major slide locations within the western gulf area and these all lie seaward of the proposed lease area. However, slumping within the Western Gulf of Alaska area is possible along the steeply sloping margins of sea valleys, especially where unusual thicknesses of fine-grained sediments have accumulated. Damage to offshore structures and pipelines due to slumping or sliding sediments could be extensive.

Thus areas where sediments could possibly slump or slide should be avoided.

4.3.2.5 Ground Failure and Liquefaction

Another hazard which is associated with areas underlain by unconsolidated sediments is ground failure and/or lateral spreading of sediments without actually sliding, resulting in subsidence. This increases the likelihood of extensive flooding along coastal areas. With increased offshore petroleum exploration many deltas along the Gulf of Alaska coast may be potential sites for construction of processing facilities because they are usually the only extensive flat ground available (water depths in such areas, however, may be inadequate for ocean-going shipping). However, many of these deltas are prone to earthquake induced liquefaction and sliding due to their loose, water saturated sandy soils (Plafker, Bruns, and Page,. 1975).

Liquefaction and resulting ground failure is caused by the compaction of granular soils when they are subjected to vibrations. This leads to increased pore water pressure and a loss in soil shear strength. Liquefaction may cause: a loss of lateral support by foundation soils; excessive lateral movement of a structure; large vertical subsidence and/or tilting or overturning of structures (Kallaby, 1978).

Western Gulf of Alaska offshore shelf sediments are not likely to liquefy because they have been normally consolidated as a result of slow deposition and reworking by currents. This compares with the Copper River prodelta area in the Northern Gulf of Alaska, where sediments are deposited faster than they can consolidate into stable soils. However, subsidence and/or consolidation of sediments on a small scale caused the closing of a cannery site at Shearwater on Kodiak Island. Extensive damage could result from ground failure (subsidence) and/or liquefaction. Flooding and structural damage to onshore facilities (LNG plants, service bases, etc.) 'could occur. Damage to offshore structures as a result of ground failure is also possible.

4.3.2.6 Volcanic Hazards

The Western Gulf of Alaska region contains 17 volcanoes which have been active within the past 10,000 years; eight of these have been active since 1700 A.D.

Volcanoes are located along the entire northwest side of Cook Inlet, Alaska Peninsula and Aleutian Island system (see Figure 4-2).

Any of the 17 volcanoes could be active in the future. They usually eject pyroclastic material ranging in size from dust to clasts a few meters in diameters. Ash has been deposited more than 150 kilometers (93 miles) away. The primary damage would be caused from ash falls.

4.3.2.7 Other Hazards

Other hazards possible within the Western Gulf of Alaska area include: (a) rapid sedimentation or scour in the deltas of major streams which can cause burial or damage to structures on the sea floor, especially pipelines; and (b) gas charged sediments which present hazards to drilling operations (however there is little evidence to support the latter, due to lack of data).

4.3.2.8 Summary

The geologic hazards prevalent with the Western Gulf of Alaska area may have direct impacts on OCS petroleum activities. However, it is unlikely that these activities will be seriously jeopardized. Seismicity could potentially halt drilling operations and cause extensive damage to pipelines and onshore facilities. However, the likelihood of an earthquake with a large enough magnitude to cause such damage is relatively small. For technical papers on seismic design considerations for offshore platforms the reader is referred to Idriss, Dobry and Power, 1977 (Soil Response Considerations), Sharpe, 1977 (Earthquake Considerations - Genera?), Watt, Boaz, and Dowrick, 1978 (Response of Concrete Platforms),

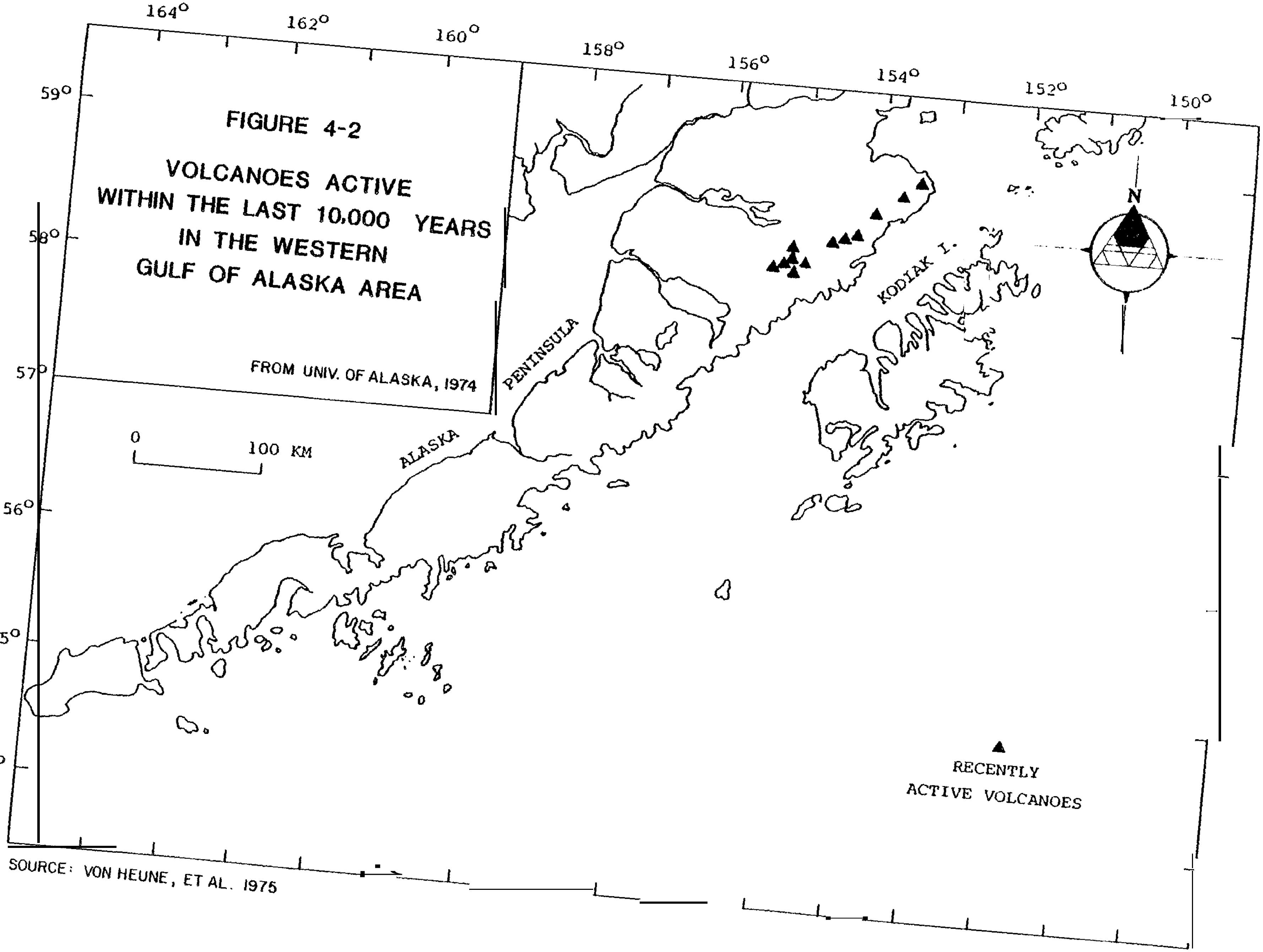


FIGURE 4-2

VOLCANOES ACTIVE WITHIN THE LAST 10,000 YEARS IN THE WESTERN GULF OF ALASKA AREA

FROM UNIV. OF ALASKA, 1974

SOURCE: VON HEUNE, ET AL. 1975

Bea, 1976 and 1978 (Earthquake Design Criteria - Gulf of Alaska), and Arnold et al., 1977 (Soil-Pile-Structure Systems).

Faulting and tectonic deformation on a small scale, is a very real possibility. However, faulting and deformation on the order of the "assumed" Pamplona Ridge foundering are highly unlikely.

Submarine slides and slumps are potentially one of the most serious hazards for offshore facilities. However, thorough investigations including seismic profiling and bottom soil investigations can define this hazard. In some areas of the Gulf of Alaska unstable soils predominate, therefore the potential for slumps and slides is much greater (e.g. the Copper River Prodelta area). However, offshore activities within the Western Gulf of Alaska are not as likely to be affected by slumping sediments since the available data indicates large areas of reworked sediments and glacial deposits, normally consolidated to over consolidated, less susceptible to instability. For the same reason bottom sediments in the Western Gulf of Alaska may not be as susceptible to liquefaction. This is not to say the hazard does not exist, but the potential for damage to facilities is less. Liquefaction is is much more important and potentially severe hazard onshore at the mouths of streams and will play an important role in onshore facility site selection. Table 4-7 summarizes the relatively magnitude of several geologic hazards on various onshore and offshore petroleum exploration and production facilities for the Western Gulf of Alaska.

4.3.3 Biology

Detailed discussions of biological background information and potential impacts of petroleum development can be found in a number of existing documents (U.S. Department of Interior, 1977; and Outer Continental Shelf Environmental Assessment Program series). This study is primarily interested in those environmental factors that could effect specific constraints to petroleum development and, therefore, must be taken into consideration when planning such development. In most cases constraints will be imposed by site specific environmentally sensitive areas rather

TABLE 4-7

RELATIVE MAGNITUDE OF DAMAGE

Facility \ Hazard	Ground Shaking	Fault Displacement & Tectonic Deformation	Slumping & Sliding	Gas Charged Sediments	Liquefaction & Ground Failure	Sedimentatio or Scour
Concrete Platform (gravity platform)	4	5	5	2	5	3
Steel Platform	2	5	5	2	5	4
Jack-Up Rig	4	4	4	3	5	2
Semi-submersible	1	2	1	3	1	1
Offshore Pipelines	2	5	5	1	4	5
Service Bases	2	5	5	N/A	5	N/A
LNG Facilities Storage and Pumping Stations	4	5	5	N/A	5	N/A

Scale: Less -- 1-2-3-4-5 -- Most

Note: These figures do not represent the likelihood of occurrence of any particular hazard.

Source: Dames & Moore

than diffuse resources such as high seas fisheries. Such diffuse resources may be important, but, assuming that development is to occur, it is not likely that activities will be restricted over a large and poorly defined area. The following discussion of bio-environmental factors that could impose constraints on offshore discussion is an overview of the kinds of factors that are likely to influence the planning process.

4.3.3.1 Ecologically Sensitive Areas

Some kinds of animals tend to concentrate in relatively small areas during the least part of their life cycle and are, therefore, highly vulnerable at that location. Some'of the more significant of these areas are as follows:

- Harbor seal and sea lion breeding rookeries and hauling areas Recent research has identified most of the critical sites (Science Applications, Inc. , 1978). Constraints on development could be applied if proposed activities were too close to hauling areas or if the probability of spilled oil reaching a site were too high. Marine mammals are very abundant around the Kodiak Archipelago. Breeding rookeries and hauling grounds are scattered along the coastline.

- Sea otter concentrations - Sea otter concentrations are not necessarily confined to small areas. However, these animals are considered to be the most sensitive of the marine mammals to oil pollution (Schneider, 1976) and areas that provide good sea otter habitat may be protected from some kinds of development. High density sea otter populations currently exist at the north and south ends of the Kodiak Archipelago.

- Seabird nesting colonies - Recent research has identified the locations of most major and minor colonies in the Western Gulf (Science Applicatons, Inc., 1978). Usually the colonies are on cliffs or rugged terrain and are not likely to conflict directly with siting of onshore facilities; however, constraints could be applied if activity associated with development was planned to occur in close proximity to a colony or if the probability of spilled oil reaching the colony vicinity was high.

- Salmon spawning sites - The Alaska Department of Fish and Game has identified anadromous fish streams that empty into the Gulf of Alaska (ADF&G, 1975). In some cases salmon spawn intertidally at stream mouths and are vulnerable to oil pollution. Both intertidal and instream salmon spawning could affect the siting of facilities and transportation corridors. Brown and black bear concentrations are also often associated with salmon spawning streams.

Another kind of ecologically sensitive area is represented by regions that contribute a disproportionate amount to the overall productivity of the gulf ecosystem and/or regions that provide critical habitat for important species:

- Kelp beds - Kelp and its associated biological assemblage are found on highly productive rocky intertidal and subtidal areas. There is evidence (Dames & Moore, 1977; and Zimmerman et al, 1977) that the export of organic matter from these communities plays an important role in sustaining the productivity of other areas where primary productivity (green plant growth) is low. Also, kelp beds are important habitat for sea otters and for some stages in the life history of commercially valuable fish and shellfish. Kelp beds have been mapped for the Gulf of Alaska (Zimmerman and Merrell, 1976). It is possible that the siting of shore facilities or offshore platforms may have to consider these productive areas.

- Eelgrass beds - Shallow areas with dense eelgrass growth are known to be productive ecosystems and may contribute organic matter to areas outside the bed. Eelgrass is usually located in protected bays and is susceptible to oil pollution.

- Estuaries and bay - Estuaries, bays, and fjords are often biologically important and, if a variety of ecological values are known to be present, may have to be considered in planning petroleum development. Some of the bays on the east coast of Kodiak are sensitive in this regard.

- King crab critical habitat - Waters off the southern and northeastern coast of Kodiak have been designated by the Alaska Department of Fish and Game as vital king crab rearing habitat (ADF&G, 1976). Because of the economic value of this resource, constraints could be imposed to protect these areas.

- Razor clam habitat areas - Razor clams are an important recreational and commercial resource. The sandy beach habitat type favored by clams is limited and, therefore, known clam flats are likely to be protected from potential encroachment.

- Marine mammal migration routes - The gray whale, an endangered species, makes yearly migrations through the Gulf of Alaska, apparently traveling close to shore (Fiscus et al., 1976). Constraints may be applied to activities that could interfere with the migration.

- Coral beds - Commercially valuable coral beds are located off Kodiak Island. Oil platforms, underwater pipelines, and various anchored facilities could damage this resource.

4.3.3.2 Commercial Fishing

Some potential constraints relating to protection of fish and shellfish stocks were mentioned in the previous section. As the life histories of commercial species become better known, additional sensitive areas are likely to be defined and appropriate constraints applied. The ecological sensitivity of the southeastern coast of the Kodiak Archipelago combined with the economic sensitivity of the fishing industry suggests that petroleum development will be particularly closely watched in the western gulf.

Experience in the North Sea (University of Aberdeen, 1978) and elsewhere indicates that the greatest conflicts between the petroleum industry and the fishing industry are related to interference with the ability of fishermen to fish effectively. One aspect of this interference relates to loss of access to fishing grounds; however, the large area involved, along with economic limitations on maximum numbers of drilling platforms, suggests that this should not be a serious problem in the Gulf of Alaska. Of perhaps greater importance are possible gear entanglement problems due to underwater pipelines, buoys, and industrial debris on the ocean bottom. Enforcement of existing regulations as well as initiation of new regulations may be imposed on the petroleum industry to minimize these problems.

4.3.3.3 Sport Fishing and Hunting

Significant sport fishing activity is limited to bay adjoining population centers (Resurrection Bay, Kachemak Bay, Chimiak Bay). The primary impact on the fishery, aside from potential oil spills, will probably result from increased marine traffic near harbor areas. Traffic zoning could be instituted in selected areas.

In most cases terrestrial game animal populations are not sufficiently concentrated to impose constraints on oil development. A possible exception concerns brown bear concentration and vital habitat areas on Kodiak Island. Kodiak brown bears constitute an important resource from both hunting and ecological standpoints. Constraints could be imposed on the siting of onshore facilities if impact on bears were suspected.

4.3.3.4 Subsistence Hunting and Fishing

Subsistence hunting and fishing as a total life-style is unusual in the Gulf of Alaska, although there are many natives and non-natives that depend, to some degree, on fish and wildlife resources for subsistence. In most cases the values of particular resources are not strictly limited to subsistence but are combined with other uses. It is possible that local areas traditionally exploited for subsistence hunting or fishing could be protected from development.

4.3.3.5 Lands Classified for Protection of Natural Values

Currently in the Western Gulf some of the coastline is bordered by the Chugach National Forest. Any proposed shoreline development in this area would have to be coordinated with the National Forest land use plans. The Kodiak National Wildlife Refuge may also have to be considered in planning petroleum development. In addition, the state-implemented Coastal Zone Management Program has land use planning authority and development will need to be coordinated with this agency.

Final congressional resolution of Section 17(d)(2) of the, Alaska Native Claims Settlement Act has been delayed until 1979. One proposal under this act includes the establishment of classifications for federal land bordering the Western Gulf of Alaska as follows:

Alaska Coastal Wildlife Refuge - Barren Islands
Kenai Fjords National Monument

Some or all of these proposed land classifications are likely to be included in the final D-2 legislation. Petroleum development in the vicinity of these land areas is likely to be restricted if the legislation is enacted.

4.3.4 Environmental Regulations

The U.S. Department of Interior, as administrator of outer continental shelf mineral resources, is mandated to protect marine and coastal environments via a number of legislative acts including: National Environmental Policy Act of 1969, Coastal Zone Management Act of 1972, Estuary Protection Act of 1973, Fish and Wildlife Coordination Act, and others. These various acts require that environmental impact be considered in the planning and decision-making process relating to development of petroleum resources. Therefore, a coordinated industrial-governmental multidisciplinary effort will be involved in the evaluation of any proposed development activity. In addition to the general planning requirements, specific regulations relating to offshore procedures are presented in the Outer Continental Shelf Lands Act (as amended in September 1978), titles 30 and 43 of the Code of Federal Regulations, U.S.G.S. OCS operating Orders for the Gulf of Alaska, Stipulations required to mitigate impacts, and the Environmental Protection Agency regulations pertaining to offshore oil and gas extraction. Some of the specific environmental regulations that could affect the course of development by restricting activities or making certain procedures impractical include:

- EPA discharge standards for production waters and other by-products of the drilling operation will affect the design of facilites and may affect the practicality of procedures such as offshore loading of oil.

- Stipulations require that areas of historical or archeological importance be protected.

- Stipulations require that facilities (including pipelines) not interfere with commercial fishing, marine mammals, or bird rookeries.

It should be noted that Federa? regulations governing OCS activities are incomplete and in a process of evolution. The OCS Orders for the Gulf of Alaska will probably be replaced by a new set of National Orders. Also, implementation of the Marine Sanctuaries Act could affect petroleum development by increasing restrictions or requiring a more exhaustive planning effort. The area surrounding Kodiak Island has been nominated for inclusion in the sanctuary system.

In addition to those regulations that pertain specifically to OCS petroleum development, there are numerous general regulations and permit requirements that may apply to various aspects of onshore and offshore development. These are listed on Table 4-8.

TABLE 4-8

PERMITS AND REGULATIONS CONCERNING GULF OF ALASKA PETROLEUM DEVELOPMENT

AGENCY	PERMIT/ACTIVITY	AUTHORITY
STATE OF ALASKA		
Department of Natural Resources	Oil and Gas Leases	Alaska Statute 38.05.180
	Pipeline Rights-of-Way	Alaska Right-of-Way Leasing Act
	Gravel Permits and Sales	Alaska Statute 38.05
	Water Use Permits	Alaska Water Use Act; Alaska Statute 46.15.010
Department of Fish & Game	Water Use Permits	Fish & Game Act of 19$9; Alaska Statute 16.05.870
	Hydraulic Permits	Fish & Game Act of 19S9; Alaska Statute 16.05870
	Authority to Remove Nuisance Wildlife	Fish & Game Act of 1959; Alaska Statute 16.05.870
Department of Environmental Conservation	Water Quality Standards	Alaska Water Quality Standards 1973
	Ballast Water Discharge Permit	Alaska Statute 46.03.750
	Surface Oiling Permit	Alaska Statute 46.03 .0S0
	Solid Waste Management Permit	Alaska Statute 46.03.050
	Air Quality Standards	Alaska Statute 46.03.050
	Burning Permit	Alaska Statute 46.03.050
FEDERAL GOVERNMENT		
Army Corps of Engineers	Permit to Work in Navigable Waters	Refuse Act; Rivers & Harbors Act 1899, Title 33 Code of Federal Regulations Part 209
	Permit to Discharge into Nav. Waters	Water Quality improvement Act 1972; Title 33 [ode of Federal Regulations Part 209
U.S. Coast Guard	Bridge Permits-Navigable Waters	Title 33 Code of Federal Regulations Part 114
Bureau of Land Management	Protection of Critical Habitat	Federal Land Policy Management Act 1976
	Special Use Permits:	
	Gravel Mining	Title 43 Code of Federal Regulations, Part 2920
	Construction Camps	Title 43 Code of Federal Regulations, Part 2920
	Timber Disposal	Title 43 Code of Federal Regulations, Part 5400
	Communication Sites & Right-of-Way	Title 43 Code of Federal Regulations, Part 2920
	Construction Disposal Areas	Title 43 Code of Federal Regulations, part 2920
	Gravel Disposal	Title 43 Code of Federal Regulations, Part 3610
	Airport Leases	Title 43 Code of Federal Regulations, Part 2911
	Oil and Gas Leases	Mineral Leasing Act of 1920 and Revisions
	Right-of-Way Permits	Federal Land Policy and Management Act 1976
	Off-Road-Vehicle Permits	Sikes Act
Environmental Protection Agency	Wastewater Discharge Permit	Water Pollution Control Act 1972
	Oil Pollution Prevention	Water Pollution Control Act 1972
	Control Oil Spill Clean-up	Water Pollution Control Act 1972
Fish & Wildlife Service	Protection of Fish, Wildlife & Habitat	Fish & Wildlife Coordination Act 1973
	Outer Continental Shelf Development	Fish & Wildlife Coordination Act 1973
	Estuary Protection	Estuarine Study Act of 1968
	Special Use Permits -- Wildlife Ranges and Refuges	Title 50 Code of Federal Regulations
	Marine Mammal Protection	Marine Mammal Protection Act 1972 (Polar Bear, Walrus, Sea Otter)
	Endangered Species Protection	Endangered Species Act 19?3
	Eagle Protection	Eagle Act of 1972
	Waterfowl Protection	Migratory Bird Treaty Act
National Marine Fishery Service	Protection of Anadromous Fish Habitat	Fish & Wildlife Coordination Act 1973
	Marine Mammal Protection	Marine Mammal Protection Act 1972 (Whales and Seals)
	Outer Continental Shelf Development	Fish & Wildlife Coordination Act 1973
Department of Transportation	Pipeline Safety & Valve Locations at Stream Crossings	Title 49 Code of Federal Regulations, Part 195

Source: Dames & Moore

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4.4 Production System Selection

This section briefly reviews some of the principal criteria influencing an operator's selection of a field development plan. In particular, the major considerations relating to the feasibility of two competing transport systems -- offshore loading vs. pipelines -- are discussed. Secondly, the production systems and related platforms described in this chapter are summarized and the selection of production systems for costing and economic evaluation is explained.

A number of factors influence an operator's decision on the production/transportation strategy 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.

4.4.1 Field Size

An economic analysis (such as this study) will define the necessary reserve size thresholds to justify production under a number of alternate production systems including pipeline vs. offshore loading transportation plan. 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.

4.4.2 Reservior and Production Characteristics

Reservoir and production characteristics are a major determinant of transportation requirements (pipeline capacity, storage requirements) and platform equipment requirements. (For a discussion of reservoir evaluation and field development planning the reader is referred to a paper by Kingston (1975) on the North Sea Brent field.) The plan will identify the optimal platform requirements, identify and schedule the development well program, gas and water reinfection wells and rates, and platform equipment processing requirements which are, in part, determined by the transportation option selected.

4.4.3 Quality and Physical Properties of Oil and Gas

The transportation system (pipeline or tanker) will dictate crude specifications for delivery to the selected transportation system. Important crude properties to be considered in the design of a transportation system (pipeline and/or tanker) include:

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

- Salt water -- some salt water may still be present in the crude oil after treatment on the platform. Some corrosion in pipes and particularly in storage tanks may result from the presence of salt in the crude. The principal problem of salt water is economic (Allcock, 1978a). Not only is it costly to separate the water from oil, it is even more difficult 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, although removal of the water onshore may be less expensive than offshore.

- Sulphur -- sulphur or hydrogen sulphide is a contaminant in the crude which, if left in the crude, can cause rapid deterioration in the properties of steel with resultant damage to pipelines.

These and other factors influence pipeline and processing equipment design. There are obvious 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.

For offshore tanker loading the vapor pressure of the crude must be limited to the range of 8 to 14 pounds RVP (Reid Vapor Pressure) since tankers can only carry oil with a limited vapor pressure (Penick and Thrasher, 1977a,b). Condensates have to be removed and reinfected into the reservoir 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.

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.

4.4.4 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 4-9, 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, as discussed below, the ultimate destination of the crude and the number of terminal handlings are also important considerations.

Potential discovery sites in the Gulf of Alaska within the study area all lie within 81 kilometers (50 miles) of the closest landfall although lack of suitable deep water terminal sites may necessitate longer pipelines than those dictated by the shortest distance to shore. These factors may provide additional impetus to selection of an offshore loading system in some locations.

TABLE 4-9

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 pipelength.	Cost per barrel similar for all locations, increases slightly with water depth.

Source: Allcock, 1978b.

4.4.5 Meteorologic Conditions

The most important contrast between pipeline transport and offshore loading of oil is the constraints placed on the latter by weather which does not affect the operation of pipelines. Offshore loading of oil onto tankers in the Gulf of Alaska, like the North Sea, will be restricted by weather conditions. There is insufficient meteorologic sea state data for the Gulf of Alaska to accurately estimate the amount of weather related downtime when tankers cannot load. In the North Sea, total downtime, including weather, of offshore loading production systems ranges from 20 to 30 percent.(1) As indicated in Section 4.3.1.6, tankers can remain on station in seas up to 8 meters (25 feet). Without storage capability an offshore loading production system experiences a significant (economic) loss of production. Furthermore, some reservoirs may be damaged and production potential limited by such stop-go production. Therefore, the operator has to compare the economic benefits of storage vs. the additional investment costs of storage facilities.(2) Design of offshore storage facilities has to match production rates, the storage volumes, frequency and size of tankers and expected weather and maintenance (of the SPM) downtime. Furthermore, the storage and loading system must allow for very high pumping rates when a tanker is available to load.

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(1) In this study, a conservative production capability of 65 percent of annual capacity has been assumed in the economic analysis of offshore loading systems with no storage. This figure is slightly less than that recorded for the North Sea's Argyll and Montrose fields which are located in the central North Sea where somewhat more favorable weather conditions than the northern North Sea or Gulf of Alaska occur.

(2) To date only concrete platforms have provided sufficient storage capability to permit maximum production rates to be sustained; storage capacities range from 800,000 to 1,000,000 barrels (Table 4-2). Shell/Esso's Brent storage buoy, an interim production and back-up storage facility, has 300,000 bbl of storage but is not intended to handle peak production since the Brent field will produce into a pipeline.

4.4.6 Destination of the Crude

In the Gulf of Alaska most, if not all, the crude will be exported to the lower 48 states. Some oil may be destined for refining in Alaska (e.g. Upper Cook Inlet) but that will also be shipped by tanker due to the lack of onshore transportation facilities. Onshore pipeline terminals will serve, therefore, as transshipment facilities. Depending on the type of crude produced, the terminal will complete stabilization of the crude, recover liquid petroleum gas (LPG), treat tanker ballast, provide storage for about ten days production and have loading jetties for crude and LPG tankers. The cost of the terminal will be borne by the offshore field(s) it serves.

Offshore loading of crude dispenses with the need (and expense) of a shore terminal since tankers can load direct to refineries in the lower 48. However, valuable condensates have to be reinfected and not able to generate revenue. Other factors being equal offshore loading is favored by isolation from markets and onshore facilities.

In the North Sea, where a majority of the fields are located over 80 miles from shore, two major oil terminals have been constructed north of the United Kingdom mainland -- Flotta in the Orkney islands (500,000 bpd capacity) and Sullom Voe in the Shetland islands (1,200,000 bpd, phase I capacity). The Flotta terminal lies at the terminus of a 217 kilometers (135 mile), 30-inch pipeline from the Piper and Claymore fields (combined reserves of nearly one billion barrels); Sullom Voe is the terminus for two 36-inch pipelines serving a cluster of fields from 139 to 1.61 kilometers (80 to 100 miles) northeast of the Shetlands, collectively referred to as the Brent and Ninian systems. In contrast, the North Sea's largest field, Statfjord (estimated reserves 3.8 billion barrels), will initially be produced by offshore loading pending a final decision on construction of a pipeline traversing the 305 meter (1,000 feet) deep Norwegian trench to link the field with a terminal at Sotra in Norway. Critics of this exceedingly expensive project argue that since the oil will be transshipped from the terminal to refineries elsewhere in western Europe, the pipeline and terminal cannot be economically justified since crude could just as well be produced directly to tankers and shipped directly to west European refineries as the interim production plans specify. (Oil and Gas Journal, August 28, 1978, p. 100)

All the North Sea fields with less than one billion barrel reserves and isolated from other discoveries are produced by offshore loading. Currently, the largest of these is Beryl with estimated recoverable reserves of about 550 million barrels. If some of these fields were closer to shore or other fields, a pipeline may have been selected rather than an offshore loading system.

4.4.7 Economics

Economics will ultimately dictate the selection of the production and crude oil transportation system. The various cost components of the alternate systems are presented in Table 4-9. This study attempts to define those economic components and assess their relative sensitivity in the economic analysis of offshore petroleum resource development.

4.4.8 Summary of Technology Options and Production System Selection for Economic Analysis

The review of current and imminent petroleum technologies conducted to select the production systems for economic screening indicates that the North Sea to some extent serves as a technology model although there are important environmental contrasts. While oceanographic and meteorologic conditions are similar in the North Sea and Gulf of Alaska (somewhat more severe storm conditions can be estimated in the gulf), there are significant contrasts in geology which are particularly important with respect to the feasibility and design of fixed platforms and pipelines. The Gulf of Alaska lies in one of the most seismically active zones in the world and there are extensive areas of potential unstable bottom soils and soils with low bearing capacities. These factors pose design problems for both steel jacket and concrete gravity platforms, the principal types of platforms employed to date in the North Sea. Both platform types can be designed to withstand earthquake loadings but the application of concrete platforms, especial"ly, is restricted by soil conditions (Watt, Boaz and Dowrick, 1978).

One of the advantages of the concrete platform has been its storage capability, which significantly improves the economics of offshore loading of crude. An offshore loading system is favored in situations where a pipeline to shore and marine terminal can not be economically justified -- generally where a field is distant from shore and isolated from other fields (with which it could possibly share pipelines and terminals). Offshore storage capability can also be provided by a permanently moored tanker (of uncertain feasibility in the Gulf of Alaska). Storage capability has also been incorporated in a number of proposed "hybrid" platform designs, such as the steel gravity platform, semi-submersible concrete (Condrill) platform and loading/mooring/storage (LMS) platform. Offshore storage may also be provided by steel (e.g. SPAR) and concrete storage/loading buoys separate from the drilling/production platform.

To develop marginal fields and fields in deeper water (other factors being equal, for a given field size the deeper the water the. greater the field development costs using a fixed platform) a number of floating or compliant platform designs have been proposed. These designs have, in part, been necessitated by the fact that fixed steel or concrete platforms are reaching their limit of economic feasibility (under current economic conditions) at 183 meters (600 feet) water depth in storm-stressed environments such as the North Sea. In less severe operating environments fixed steel platforms have been installed in water depths greater than 183 meters (600 feet), e.g. Exxon's Hondo platform in 244 meters (800 feet) of water in the Santa Barbara channel and Shell's Cognac platform in over 1,000 feet of water in the Gulf of' Mexico. The floating and compliant platform designs include the guyed tower, articulated tower, tension leg platform and a variety of semi-submersible structures (including converted exploration rigs); the latter two designs are floating structures. Rather than resist environmental loading of waves etc. these platforms are designed to accommodate, to a lesser or greater extent, these forces. Floating and compliant structures require less materials (e.g. steel) to construct, and less offshore construction time. Floating systems involving subsea completed wells can reduce field development time and speed return on investment. For Gulf of Alaska fields, floating systems would also be favored in areas where soil conditions do not favor fixed platforms.

Undoubtedly, the trends in offshore petroleum development in the 1980's, as operations move into deeper waters and marginal fields need to be produced, will include increasing use of hybrid, compliant and floating platform designs and subsea completed wells. To improve the economics of those systems that do not produce into pipelines, offshore storage facilities will be required; probably semi-submersible or buoy structures and sea floor tanks. Steel jacket platforms and to a lesser extent concrete platforms will still have a major role, at least in waters of less than 183 to 305 meters (600 to 1,000 feet). The trend in design of these structures will (and has been) reduction of weight and material requirements such as steel.

In predicting the production technologies that may be used in Gulf of Alaska petroleum development in the 1980's, the petroleum technology reviewed in this chapter has to consider the geography of the Gulf of Alaska, in particular two important considerations:

- The Gulf of Alaska is isolated from petroleum markets and transportation systems (pipelines etc.); most if not all petroleum production will be shipped to the lower 48 states;

- Most potential discovery sites (within the study area) are located less than 81 kilometers (50 miles) from shore; production through pipelines to shore, other factors being equal, is favored especially if a number of fields are sufficiently close together to share pipeline and shore terminal development costs.

In the selection of production systems for costing and economic screening, it is important to note that the available cost data base (see Appendix B) mainly pertains to conventional fixed platforms with pipeline-to-shore or offshore loading production systems, and there is little or no cost data on the various hybrid and floating/compliant platform systems summarized above. This has, in part, influenced the production systems selected for economic screening. The economic screening can identify those field sizes and locations where more cost effective technologies would be required to develop such "marginal" fields.

The production systems selected for economic screening are systems currently used in the North Sea which, to various degrees, may have application in the Gulf of Alaska. These are:

- Floating production platform with maximum of 20 producing wells (subsea completions). Limited to 65 percent production due to no storage. Offshore loading with single point mooring. No water depth limitation.

- Single steel jacket platform, limited to 65 percent production due to no storage and inaccessibility of pipeline. Offshore loading with single point mooring. Water depths: 31 to 183 meters (100 to 600 feet).(1)

- Single steel jacket platform. Storage buoy allows full production equal to 96 percent of capacity, Water depths: 31 to 183 meters (100 to 600 feet).

- Single steel jacket platform. Pipeline to shore terminal shared with other producing fields allows full production equal to 96 percent of capacity, Water depths: 31 to 183 meters (100 to 600 feet).

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(1) Water depth ranges specified are those screened in economic analysis of each system.

- Concrete platform. Storage allows full production equal to 96 percent of capacity. Offshore loading with single point mooring. Water depths: 91 to 183 meters (300 to 600 feet).

- Concrete platform as part of a multi-platform field. Pipeline to shore terminal allows full production equal to 96 percent of capacity. Water depths: 91 to 183 meters (300 to 600 feet).

- Multiple steel jacket platforms. Pipeline to shore terminal allows full production equal to 96 percent of capacity. Water depths: 31 to 183 meters (100 to 600 feet).

- Single or multiple steel platforms. Gas pipeline to shore, gas converted to LNG. Water depths: 31 to 183 meters (100 to 600 feet).

The systems specified above have al been used in the North Sea[1] and are believed to be applicable (with suitable modification) for use in the Gulf of Alaska. While no steel jacket platform system producing direct to tankers in the North Sea o date has had sufficient storage capability to produce full-time at maximum rates (Shell's Brent field SPAR buoy with 300,000 bbl capacity comes closest to this), it has been assumed that offshore storage technology by the 1980's will provide sufficient storage capability in conjunction with production from a steel jacket platform to allow full-time or maximum production.

The first North Sea application of a permanently-moored tanker as a storage facility is planned for Shell's Fulmar field which is scheduled to commence production in 1981; the field will be developed with a single conventional steel jacket platform (Offshore, October, 1978).

In the scenarios selected for detailed description (Chapter 9.0), the production systems specified involve fixed platforms with some produc-

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(1) North Sea gas to date has not been converted onshore to LNG for shipment elsewhere.

tion to shore via pipeline and some oil production loaded directly to tankers offshore. The offshore loading systems include both platforms with and without storage capacity; for those with storage capacity a steel platform and adjacent storage buoy or concrete platform with internal storage have been indicated. There is insufficient data on bottom geology to properly assess problems relating to the feasibility of concrete platforms or similar gravity hybrids in the Gulf of Alaska except to identify active slump areas which obviously pose problems for fixed platforms, pipelines and subsea equipment. In terms of various industry viewpoints, concrete platforms have evolved from a cost effective alternative to steel platforms to a less favored and more expensive option. Nevertheless, concrete platforms or similar hybrids may have a role in Gulf of Alaska petroleum development and the scenario specifications reflect such a possibility.

5.0 EMPLOYMENT

5.1 Introduction

This section provides an introduction to manpower requirements for petroleum development generally, and to Alaska's offshore programs in particular. It also provides the definitions, assumptions, and methods used to generate the manpower estimates for each scenario in Section 9.0. Refer to Section 9.0 for the results of the analysis described in this section.

5.2 Three Phases of Petroleum Exploitation

Exploitation of a petroleum reserve involves three distinct phases of activity -- exploration, development, and production. The exploration phase encompasses seismic and related geophysical reconnaissance, wild-cat drilling, and "step out" or delineation drilling to assess the size and characteristics of a reservoir. The development phase involves drilling the optimum number of production wells for the field (many hundreds of wells are used to produce a large field) and construction of the equipment and pipelines necessary to process the crude oil and transport it to a refinery or to tidewater for export. The production phase involves the day-to-day operation and maintenance of the oil wells, production equ-ipment, and pipelines, and the workover of wells. later in their producing life.

The three phases of petroleum exploitation overlap and all three may occur simultaneously. Exploration for additional fields continues in the vicinity of a newly discovered field as that field is developed and put into production. On the North Slope, for example, where the Prudhoe Bay field is in production, exploratory and delineation drilling will continue for several more years. Development activity typically continues after the initial start-up of production. Operators need to start production as soon as possible to begin to recover expenses of field development (Milton, 1978). In the North Sea, for example, production from some fields was initiated with temporary offshore loading systems while development drilling continued and before underwater pipeline construction began.

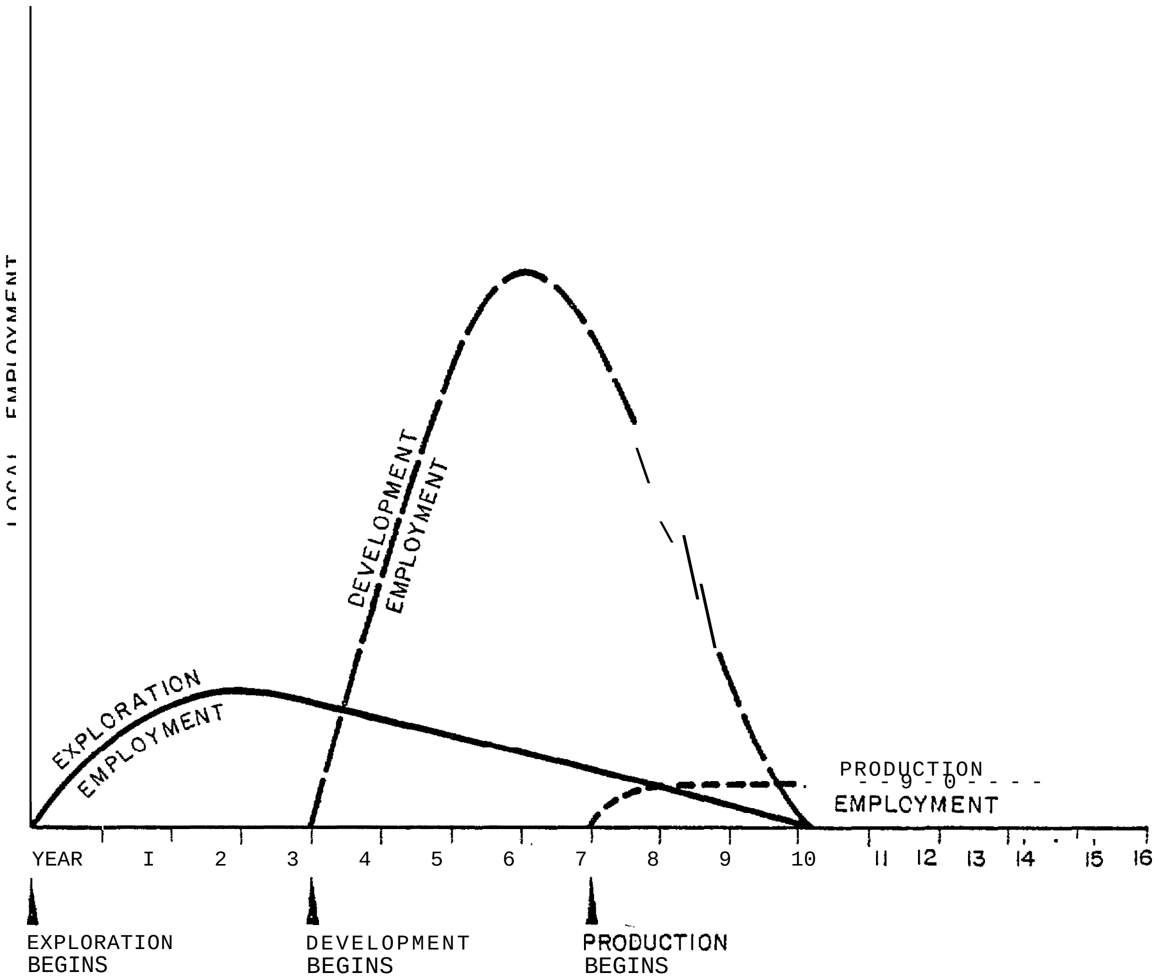
Local employment[1] created by each phase of the petroleum exploitation process tends to have a characteristic magnitude and attributes. For example, exploratory work is not particularly labor intensive, and wildcat crews come and go with drilling contractors. Local residents are most likely to benefit indirectly from expenditures made for exploration programs rather than from direct employment in the oil field. The development phase creates the highest levels of employment locally, and much of this employment is in the construction and transportation industries. Labor directly associated with drilling and installing crude processing equipment is highly skilled, Because of automation, the production phase does not require a substantial work force. This work force will include many experienced oil field operators recruited from outside the area or transferred from other fields by the owner companies.

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

5.3 Characteristics of Offshore Petroleum Development and Some Implications for Alaska

Offshore petroleum development has several important general characteristics that distinguish it from onshore development, and each of these has implications for the economic impacts that will be experienced in Alaska. The first of these general characteristics is the extreme

(1) Local employment refers to employment at or near the petroleum reservoir. It does not include the manufacturing and construction employment created away from the site, such as that involved with the building of process equipment and offshore platforms, nor does it include professional, administrative, and clerical work that occurs in regional headquarters (London and Aberdeen in the case of North Sea fields and Anchorage in the case of Alaska fields, for example).



SOURCE: DAMES & MOORE

FIGURE 5-1

LOCAL EMPLOYMENT CREATED BY THE THREE PHASES OF PETROLEUM EXPLOITATION, A HYPOTHETICAL CASE specialization of the offshore petroleum industry. An offshore drilling and construction program typically requires a very large number of contractors who supply special services and high technology equipment. Deepwater marine construction for the petroleum industry involves engineering design, component fabrication, and installation techniques that are among the most sophisticated and expensive in the world. United States firms pioneered offshore petroleum engineering and technology in the Gulf of Mexico and major U.S. firms located in Texas and Louisiana such as Brown and Root, Inc. and J. Ray McDermott, Inc. still dominate the industry. Since the development of North Sea gas and oil reserves, Dutch, German, British, French, Norwegian, Swedish, and Finish firms have entered the industry. Italian and Spanish firms are now active in the Mediterranean Sea. As offshore petroleum fields are discovered in waters of the Outer Continental Shelf in Alaska, they will be developed by the large U.S. firms. Participation of Alaska-based contractors in an offshore petroleum development program will mainly be limited to onshore construction requirements, which may or may not be large.

Development of an offshore oil field may occur without a great deal of onshore construction work. Wells and most of the processing equipment are located offshore. Typically there is little requirement for overland pipeline transportation. If oil comes ashore at all, it does so at the most convenient landfall and is stored for tanker transport.(1) Development of onshore fields on the North Slope, in contrast, created a large amount of civil construction work -- drill pads, roads and road maintenance, bridges, pump station sites, the pipeline construction pad, etc. -- for which local contractors were capable of bidding. An offshore development program would not necessarily involve much of this type of work. On the other hand, if large shore bases, marine terminals, and gas treatment/liquefaction plants are required (they may not be), the construction of these facilities generate substantial onshore employment.

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(1) Natural gas from offshore fields will create demand for considerable onshore pipeline capacity if a national market is at hand, as in Great Britain, Netherlands, or Germany. In Alaska no such market exists; offshore gas will be exported in liquified form, and require the construction of a liquefaction plant,

An aspect of the major firms active in offshore petroleum development is their international character. These firms have more or less regular, experienced crews who are dispatched to jobs around the world. Many of the firms provide specialty services that require only short visits to the oil field. Ordinarily, however, the drilling and construction crews work 12 hour per day shifts for 14, 21 or 28 days and then take an equal number of days off. They are provided round-trip airfare from their point of hire for these rotations.

The unfortunate implication of this aspect of the offshore petroleum industry for Alaskan workers is that Alaskans face an international labor market which does not recognize the high cost of living here. Contractors are likely to have a seasoned work force on the payroll or a long "call up" list. Because there is not a local offshore construction industry, Alaska workers are not likely to have the skills and experience required by contractors who might need new hires. Furthermore,. offshore contractors will doubtless pay wages at rates prevailing on the Gulf coast of the United States, where most of the firms are headquartered. In the Gulf of Alaska from 1975 to 1978, for example, workers on the offshore vessels were virtually all from out-of-state, many of these from Texas and Louisiana. Their wages were significantly less than those received by non-salaried onshore oil field workers in Alaska (Dames & Moore, 1978c).

Offshore petroleum activity that may occur in the waters of the Gulf of Alaska is not reached by state regulatory or taxing authority. Only onshore activity is within state jurisdiction. Alaska's so-called local hire (also known as Alaska hire) statute was declared unconstitutional by the U.S. Supreme Court.[1] Even if the state successfully fashions a

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(1) On June 22, 1978, the Court held the Alaska Hire Statute unconstitutional because it violates the Privileges and Immunities Clause of Article IV Section 2. The Court ruled that the Alaska Hire Statute was too imprecise and ineffective to accomplish its ostensible objective of reducing unemployment in Alaska, which is largely the result of lack of training and skills among the jobless or remoteness from employment opportunities. Furthermore, the statute gave preference to all Alaska residents, unemployed or not. Also, the Court held that the state's ownership of oil and gas lands was not an adequate foundation for the statute which reached employers who have no connection with the state's oil and gas, perform no work on state land, have no contractual relationship with the state, and receive no payment from the state.

new statute that gives local residents preferential treatment in hiring and also meets the Court's constitutional standards, it will not apply to employment on the offshore platforms.

Coastal municipalities (cities and boroughs) that are within the orbit of offshore activity and experience permanent population growth as a consequence will be eligible to receive additional state revenue sharing income through the per capita distribution formula used by the state for this revenue distribution. The municipalities and the state will be able to tax the real and personal property of the oil companies and contractors that are located within their boundaries, but they will not be able to extend their taxing power to the very valuable platforms and producing equipment located beyond the three-mile limit of state jurisdiction.

5.4 Employment Contrasts Between North Sea Petroleum Development and Projected Gulf of Alaska Petroleum Development

From the technological viewpoint, North Sea oil development offers an excellent example of things to come if commercial fields are discovered in the Gulf of Alaska. The same is not true from an employment viewpoint. There are many contrasts between the employment created in Scotland and Europe by North Sea oil development and that which will be created in Alaska by a find in the Gulf of Alaska. One important difference between the North Sea and the Gulf of Alaska is the size and number of oil fields: projections of maximum recoverable reserves to be found in the Gulf are a small fraction of the proven reserves in the North Sea, Another major difference between the North Sea and the Gulf of Alaska is the proximity of the former to highly developed industrial centers. Major shipbuilding and manufacturing complexes existed in Scotland, the Netherlands, Norway, Sweden, Finland and Germany, which quickly responded to the demand for offshore platforms, equipment, ships, barges, and engineering services. No such industrial centers exist in Alaska, and as a consequence the bulk of employment created by the development of offshore oil fields in the Gulf will occur outside the state, much of it in Japan, the Puget Sound area, San Francisco, and Los Angeles.

At the peak of North Sea development activity in 1976, there were some 26,000 people employed in firms wholly related to North Sea petroleum in Scotland alone. An additional 13,000 were estimated to be employed by firms partially related to North Sea petroleum. These employees were engaged in the fabrication of steel jackets, concrete platforms, deck modules (processing and other equipment installed on the platform deck), and in manufacturing and overhauling oil field tools and equipment. In contrast to employment from this source, only 5,000 people in Scotland were estimated to be employed in construction work directly related to North Sea development, (1)

It seems certain that steel and concrete jackets for the Gulf of Alaska will be manufactured in Japan or shipyards of the U.S. West Coast rather than in Alaska. Because of high labor and material costs in Alaska, manufacturing of modules and oil field tools and equipment also will occur elsewhere. Thus, local employment in Alaska will be limited to that necessary to install and commission platforms, lay pipelines, and construct onshore facilities.

Support bases in Alaska will not be comparable in function or size to the North Sea facilities at Aberdeen and Peterhead on the east coast of Scotland. Rather, the Alaska shore bases will more closely resemble the "forward bases" in the Shetland and Orkney Islands. Tacoma and Seattle as well as other West Coast and Gulf coast harbors will perform many of the functions performed by Aberdeen and Peterhead (loading of modules, preparing jackets for towout, etc.). Only if there are very large discoveries in the Gulf of Alaska will local facilities be built for the major repair and overhaul of supply boats and semisubmersible platforms.

(1) The following are estimates of employment generated in Scotland by. North Sea oil development at the end of 1976:

Employment in "wholly related" firms	26,000
Employment in "partially related" firms	13,000
Construction employment: direct facilities	5,000
Construction employment: other work (offices, etc.)	4,000
Secondary employment (multiplier of 1.4)	19,000
Total	67,000

See: Gaskin (1977).

5.5 Labor Productivity in Offshore Operations

The length of time and the crew size required to accomplish any task depend upon the productivity of the labor force. Experience of the crew, quality of project supervision, state of labor relations, and job conditions are conventional productivity factors. In Alaska and the North Sea, for example, where long days of hard work, isolation, and bad weather are typical, additional productivity factors become important considerations. These are the number of hours worked per day (efficiency drops off sharply after eight hours), the number of days worked consecutively without a break (efficiency drops as the length of the rotation increases), the amount of daylight, and temperature.

In the case of offshore work, weather is also a critical determinant of much labor productivity. Winter gales can cause all activity to stop, or it can effectively stop all work if helicopters and supply boats cannot service drilling rigs, platforms, lay barges or derrick barges. Even if work is not suspended, weather can greatly reduce productive efficiency. An industry guide, Cost Estimating Manual for Pipelines and Marine Structures (Page, 1977), projects the productivity loses for certain tasks caused by wind, current, and waves. These are shown in Tables 5-1 through 5-3. Tasks affected by wind and currents are, for example, installing platform jackets, and setting piling.

It is evident that these productivity factors can profoundly affect the scheduled completion of a job. Offshore work in an area such as the Gulf of Alaska and the North Sea, where high wind and waves are commonplace, where it is very cold and there are long hours of darkness during the winter, and where crews work 12-hour shifts up to a month at a time without a day off, labor productivity may be a third or less of labor productivity in, say, Gulf of Mexico, where conditions are not as severe.

5.6 Definitions

It is very important that terms are defined before beginning a discussion of the manpower requirements for the discovery, development, and

TABLE 5-1

WIND PRODUCTIVITY FACTORS

Description	Wind Miles Per Hour	Percent Efficiency
Calm	o - 1	100
Light Air	1 - 3	100
Slight Breeze	4 - 7	95
Gentle Breeze	8 - 12	90
Moderate Breeze	13 - 18	75
Fresh Breeze	19 - 24	50
Strong Breeze	25 - 31	30

Source: Cost Estimating Manual for Pipelines and Marine Structures {Page, 1977).

TABLE 5-2

CURRENT PRODUCTIVITY FACTORS

Average Total Current in Feet Per Second	Percent Efficiency
0.0 to 0.5	100
0.5 to 1.0	97
1.0 to 2.0.	95
2.0 to 2.5	90
2.5 to 3.0	85
3.0 to 3.5	78
3.5 to 4.0	70
4.0 to 5.0	65

Source: Cost Estimating Manual for Pipelines and Marine Structures (Page, 1977).

TABLE 5-3

WAVE PRODUCTIVITY FACTORS

Equipment and Type of Operations	WAVE HEIGHT IN METERS (FEET) AND PERCENTAGE EFFICIENCY FOR:					
	Safe Efficient Operations		Marginal Operations		Dangerous and/or Inefficient Operations	
	Wave Height Meters (feet)	Percent Efficiency	Wave Height Meters (feet)	Percent Efficiency	Wave Height Meters (feet)	Percent Efficiency
Deep Sea Tug:						
Towing Derrick Barge	0-1.2 (0-4)	100-70	1.2-1.8 (4-6)	70-50	1.8+ (6+)	50-20
Towing Material Barge	0-1.2 (0-4)	100-70	1.2-1.8 (4-6)	70-50	1.8+ (6+)	50-20
Working Derrick Barge	0-0.6 (0-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Working Material Barge	0-0.6 (0-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Crew Boats [18 to 27 Meters (60 to 90 Feet) Long]:						
Underway	0-2.4 (0-8)	100-80	2.4-4.6 (8-15)	80-40	4.6+ (15+)	40-10
Loading or Unloading Crews	0-0.9 (0-3)	100-70	0.9-1.5 (3-5)	70-50	1.5+ (5+)	50-20
Oerrick Barge:						
Small Barge-Underway	0-0.6 (0-2)	100-70	0.6-0.9 (2-3)	70-50	0.9+ (3+)	50-20
Large Barge-Underway	0-0.9 (0-3)	100-70	0.9-1.5 (3-5)	70-50	1.5+ (5+)	50-20
Small Barge-Platform Building	0-0.6 (0-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Large Barge-Platform Building	0-0.9 (0-3)	100-70	0.9-1.2 (3-4)	70-40	1.2+ (4+)	40-10
Small Barge-Buoy Laying	0-0.6 (0-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Ship-Mounted Derrick:						
Platform Building	0-1.2 (0-4)	100-70	1.2-1.8 (4-6)	70-50	1.8+ (6+)	50-20

Source: Cost Estimating Manual for Pipelines and Marine Structures, 1977.

production of a petroleum field. Although several studies of OCS petroleum impact have now been made which include manpower estimates, neither a uniform set of definitions nor an articulated methodology has emerged (see, for example, NERBC, 1976). Indeed, no attempt has been made in these to define such basic terms as jobs and employment, and the methods used by them to calculate manpower totals are opaque at best.[(1)] The following definitions are used in the present study:

Job

A job is a position, such as driller, roustabout, or diver, rather than a specific task or the person who performs the task or fills the position;

Crew

A crew is a group of individuals who fill a set of jobs; a drilling crew, for example, is a group of men who fill generally standardized jobs necessary to accomplish the task of drilling a well;

Shift

Shift refers to the hours worked by each crew each day; a normal shift for offshore crews is 12 hours, and there are two shifts per day;

Monthly Average Labor Force

This is the average number of people employed per shift per month over the life of the task. An estimate of the monthly average work force is made when several crews are combined into a composite estimate of work force size and/or when the task for which an estimate is being made has a fluctuating monthly labor force.

(1) Because terms are not clear, manpower estimates are not readily comparable. It is seldom evident, for example, if all crews are counted (most offshore work has more than one crew on site) and if off-site employment is counted.

Rotation Factor

The rotation factor is defined as $(1 + \frac{\text{number of days off duty}}{\text{number of days on duty}})$; if a crew worked for 14 days and then took 14 days off, the rotation factor would be two $(1 + \frac{14}{14} = 2)$; if a crew worked 28 days and took 14 off, the rotation factor would be 1.5 $(1 + \frac{14}{28} = 1.5)$;

Total Employment

Total employment is the total number of men employed, and it is found by the formula: jobs (crew size) x number of shifts/day x rotation factor; for example, if a new task creates 10 positions, and two crews each work consecutive 12-hour shifts, and the men work 14 days and take 7 off, then total employment is 30 (10 x 2 x 1.5); thus, total employment includes on-site employment and off-site employment;

On-Site Employment

On-site employment is composed of the workmen who are not on leave rotation, or two complete crews if two shifts are worked per day;

Off-Site Employment

Off-site employment is the group of employees who are on leave rotation and not physically present at the work site.

Net Employment

Net employment refers to net additions to the work force. Total employment associated with a petroleum development program is probably not net employment because the major industry contractors have steady crews that move around the world as new fields are developed.

Man-Months

A man-month is the employment of one man for one month.[1] Thus, a man-month is a measure of work that incorporates the element of duration of work. This unit of measure is necessary to compare labor that varies in length. Suppose a project had three components: component A employed 100 men for two months; component B employed 50 men for three months; and component C employed 80 men for 12 months. To say the project resulted in employment of 230 is to say little about it" because there is no indication of how long the employment lasted. Although component C employed only 80 men, it was responsible for over four times as much employment as component A, which employed 100 men for a shorter period (960 man-months vs. 200 man-months).

In this report a distinction is made between on-site man-months of employment and total man-months. On-site man-months represent the number of men physically present at the worksite and on the payroll (workers on leave rotation are not typically paid) during the project.

(1) A month of employment (30 days) can involve very different amounts of work depending upon the hours worked during the week, Notice, for example, that 8,000 man-hours of work are accomplished by 50 men working 40 hours per week for four weeks, while 16,800 are accomplished by 50 men working 84 hours per week (equivalent of seven 12-hour days) for four weeks. Both cases might be said to represent 50 man-months of employment, sinch both involve 50 men for one month. However, one could argue that the first case represents 50 man-months and the second roughly twice that amount since men must have a reasonable amount of time to recuperate from their labor. In the case of OCS employment at hand, men normally work long shifts for long periods, and then have a long rest break. Thus, in the example used above, it would be likely that 50 men would work 12 hours per day for the first 15 days and then take the second 15 days off, while a second group would rest the first 15 days and work the second 15-day period. This would be the equivalent of 100 man-months (50 men x 1 shift x rotation factor of 2 x 1 month) based on a work week of some 40 hours.

Nevertheless, in the example above, there were no more than 50 men physically present on the worksite at one time, and there were no more than 50 men on the employer's payroll at one time. Therefore, on the basis of a definition of a man-month that involves soley the duration of a worker's paid presence at the site, there were only 50 man-months of employment.

This number represents actual labor expenditures for tasks (such as building an oil terminal, installing a platform, etc). Total man-months include on-site workers and off-site workers. This number indicates the overall laborforce requirements of the project. Monthly average total laborforce levels -- that is, the monthly average number of men engaged in all phases of work during the year -- can be derived by dividing the total number of man-months by 12.[1]

The scope of employment covered in this study is that which is generated in the field, that is direct employment on the platforms, on the supply boats, barges, and helicopters, at the shore bases, and at field construction sites if there are any. The clerical, administrative, engineering, and geological work that occurs off the site or away from the shore support bases is not included. Neither is indirect or induced labor included in this analysis.

5.7 Description of Method and Assumptions

For maximum analytical utility, manpower estimates are needed for each month of each year; for onshore as well as offshore employment; for on-site as well as off-site employment; and for each important industrial sector.

Monthly estimates are required because it is necessary to know employment levels for the months of January and July. Per capita distributions of state revenue sharing programs are based on the populations of municipalities in these months. However, since offshore population cannot be counted for this purpose, nor can off-site population (that is, workers on leave rotation), it is also necessary to distinguish between these categories of employment. Also, for impact analysis generally it is necessary to distinguish between offshore and onshore

(1) If a crew of 50 men worked 12 hours per day for the first half of each month for one year, and a second crew worked for the second half of each month for the year, on-site employment would be 600 man-months (50 x 12); total employment would be 1,200 man-months (50 + 50 x 12); and the average monthly laborforce would be 100 men.

labor force levels, because offshore workers have very little or no contact at all with the local economy.

To enhance the sophistication of the effort generally and to increase its usefulness for impact analysis, employment is categorized by the four main industries that are involved in petroleum development: petroleum, construction, transportation, and manufacturing. Probably over 98 percent of the field labor associated with the exploration, development, and production of petroleum fall within one of these four Standard Industrial Classification (SIC) sectors.[1]

It was necessary to identify the basic tasks of each phase that generate significant employment. A unit of analysis, such as a well, platform, or construction spread, was established for each of these labor-generating tasks, which are the basic "building blocks" of the system. Manpower requirements for each unit of analysis were estimated, as were the number of shifts worked each day, and the labor rotation factor for that task. This 'information is presented in Table 5-4.

Crew size or the length of employment for some activities is not influenced by the size of the oil field or physical conditions such as water depth. Well drilling, for example, requires basically the same size crew in waters of 50 feet or 800 feet. This is not the case with other activities such as platform installation or pipelaying. Here, the size of the field (which determines the size and number of platforms used) and the depth of water are critical determinants of crew size and duration of employment. To account for these variations, a general set of scale factors was used to increase or decrease labor requirements when field size and other conditions required that adjustments be made. Scale factors are shown in Table 5-5. Scale factors are applied to either the duration of work or the crew size. In the case of pipelaying, scale factors were applied to the rate of progress (e.g. a scale factor of greater than one slowed the rate of progress).

(1) Environmental engineering consulting services, and contract communications work are sources of minor employment that come to mind that do not fall within these four industrial sectors.

TABLE 5-4

MANPOWER EMPLOYMENT MODEL

Phase	Industry		Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[2] (in months)	Crew Size or Monthly Average Work Force/ Unit of Analysis[1] (number of people) Offshore	Onshore	Number of Shifts/Day	Rotation Factor	Scale Factor
Exploration	A. Petroleum	1	Exploration Well	Well	5	28 0	0 6	2 1	2 1	Crew Size
		2	Geophysical and logic Survey	Crew	5	25 0	0 2	1 1	1 1	N.A.
	B Construction	3	Shore Base Construction	Base	Assigned	Assigned			1.11	N.A.
	C Transportation	4	Hel for Rigs	Well	Same as Task 1	0	5		2	N.A.
		5	Supply/Anchor Boats for Rigs	Well	Same as Task 1	26 0	0 2	1 1	1.5 1	N.A.
	D. Manufacturing									
Development	A. Petroleum	6	Development Dri ing	Platform	Assigned	28 if 1 rig 56 if 2 rigs	6 if 1 rig 12 if 2 rigs	2 1	2 1	N.A.
	B. Construction	7	Steel Jacket Installation and Commissioning	Platform	4	200 0	0 25	2 1	2 1.11	Crew Size
		8	Concrete Installation and Commissioning	Platform	0	200 0	0 25	2 1	2 1.11	Crew Size
		9	Vacant							
		10	Shore Base Construction	Base	Assigned	0	Assigned Monthly	0 1	0 1.11	Assigned
		11	Single-Leg Mooring System	System	6	00 0	0 25	2 1	2 1.11	Crew Size
		12	Pipeline Offshore, Gathering, Oil and Gas	Spread	Assigned	00 0	0 25	2 1	2 1 11	Assigned
		13	Pipeline Offshore, Trunk, Oil and Gas	Spread	Assigned	25 0	0 35	2 1	2 1. 11	Assigned
		14	Pipeline Onshore, Trunk, Oil and Gas	Spread	Assigned	0	300	1	11	Assigned

TABLE 5-4 (Cont.)

Phase	Industry	Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[2] (in months)	Crew Size or Monthly Average Work Force/ Unit of Analysis[1] (number of people) Offshore	Onshore	Number of Shifts/Day	Rotation Factor	Scale Factor
		15 Pipe Coating	Pipe Coating Operation	Assigned	0	175	1	1.11	Crew Size
		16 Marine Terminal	Terminal	Assigned	0	Assigned Monthly	1	1.11	Assigned
		17 LNG Plant	Plant	Assigned	0	Assigned Monthly	1	1.11	Assigned
		18 Crude Oil Pump Station Onshore	Station	12	0	200	1	1.11	Crew Size
		19 Vacant							
		20 Vacant							
	C. Transportation	21 Helicopter Support for Platform	Platform; Same as Tasks 7 & 8	Same as Tasks 7 & 8	0	5	1	2	N.A.
		22 Helicopter Support for Lay Barge	Lay Barge Spread; Same as Tasks 12 & 13	Same as Tasks 12 & 13	0	5	1	2	N.A.
		23 Supply/Anchor Boats for Platform	Platform; Same as Tasks 7 & 8	Same as Tasks 7 & 8	39 0	0 12	1 1	1.5 1	N.A.
		24 Supply/Anchor Boats Lay Barge	Lay Barge Spread; Same as Tasks 12 & 13	Same as Tasks 12 & 13	65 0	0 12	1 1	1.5 1	N.A.
		25 Tugboats for Instal-lation & Towout	Platform	Same as Tasks 7 & 8	40	0	1	1.5	N.A.
		26 Tugboats for Lay Barge Spread	Lay Barge Spread; Same as Tasks 12 & 13	Same as Tasks 12 & 13	20	0	1	1.5	N.A.
		27 Longshoring for Plat-form Construction	Platform; Same as Tasks 7 & 8	Same as Tasks 7 & 8	0	20	1	1	Crew Size

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TABLE 5-4 (Cont.)

Phase	Industry	Task		Unit of Analysis	Duration of Employment/ Unit of Analysis[2] (in months)	Crew Size or Monthly Average Work Force/ Unit of Analysis[1] (number people] Offshore	Onshore	Number of Shifts/Day	Rotation Factor	Scale Factor
		28	Longshoring for Lay Barge	Lay Barge Spread; Same Tasks 12 & 13	Same as Tasks 12 & 13	0	20	1	1	Crew Size
		29	Tugboat for SLMS; (Task 11)	Same as Task 11	Same as Task 11	10	0	1	1.5	N.A.
		30	Supply 8oat for SLMS; (Task 11)	Same as Task 11	Same as Task 11	13	0	1	1.5	N.A.
	D. Manufacturing									
Product ion	A. Petroleum	31	Operations and Maintenance (routine preventive)	Platform	Assigned	35	0	2	2	Crew Size
		32	Oil Well Workover and Stimulation	Platform	Assigned	12	0	1	2	N.A.
	B. Construction	33	Maintenance and Repair for Platform and Supply Boats (replacement of parts. rebuild, painting, etc.)	Platform	Assigned	8 0	0 8	1 1	2 1	Crew Size
	C. Transportation	34	Helicopters for Platform	Platform	Same as Task 31	0	5	1	2	N.A.
		35	Supply Boats for Platform	Platform	Same as Task 31	12	0	1	1.5	N.A.
		36	Terminal and Pipeline Operations	Terminal	Assigned	0	42	2	2	Crew Size
		37	Longshoring for Platforms	Platform	Same as Task 31	0	4	1	1	Crew Size
	D. Manufacturing	38	LNG Operations	LNG Plant	Assigned	0	30	2	2	Crew Size

[1] "Assigned" means that scenario-specific values are used, and that no constant values are appropriate.
[2] Different labor force values may be substituted for these if deemed appropi rate by site-specific characteristics.

Additional notes on next page.

Source: Dames & Moore

NOTES TO TABLE 5-4

Task	
1	Average 28-man crew per shift on drilling vessel and six shore-based positions (clerks, expeditors, administrators); shift on drilling vessel includes catering and oil field service personnel
2	Approximately one month of geophysical work per well based on 322 kilometers (200 miles) of seismic lines per well at approximately 24 kilometers/day (15 miles/day) x 2 (weather factor); 25-man crew and two onshore positions; crew can work from May through September
3	Requirements for temporary shore base construction varies with lease area
4	One hel icopter per dril 1 ing vessel ; two pi lots and three mechanics. per hel icopter; considered onshore employment
5	Two supply anchor boats per rig; each with 13-man crew
6	Two drilling rigs per platform; average 28-man crew on dri ll ing vessel and six shore-based positions; shift on drilling vessel includes catering and oil field service personnel
7, 8, 9	Includes al l 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
12	Rate of progress assumed to be average of 1.6 kilometers (one mile) per day for al 1 gathering line; scale factors not applied to gathering line
13	Rate of progress averages 1.2 kilometers (0.75 mile) per day of medium-size trunk 1 ine in water of medium depth; scale factors applied in shallow or deeper water and for field size; rate of progress makes allowance for weather down-time, tie-ins, and mobil ization and de-mobil ization
14	Rate of progress averages 1.2 kilometers (0.75 mile) per day of buried medium-size onshore trunk l ine in moderate terrain; scale factors appl ied for elevated pipe or rocky terrain and for field size
15	Rate of progress for pipe coating is 1.6 kilometers/day (one mile/day) for 20-36" pipe; 2.4 kilometers/day (1 .5 miles/day) for 10-19" pipe
16	See Table 5-7
17	See Table 5-7
20	See Table 5-7
21	One hel icopter per" platform
22	One helicopter per 1 ay barge spread
23	Three supply/anchor boats per platform
24	Five supply/anchor boats per lay barge spread
25	Four tugs for towout per platform; 10-man crew per boat
26	Two tugs per 1 ay barge spread; 10-man crew
30	One tugboat per SLMS
31	One supply boat per SLMS
32	Assumed to begin five years after production begins
33	Assumed to begin five years after production begins

Scale factors are a necessary element of the manpower model to reduce to a manageable number the inputs required by it, and also to generate estimates for which specific references are not available in the literature. Scale factors in Tables 5-5A and 5-58 were derived by a process of trial and error from a wide variety of information about crew sizes and manpower requirements of petroleum activities of a different nature and scale. They represent a single set of factors that seem to best express the relationships that exist between manpower demands of disparate projects and activities. For example, in the case of platform operating personnel (task 31, Table 5-4), the small offshore platform of Marathon Oil Company in Upper Cook Inlet (Dolly Varden) has an offshore crew of approximately 23 per shift (46 total, Marathon Oil Company, 1978), while the very large North Sea platforms have crews of approximately 60 per shift (120 total, Addison, G. D., 1978). Thus, these two crew sizes have a relationship that generally matches the scale factors in Table 5 -5A. They also suggest a crew size for a platform of moderate and large size. The scale factor of 1.0 corresponds to a crew of 36 (derived), the scale factor of 1.3 corresponds to a crew of 47 (derived), a scale factor of .7 corresponds to a crew of 25 (contrasted to 23 of Marathon platform), and a scale factor of 1.7 corresponds to a crew size of 61 (contrasted to 60 of typical North Sea very large platform). While the use of a single general set of scale factors introduces a measure of distortion into the manpower estimating process, the distortion seems to be well within an acceptable overall range of accuracy.

Occasional deviation from the scale factors in Tables 5-5A and 5-5B is necessary, as for example in the construction of major onshore facilities which do not appear to have a simple, linear relationship between project size and labor force requirements. Also, in the case of these onshore construction projects, monthly labor force levels vary greatly, so it was necessary to develop complete sets of monthly employment figures. These estimates are shown in Tables 5-6A and 5-6B. The numbers in Tables 5-6A and 5-6B are general estimates derived from available information about the length of construction and peak workforce of

TABLE 5-5A

SCALE FACTORS USED TO ACCOUNT FOR INFLUENCE OF
FIELD SIZE AND OTHER CONDITIONS ON MANPOWER REQUIREMENTS

Scale Factor	Field Size	Water Depth	Pipelay Conditions Offshore and Onshore
0.7	Small	Shallow	Easy
(Base Case) 1.0	Moderate	Moderate	Moderate
1.3	Large	Deep	Difficult
1.7	Very Large	Very Deep	Very Difficult

Source: Dames & Moore

TABLE 5-5B

RATES OF PROGRESS OF INSTALLING TRUNK PIPELINES,
ONSHORE AND OFFSHORE, DERIVED FROM SCALE FACTORS IN TABLE 5-5A

Scale Factor	Pipe Diameter (inches)	Rate of Progress Kilometers/Day	(Miles/Day)
0.7	10 or less	1.8	(1.1)
1.0	11 - 19	1.21	(.75)
1.3	20 - 29	.92	(.57)
1.7	30 or greater	.71	(.44)

Source: Dames & Moore

TABLE 5-6A

MANPOWER ESTIMATES FOR MAJOR ONSHORE CONSTRUCTION, SUMMARY[1]

Facility	Size	Approximate Capacity	Duration of Construction	Approximate Peak Employment (number of people)
Oil Terminal (BD)	Small	200,000 minus	24	400
	Medium	200,000 - 500,000	30	750
	Large	500,000 - 1,000,000	36	1200
	Very large	1,000,000 plus	42	4000
LNG Plant (MMCFD)	Small	500 minus	24	800
	Medium	500 - 1,000	30	1200
	Large	1,000 - 1,500	36	2000
	Very large	1,500 plus	42	4500
Shore Base (field size in MMBD)	Medium	1.5 minus	12	800
	Large	1.5 plus	16	1000

[1]Monthly manpower requirements presented in Table 5-6B.

Source: Dames & Moore (see text)

TABLE 5-6B

MONTHLY MANPOWER LOADING ESTIMATES, MAJOR ONSHORE CONSTRUCTION PROJECTS

Facility: Oil Terminal
Size: Small
Duration of Construction: 24 Months
Approximate Peak Employment (number of people): 400

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	34	69	102	136	170	204	238	272	306	340	374	408	408	374	340	306	272	238	204	170	136	102	68	34

Facility: Oil Terminal
Size: Medium
Duration of Construction: 30 Months
Approximate Peak Employment (number of people): 750

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	50	100	150	200	250	300	350	400	450	500	550	600	650	700	750	750	700	650	600	550	500	450	400	350

Month:	25	26	27	28	29	30
Workers:	300	250	200	150	100	50

Facility: Oil Terminal
Size: Large
Duration of Construction: 36 Months
Approximate Peak Employment (number of people): 1200

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	67	134	201	268	335	402	469	536	603	670	737	804	871	938	1005	1072	1139	1206	1206	1139	1072	1005	938	871

Month:	25	26	27	28	29	30	31	32	33	34	35	36
Workers:	804	737	670	603	536	469	402	335	268	201	134	67

Facility: Oil Terminal
Size: Very Large
Duration of Construction: 42 Months
Approximate Peak Employment (number of people): 4000

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	190	380	570	760	950	1140	1330	1520	1710	1900	2090	2280	2470	2660	2850	3040	3230	3420	3610	3800	3990	3990	3800	3610

Month:	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42
Workers:	3420	3230	3040	2850	2660	2470	2280	2090	1900	1710	1520	1330	1140	950	760	570	380	190

TABLE 5-60 (Cont.)

Facility: LNG Plant
Size: Small
Duration of Construction: 24 Months
Approximate Peak Employment (number of people): 800

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	67	134	201	268	335	402	469	536	603	670	737	804	804	737	670	603	536	469	402	335	268	201	134	67

Facility: LNG Plant
Size: Medium
Duration of Construction: 30 Months
Approximate Peak Employment (number of people): 1200

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	80	160	240	320	400	480	560	640	720	800	880	960	1040	1120	1200	1200	1120	1040	960	880	800	720	640	560

Month:	25	26	27	28	29	30
Workers:	480	400	320	240	160	60

Facility: LNG Plant
Size: Large
Duration of Construction: 36 Months
Approximate Peak Employment (number of people): 2000

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	110	220	330	440	550	660	770	880	990	1100	1210	1320	1430	1540	1650	1760	1870	1980	1980	1870	1760	1650	1540	1430

Month:	25	26	27	28	29	30	31	32	33	34	35	36
Workers:	1320	1210	1100	990	880	770	660	550	440	330	220	110

Facility: LNG Plant
Size: Very Large
Duration of Construction: 42 Months
Approximate Peak Employment (number of people): 4500

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	215	430	645	860	1075	1290	1505	1720	1935	2150	2365	2580	2795	3010	3225	3440	3355	3870	4085	4300	4515	4515	4300	4085

Month:	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42
Workers:	3870	3655	3440	3225	3010	2795	2580	2365	2150	1935	1720	1505	1290	1075	860	645	430	215

TABLE 5-6B (Cont.)

Facility: Shore Base
Size: Small-Medium
Duration of Construction: 12 Months
Approximate Peak Employment (number of people): 800

Month:	1	2	3	4	5	6	7	8	9	10	11	12
Workers:	134	268	402	536	670	804	804	670	536	402	268	134

Facility: Shore Base
Size: Large
Duration of Construction: 16 Months
Approximate Peak Employment (number of people): 1000

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Workers:	125	250	375	500	625	750	875	1000	1000	875	750	625	500	375	250	125

Source: Dames & Moore (see text)

similar facilities.[1] It was assumed that peak employment on a construction project of this type would reach a brief plateau at approximately midway through the project, and that it would steadily increase prior to the peak and steadily decrease after the peak had been reached. Thus, a graph of the manpower requirements for these projects would generally approximate an equilateral triangle with a blunt tip. This assumption allowed monthly manpower estimates to be calculated once the peak level and construction period were identified.

Identifying typical crew sizes and reasonable monthly average work force levels for the various labor-generating activities constituted the major research task. Information was obtained from many sources -- trade journals (advertisements as well as articles), industry equipment specifications, interviews with contractors experienced in offshore work, government studies including offshore petroleum impact assessments, professional papers, and cost estimating manuals.

A computer was utilized to calculate and sum the manpower requirements for each scenario. It used the following basic formula for each task, all of which were coded by industry:

> Number of units x crew size x duration of task x number of shifts x rotation factor x scale factor

The information in Table 5-4 comprises the framework of the computer model. For each task, inputs were provided for the number of units, the starting year and month, and if necessary the duration of employment for the unit. Because most tasks involved units which started and ended at different times, a separate entry was usually required for each unit. For example, platforms are built and go into production at different

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(1) Amoong the more helpful references are: Sullom Voe Environmental Advisory Group (1976); El Paso Alaska Co. (1974); Dames & Moore (1974); Crofts (1978); Akin (1978); Pipeline and Gas Journal (1978a); Larminie (1978); Addison (1978) Duggan (1978); Trainer et al. (1976). These sources provided information about peak workforce levels and/or construction periods for oil terminals or LNG plants. Shore base construction estimates in Tables 5-6A and 5-6B are by Dames & Moore.

times, so each platform was entered separately with approximate dates, lengths of operation, scale factors, etc.

Off-site employment is derived from the rotation factor. If the rotation factor is two, then one-half of the total manpower requirement for the task would be off-site each month; if 1.5, one-third would be off-site each month; and if 1.11, slightly more than one-tenth would be off-site each month.

Transportation requirements are triggered by petroleum and construction activity. Thus, the input for number of units, starting dates, and duration of work for the transportation tasks were tied to the same inputs for each petroleum and construction task. For example, each pipelaying spread requires tug and supply boat service for the same length of time the spread is working. Thus, for each pipelaying spread entered (tasks 12 and 13), its transportation requirements were automatically calculated and assigned to the same months.

Summary employment tables in Section 9.0 show total man-months of labor for each year. Employment for each month has been calculated separately and is available if needed.

A companion report titled "Northern Gulf of Alaska Petroleum Development Scenarios" contains in Appendix D a step-by-step exploration of the deviation of manpower estimates with this model.

6.0 SHORE FACILITIES AND SITING CRITERIA

6.1 Introduction

The requirements for shore facilities in support of offshore petroleum development are extremely varied. It is probably reasonable to assume that if the economics are favorable most adverse siting conditions could be overcome. For example, vessel draft requirements can be accommodated by dredging, extension of piers and offshore loading; the Drift River oil terminal is an example of the latter. Land can be leveled for the construction of facilities; construction of Alyeska's Valdez terminal involved considerable earth and rock excavation. Breakwaters can be constructed to provide sheltered waters. Marine and overland pipelines can be extended to accommodate facility siting. It would be desirable to have road access to marine oil terminal and LNG plants (the principal onshore petroleum facilities that may be required by western Gulf of Alaska OCS development) but it is also possible to build these facilities without this transportation convenience and rely more heavily on air and' sea transport.

While the most economical shore facility site would probably be that with none of the limitations cited above, facility siting in many cases is a compromise between various technical criteria and environmental and socioeconomic suitability.

As indicated in Table 6-1, the principal site selection criteria for marine terminals and LNG plants employed in the scenario analysis are:

- Proximity to offshore fields
- Adequate water depth
- Adequate maneuvering room
- Sheltered anchorage

TABLE 6-1

SUMMARY OF PETROLEUM FACILITY SITING REQUIREMENTS

cility	Land Hectares (Acres)	Water Depth Meters (Feet)	No. of Jetties/ Berths	Jetty/ Dock Frontage Meters (Feet)	Minimum Turning Basin Width Meters (Feet)	Potential Sites in Western Gulf of Alaska[5]	Comments
ude Oil Terminal[1]							
Small-Medium (<250,000 bd)	30 (75)	15-23 (50-75)	1	457 (1500)	1220 (4000)	Ugak Bay	
Large (500,000 bd)	138 (340)	"	2-3	914-1371 (3000-4500)	"	"	
Very Large (>1,000,000 bd)	300 (740)	"	3-4	1371-1829 (4500-6000)	"	"	
G Plant (400 MMCFD)[2]	24 (60)	11-15 (35-50)	1	304-610 (1000-2000)	1220 (4000)	Ugak Bay	In addition to throughout, size of plant will also depend on amount of conditioning required for gas
Construction Support Base[3]	16-30 (40-75)	4.5-6 (15-20)	5-10	304-610 (1000-2000)	304-457 (1000-1500)	Seward, Kodiak	Size of base will be variable depending on functions and storage requirements; multi-purpose base supporting pipe-laying and platform installation assumed here

[1] Trainer, Scott and Cairns, 1976; Sullom Voe Environmental Advisory Group, 1976; Cook Inlet Pipeline Co., 1978; NERBC, 1976.
[2] Dames & Moore, 1974.
[3] Alaska Consultants, 1976.
[4] Woodward-Clyde, 1977.
[5] Potential sites are too numerous to list here - Ugak Bay was site selected by study team for Middle Albatross Bank discoveries; see Woodward-Clyde (1977) for description of potential sites along west coast of Kodiak and Afognak Islands.

- Adequate flat lying land for construction on land with no significant topographic impediments

- No apparent land status or land use conflicts

- No overriding environmental limitations.

For additional and more comprehensive descriptions of onshore petroleum facilities required for offshore development and their siting requirements the reader is referred to reports by Alaska Consultants, Inc. (1976) on marine service bases and the New England River Basins Commission (NERBC, 1976).

6.2 Principal Shore Facilities Required by Western Gulf of Alaska Petroleum Development

6.2.1 Marine Terminals

A significant portion of western Gulf of Alaska crude production will probably be brought to shore for further processing and transshipment to lower 48 markets at a marine terminal. Such a terminal would load crude oil received by pipeline from offshore production platforms onto tankers for delivery to refineries; the terminal may complete stabilization of the crude, recover LPG, treat tanker ballast and provide storage for about 10 days production (the functions of the terminal and its facilities will in part depend on the quality of the crude stream).

The major siting requirements of such a terminal are given in Table 6-1, There are several marine terminals in southcentral Alaska that may serve as examples.

The Alyeska terminal at Valdez sits on 364 hectares (900 acres) and is one of the largest in the world. It is designed to service three tankers, of between 16,320 metric tons and 255,000 metric tons [16,000 to 250,000 dead weight tons (DWT)] each, simultaneously. The largest feature of the terminal is the tank farm, which currently contains 15 tanks. Each tank is 76 meters (250 feet) in diameter and 19 meters (62 feet) high, with a capacity of 510,000 barrels each. There are also three ballast water storage tanks each with a 420,000 barrel capacity. In addition to the tank farm the terminal contains three docks -- two stationary and a floating, the fixed docks being 37 meters (122 feet) long and the floating dock 119 meters (390 feet) long. The terminal also contains the main operations control center for the entire trans-Alaska pipeline system (Al yeska Pipeline Service Company, 1972),

The Drift River terminal, located on the west side of Cook Inlet, presently has a maximum capacity of 250,000 barrels per day with storage provided by seven 270,000 barrel tanks. The terminal can accommodate tankers up to 81,6(10 metric tons (80,000 DWT tons) (Cook Inlet Pipeline Co., 1978).

The potential oil and gas resources of the western Gulf of Alaska, allocated according to the assumption that 80 percent are located in the Albatross basin and 20 percent in the Tugidak basin (see Chapter 3.0), would indicate that the potential requirement exists with the high find resource estimate for an oil terminal along the east coast of Kodiak or Afognak Island with the capacity of up to 384,000 bpd; this requirement assumes that field distribution and economics indicate or dictate a shared pipeline and terminal.

6.2.2 Liquified Natural Gas Plants

Liquified natural gas plants (LNG) are needed when the consumer is not within economic pipeline distances. Because of the geographic isolation of the western Gulf of Alaska and distance to existing or planned transmission lines (e.g., Alcan) or gas processing facilities (e.g., Upper Cook Inlet LNG plant[s]), natural gas in commercial quantities would either be converted locally to LNG for export to the lower 48 states or used as petrochemical feedstock within the state. The scenarios postulated in this study assume conversion to LNG.

Natural gas arriving at an LNG plant will contain methane and varying proportions of nitrogen, helium, water vapor, carbon dioxide, hydrogen sulphide, organic sulfur compounds, ethane, and heavier hydrocarbons. All of these components, except methane, will affect the liquefaction process. Therefore, many of the minor constituents of natural gas will be removed prior to or during liquefaction. (Energy Communications, Inc., 1972).

Land requirements for an LNG plant vary according to type of gas and quantity of gas to be processed. A plant with a total vaporization capacity of 400 MMcfd of gas would require about 24 hectares (60 acres) of land with an all-weather wharfage. The site should be relatively flat lying, with good drainage. Facilities at the site will include administration facilities, shop and warehouse, utilities, water filtration facilities, sanitary facilities, control house, compressor stations, and a gate house. A plant processing 400 MMcfd would probably require LNG tanks with a total capacity of 1.1 million barrels. Most of the space utilized at an LNG plant is for safety, and storage (Dames & Moore, 1974).

The major siting requirements of LNG plants are summarized in Table 6-1.

6.3 Service and Support Bases

Service and support bases includes two principal types:

- temporary bases, which support exploration and exploratory drilling.

- permanent bases, which are set up after a commercial find and support field construction, development drilling activities, and field operations.

Table 6-1 summarizes the requirements for a permanent construction support base.

6.3.1 Temporary Bases

Temporary bases are the links between onshore and offshore activities during the exploratory phase of development. The principal activity of a temporary service base is the transfer of materials and workers between the shore and the offshore operations. A temporary service base requires all-weather berthage for supply and crew boats, dock space for loading and unloading, warehousing and open storage areas, a helipad, and space to house supervisory and communications personnel.

The size and amount of activity at a service base are directly proportional to the number and kinds of vessels and drill rigs being serviced; however, temporary bases are generally small with limited acreage. They are set up on flat, vacant, waterfront land with a marginal wharf. Most of the land is utilized as open storage for pipes, tubular goods, and drilling supplies. Various buildings are located on the property as well as fuel storage tanks (Alaska Consultants, 1976; NERBC, 1976),

Temporary service bases established for the exploration phase following the first generation northern Gulf of Alaska Lease Sale No. 39 were located at Yakutat, Seward and to a minor degree Yakataga. Each of these bases served a different purpose; Yakutat primarily as a crew change facility and storage area for tubular goods shipped up from the lower 48; Yakataga was utilized primarily for crew changes and ferrying services and supplies from either Yakutat or Seward; and Seward provided important road and rail connections with Nikiski/Kenai and Anchorage as well as some equipment supply storage and a potable water supply. Of these sites only Seward in located close enough to potential lease tracts in the western Gulf of Alaska to serve as a temporary or permanent service base. Traits on the northern Albatross Bank lie within 322 kilometers (200 miles) of Seward. All of the potential lease tracts, however, lie within a 322 kilometer (200 mile) radius of the City of Kodiak.

6.3.2 Permanent Service Bases

The permanent service base performs the same function as a temporary base; however, permanent bases are larger due to increased activity. The various factors which influence the location of permanent bases are:

- distance to drilling

- costs
- land availability
- public attitudes
- available harbor facilities
- social facilities.

No permanent service bases have been established to date in the Gulf of Alaska. The only Alaskan analog is the Upper Cook Inlet base at Nikiski/Kenai. However, North Sea permanent service bases, such as the Norscot Base at Lerwick, Peterhead Refuge Harbor, Dundee Petrosea and the Seaforth Maritime base in Aberdeen can be used as examples of bases, with varying capacities, for an evaluation of Gulf of Alaska facility requirements (Cambridge Information & Research Services, Ltd., 1976).

Land requirements for permanent bases generally range from 12 to 30 hectares (30 to 75 acres) of waterfront land. Most of the land is utilized for warehouse and open storage space. About 929 square meters (10,000 square feet) are required for permanent structures to house offices and communications, and one acre helicopter space per platform. The Norscot base at Lerwick Shetland Island is an example of a relatively small base, covering about 12 hectares (30 acres). However, even utilizing only 12 hectares (30 acres), it has the capacity to berth nine supply boats. The permanent service bases for the northern Gulf of Alaska may vary in size depending on need; however, it is reasonable to assume they will be slightly larger. This is due to the distance from major supply outlets causing the need to store large quantities of supplies (Alaska Consultants, 1976).

Materfront requirements include an all-weather, sheltered harbor large enough to accommodate semi-submersible drilling rigs, pipelaying barges and several supply boats. There should be ample turning room (an area five times the width of the largest vessel) and berthing space for supply boats and anchorage. Wharf space is required at 122 meters (400 feet) per rig or platform being serviced. The channel depth should be 4.5 to 7.6 meters (15 to 25 feet) at low tide. Other requirements are summarized on Table 6-1.

6.3.3 Platform and Pipeline Installation Support Bases

Support bases for platform and pipeline installation are usually set up by companies involved in installation. These bases are similar to temporary bases and often utilize the same facilities. One base can support several platform or pipeline installation operations at once.

The land and waterfront requirements include about two hectares (five acres) of land for a base supporting one pipeline installation or up to four platform installations per year. Also one acre is needed for a helipad and 929 square meters (10,000 square feet) for temporary office space. The waterfront requirements are the same as a temporary service base. However, an additional 61 meters (200 feet) of wharfage are preferable for each pipeline or platform installation. Siting requirements are summarized on Table 6-1. Anticipated pipelaying activities in the western Gulf of Alaska area will utilize permanent service bases.

Because of existing infrastructure, materials and labor forces on the west coast of the United States, and Japan, steel platforms will not be constructed in Alaska. This study assumes that they will be fabricated elsewhere and transported to Alaska.

6.4 Site Selection for the Mestern Gulf of Alaska

Siting facilities for the western Gulf of Alaska will provide a greater number of options than was the case in the northern Gulf. The Kodiak Island complex has several deep bays which appear to meet the siting requirements for the facilities detailed above. The high find scenario described in this study is the only one which specifies development of major onshore facilities, in particular an oil terminal and LNG plant.

Two recent studies have evaluated service base and oil terminal siting options for western Gulf of Alaska petroleum development. Woodward-Clyde Consultants (1977) conducted a systematic assessment of potential marine terminal and service base sites evaluating and ranking them according to engineering and geotechnical feasibility, environmental, and socioeconomic considerations. The study also considered pipeline land falls and overland pipeline routes to potential terminal sites.

As part of an impact assessment of Kodiak OCS development conducted for the State of Alaska Department of Community and Regional Affairs, Simpson, Usher, Jones, Inc. (1977) evaluated service base location, in particular, a comparative assessment of the relative merits of Seward and Homer as temporary and permanent service bases. The report noted that there were three alternative support base modes:

1. The use of Seward throughout both exploration and development phases.

2. The use of Seward during the initial exploration phases with a partial on total move to Kodiak as development and production progress.

3. The use of Kodiak Island for onshore facilities throughout the entire exploration, development, and production phases.

One of the determinants of Seward's role would be its role in northern Gulf of Alaska petroleum development and the expanded infrastructure resulting from that development. The Simpson, Usher, Jones report concluded that the most likely case would be No. 2 (above) whereby Seward is the service base for exploration with the role transferred to the Kodiak during the development and production phase.

The major portion of the reserves specified in the scenarios (Chapter 9.0) are assumed to be located on the middle Albatross Bank about 50 miles southeast of the City of Kodiak. The high find scenario postulates that the oil or gas would be brought to shore via a pipeline to an oil terminal or LNG plant located on Kodiak Island.

In the absence of geologic hazard data for the offshore area of Kodiak Island it is assumed that the most direct route to shore would be used. A map of the lease blocks shows that a find in this region of Albatross

Bank might well favor a direct route to shore in the area of Chiniak Bay. This bay is the location of the Municipality of Kodiak, the Coast Guard facilities and a large seasonal seafood processing facility. Demand on the already existing services, especially water supply, are already at a premium. It is possible that if it is the desire of the local population to have these facilities located near the city and sewer and water utilities could be developed. This would be a viable option. However, of the possible sites under consideration this is the least desirable in terms of water depth requirements. Either extensive dredging or extremely long piers would be required to obtain the necessary water depth for tanker traffic. In addition, the National Ocean Survey navigational map (No. 16580, 1978) indicates the presence of numerous rocks. Two other bays within the region were considered as possible sites for facility development, namely, Ugak and Kiluida. Ugak Bay is approximately 32 kilometers (20 miles) south of Chiniak Bay. It is about 24 kilometers (15 miles) long and 8 kilometers (5 miles) wide at its mouth. It is amply deep for tanker traffic and except for its northern shore is relatively free of obstructions. Kiluida Bay is located approximately 24 kilometers (15 miles) to the south. It is 19 kilometers (12 miles) long and about 4.8 kilometers (3 miles) wide. It is slightly less desirable from navigational considerations but it does have sufficiently deep water,

Kiliuda and Ugak have deep water relatively close to shore and ample turning space for tankers. Along the coasts of bays steep slopes intersect the shoreline. Such features are highly undesirable for facility siting. However, many small streams emptying into Kiluida and Ugak Bays have produced relatively flat floodplains adjacent to the coastline. The floodplains developed by some of these streams comprize several hundred acres. The Woodward-Clyde Consultants siting report selected two sites in each of these bays. Of the sites investigated in that report an area on the southern side of Kiluida ranked highest overall when the available biological and socioeconomic factors were considered. On the other hand, the site that we have chosen as best suited for facility siting is the site identified on the north side of Ugak Bay at the headland east of Saltery Cove. In absence of contradictory data there appears to be relatively little difference in the acceptability between sites in Ugak and Kiluida Bays. This is based on the scoring procedure used in the Woodward-Clyde report (op tit, 1977). The northern shore of Ugak Bay is at this time connected to the city of Kodiak in part via a gravel road (maintained) and the remainder via an unmaintained, 4-wheel drive trail. This trail, in all likelihood could be upgraded. This would alleviate the need of constructing a separate airport and probably other services and utilities. Therefore, it appears that the Ugak Bay site would be the more desirable location.

The Ugak Bay site appears to have at least 405 hectares (1,000 acres) of usable land for facility development. Several rivers empty into Saltery Cove and this has resulted in water depths less than required for tanker traffic. Therefore, development would require either initial dredging and the use of piers. Without compositional knowledge of the dredged material it may be assumed that a portion of it could be used as landfill in the area to be developed.

In our opinion the pipelines would be brought to the site entirely underwater. It is felt that this would lessen the aesthetic impact. A sea-land route would require considerably longer lines. We also assume that the corridor would be a direct route from the field to the site. Further study of the offshore sediments and geologic hazard identification may require a variance in this routing design.

We recognize that this choice is based on limited data and alternatives are available. Unlike the northern Gulf where there was a limited number of possible sites there are a number of options in the western Gulf. As a result, biological and other environmental consideration have a great deal of influence in the final selection. The Saltery Cove site has been chosen since it not only has been identified by others as having a relatively low overall impact but it is logistically well-situated for pipeline routing and access to existing infrastructure.

7.0 THE ECONOMICS OF FIELD DEVELOPMENT IN THE GULF OF ALASKA

7.1 Production Systems for the Gulf of Alaska

The economic analysis of field development in the Gulf of Alaska relies on the production technologies described in Section 4.0.

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

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

Sensitivity and Monte Carlo procedures are used in the analysis to allow for uncertainty in the costs of technology and in the price of the oil and gas. A range of outcomes rather than single valued solutions is determined by the analysis to reflect this uncertainty.

The model along with the assumptions are described in detail in Appendix C. In general, the model calculates the discounted cash flows -- investment outflows and revenue inflows -- from production with different. production systems at different water depths and distances to shore to examine how these different physical characteristics affect the decision to develop a discovered field.

It is important to emphasize that the model includes neither bonus payments, nor exploration costs nor the time for these activities. These are large sums of money and several years of discounting future revenues. Were they included the minimum field sizes would be larger. As discussed in Appendix C the objective of this analysis is to determine the minimum field size to justify various production technologies and subsequently, in later chapters to identify impacts on the State of Alaska. This objective differs from that of an exploration economic assessment or a lease bonus calculation, although the basic model is the same in each case. The main differences relate to the treatment of geologic risk and exploration costs which are excluded in this analysis.

Listed below are the essential characteristics of the production systems that comprise the development scenarios. The economics of all but the Storage Buoy System have been analyzed with the model. The economics of a steel platform production system with storage is very similar to that of the concrete platform production system. The minimum field size calculations for Storage Buoy System thus apply closely to the concrete platform system.

- Floating production system restricted to 20 producing wells (subsea completions) with two service wells. Limited to 65 percent production due to no storage. Offshore loading with single point mooring. No water depth limitation.

- Single steel platform with up to 40 producing wells and four service wells. Limited to 65 percent production due to no storage and inaccessability of pipeline. Offshore loading with single point mooring. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single steel platform with up to 40 producing wells and four service wells. Storage buoy allows full production equal to 96 percent of capacity. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single steel platform with up to 40 producing wells and four service wells. Pipeline to shore terminal shared with other producing fields allows full production equal to 96 percent of capacity. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Concrete platform with up to 40 producing wells and four service wells. Storage allows full production equal to 96 percent of capacity. Offshore loading with single point mooring. Water depths: 91 to 183 meters (300 to 600 feet).

- Concrete platform with up to 40 producing wells and four service wells as part of a multi-platform field. Pipeline to shore terminal allows full production equal to 96 percent of capacity. Water depths: 91 to 183 meters (300 to 600 feet).

- Multiple steel platforms with up to 40 producing wells per platform and four service wells. Pipeline to shore terminal allows full production equal to 96 percent of capacity. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single or multiple steel platforms with up to eight gas producing wells per platform and one service well. Pipeline to shore for conversion to LNG. Water depths: 30.5 to 183 meters (100 to 600 feet).

7.2 Uncertainty of the Values of the Critical Parameters

Not one of the values of the economic and physical parameters that will affect the decision to develop some future discovered field in the Gulf of Alaska is known with certainty, Clearly, the quality of this future discovered oil is unknown. The exact water depths where a discovery will be made is not known. Neither is the field location known nor a suitable shore terminal site. Each of these is critical to the decision to develop.

Development costs which are expected to be extremely large can only be estimated in a broad range under today’s economic conditions and today’s technology. Late 1980’s technology and its costs can no more be pinned down with any certainty for this analysis than can future prices.

In view of the vast uncertainty attached to evaluating the economics of field development in the Gulf of Alaska, values for the variables that enter into the solution of the model have either been assumed to be a single value or entered as a range of values. Sensitivity and Monte Carlo analytical techniques have been used to test the effects on field development of the estimated range of values for investment and operating costs and oil and gas prices. Sensitivity analysis has been used in every case to show the effect on the minimum field size of changing the values for oil and gas prices and development costs. Monte Carlo simulation is used with a selected oil development case and a selected gas development case to develop a sampling distribution of the probability of achieving an assumed 15 percent hurdle rate in view of the vast uncertainty of prices and costs. In the Monte Carlo runs prices and costs were allowed to vary within the boundaries of their ranges described in Section III of Appendix C for that field size previously calculated as the minimum required for development assuming mid-range cost and price values.

7.3 The Assumptions of the Model Restated

The physical characteristics of production including critical assumptions such as initial well production rates that affect the economic calculations are described and discussed in Section IV of Appendix C. The financial and economic assumptions are discussed in Section III of Appendix C. Restated below are: (1) the explicit assumptions of the model; (2) the assumed values for the variables entered as single values; and (3) the range of values for the variable which are tested with sensitivity and Monte Carlo procedures.

7.3.1 Assumed Production Characteristics

- Initial production per well assumed:

  2500 Barrels per day for oil (bbl/d)
  25 Million cubic feet per day for gas (MMcf/d)

- Two drilling rigs on a typical large 40 producing well platform are each assumed to complete eight wells a year. Four service wells are assumed for 40 producing wells.

- Oil production for a typical 40 producing well platform in up to 91 meters (300 feet) of water is assumed to begin in the sixth year, when the first 16 wells are completed, step-up one year later to 30 producing wells, and step-up again, in the eighth year, to maximum production. At water depths greater than 91 meters (300 feet) add one more year delay.

- Platforms are assumed to produce 96 percent of capacity for full-time systems and 65 percent of capacity for offshore loading, no storage systems.

- Oil production is assumed to continue flat until 45 percent of recoverable reserves are produced and then decline exponentially. Figure C-1 in Appendix C depicts the production profile for a typical single platform field.

- Between 65 and 70 percent of the recoverable reserves of oil are produced within the first 40 percent of field life.

- Production decline rates vary as a function of production system, reserves recovered per well, and the assumed initial production rate. Calculated decline rates for the various systems analyzed vary typically between 14 percent and 23 percent.

- Secondary recovery is assumed to begin when 65 percent to 70 percent of recoverable reserves are produced.

- Oil well spacing varies from 40 to 131 hectares (100 to 325 acres) per well as a function of reservoir characteristics and average depth of reservoir.

- Eight or sixteen gas wells per platform are assumed.

- Gas production is assumed to begin with four wells in the fifth year and step up to full production at the rate of four wells a year, then continue flat until 75 percent of recoverable gas is produced. Production then declines exponentially somewhat rapidly. A decline rate between 20 percent and 35 percent depending on gas reserves per well is used.

- Non-associated gas wells are assumed to be spaced between 162 to 404 hectares (400 to 1,000 acres) per well as a function of average reservior depth and number of platforms. Market demand rather than reservoir engineering is assumed to determine the extraction rate and, therefore, well spacing.

- Pipeline distances to shore are considered to be either 81 to 129 kilometers (50 or 80 miles). Sixteen kilometers or ten miles of small diameter spur lines are assumed for platforms sharing a major trunkline.

- Water depths are considered to be 30.5 meters (100 feet), 91 meters (300 feet) or 183 meters (600 feet).

7.3.2 Financial Assumptions and Assumed Values for Fixed Variables

- Prices and costs are held constant in 1978 dollars.

- The model uses continuous discounting. Discounting of cash flows begins with the first development investment.

- Net present value calculations use 10 percent and 15 percent as the upper and lower limit value of money.

- Sensitivity analyses assume 15 percent value of money.

- Federal tax rate is assumed to be 48 percent.[1]

- No state or local taxes are assumed.

- No depletion allowance is allowed.

- Royalty rate is assumed at 16-2/3 percent.

- Investment tax credit on tangible investments is assumed to be 10 percent.

- No bonus bid or exploration costs are included; again, it should be emphasized that this analysis investigates the economics of the production systems required to develop oil and gas fields in the Gulf of Alaska with assumed reservoir characteristics.

- Seventy percent of capital investment is assumed tangible and is depreciated over the production life of the field using the units-of-production method.

- Thirty percent of capital investment is assumed intangible drilling costs and is expensed against revenue from production.

- Investment schedules vary with the different production systems and with water depth. Time lags and costs incurred for permits, etc. from time of discovery to initial development investment are assumed to be expensed against corporate overhead. Typical investment schedules vary from four to five years for the non-associated gas system to six or seven years for a single platform oil system. Seven or eight year investment schedules are assumed for two platforms; eight or nine years for three platforms.

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(1) Effective January 1, 1979, Federal Tax Rate changed to 46 percent. This analysis was done before the change was announced.

- Annual operating costs are assumed to be constant per platform and not to vary with production. Thus, as production declines over time, the cost per barrel produced rises.

7.3.3 Variables Entered as a Range of Values

- Oil prices are entered at $11.00, $12.00 and $15.00 BBL.

- Gas prices are entered at $1.75, $2.00 and $2.25 MCF.

- Annual operating costs in millions of dollars are entered as follows:

	Low	Mid	High
Floating Production System	$20	$ 25	$35
Single Platform Oil or Gas System	$25	$ 35	$50
Two Platform Oil Systems	$50	$ 70	$100
Three Platform Systems	$75	$100	$140

- Tangible and intangible mid-range costs are entered. For sensitivity and Monte Carlo analysis, lower limits are estimated to be 75 percent of tangible and intangible mid-range values; upper limits are estimated to be 140 percent of mid-range values.

7.4 The Analytical Results

7.4.1 Summary: Minimum Field Sizes for Development

Table 7-1 summarizes the results for the estimated minimum field size for the development calculation. The minimum field size for six different oil production systems and one system for producing gas are shown on Table 7-1 for both 10 percent and 15 percent value of money. The mid-range values for costs, $12.00 barrels (bbl) oil and $2.00 thousand cubic feet (mcf) gas, are assumed in the minimum field calculation on Table 7-1.

TABLE 7-

MINIMUM F ELD SIZES FOR DEVELOPME

	Mid-Range Investment ($ Million) (1978)	Number of Wells	Minimum Size Field (MMBBLS) 10%	15%	R.O.R. A/T@ Field Size Shown (MMBBLS)	Production Characteristics For Minimum Fiel at 15%: First Production Year	Peak Producing Year	Decline Year	Decline Rate	Total Producing Years	Effective Average Peak Product (MBD)
Sma 1 Field Systems											
1) Floating System -65% Production	340.5	20	1 5	Not Economic[1]	150/11.7%	5	5	9.4	.14	15.7[3]	32.5
2) Steel Platform 100 Ft. - No Storage - SPM -65% Production	288.2	20	>100	>100	100/7.8%	-	-		-	-	32.5
Steel Platform System											
- No Storage - SPM: Offshore Loading - 65% Production											
3) 100 Ft.	397.9	40	110	190	200/15.3%	6	8	0.5	.19	16.2	65
4) 300 Ft.	443.1	40	160	Not Economic	300/13.7%	6	8	9.75	.22	13.7[3]	65
5) 600 Ft.	685.2	40	Marginally Economic[2]	Not Economic	450/10.2%	7	9	6.3	.08	34[3]	65
Concrete Platform											
- SPM: Offshore Loading - Storage - 350 Day/Year Production											
6) 300 Ft.	538.0	40	130	225	225/15.1%	6	8	8.75	.22	13.4	96
7) 600 Ft.	723.4	40	250	Not Economic[1]	450/12.1%	7	9	13.6	.12	25.8[5]	96

[1]Production systems that are not economic require so long a production profile to recover the upper limit field size tested that any more reserves would be recovered so far into the future with the assumed system that additional reserves would change little the economic outcome. Either a faster recovery system or higher prices would be required to justify recovery.

[2]The production system that is marginally economic exceeds the hurdle rate but requires 34 years to recover the reserves. We judge that an oi producer would not adopt a system that would require so long to exhaust reserves.

[3]Where no field size is economic at 15 percent, production profile for minimum field at 10 percent is shown.

TABLE 7-i (Cont.)

	Mid-Range Investment ($ Million) 1978)	Number of Wells	Minimum Size Field 10% (MMBLS)	Minimum Size Field 15% (MMBLS)	R.O.R. A/T@ Field Size Shown (MMBBLS)	Production Characteristics For Minimum Field at 15%: First Production Year	Peak Producing Year	Decline Year	Decline Rate	Total Producing Years	Effective Average Peak Production (MBD)
Two Steel Platforms With 50 Mile Pipeline To Shore Terminal											
8) 300 Ft.	1006.3	80	260	510	510/15.0%	6	9	10.6	.20	15.5	192
9) 600 Ft.	1490.5	80	550	Not Economic	1000/ 12. 0%	7	10	12.0	.19	16.7	192
Three Steel Platforms With 80 Mile Pipeline To Shore Terminal											
10) 300 Ft.	1431.1	120	400	760	760/15.0%	6	10	11.2	.21	16.1	288
11) 600 Ft.	2134.1	120	825	Not Economic	1500/ 12. 5%	[illegible]	[illegible]	12.4	.19	1[illegible].33	288
Single Platform With Shared 50 Mile Pipeline To Shore With 10 M. Spur											
12) 300 Ft.	507.9	40	120	215	300/16.2%	6	8	10.2	.20	15.3	96
13) 600 Ft.	750.0	40	290	Not Economic	450/12.7%	7	9	11.8	.18	17.03	96
Single Platform Non-Associated Gas With Shared 50 Mile Pipeline											
14) 30.5 M (100 Ft.)	212.7	8	0.6 TCF	1.15 TCF	1.15 TCF/15.0%	5	6	12.8	.17	15.3	192 MMCFD
15) 91 M (300 Ft.)	265.9	12	5	1,25 TCF	1.25 TCF/15.0%	5	7	14.0	.25	16.5	288 MMCFD
16) 183 M (600 Ft.)	506.4	16	1.3	Not Economic	2.0 TCF/12%	6	9	14.5	.31	13.0	384 MMCFD
17) 183 M (600 Ft.)	601.5	24	6	Not Economic	3.5 TCF/14.2%						576 MMCFD

*Production profile for 450 MMB field.

[illegible] only required 10 percent eight wells would be sufficient

It is important to emphasize that there is no single valued solution for any calculation reported in this analysis. It also is important to emphasize that these calculations are sensitive to the relative relationships of prices and costs and these are assumed fixed at their 1978 levels for the resources described in Section 111.2, Appendix C.

Different rates of inflation for prices and costs could significantly change this relationship and affect the economic solutions. Appendix C discusses the methodology. This analysis relies on a range of values for prices and costs to identify the plausible range of values for the calculated decision variables under 1978 economic conditions. While Table 7-1 shows single-value minimum field sizes, the figures that follow in Section 7.4.3 emphasize the actual range in economic field sizes.

A considerable amount of information is summarized on Table 7-1. The first column shows the mid-range total investment required for the specified production system for a given water depth and pipeline distance to shore. Costs range from $228 million for a single steel platform offshore loaded in 30.5 meters (100 feet) of water to $2.1 billions for three platforms in 183 meters (600 feet) of water 129 kilometers (80 miles) from shore. The second column shows the number of producing wells assumed to be housed on the platform. An additional service well is assumed for every ten producing wells. Forty producing oil wells are assumed for most platform systems.

The third column shows the calculated minimum field size bracketed by 10 percent to 15 percent value of money for each production system at different water depths. The values shown refer to recoverable reserves. The fourth column shows the internal rate of return on investment calculated for the largest field size evaluated with the model. Where no field size is able to earn 15 percent, the values in this column show how close to 15 percent the upper limit field size allows.

The next five columns show the production characteristics for the minimum field size at 15 percent or, where indicated, 10 percent. First year of production, peak production year, first year of decline and decline rate are shown as well as the total producing life of the field.

The last column shows average peak production rate for the system. Assuming each well produces 2500 bbl/d, a 40 well platform can produce 100 MMbbl/d. The average production rate assumes four percent downtime for pipeline and offshore loading systems with storage; 35 percent downtime for offshore loading systems with no storage.

Several important conclusions are suggested by Table 7-1:

- The economic results are extremely sensitive to the value of money. Minimum field sizes for all systems at. all water depths vary greatly at discount rates between 10 percent and 15 percent.

- The economic results are extremely sensitive to water depth. All cases show that investment costs rise dramatically with water depth. The minimum field size increases with water depth.

- No field smaller than 215 MMbbl recoverable reserves will meet a 15 percent hurdle rate in the Gulf of Alaska under any production system tested in 91 meters (300 feet) of water.

- Oil fields at 183 meters (600 feet) water depth are not economic [1] assuming 15 percent value of money under any production system.

- Production systems allowing for no storage and offshore loading that are assumed shut-down 35 percent of the time are less economic than full-production systems. Case 4 compared to 6

(1) Production systems that are not economic require so long a production profile-to recover the upper limit field reserves that additional reserves would change little the economic outcome. Either a faster recovery system, higher prices or lower costs would be required to justify recovery.

shows that although investment cost is 22 percent larger in Case 6, which allows full-time production, minimum field size at 10 percent value of money is almost 20 percent smaller. At 15 percent value of money, Case 4 is not economic at any field size while Case 6 is economic with a 225 million barrels (MMbbl) field.

- A single steel platform supporting one-half the cost of a pipeline to shore and a share of shore terminal cost proportionate to share of throughput is slightly more economic than a concrete platform with storage loaded offshore. Case 12 compared to Case 6 shows that estimated mid-range costs are slightly smaller for the pipeline system and minimum field size, accordingly, is slightly smaller.

- Relatively small non-associated gas fields -- under 1.25 tcf -- are economic at $2.00 mcf in water depths up to 91 meters (300 feet).

  An 8-well production system will earn 15 percent in 30.5 meters (100 feet) of water with a 1.15 tcf gas field. The same system will earn 10 percent in 91 meters (300 feet) of water with a 0.75 tcf field. (Case 14)

  A 12-well production system with 1.25 tcf field size will earn 15 percent in 91 meters (300 feet) of water. (Case 15)

- No gas field size is able to earn 15 percent in 183 meters (600 feet) of water with production 1 imited by demand to 24 wells producing 576 MMcfd on average over the year. (Case 17) With 32 wells producing to increase the rate of recovery, the minimum economic field size to earn 15 percent is between 3.0 and 3.5 tcf. (This is not shown as explained in conjunction with Figure 7-42 because industry spokesmen believe demand forces are more likely to limit gas producton than reservoir optimization considerations.)

7.4.2 Distribution of Development Costs

7.4.2.1 The Effect of Water Depth on the Distribution of Field Development Cost

Tables 7-2 and 7-3 show the percentage of distribution of development costs for typical oil and gas steel platform production systems at various water depths in the Gulf of Alaska. The oil platform allows for no storage. While a concrete platform with storage is more costly, the percentage distribution of costs is similar.

No bonus payment of exploration costs are included either in Table 7-2 or 7-3. As discussed in Appendix C, development costs are considered those after discovery.

Tables 7-2 and 7-3 show the increasing relative share of platform structure costs at increasing water depths. From 30.5 to 183 meters (100 to 600 feet), platform costs increase nearly four times. Figure 7-1 shows the effect of the increase in platform investment costs on field development economics. A 300 MMbbl field produced from a single steel platform and offshore loaded earns 18.5 percent in 30.5 meters (100 feet) of water and 8.3 percent in 183 meters (600 feet). Different production systems would earn different rates of return; but the inverse relationship between water depth and rate of return would not change.

As previously indicated, no oil production system analyzed in 183 meters (600 feet) of water earned a 15 percent rate of return. There are no combinations of platforms and field sizes at 183 meters (600 feet) water depth that can recover the oil fast enough to earn 15 percent under the assumptions of the analysis. Either higher prices, lower costs or peak production rates in excess of 2,500 bbl/d well are required to allow an oil field to earn 15 percent in 183 meters (600 feet) in the Gulf of Alaska.

TABLE 7-2

OIL: Percentage Distribution of Development Costs For A Single Steel Platform With Off-Shore Loading At Various Water Depths: Maximum Production -- 100 Mbbl/d

	100 Feet	300 Feet	600 Feet
Platform Fabrication & Installation	25.0%	32.1%	54. 3%
Platform Equipment & Misc.	24.6	22.7	16.4
Development Wells (44)	36.5	32.7	21.2
Single Point Mooring	13.9	12.5	8.1
	100.0%	100.0%	100.0%
Total Mid-Range Investment: $ Million (1978)	397.9	443.1	685.2
Of which, Platform Cost: $ Million	99.3	142.3	371.8

TABLE 7-3

GAS: Percentage Distribution of Development Costs For A Single Steel Platform At Various Water Depths Sharing A Pipeline To Shore: Maximum Production -- 400 MMcf/d

Platform Fabrication & Installation	49. 2%	53.7%	73.5%
Platform Equipment & Misc.	15.4	14.2	9.7
Development Wells (9)	21.9	19.9	10.4
Spur and 50-Mile Pipeline to Shore	13.5%	12.2%	6.4%
	100.0%	100.0%	100.0%
Total Mid-Range Investment: $ Million (1978)	240.7	265.9	506.9

Source: Based on Estimated Costs in Appendix B.

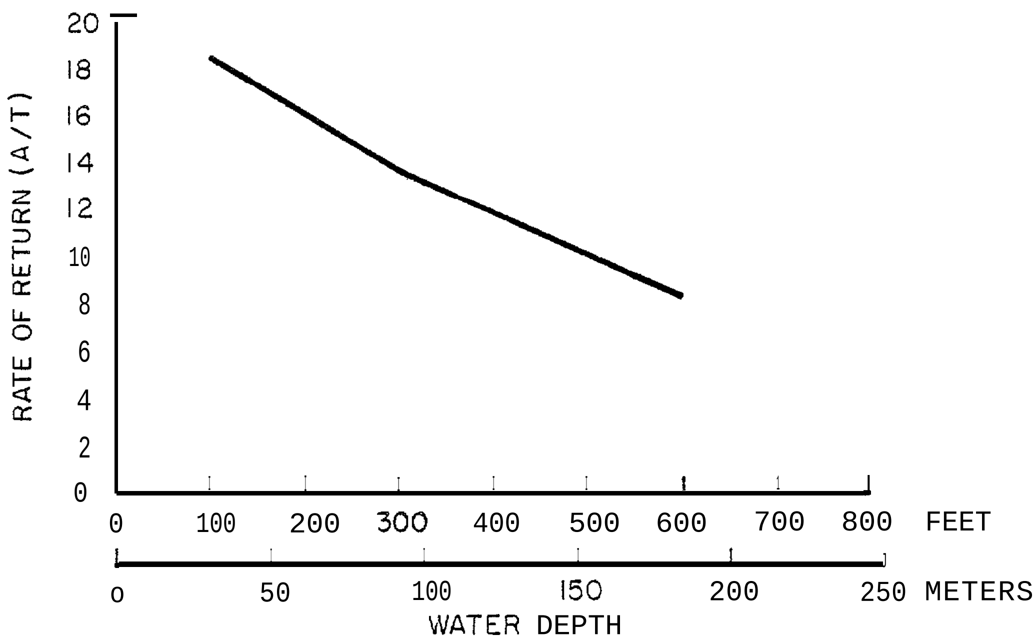


FIGURE 7-1

INTERNAL RATE OF RETURN
FOR 300 MILLION BARREL FIELD
AT DIFFERENT WATER DEPTHS
(SINGLE STEEL PLATFORM WITH OFFSHORE LOADING)

7.4.2.2 Impact of Pipeline Cost and Shore Terminal Cost on the Distribution of Development Cost

Table 7-4 shows the percentage distribution of development costs among fully equipped oil platforms, pipelines and shore terminals. The share of total shore terminal costs allocated to each of the systems on Table 7-4 is proportionate to each system's assumed share of terminal peak throughput. The terminal is assumed to be capable of handling 650 Mbbl/d.

Clearly, platform production costs dominate the development expenses to bring a field on-stream in the Gulf of Alaska. The economics of development, therefore, are proportionately much less sensitive to pipeline cost than to water depth in this analysis. The memo case of the single platform system shows that under the worst plausible assumption, an unshared 129 kilometer (80-mile) pipeline, pipeline cost amounts to only 18 percent of total at 91 meters (300 feet), 12 percent of total at 183 meters (600 feet).

7.4.3 Minimum Required Price to Justify Field Development

Given the estimated costs of various oil and gas production systems identified in this report, the minimum price to justify development can be calculated using the model in Appendix C. Different production systems with different investment costs yield different minimum prices for various field sizes. The minimum required price is also sensitive to water depth.

7.4.3.1 Oil

Figure 7-2 shows the minimum required price to develop a known oil field with a single steel platform oil producing system in 91 meters (300 feet) and 183 meters (600 feet) of water sharing a pipeline to shore and paying a share of shore terminal cost proportionate to peak throughput. Forty producing wells are assumed. Table 7-1 previously showed that this system is the most economic of all single platform systems analyzed.

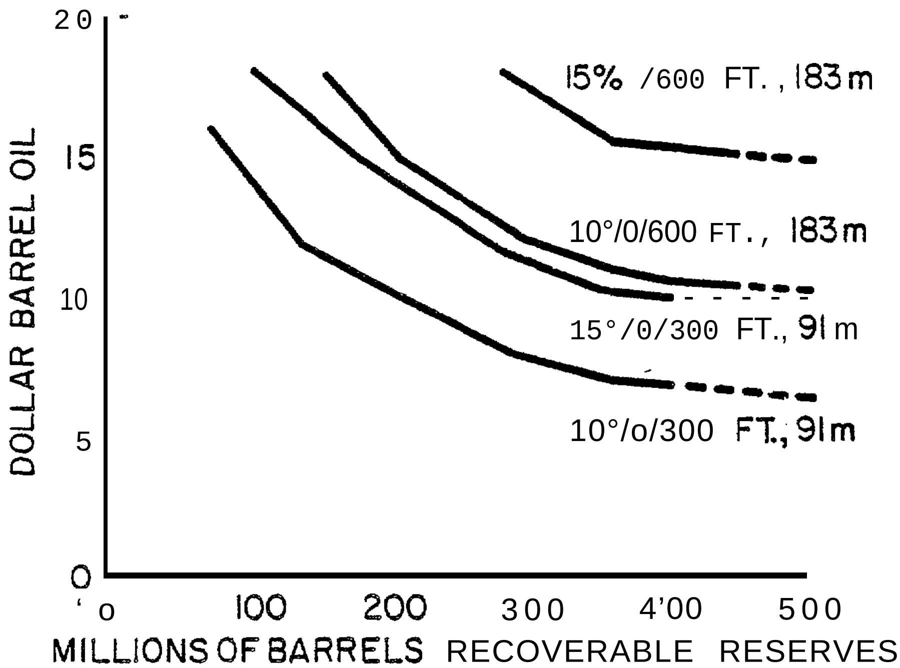


FIGURE 7-2

MINIMUM REQUIRED PRICE TO JUSTIFY DEVELOPMENT AS A FUNCTION OF FIELD SIZE & WATER DEPTH :- OIL SINGLE STEEL PLATFORM WITH PIPELINE TO SHORE

TABLE 7-4

OIL: Percentage Distribution of Mid-Range Development Costs Between Platforms, Pipeline and Shore Terminal -- One and Two Platform Production Systems

	91 METERS (300 FT.)		183 METERS (600 FT.)	
	$ Million	%	$ Million	%
Single Steel Platform, w/40 Producing Wells	387.9	76.4	630.0	84
½ Share 50 Mile Pipeline[2]	37.5	7.4	37.5	5
15.5% Share Shore Terminal[3]	82,5	16.2	82.5	11
	507.9[4]	100.0	750.0[5]	100.0
Memo:				
To assume full-share $0-mile pipeline	574.4	100.0	846.5	100.0
Pipeline Share	104.0	18.1	104.0	12.1
Two Steel Platforms w/40 Producing Wells Each[1]	775.8	74.3	1260.0	82.4
Full Share 80-Mile Pipeline[6]	104.0	10.0	104.0	6.8
31% Share Shore Terminal[3]	165.0	15.7	165,0	10.8
	1044.8[7]	100.0	1529.0[7]	100.0

[1] Maximum platform production equals 100 MBD.

[2] Trunk line costs $1.3 million/mile plus $5.0 million spur line.

[3] 650 MBD capacity shore terminal estimated cost is $535 million. Share of cost equals share of capacity at peak daily throughput.

[4] This is Case 12 on Table 7.1.

[5] This is Case 13 on Table 7.1.

[6] Pipeline costs $1,3 million/mile.

[7] These are similar to cases 8 and 9 on Table 7.1 which assume 50-mile pipeline,

Source: Based on Estimated Costs in Appendix B.

Furthermore, for field sizes less than 500 MMbbl, Section 7.4.4 will show that single platform development is more optimal than two or three. Accordingly, the minimum required price for any field size less than 500 MMbbl calculated for this system will envelop the minimum price that can be calculated for any other single platform system.

Figure 7-2 brackets the minimum price at 10 percent and 15 percent for field sizes up to 500 MMbbl. Figure 7-2 demonstrates two important conclusions of the analysis:

- The minimum price calculated with the model is very sensitive to the value of money used in the calculations and the water depth of the field. A 200 MMbbl field in 91 meters (300 feet) which breaks even with the development costs at $10.00 bbl at 10 percent value of money, requires $14.00 at 15 percent. . A 300 MMbbl field in 183 meters (600 feet) which breaks even at $12.00 bbl at 10 percent, requires $17.50 bbl at 15 percent.

- The minimum price calculated with the model is little affected by production from fields larger than 350 MMbbl assuming initial well productivity of 2500 b/d.

Under the assumptions of the model discussed in Appendix C, 350 MMbbl is the largest field size that can be produced from a 40 producing well platform in about 20 years. Adding five years from initial investment to initial production means that the last barrels of oil from fields larger than 350 MMbbl are captured beyond 25 years into the future. The present value of this oil has little impact on the calculation of the minimum price for field development. Thus, the minimum required price at 91 meters (300 feet) does not drop much lower than $10.00 bbl at 15 percent or $7.00 bbl at 10 percent as fields increase beyond 350 MMbbl produced with this system.

7.4.3.2 Non-Associated Gas

Figure 7-3 shows the minimum required price for developing a known gas field with the production systems described in Chapter 4.0. Mid-range

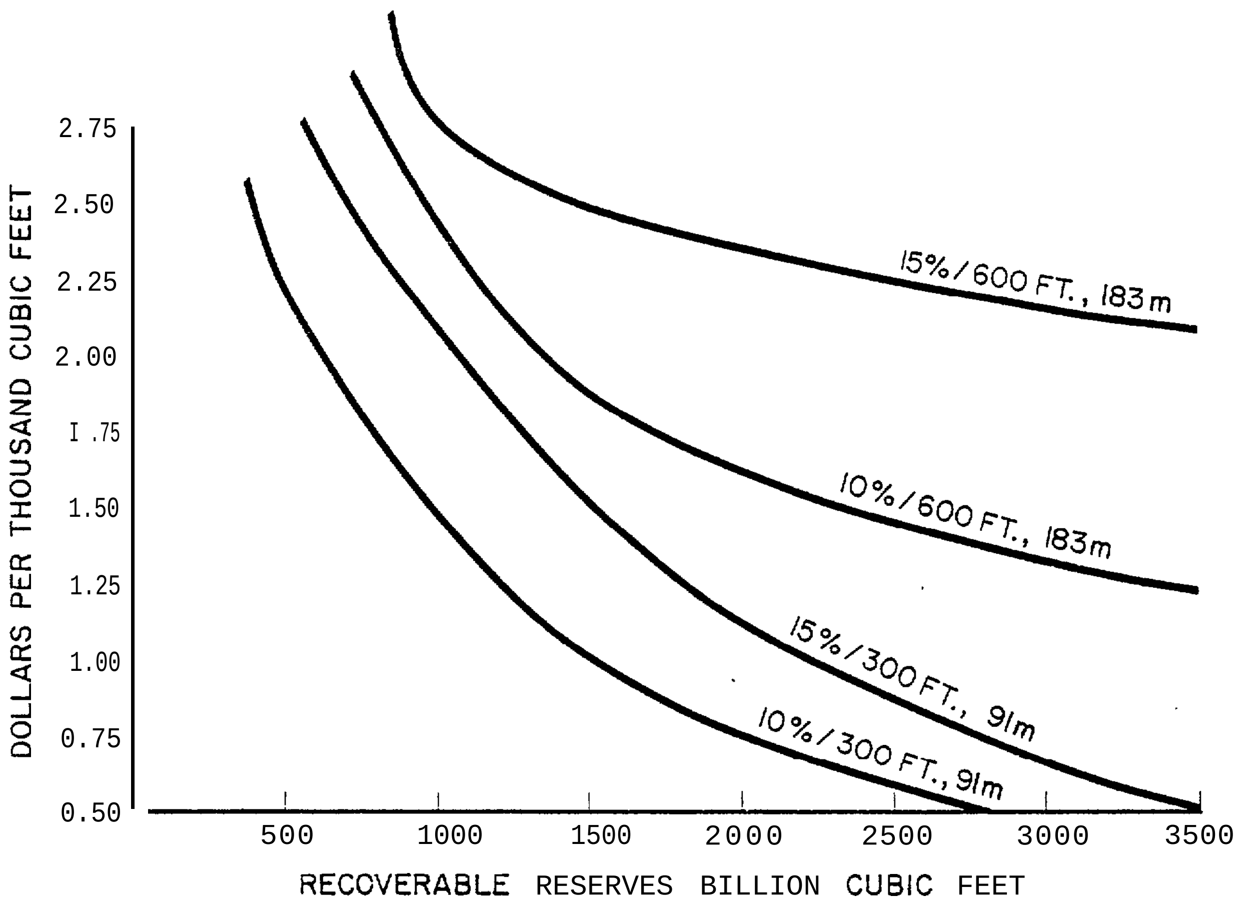


FIGURE 7-3

MINIMUM REQUIRED PRICE FOR DEVELOPMENT
AS A FUNCTION OF FIELD SIZE & WATER DEPTH: - GAS
SINGLE STEEL PLATFORM WITH PIPELINE TO SHORE

investment costs are assumed in Figure 7-3. Figure 7-3 assumes a single steel platform production system in 91 and 183 meters (300 and 600 feet) of water. The number of wells on the platform are assumed to be sufficient to recover reserves in about 15 to 20 years for fields 3.0 tcf and smaller. Wells are assumed to produce 25 MMcfd. Eight wells are assumed for fields less than 1.0 tcf; 12 wells for field for 1.0 tcf and 1.5 tcf; 16 wells for 2.0 tcf and 2.5 tcf; 24 wells for 3.0 tcf and 3.5 tcf. The peak production from 24 wells is considered throughout this analysis the upper limit than can be processed by shore facilities due to constraints on demand for LNG. With 24 wells 3.0 tcf can be recovered in about 23 years; 3.5 tcf can be recovered in about 27 years.

The curves for 30.5 meters (100 feet) water depth are slightly lower than 91 meters (300 feet) curves and are not shown.

The minimum required price calculated with the model is sensitive to water depth, the value of money and size of field.

For a 1.0 tcf field and mid-range investment costs:

- $1.50 Thousand cubic feet (Mcf) is the minimum price to justify development at 91 meters (300 feet) and 10 percent;

- $2.10 Mcf is the minimum price at 91 meters (300 feet) and 15 percent;

- $2.40 Mcf is the minimum price at 183 meters (600 feet) and 10 percent;

- $2.75 Mcf is the minimum price at 183 meters (600 feet) and 15 percent.

For a 2.0 tcf field, the minimum price to justify development is:

- $0.75 Mcf is the minimum price at 91 meters (300 feet) and 10 percent;

- $1.15 Mcf is the minimum price at 91 meters (300 feet) and 15 percent;

- $1.75 Mcf is the minimum price at 183 meters (600 feet) and 10 percent;

- $2.50 Mcf is the minimum price at 183 meters (600 feet) and 15 percent.

7.4.4 The Decision to Develop With One or More Platforms

Table 7-1 shows the minimum field size to justify one, two or three steel platforms at different water depths but gives no insight about the decision to develop with one or more platforms. Interrelated physical reservoir and production characteristics and economics govern the decision. To simplify the discussion, platforms are assumed to accommodate 40 producing wells at a peak production rate of 2,500 bbl/d/well. Reservoir thickness and depth is not assumed to be limiting.

The single platform begins production beginning with the sixth year following initial development investment and reaches its 100 Mbbl/d peak beginning with the eighth year. The two platform system also begins production from its first platform beginning with the sixth year but reaches its peak of 200 Mbbl/d beginning with the ninth year, The three platform system starts production in the sixth year and reaches its peak of 300 Mbbl/d beginning with the tenth year following initial development investment.

Table 7-5 shows the internal rates of return for one, two and three platform systems in 91 meters (300 feet) of water for field sizes from 120 MMbbl to 1,000 MMbbl. The one platform system is assumed to share one-half of an 81-kilometer (50-mile) pipeline to shore and a part of shore terminal cost proportionate to throughput. The two and three platform systems absorb the entire cost of the 81-kilometer (50-mile) pipeline and pay a proportionate share of the shore terminal cost. Estimated shore terminal cost is $535 million. Terminal capacity is assumed to be 650 Mbbl/d.

TABLE 7-5

The Rate of Return For Developing Different
Field Sizes With One, Two or Three Platforms

	Number of Platforms[1]		
Field Size[2] (Million Barrels)	One[3] %	Two[4] %	Three[5] %
120	10.0		
150	10.6		
300	16.2	10.6	
450[6]	17.5E	13.5	10.9
500	17.5E	14.6	11.3
750		18.5E	14.8
1000		18.5E	18.5

Source: Dames & Moore Estimates

Notes:
[1] Each platform is assumed to house 40 producing wells at a peak rate of 2500 B/D/well. Other production assumptions are discussed in Appendix C and in Section 7.

[2] Recoverable reserves.

[3] Case 12 on Table 7.1. Production begins in sixth year and reaches 100 MBD peak in the eighth year.

[4] Case 8 on Table 7.?. Production begins in sixth year and reaches 200 MBD peak in the ninth year.

[5] A modification of Case 10 on Table 7.1. Production begins in the sixth year and reaches 300 MBD peak in the tenth year.

[6] Estimated rates of return are extrapolations.

Table 7-5 allows the following conclusions:

- The second platform does not become more economic than a single platform system until a field in excess of 500 MMbbl is produced. (500 MMbbl can be produced with a single platform is slightly less than 30 years.)

- The third platform does not become more economic than the two platform system until a field in excess of 1.0 billion barrels is produced.

- Although production-per-platform of reserves greater than 350 MMbbl has little impact on the calculated rate of return, the "lumpiness" of investment does not allow the addition of another platform at that point. Vastly larger reserves are required to justify the next platform.

- If reservoir thickness or depth dictates development with two platforms of a field smaller than 500 MMbbl, the operator would have to be willing to accept a rate of return lower than 15 percent.

7.4.5 Economics of Scale: Per Barrel Investment Cost of Development

The investment cost per barrel of reserves in developing a field declines with the size of the field, assuming environmental conditions and production systems remain the same.

The method used to calculate economies of scale is derived from a concept of Adelman.(1) Section V of Appendix C shows the mathematics of computation. The production flow through time from fields of different sizes is discounted to present time in terms of the "present barrel equivalent" of the flow of oil. Aggregating this way gives much less weight to the last barrels of oil than to the first. Similarly, the

(1) M. A. Adelman, 1972.

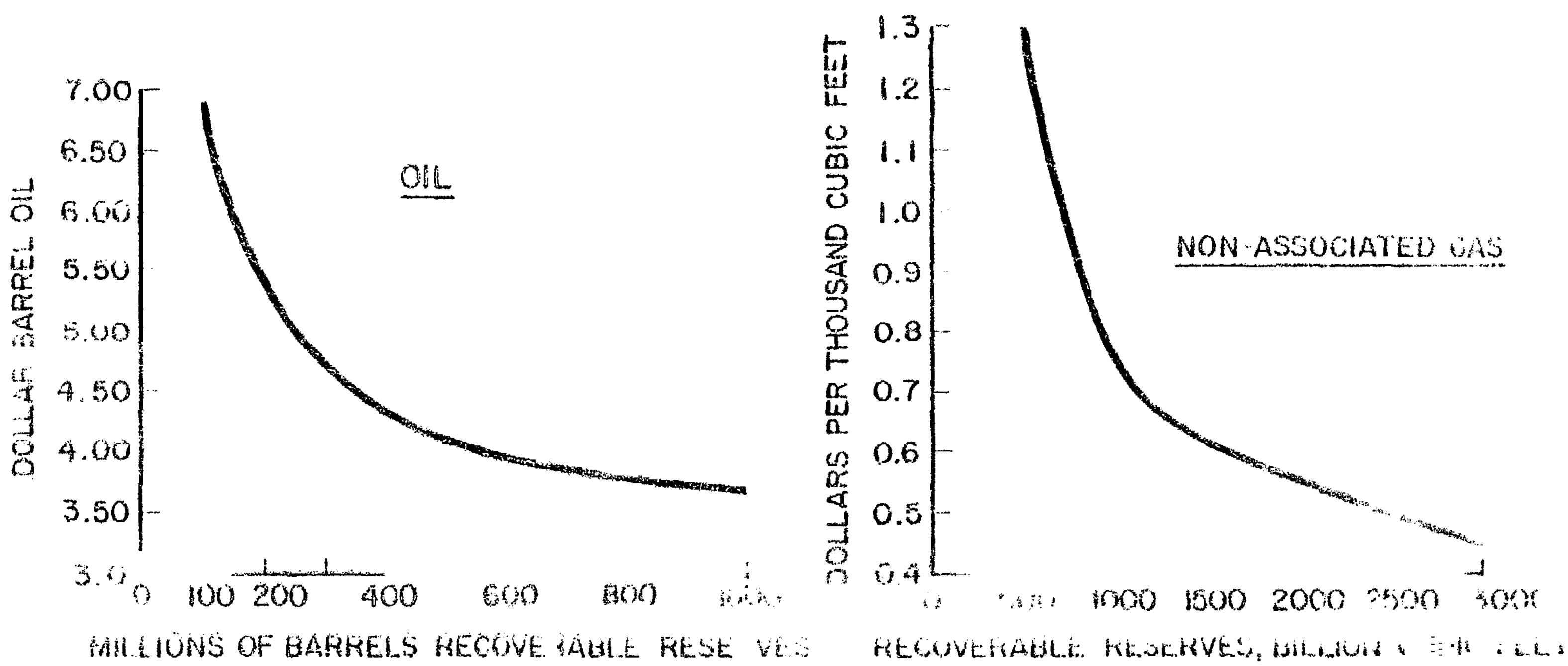


FIGURE 7-4

ECONOM ES OF SCALE: OIL & GAS DEVELOPMENT COST
PER BARREL OIL, PER THOUSAND CUBIC FEET GAS FOR
SINGLE S EEL PLA FORM WITH PIPELINE O SHORE - 91m (300 FT) WA ER DEPTH

investment flow through time is discounted to present time. Both petroleum and investment flows are discounted at 15 percent to construct Figure 7-4. Per barrel development cost is computed by dividing the present value of investment by the "present barrel equivalent" of oil or gas. Table 7-6 shows the "present barrel equivalent" of various oil and gas field sizes according to the assumptions of this report.

Figure 7-4 shows the effect of economies of scale for typical gas and oil production systems. Each system assumes a single steel platform in 91 meters (300 feet) of water with a pipeline to shore. The oil system is Case 12 on Table 7-1; the gas system is Case 15, but gas wells increase from 8-24. Different production systems at different water depths have different unit development costs but similar economies of scale characteristics. For two or three steel platform systems, the field size scale on the horizontal axis can be approximately doubled or tripled without changing the vertical scale or the location of the curves.

Development cost per barrel is not shown on Figure 7-4 for field sizes below 100 MMbbl oil or 500 Bcf gas because smaller fields are not economic. The biggest decrease in unit development costs occurs between 100 and 350 MMbbl oil and 500-1500 Bcf gas. Beyond 350 MMbbl or 1500 Bcf there is little change in the per barrel development cost.

7.4.6 Sensitivity and Monte Carlo Results for the Different Production Systems

The sensitivity tables and figures and Monte Carlo distributions in this section emphasize the uncertainty built into the economic analysis of field development under unknown conditions in the Gulf of Alaska. The minimum field size to justify development, shown in the following tables, is the one which allows the present value of revenues to just equal (or "break-even" with) the present value of development costs at a stated value of money -- 10 percent or 15 percent (see Equation #2 in Appendix C). Mid-range values for investments and operating costs, $12.00 bbl oil and $2.00 mcf gas, are assumed in the initial figures of the different producton systems discussed in the following sections.

TABLE 7-6

Present Barrel Equivalent of Production
Flows From Oil and Gas Fields

FIELD SIZE	PRESENT BARREL EQUIVALENT
OIL - MMB	
100	47
200	60
300	68
400	73
500	82
1000	88
GAS - BCF	
500	142.5
1000	250.9
1500	308.1
2000	340.8
3000	448.6

Source: Dames & Moore Estimation

NOTES : Section 5 of Appendix C describes the method for calculating "present barrel equivalent" of a production stream of oil or gas. The discount rate is 15 percent. Gas production begins in the fifth year of discounting; oil production begins in the sixth year. These values are used in conjunction with Figure 7-4.

Since any oil company's value of money is proprietary, this analysis seeks, first, to bracket the minimum field size between the 10 percent and 15 percent "break-even" curves assuming mid-range values for prices and costs. This assumes (as discussed in Appendix C) that actual industry hurdle rates lie between 10 percent and 15 percent in constant dollar discount cash flow rates of return.

This will show the size of the impact of two different discount rates on the minimum economic field size to justify development under the harsh conditions of the Gulf of Alaska.

Recognizing that the investment costs for these different technologies are estimated in this study as a range between 75 percent and 140 percent of the mid-range values described in Appendix B, the analysis seeks, second, to bracket the effect on minimum field size of upper and lower limit investment estimates. The effects of upper and lower limit operating costs also are calculated. For each of the production systems, the minimum field size calculated assuming a 15 percent discount rate, mid-range operating and investment costs on either $12.00 bbl oil or $2.00 mcf gas is recalculated for upper and lower limit costs. Where no field size can be produced in a reasonable time horizon to yield 15 percent assuming mid-range costs and $12.00 bbl oil or $2.00 gas, the minimum price to yield 15 percent has been calculated.

7.4.6.1 Floating Production System: Peak Production Rate - 50 Mbbl/d -- 65 Percent of the Time

Figure 7-5 shows the minimum field size to justify development with a floating production system, no storage and offshore loading. This system is assumed to be limited to a maximum of 20 producing wells. The minimum economic field for this system is 115 MMbbl at 10 percent value of money. No field is economic at 15 percent. Table 7-7 shows the sensitivity analysis for this system with a 150 MMbbl field -- the upper limit field size that can be recovered within 20 to 25 years with this system. At the minimum values of either tangible investments, intangible drilling costs, or operating costs, this field still does not earn

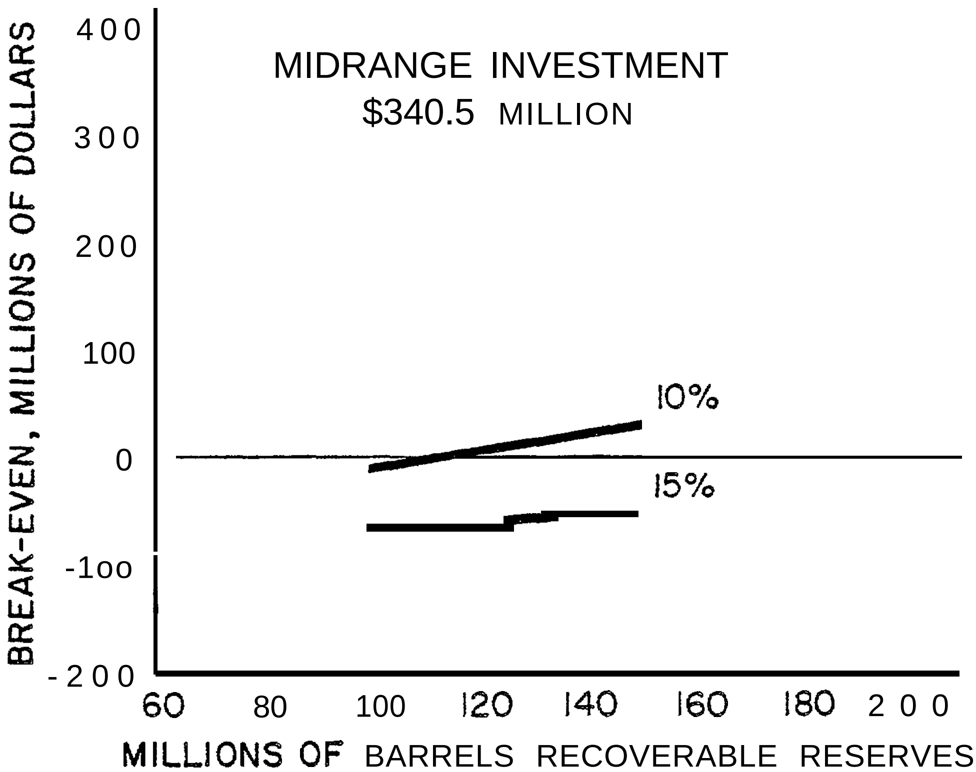


FIGURE 7-5

FLOATING SMALL PRODUCTION SYSTEM WITH NO STORAGE, SPM, OFFSHORE LOADING

15 percent. Figure 7-6 shows that $14.40 bbl is the minimum required price to earn a 15 percent return for a floating production system at its upper limit field size. On smaller fields a higher price is required to earn 15 percent.

7.4.6.2 Steel Platform, No Storage, Offshore Loading, Small Field: Peak Production - 50 Mbbl/d -- 65 Percent of the Time

Figure 7-7 shows that a field less than 100 MMbbl is not economic in the Gulf of Alaska with offshore loading and no storage. A maximum of 20 producing wells is assumed. The sensitivity results are not shown. However, as a point of reference the 50 MMbbl field earns less than one percent on mid-range input values; and less than six percent at $15.00 bbl.

7.4.6.3 Steel Platform, No Storage, Offshore Loading: Peak Production - 100 Mbbl/d -- 65 Percent of the Time

Figures 7-8, 7-9, and 7-10 show the break-even field sizes for this system for field sizes greater than 100 MMbbl at water depths of 30.5, 91, and 183 meters (100, 300, and 600 feet). This system does not allow full-time production because there is no storage. Production can occur only when there is a waiting tanker. Industry contacts think the assumption of producing this system 65 percent of the time may be optimistic in the Gulf of Alaska due to weather.

Minimum field size is bracketed by 110 and 190 MMbbl at 30.5 meters (100 feet). There is no economic field size at 15 percent value of money in 91 and 183 meters (300 and 600 feet). Production systems that do not allow full-time production are at a great economic disadvantage.

Figures 7-11, 7-12 and 7-13 show the range of estimates for minimum field size at 15 percent for the steel platform with offshore loading system in 30.5 meters (100 feet) of water based on the range of estimates for the development costs. The figures show that (1) minimum field size could be as small as 140 MMbbl or larger than 250 MMbbl at

Table 7-7

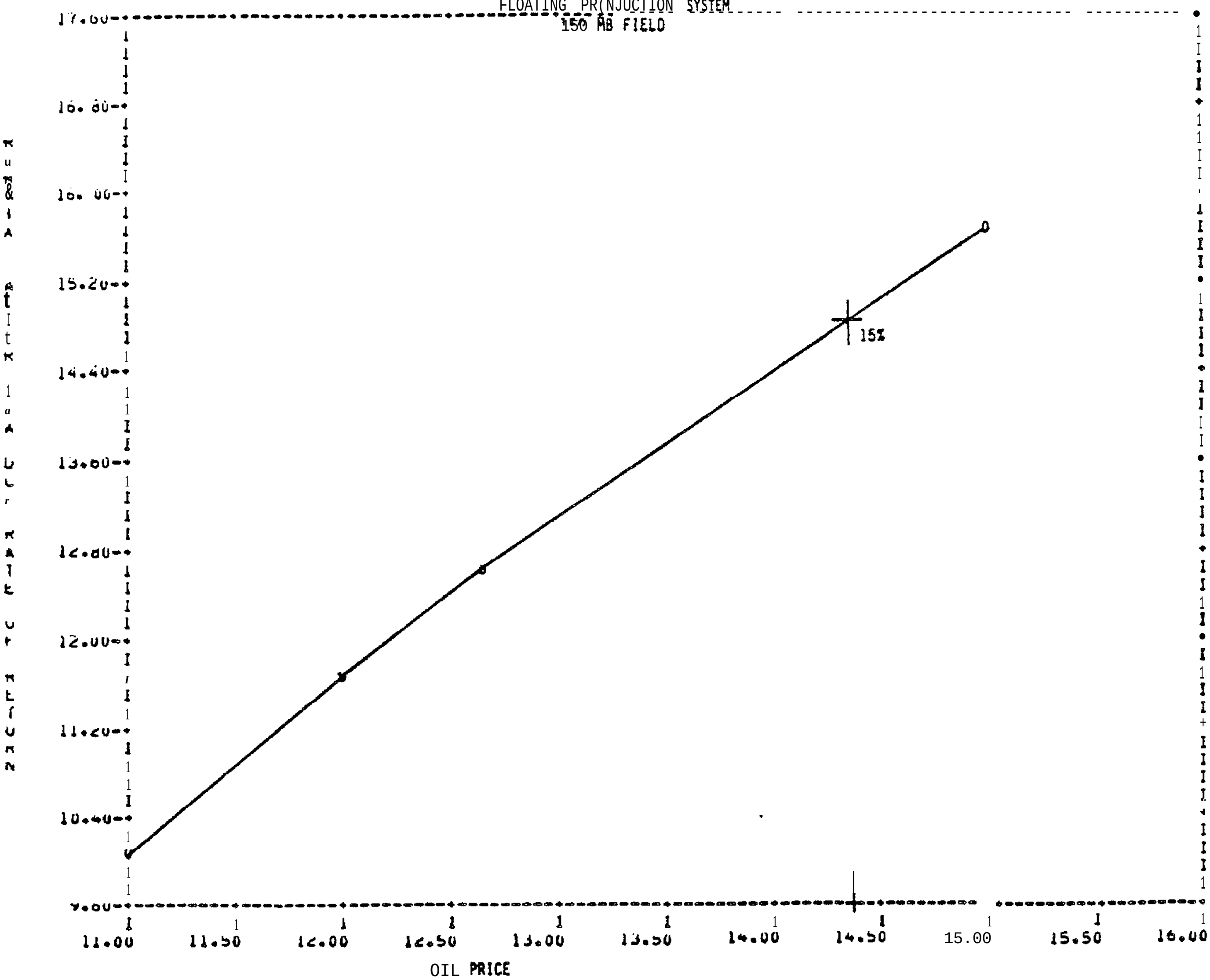
CASE 1, FLOATING PRODUCTION SYSTEM, 150 MMB FIELD

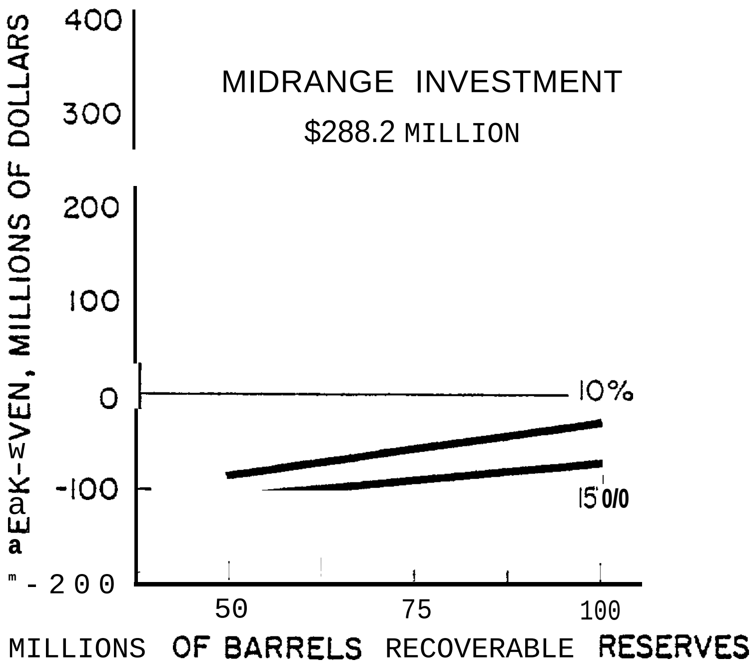
Sensitivity Analysis For After-Tax DCF Rate of Return
Result Variable (RORATX)

Probabilistic Variable Description	Minimum Value	Average Value	Maximum Value	Most Likely	Range
Tangible Investment	14.4015	11.1963	9.5204	11.6567	5.881
Oil Price	10.0954	12.6233	15.6891	11.6567	5.593
Operating Cost M$	12.5502	11.3400	9.5059	11.6567	3.044
Intangible Drill Cost M$	12.6352	11.4727	10.2652	11.6367	2.370

Figure 7-6

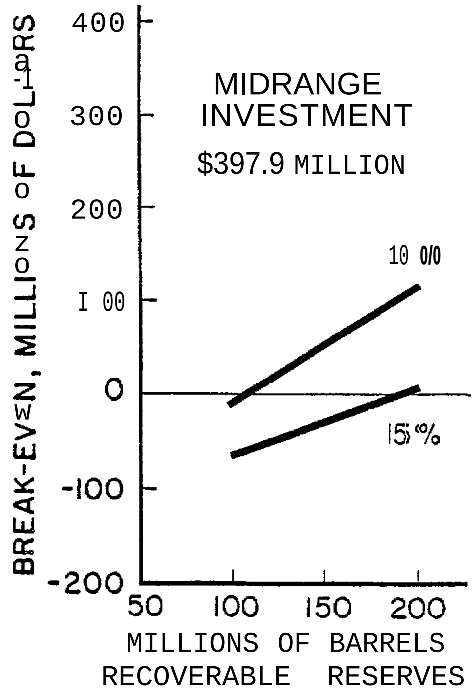
MINIMUM PRICE REQUIRED TO JUSTIFY DEVELOPMENT AT 15% VALUE OF MONEY
FLOATING PRODUCTION SYSTEM
150 MB FIELD





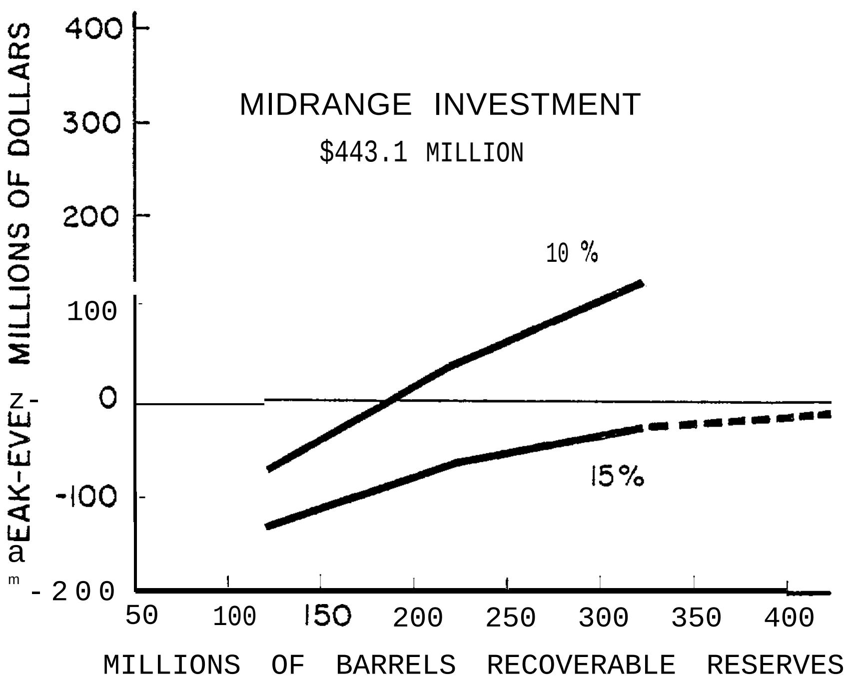
30.5m (100 FT) WATER DEPTH

FIGURE 7-7



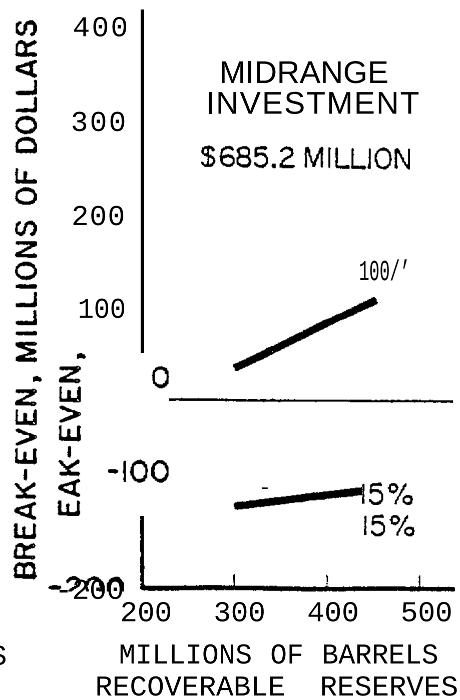
30.5m (100 FT) WATER DEPTH

FIGURE 7-8



91m (300 FT) WATER DEPTH

FIGURE 7-9



183m (600 FT) WATER DEPTH

FIGURE 7-10

STEEL PLATFORM, NO STORAGE, SPM, OFFSHORE LOADING

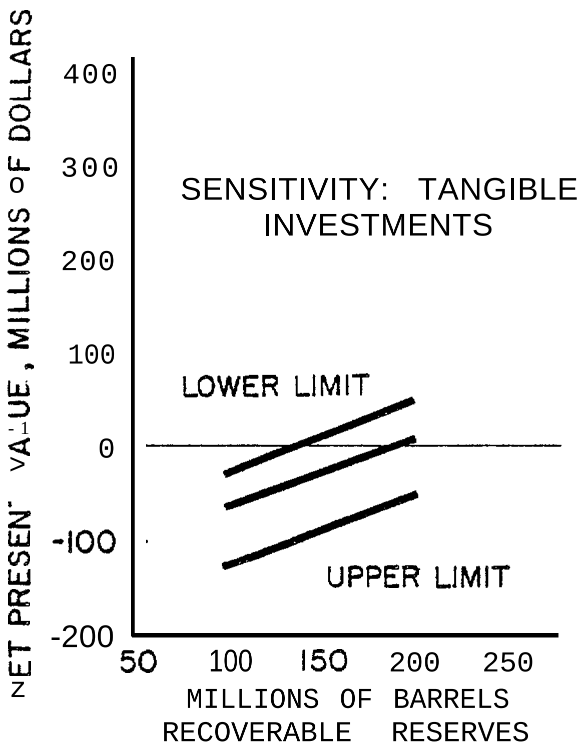


FIGURE 7-11

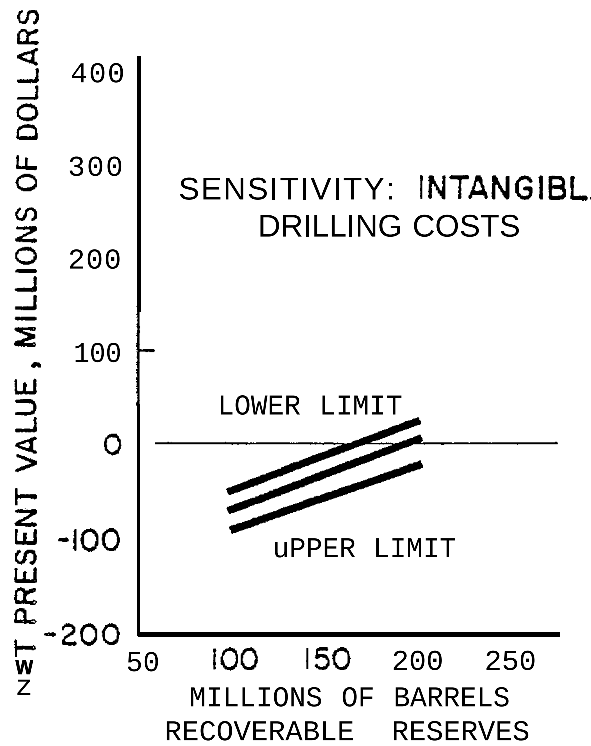


FIGURE 7-12

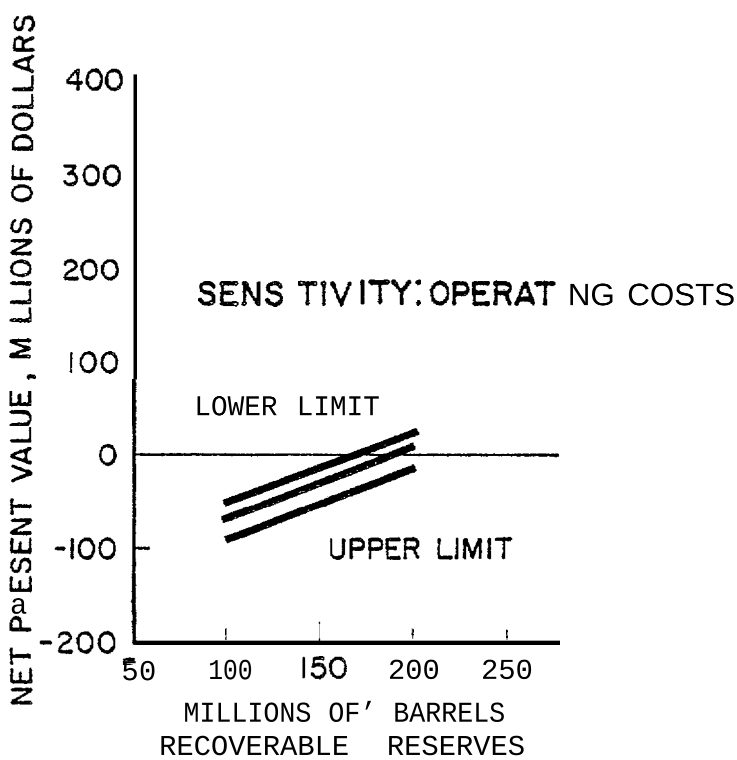


FIGURE 7-13

CASE 3: STEEL PLATFORM, OFFSHORE LOADING, 30.5m(100FT) WATER DEPTH

(NET PRESENT VALUE AT 15 %)

the lower and upper limits of estimated costs; and (2) the uncertainty of tangible investment costs has a bigger impact on the range of field size estimates than intangible costs or operating costs.

Figure 7-14 shows that $13.25 is the minimum price that will allow a 15 percent return in 91 meters (300 feet) of water for the upper field size -- 300 MMbbl -- that can be recovered within 20 to 25 years with this intermittent production system. Table 7-8 shows that at the lower estimated tangible investment costs, this production system with a 300 MMbbl field earns more than 15 percent. Sensitivity tests for the system in 183 meters (600 feet) of water are not shown. At the lower limit of costs at the largest reasonable field size, the system is not economic.

7.4.6.4 Concrete Platform With Storage and Offshore Loading: Peak Production - 100 Mbbl/d

Figures 7-15 and 7-16 show the minimum field size for the first system that allows uninterrupted production -- assumed to be at 96 percent of capacity. Minimum field size in 91 meters (300 feet) of water is bracketed by 130 to 225 MMbbl. Minimum field size in 183 meters (600 feet) at 10 percent is 250 MMbbl. No field is economic at a 15 percent hurdle rate.

The 15 percent break-even curve on Figure 7-16 demonstrates the limited economic impact on development economics of oil recovered beyond 20 years of production. This production system will recover 350 MMbbl in just over 20 years. As shown on Figure 7-16 beyond 350 MMbbl of reserves there is little change in the economic solution.

Figure 7-17, 7-18 and 7-19 show the sensitivity analysis for this system in 91 meters (300 feet) of water with a 225 MMbbl field. Two-hundred-twenty-five million barrels of recoverable reserves is the minimum field size to justify development at the 15 percent hurdle rate.

Table 7-8

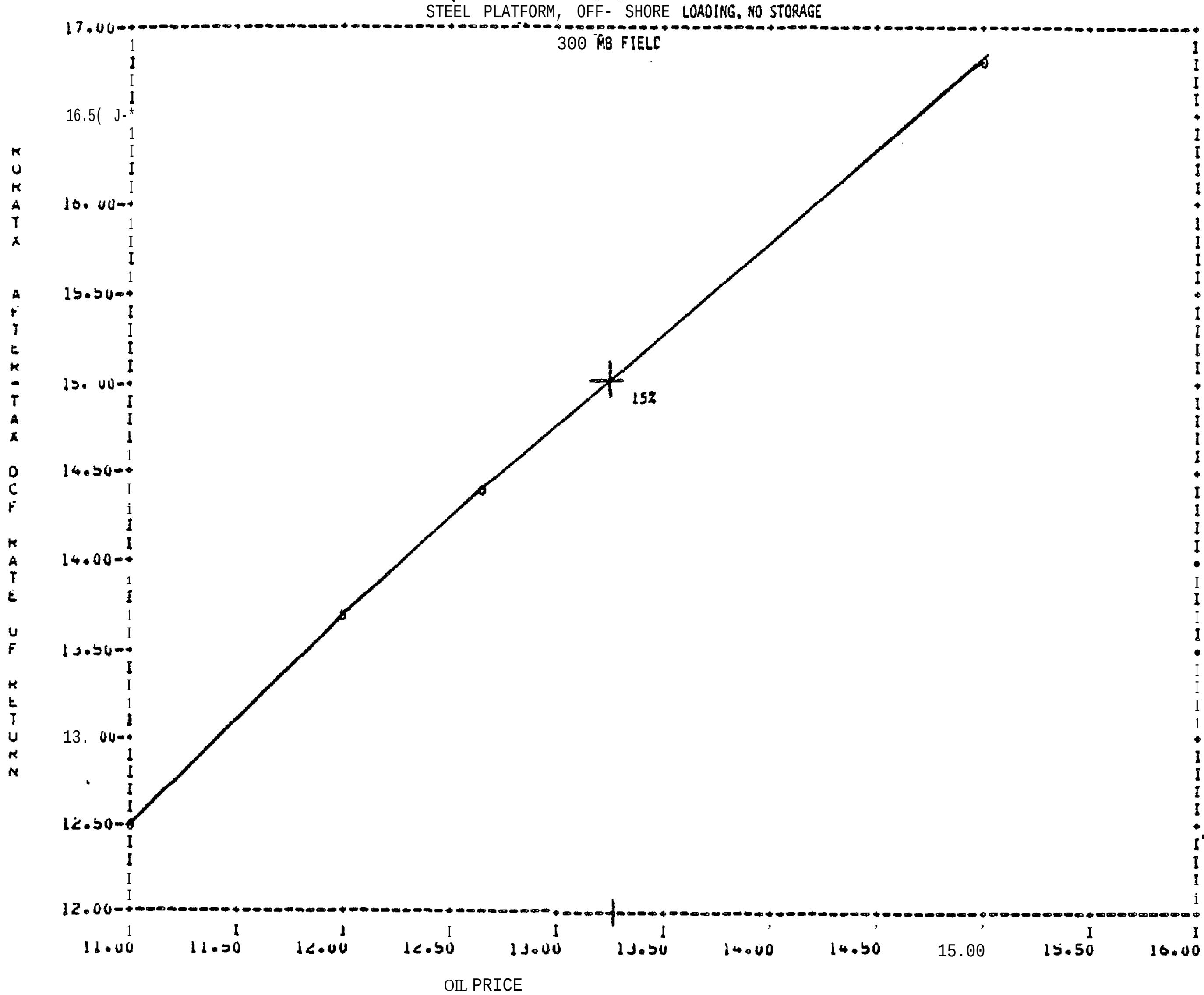
CASE 4: STEEL PLATFORM, OFFSHORE LOADING, Ni3 STORAGE, 91 METERS (300 FEET) , 300 MMB FIELD SIZE

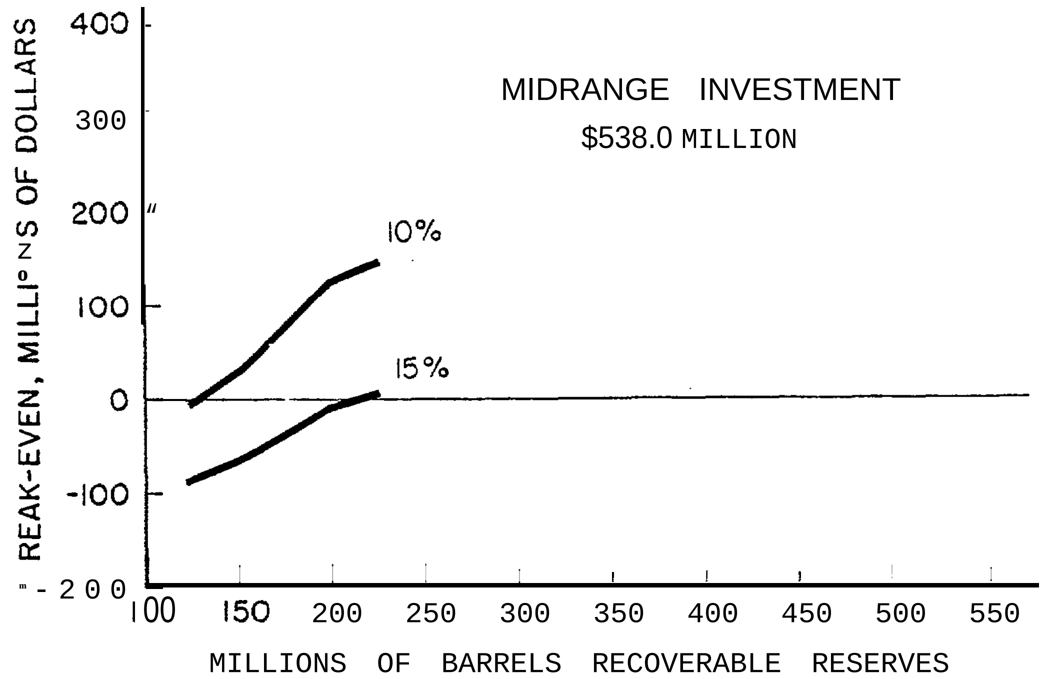
Sensitivity Analysis For After-Tax DCF Rate Of Return
Result Variable (RORATX)

Probabilistic Variable Description	Minimum Value	Average Value	Maximum Value	Most Likely	Range
Tangible Investment	15.9598	13.3052	11.0037	13.6949	4.95
Oil Price	12.4900	14.4467	16.8207	13.6949	4.33
Operating Cost M$	14.4627	13.5613	12.4185	13.6949	2.04
Intangible Cost M$	14.5111	13.5405	12.5325	13.6949	1.97

Figure 7-14

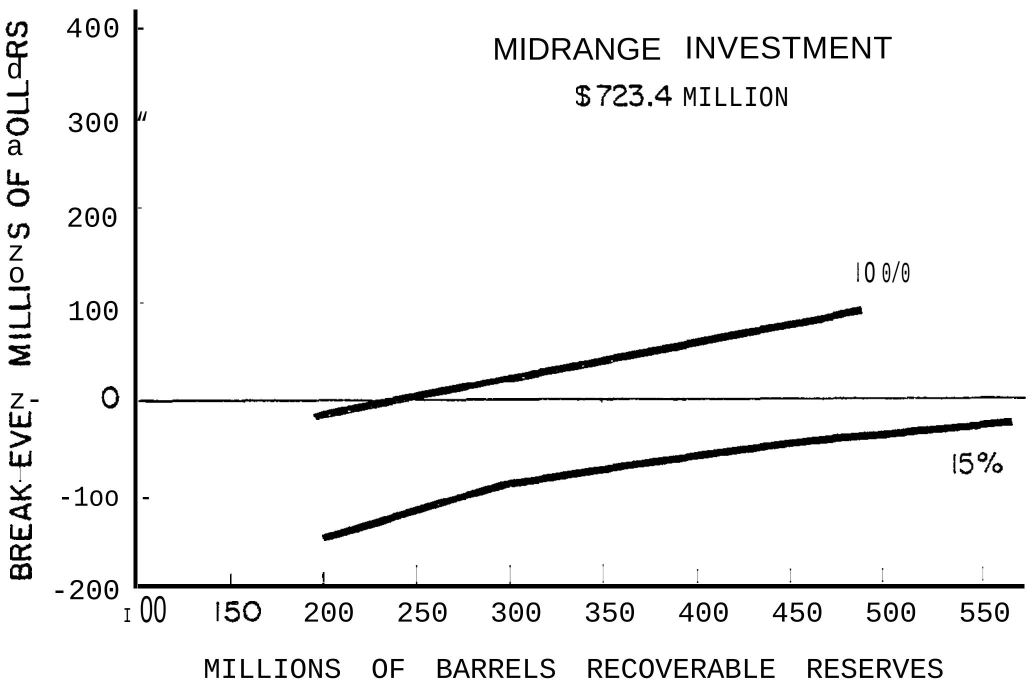
MINIMUM PRICE REQUIRED TO JUSTIFY DEVELOPMENT AT 15% VALUE OF MONEY
STEEL PLATFORM, OFF- SHORE LOADING, NO STORAGE





91m (300 FT) WATER DEPTH

FIGURE 7-15



183 m (600 FT) WATER DEPTH

FIGURE 7-16

CONCRETE PLATFORM WITH
STORAGE, SPM, OFFSHORE LOADING

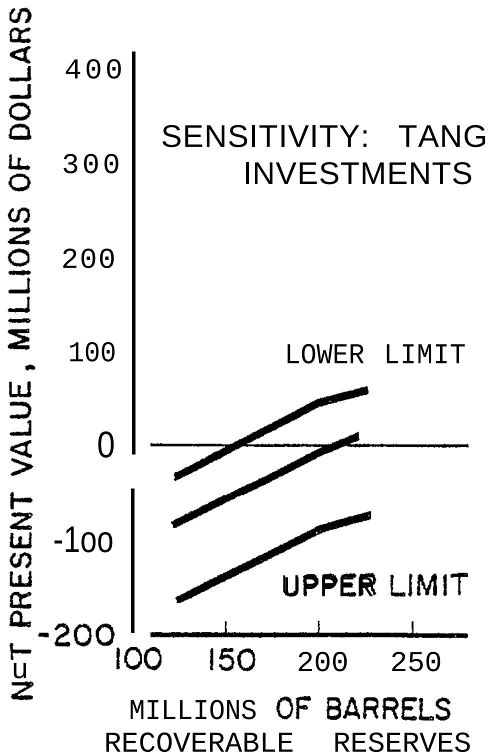


FIGURE 7-17

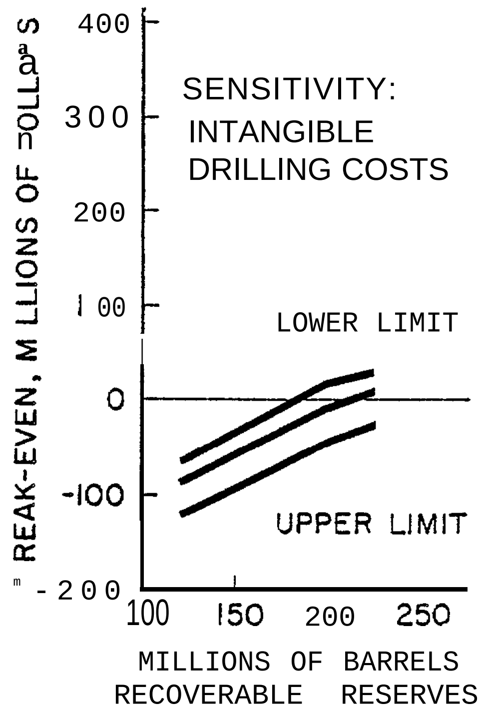


FIGURE 7-18

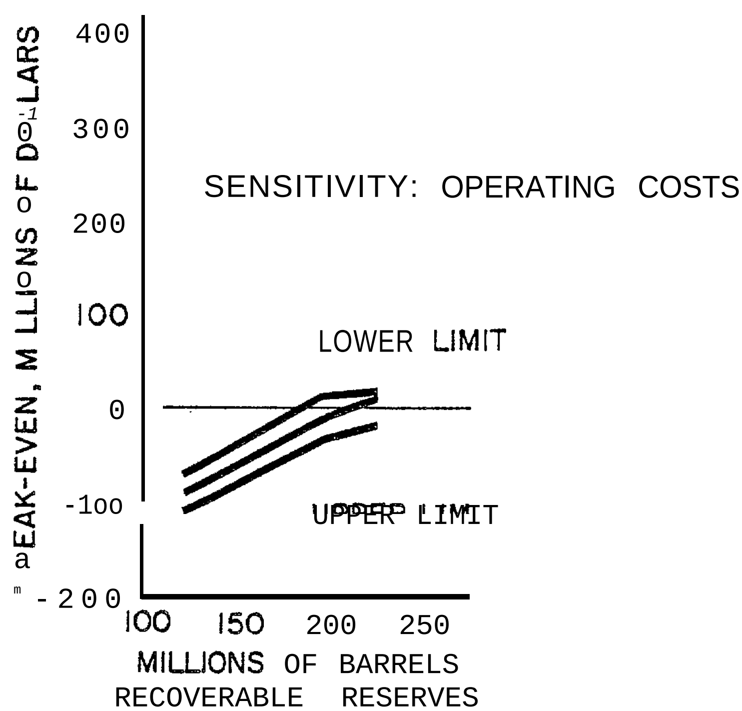


FIGURE 7-19

CASE 6: CONCRETE PLATFORM, OFFSHORE LOADING,
91m (300 FT) WATER DEPTH

Figure 7-17 compared to 7-18 and 7-19 shows that: (1) the uncertainty in tangible investments has a bigger impact on the minimum field size calculation than the range of estimates for intangible drilling costs or operating costs; and (2) minimum field size could be as small as 160 MMbbl or beyond the practical economic limit of 350 MMbbl.

A Monte Carlo analysis was done for this system with a 225 MMbbl field in 91 meters (300 feet). Table 7-9 and Figure 7-20 show the results. The probability of earning less than 15 percent is less than 49 percent. There is, therefore, 51 percent probability of earning more than 15 percent. Given all of the uncertainty of prices and costs built into the data, there is a 50-50 chance that developing a 225 MMbbl field with this system in the Gulf of Alaska would earn less than the 15 percent hurdle rate.

Table 7-9 also shows there is almost no chance of earning less than 11.3 percent and no chance of earning more than 20.3 percent. Thus, the development decision would have to be based on nearly a 50-50 chance of meeting the assumed 15 percent hurdle rate together with no chance of a bonanza payoff and little chance of earning less than 11.3 percent.

7.4.6.5 Single Steel Platform With Shared 80 Kilometer (50 Mile) Pipeline to Shore: Peak Production - 100 Mbbl/d

Figures 7-21 and 7-22 show the first pipeline to shore production system. Assumed in the cost of this production system are: (1) a 16-kilometer (10-mile) spur to connect to a 50 percent shared trunkline and (2) 15.5 percent of the shore terminal cost. (See Table 7-14.) Under these assumptions this system is estimated to be slightly less costly at 91 meters (300 feet) than the concrete platform offshore loading system.

Minimum field sizes are shown on Figure 7-21 to be slightly smaller -- between 120 and 215 MMbbl -- than for the concrete platform, offshore loading system.

Table 7-9

CASE 6: MONTE-CARLO -- CONCRETE PLATFORM
91 METERS (300 FEET), 225 MMB FIELD

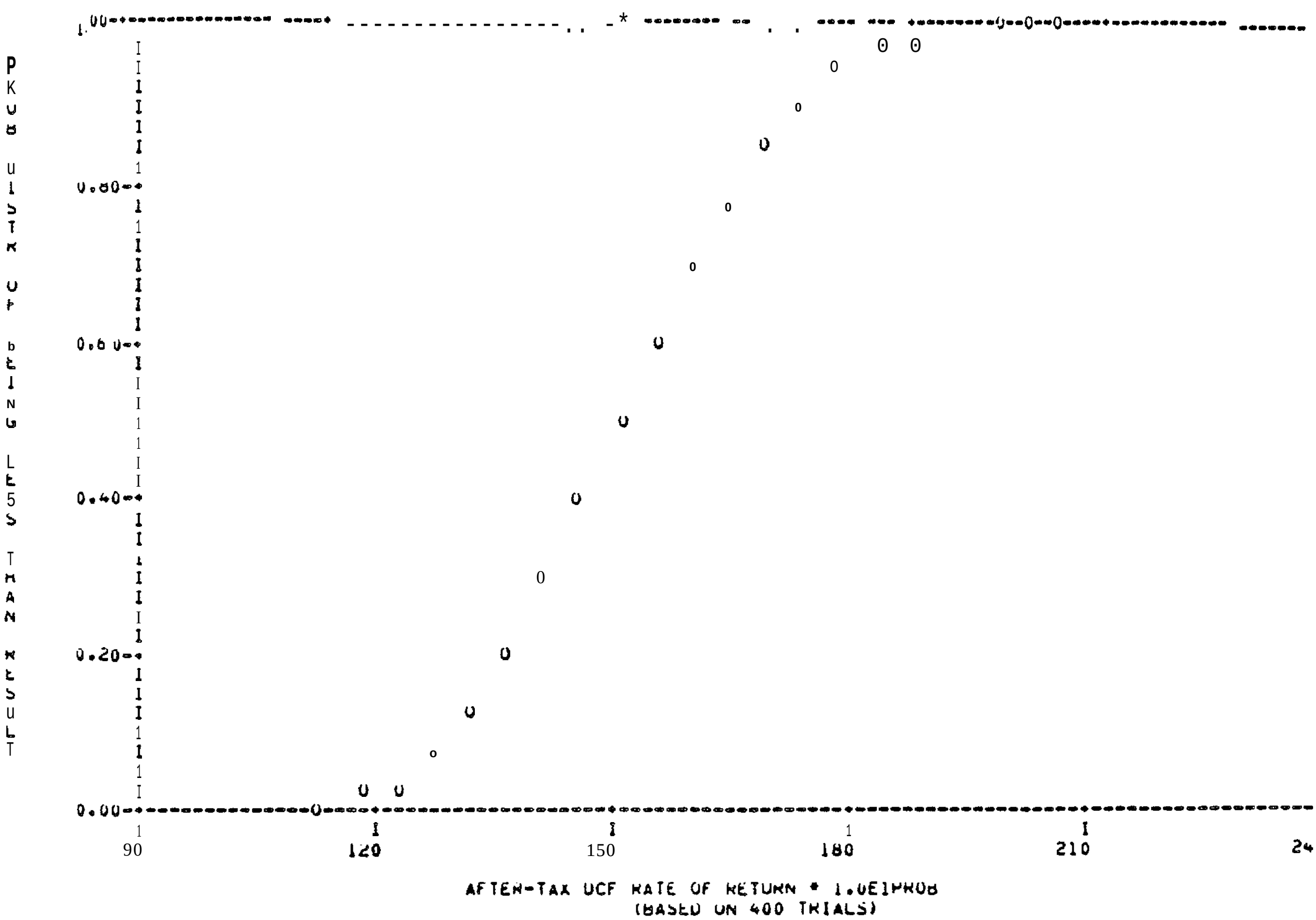
MONTE CARLO RESULTS FOR
AFTER-TAX DCF RATE OF RETURN

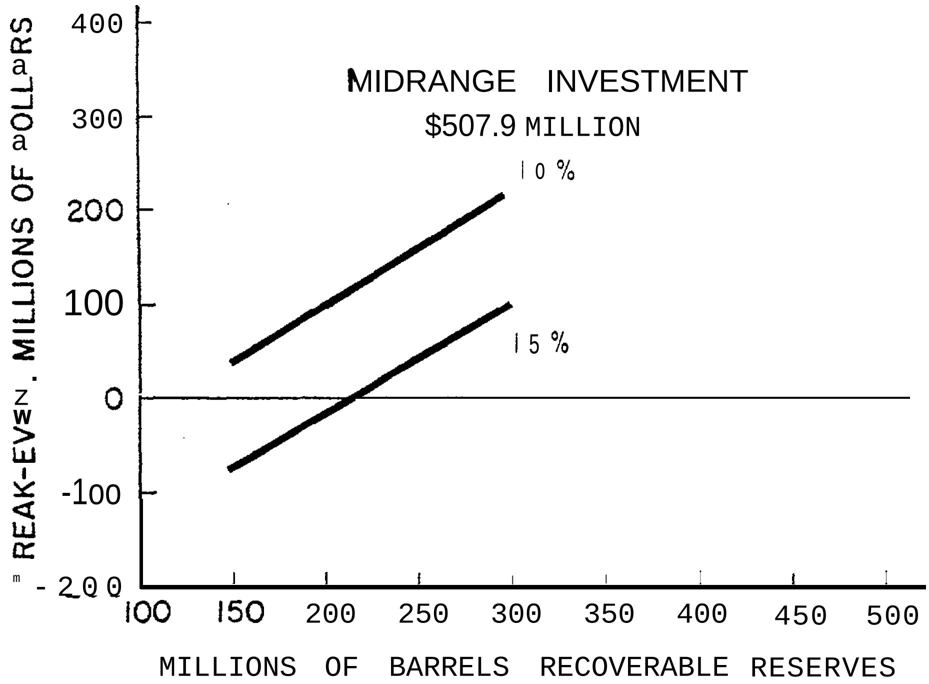
Result Value	Probability of Being Less Than Result
11.3026	.007500
11.7756	.015000
12.2436	.032500
12.7215	.067500
13.1945	.130000
13.6675	.197500
14.1404	.290000
14.6134	.335000
15.0864	.690000
15.5593	592500
16.0323	.707500
16.5053	,722500
16.9783	,857500
17.4512	.905000
17.9242	.940000
18.3972	.962500
1?,.8701	.977500
19.3431	987500
19.8161	.997500
20.2890	1.000000

EXPECTED VALUE = 15.1567
STANDARD DEVIATION = 1.7046

Figure 7-20

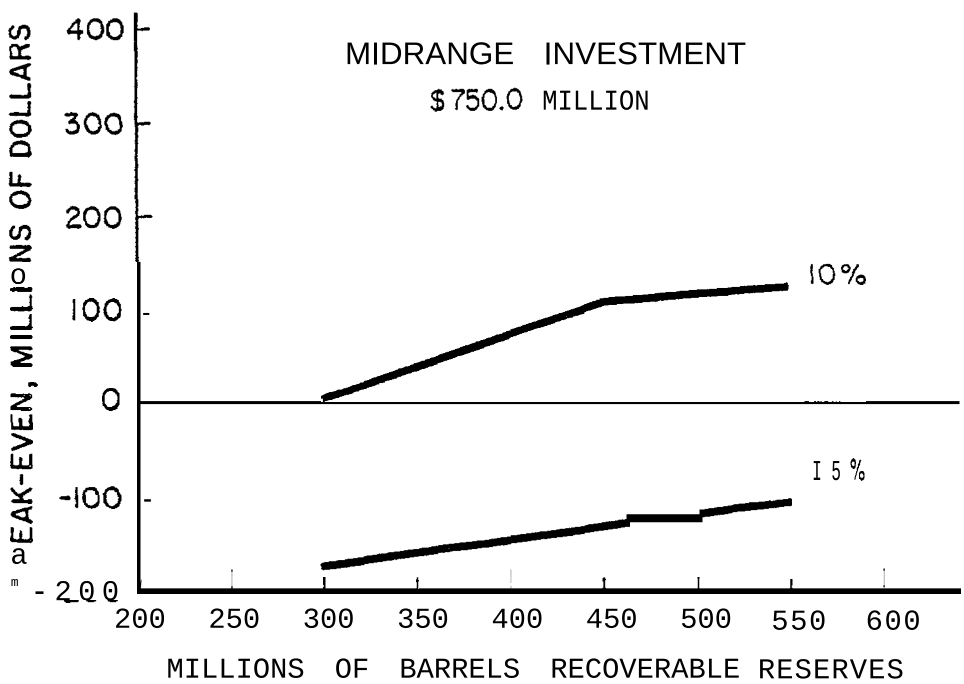
CASE 6, MONTE CARLO --CONCRETE PLATFORM -- '31 METERS (300 FEET), 225 MMB





183m (600 FT) WATER DEPTH

FIGURE 7-2!



91 m (300 FT) WATER DEPTH

FIGURE 7-22

SINGLE PLATFORM SHARING ONE-HALF OF
80 KILOMETER (50 MILE) PIPELINE TO SHORE TERMINAL

Thus, if sufficient total oil in the Gulf of Alaska were found to justify a 650 Mbbl/d capacity shore terminal, and this system as part of that total produced oil equal to 15.5 percent of capacity and paid a proportionate share of terminal cost, it would be more economic to build a pipeline to shore than a concrete platform with offshore loading. If, however, this system were required to absorb much more than the $82.5 million assumed for its 15.5 percent share of the shore terminal, the concrete offshore loading system would be more economic. The decision to go ashore or load offshore is sensitive to the cost of the shore terminal. Figure 7-22 shows the minimum field size at 183 meters (600 feet) to be 290 MMbbl at 10 percent. No field is economic at 15 percent.

Figures 7-23, 7-24, and 7-25 show the range of estimates of minimum field size at 91 meters (300 feet). Given the range of estimates of tangible investment costs minimum field size could be as low as 160 MMbbl or as high as 330 MMbbl.

Figure 7-26 shows that $14.80 is the minimum price that will allow this system in 183 meters (600 feet) of water with a 450 MMbbl field earning 15 percent. Table 7-10 shows that at the minimum estimated costs, the steel platform and pipeline system will not earn ?5 percent.

7.4.6.6 Two Steel Platforms With 80 Kilometer (50 Mile) Pipeline to Shore: Peak Production - 200 Mbbl/d

Figures 7-27 and 7-28 show the minimum field sizes to support two steel platforms with an unshared pipeline to shore. This system is assumed to support 31 percent of the cost of the 650 Mbbl/d capacity shore terminal.

Minimum field size at 91 meters (300 feet) varies between 260 and 510 MMbbl at 10 percent or 15 percent. Minimum field size is 550 MMB at 183 meters (600 feet) at 10 percent; no field is economic at 15 percent.

Figures 7-29, 7-30 and 7-31 show that: (1) the minimum field size at 15 percent for a two platform system could be as small as 390 MMbbl or

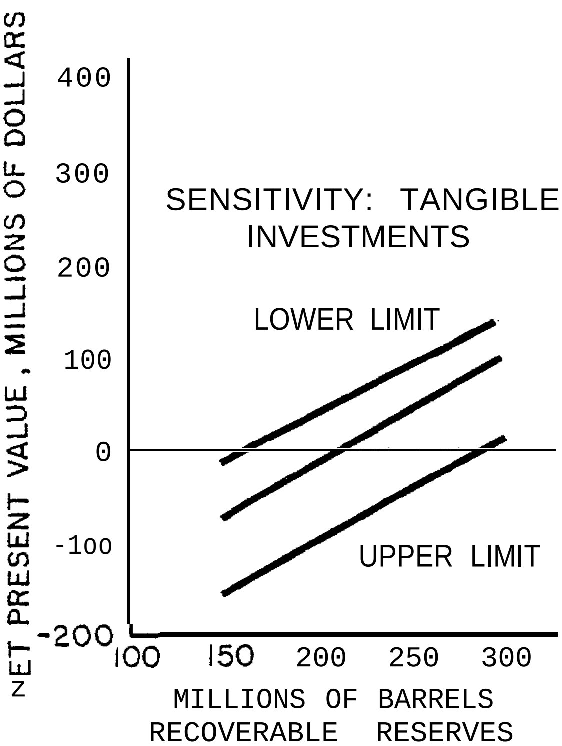


FIGURE 7-23

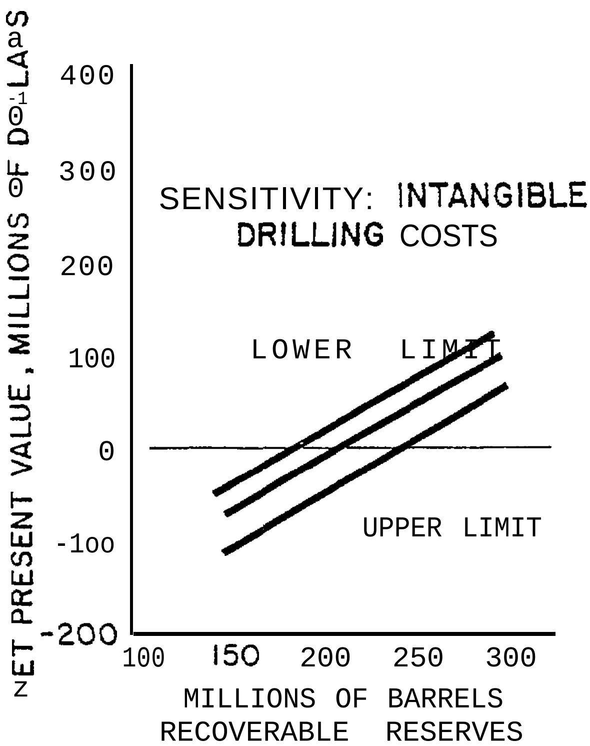


FIGURE 7-24

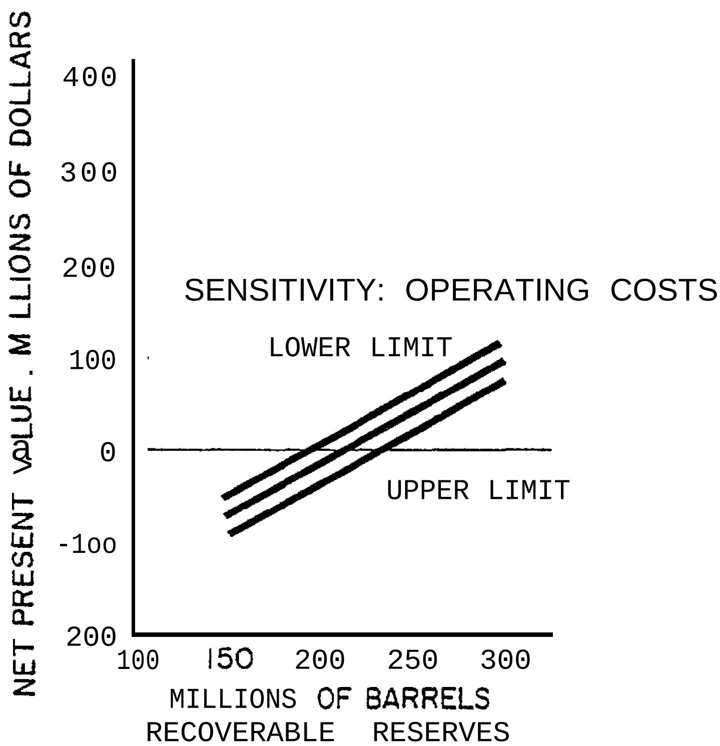


FIGURE 7-25

CASE 12: SINGLE PLATFORM WITH SHARED PIPELINE TO SHORE, 91m (300 FT) WATER DEPTH

Table 7-10

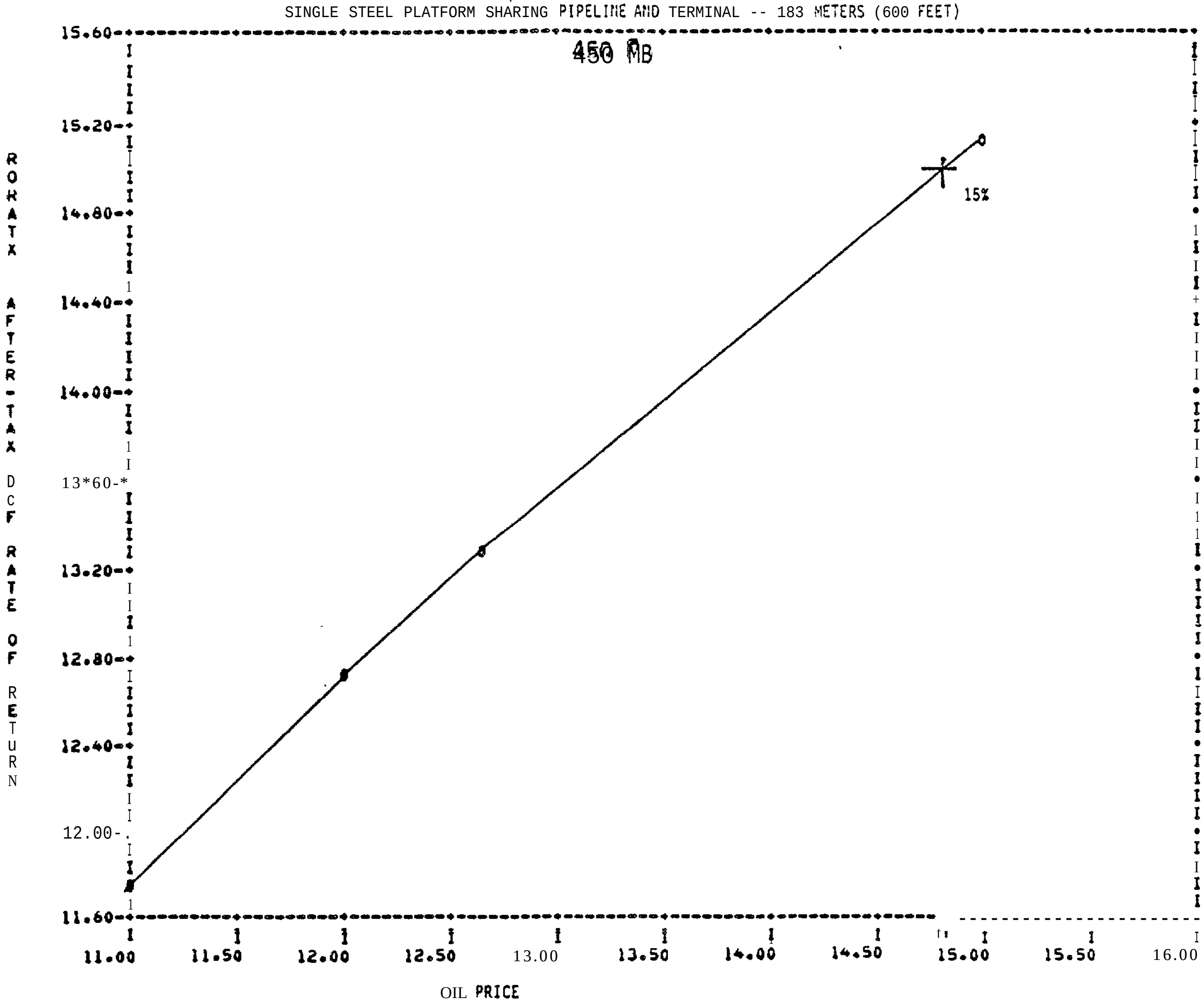
CASE 13, SINGLE STEEL PLATFORM SHARING PIPELINE AND TERMINAL, 183 METERS (600 FEET), 450 MMB

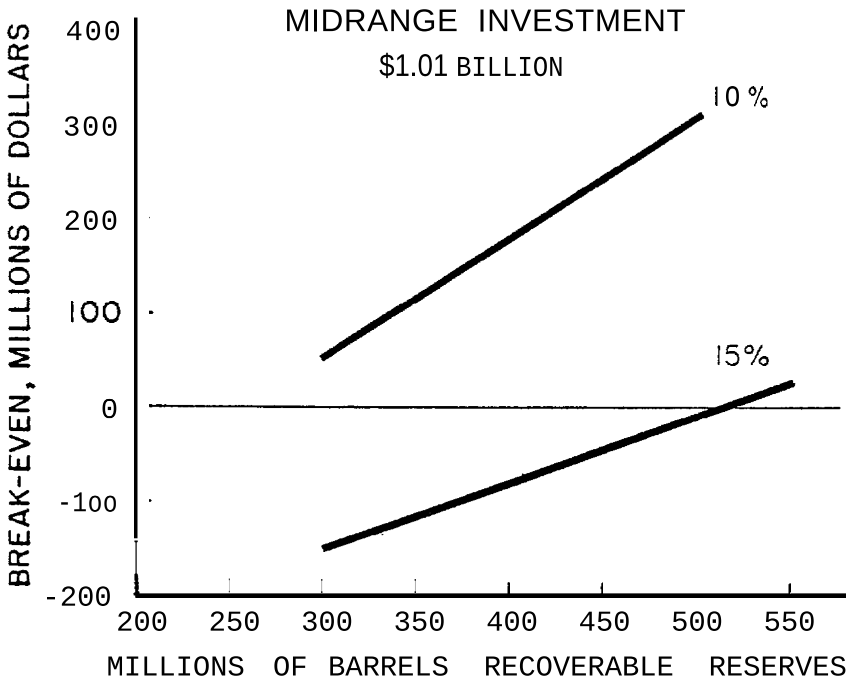
Sensitivity Analysis for After-Tax DCF Rate of Return
Result Variable (RORATX)

Probabilistic Variable Description	Minimum Value	Average Value	n o - , ; - - ; - - - - -		
Tangible Investment	14.5957	12.3909	10.4669	12.7153	4.1288
Oil Price	11.7937	13.2931	15.1313	12.7153	3.3377
Intangible Drill Cost MS	13.3919	12.5873	11.7206	12.7153	1.6712
Operating Cost M$	13.1138	12.6472	12.0768	12.7153	1.0370

Figure 7-26

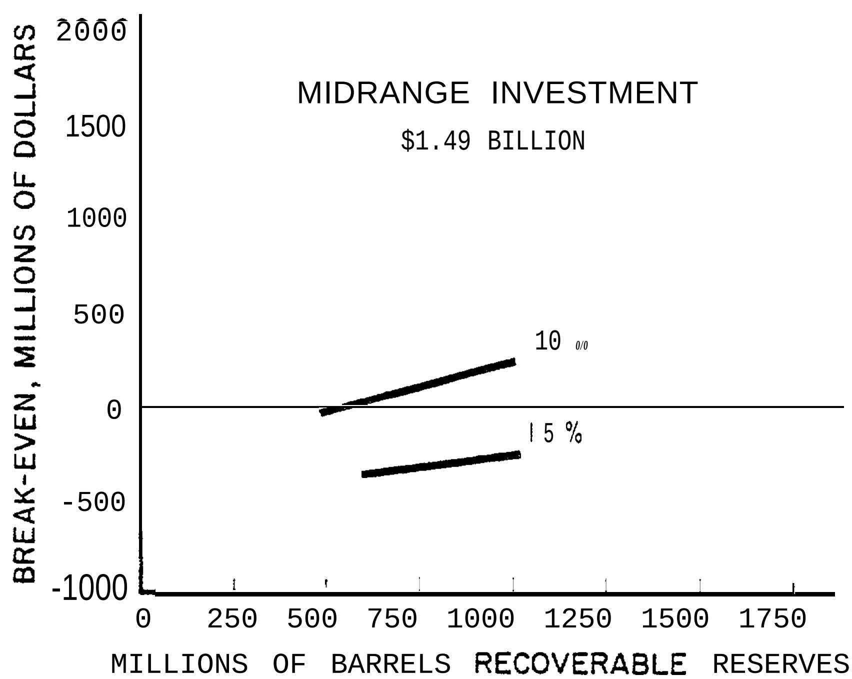
MINIMUM PRICE REQUIRED TO JUSTIFY DEVELOPMENT AT 15% VALUE OF MONEY
SINGLE STEEL PLATFORM SHARING PIPELINE AND TERMINAL -- 183 METERS (600 FEET)





91 m (300 FT) WATER DEPTH

FIGURE 7-27



183m (600 FT) WATER DEPTH

FIGURE 7-28

2 STEEL PLATFORMS WITH
80 KILOMETER (50 MILE) PIPELINE TO SHORE TERMINAL

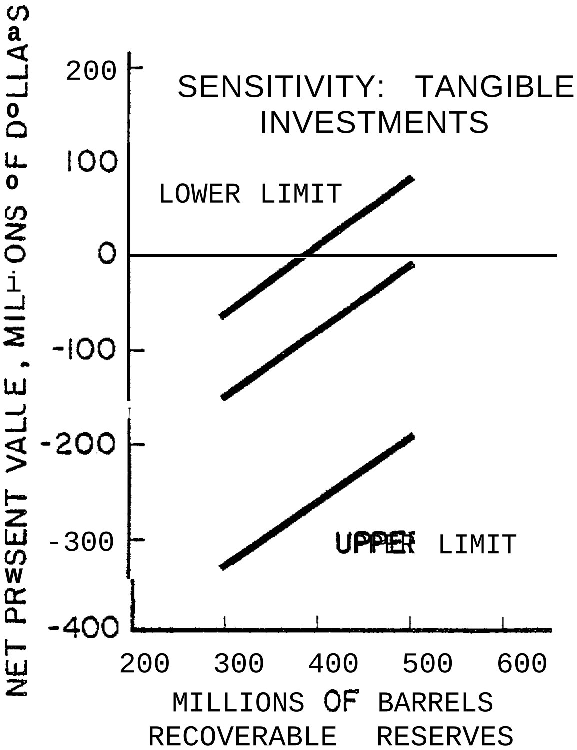


FIGURE 7-29

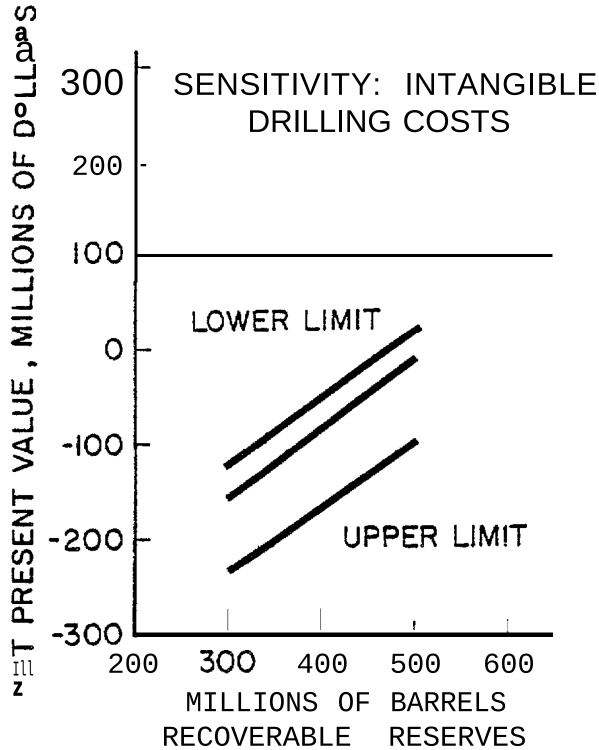


FIGURE 7-30

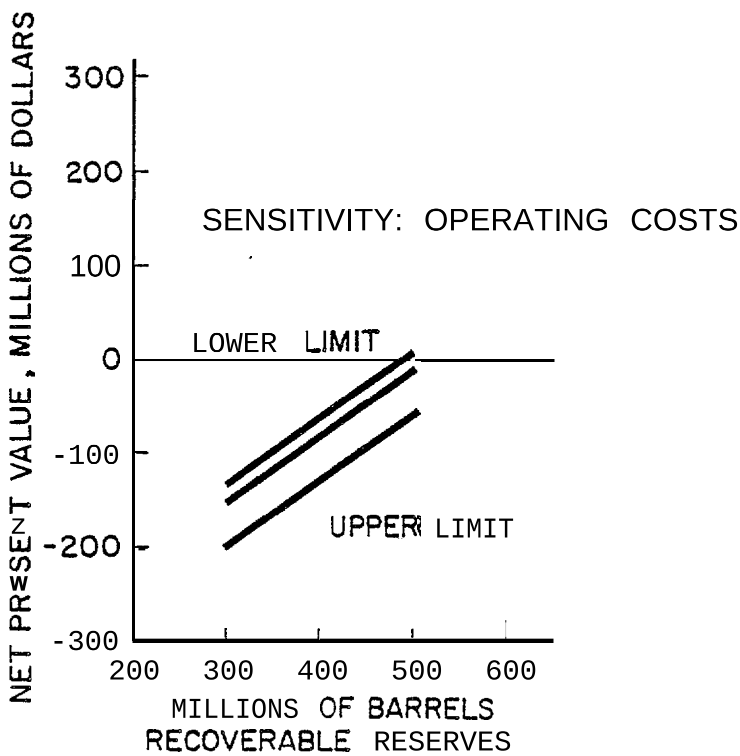


FIGURE 7-31

CASE 8: 2 STEEL PLATFORMS WITH PIPELINE TO SHORE
91m (3G0 FT) WATER DEPTH

larger than 700 MMbbl; and (2) the uncertainty of tangible investment costs has a bigger impact on the range of field size estimates than intangible costs or operating costs.

Figure 7-32 shows that at $15.00 a barrel for oil the two platform system in 183 meters (600 feet) of water does not earn 15 percent even with a 1.0 billion barrel field. Table 7-11 shows that at any minimum cost estimate the two platform system with a 1.0 billion barrel field does not earn 15 percent.

7.4.6.7 Three Steel Platforms With 129-Kilometer (80-Mile) Pipeline to Shore Terminal: Peak Production - 300 Mbbl/d

Figures 7-33 and 7-34 show the three platform production system case. Its economics are similar to the two platform case but scaled larger. Figure 7-33 shows minimum field size to be between 400 and 760 MMbbl at 10 percent or 15 percent.

Figures 7-35, 7-36 and 7-37 show the impact of the uncertainty of cost estimates on the minimum field size estimates for the three platform system at 91 meters (300 feet). Minimum field size can only be said to fall between 500 MMbbl and about 1.2 billion barrels assuming a 15 percent discount rate.

Figure 7-38 shows that for this system at 183 meters (600 feet) with a 1.5 billion barrel field, a $15.00 oil price will earn 14,9 percent given the mid-range cost estimates. Table 7-12 shows that any minimum cost estimates, this system earns less than 15 percent.

7.4.6.8 Non-Associated Gas Production With Pipeline to Shore

Figures 7-39 through 7-42 show the minimum economic field sizes for gas production from eight-well, 16-well or 24-well producing well platforms. The gas is assumed to share a pipeline ashore for conversion to LNG. (The assumptions about the economics of LNG are discussed in Appendix C.) Figure 7-39 shows that at 30.5 meters (100 feet): (1) eight

Table 7-11

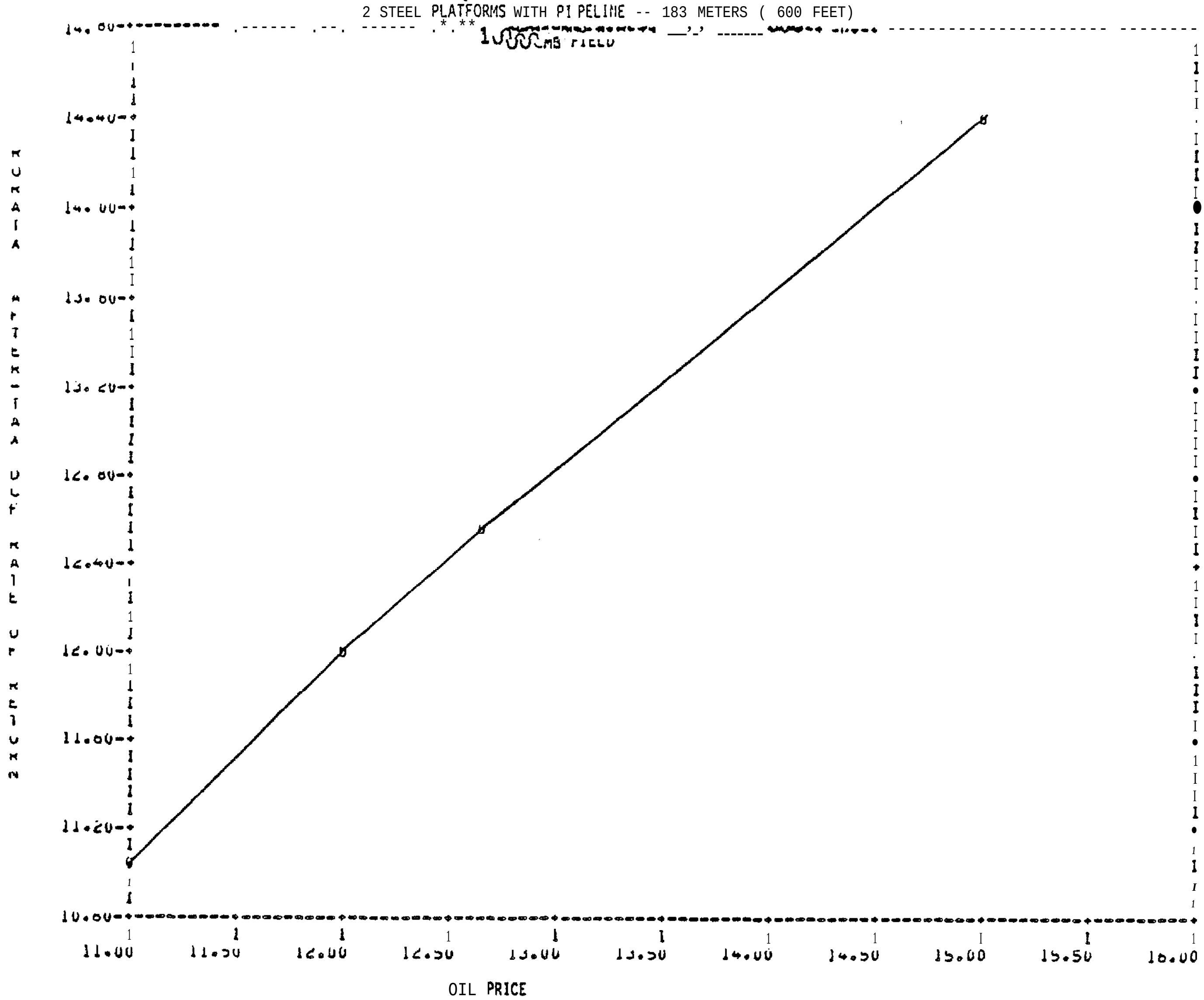
CASE 9, 2 STEEL PLATFORMS WITH PIPELINE, 183 METERS (600 FEET) , 1000 NME!

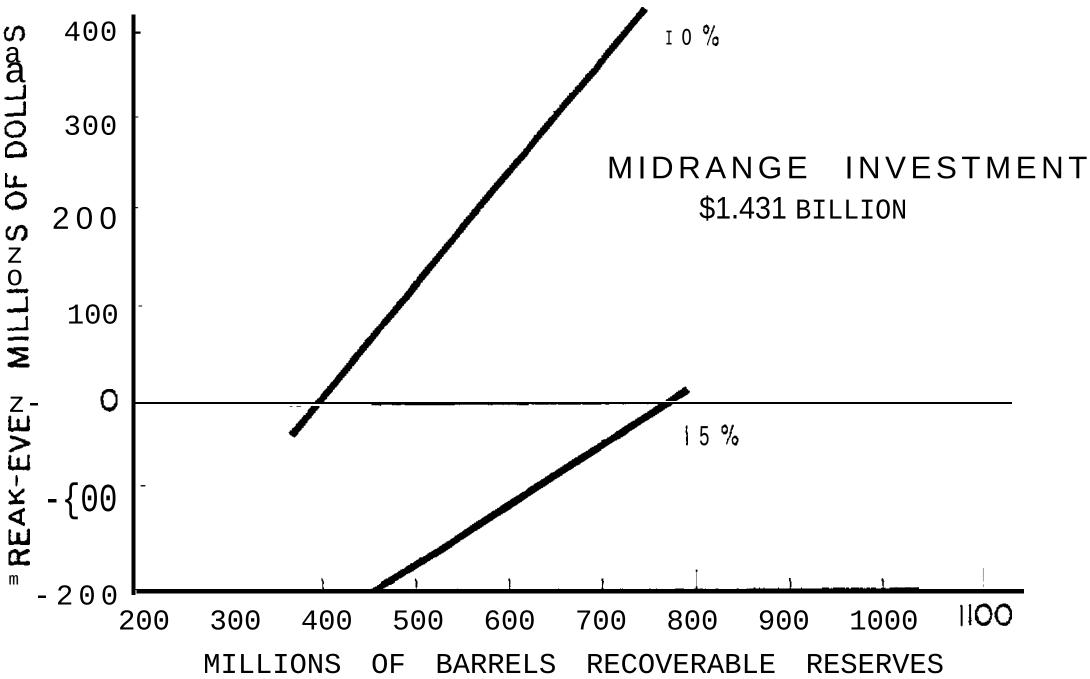
Sensitivity Analysis for After-Tax OCF Rate of Return
Result Variable (RORATX)

Probabilistic Variable Description	Minimum Value	Average Value	Maximum Value	Most Likely	Range
Tangible Investment	13.2234	11.6808	9.7931	11.9982	4.0242
Oil Price	11.0753	12.5724	14.4029	11.9982	3.3276
Intangible Drill Cost MS	12.8676	11.8709	11.0404	11.9982	1.6272
Operating Cost MS	12.4415	11.9982	11.5259	11.9982	.9156

Figure 7-32

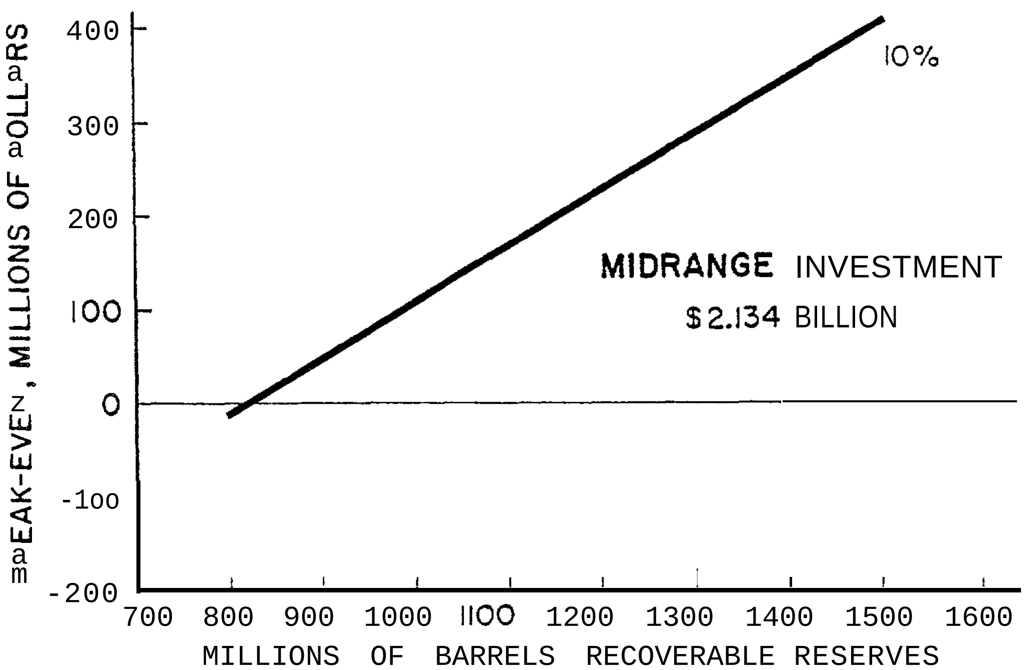
MINIMUM PRICE REQUIRED TO JUSTIFY DEVELOPMENT AT 15% VALUE OF MONEY
2 STEEL PLATFORMS WITH PIPELINE -- 183 METERS (600 FEET)





91m (300 FT) WATER DEPTH

FIGURE 7-33



183m (600 FT) WATER DEPTH

FIGURE 7-34

3 STEEL PLATFORMS WITH
129 KILOMETER (80 MILE) PIPELINE TO SHORE TERMINAL

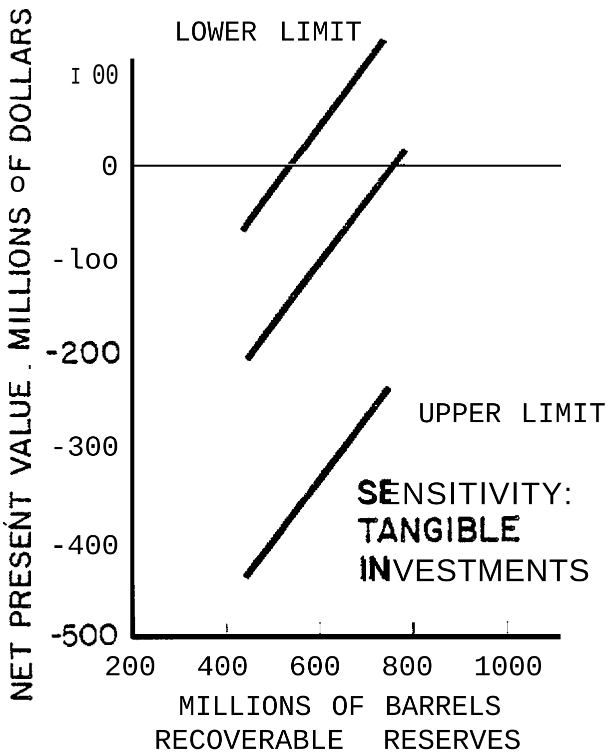


FIGURE 7-35

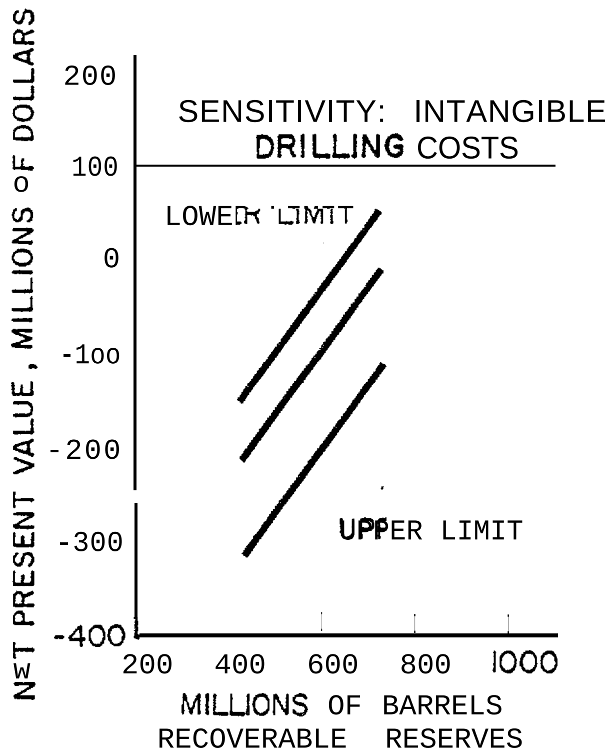


FIGURE 7-36

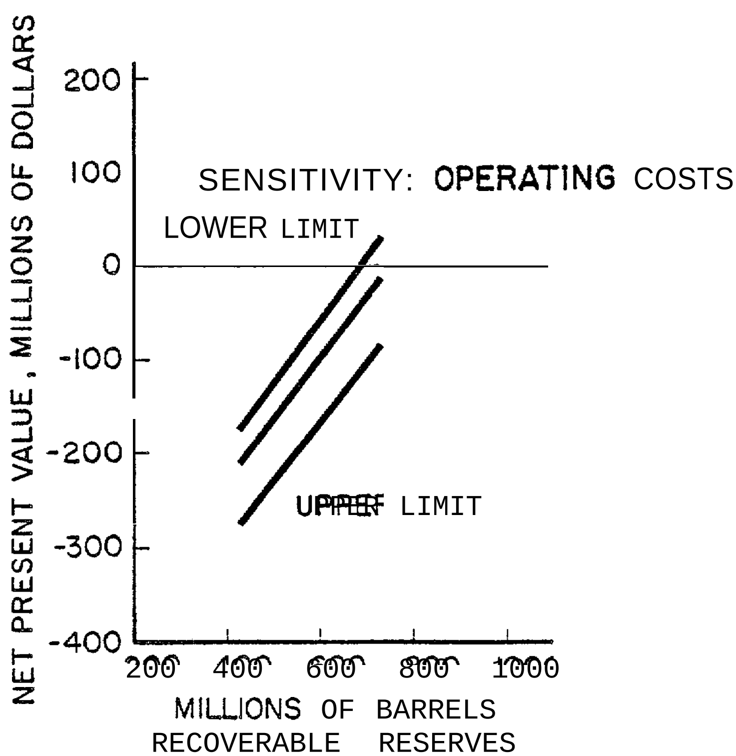


FIGURE 7-37

CASE 10: 3 STEEL PLATFORMS WITH PIPELINE TO SHORE
91m (300 FT) WATER DEPTH

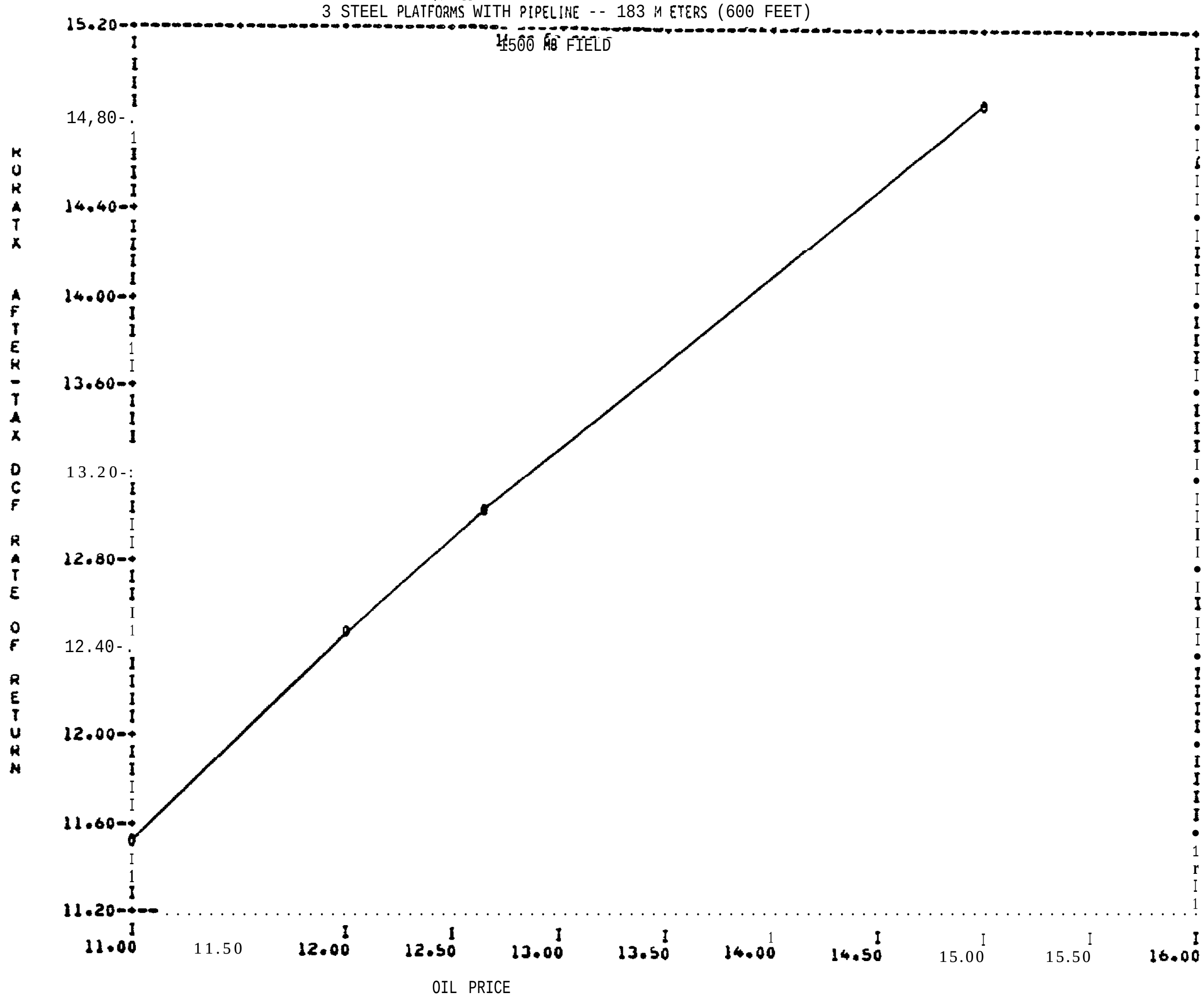
Table 7-12

CASE 11, 3 STEEL PLATFORMS WITH PIPELINE, 183 METERS (600 FEET), 1500 MMB

Sensitivity Analysis For After-Tax DCF Rate of Return
Result Variable (RORATX)

Probabilistic Variable Description	Minimum Value	Average Value	Maximum Value	Most Likely	Range
Tangible investment	14.3157	12.1345	10.2274	12.4559	4.0883
Oil Price	11.5232	13.0410	14.9027	12.4559	3.3795
Intangible Drill Cost M$	13.1284	12.3286	11.4529	12.4559	1.6755
Operating Cost M$	12.3586	12.3735	11.7760	12.4559	1.2326

Figure 7-38
MINIMUM PRICE REQUIRED TO JUSTIFY DEVELOPMENT AT 15'. VALUE OF MONEY
3 STEEL PLATFORMS WITH PIPELINE -- 183 METERS (600 FEET)



producing wells would be sufficient to earn a 10 percent return with a field as small as 600 billion cubic feet; and (2) eight producing wells would be sufficient to earn 15 percent with a field of about 1.1 tcf.

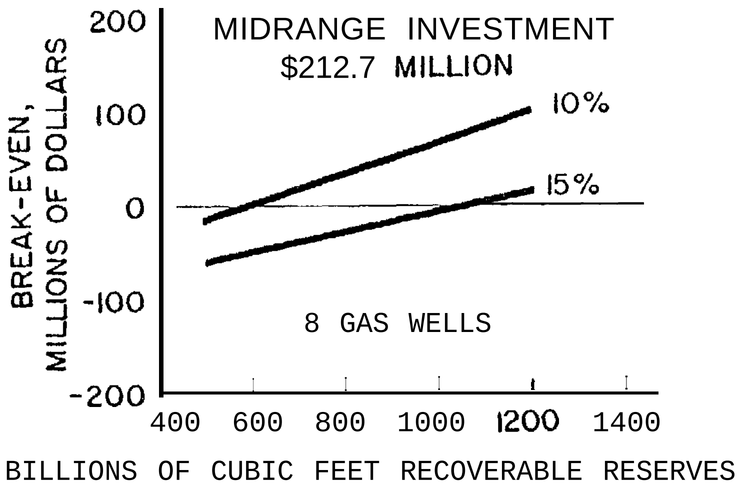
Figure 7-40 shows the minimum economic field size earn a 15 percent hurdle rate in 91 meters (300 feet) with both a 12-well and a 16-well production system. The 12-well system more accurately matches industry practices. It would recover the reserves of the minimum field size in 16.5 years. The 16-well system implies a nine-year production profile which, under most reasonable conditions and industry practices, is too fast. The minimum field size with 12 wells is 1.25 tcf; with 16 wells it is 0.75 tcf.

If 10 percent is the hurdle rate, an 8-well system would be sufficient. to produce the reservoir according to good industry practices. This system is identical to that assumed in Figure 7-39; it is not shown. A field of about 700 bcf is the estimated minimum economic size with eight wells at 10 percent value of money.

Figure 7-41 shows that at 183 meters (600 feet) with 16 wells producing 400 MMcf at peak rate, no gas field size is capable of earning 15 percent. The minimum field size to earn 10 percent is 1.25 tcf at 183 meters (600 feet).

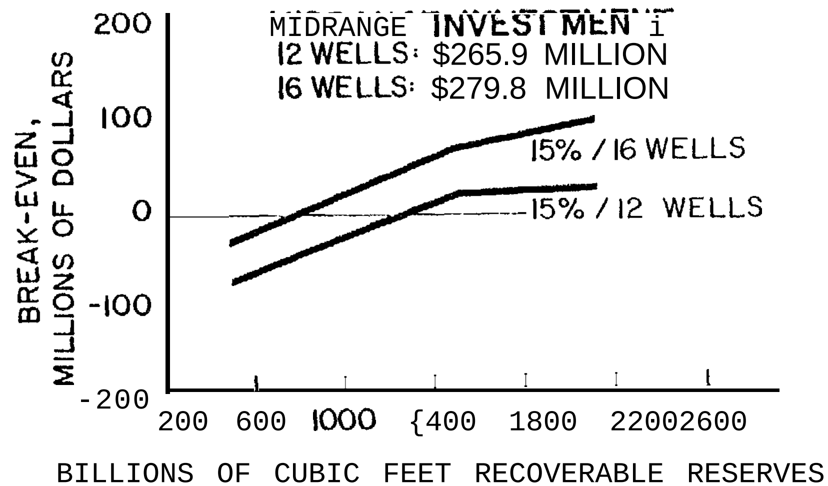
Figure 7-42 considers the effect of increasing the number of producing wells to 24 on the minimum economic gas field size. At peak production this implies 600 MMcfd assuming peak production rate per well is 25 MMcfd. As shown on Figure 7-42, with 24 wells the break-even curve at 15 percent value of money approaches its maximum value -- negative $25 million -- at 3.5 tcf and rises very little to 4.0 tcf.

Four trillion cubic feet would require a 30-year recovery profile. More producing wells would be required to recover the field nearer to the industry practice of 20 years. Increasing by eight wells to 32 would allow a 25-year recovery profile. Increasing to 40 producing gas wells would allow a more desirable 22-year recovery profile. Investment cost



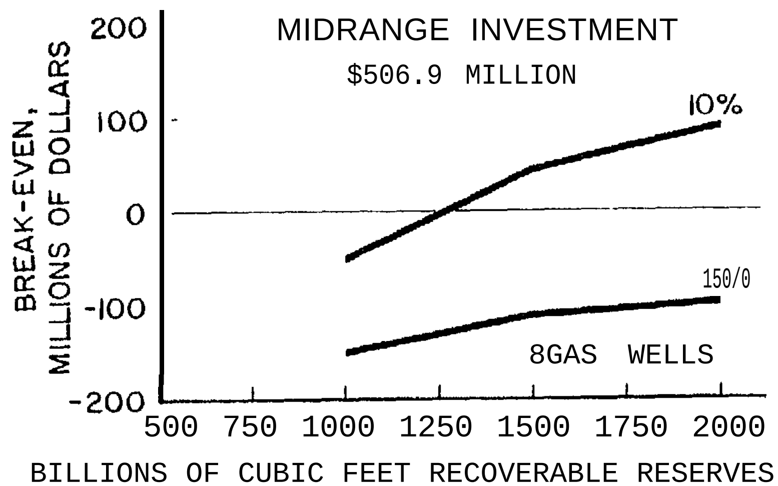
30m (100 FT) WATER DEPTH

FIGURE 7-39



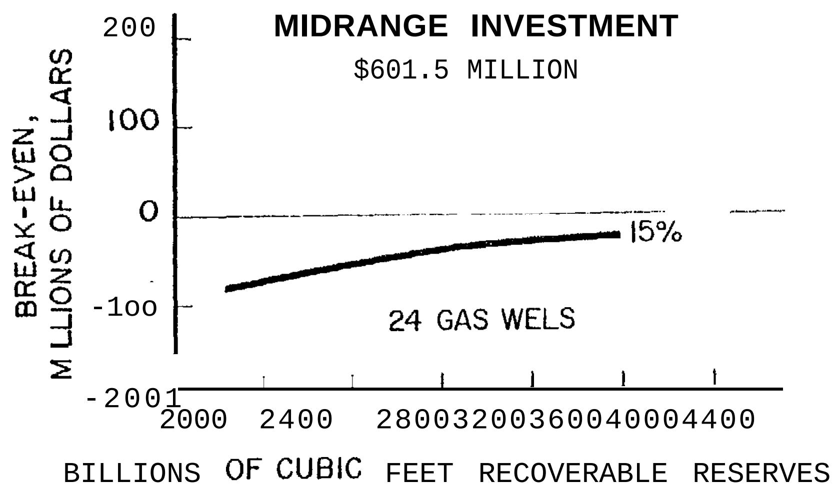
91 m (300 FT) WATER DEPTH

FIGURE 7-40



183m (600 FT) WATER DEPTH

FIGURE 7-41



183m (600 FT) WATER DEPTH

FIGURE 7-42

SINGLE STEEL PLATFORM, 8 & 16 GAS WELLS SHARING PIPELINE TO SHORE

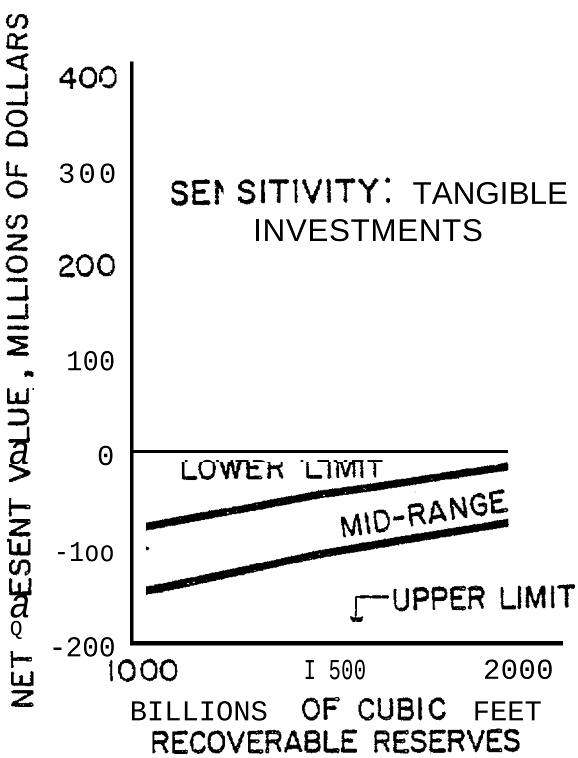


FIGURE 7-43

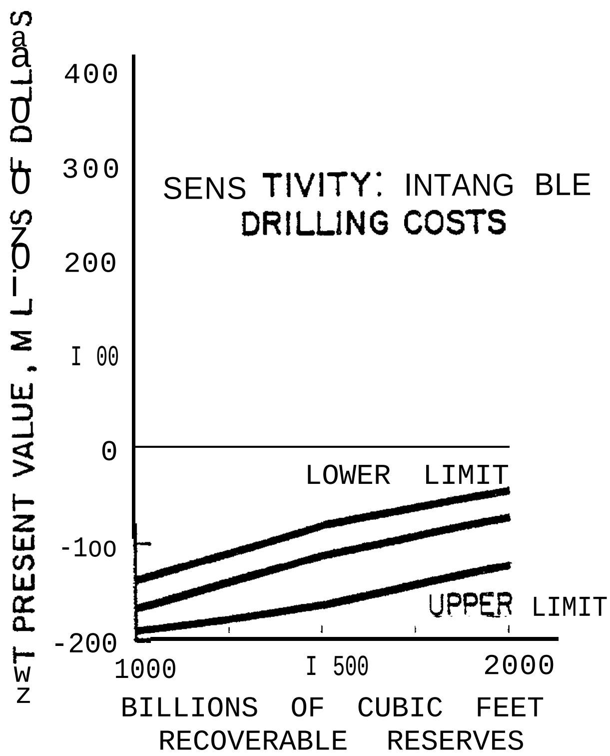


FIGURE 7-44

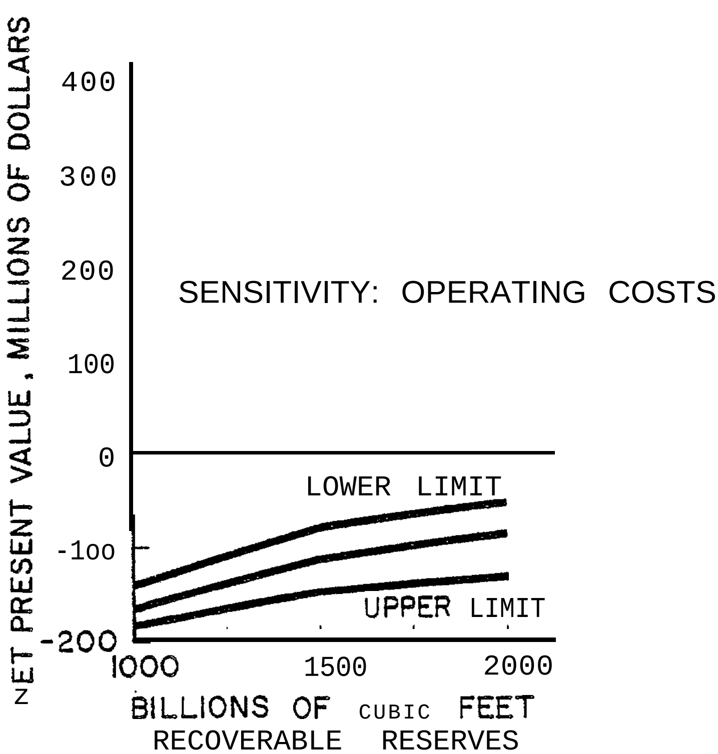


FIGURE 7-45

CASE 17: NON-ASSOCIATED GAS SINGLE PLATFORM WITH SHARED PIPELINE, 193m (600 FT) WATER DEPTH

Table 7-13

MONTE CARLO -- NON-ASSOCIATED GAS
183 METERS (600 FEET), 1.35 TCF

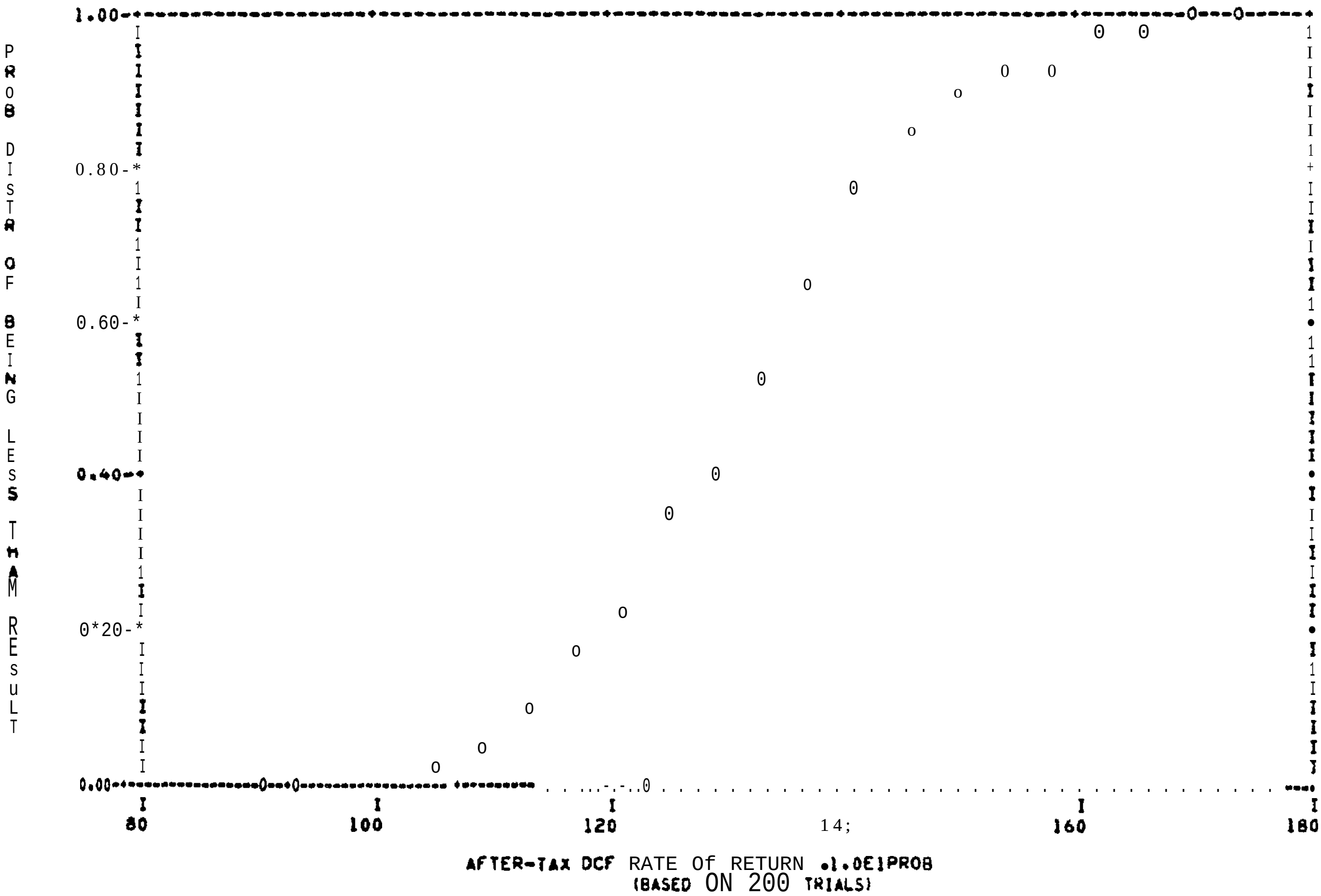
MONTE CARLO RESULTS FOR
AFTER-TAX DCF RATE OF RETURN

Result Value	Probability of Being Less Than Result
9.6524	.005000
10.0603	.010000
10.4653	.025000
10.8778	.050000
11.2863	.105000
11.6947	.175000
12.1032	.230000
12.5116	.345000
12.9201	.410000
13.3285	.525000
13.7370	.655000
14.1454	.775000
14.5539	.840000
14.9623	.890000
15.3708	.920000
15.7793	.935000
16.1877	.970000
16.5962	.980000
17.0046	.995000
17.4131	.000000

EXPECTED VALUE = 13.1945
STANDARD DEVIATION = 1.4930

Figure 7-46

CASE 17, MONTE CARLO -- NON-ASSOCIATED GAS
183 METERS (600 FEET), 1.35 TCF



would rise about $120 million to $721 .5 million to increase the number of wells, pipeline diameter and platform equipment to handle the gas produced from a 40-well system.

Forty wells, however, imply production of 1.0 bcfd of gas. This is a lot of daily gas production to process and market as LNG from Alaska. While it can be shown that some field sizes between 3.0 and 4.0 tcf in 183 meters (600 feet) of water would allow a 15 percent rate of return assuming some number of wells between 32 and 40, uncertain demand forces rather than optimum reservoir recovery characteristics are more likely to constrain field recovery in the Gulf of Alaska. To emphasize this point, this report assumes that maximum gas production of constrained by demand to allow only a 24-well platform. If production is limited to 24 wells, no gas field will earn 15 percent in 183 meters (600 feet) of water.

Figures 7-43, 7-44 and 7-45 show the sensitivity results for the 16-well system at 183 meters (600 feet). Al .5 to 2.0 tcf field will not earn 15 percent at the lower limit of the estimated costs for tangible or intangible investments or operating costs . The minimum gas price that will earn 15 percent on a 1.5 to 2.0 tcf field is close to $2.50 mcf for either field size.

Table 7-13 and Figure 7-46 show a Monte Carlo analysis for 3.5 tcf gas field in 183 meters (600 feet) with a 24-well production system. The Monte Carlo analysis shows:

- There is a 1.0 percent chance of earning less than 11.2 percent;
- There is 89 percent chance of earning less than 14.9 percent;
- There is no chance of earning more than 16.6 percent;
- The expected value is 13.6 percent.

Thus, the decision to develop a field known to have recoverable reserves of 3.5 tcf would recognize that there is little chance of making a 15 percent hurdle rate and less chance of losing money.

7.4.7 The Effect of Faster Initial Production Rates on Minimum Field Size for Development: 7500 B/D Compared to 2500 B/D

The single steel platform, with 40 producing wells sharing a pipeline to a shore terminal was shown to be the most economic type of development analyzed in this report. Case 12 in Table 7-1 reported that a 215 million barrel field in 91 meters (300 feet) of water with a total investment cost of $508 million was sufficient to earn 15 percent rate of return. Case 13 showed that in 183 meters (600 feet) of water this same system costs $750 million and, with initial production assumed to be 2500 b/d per well, there was no field size that would earn 15 percent. Cases 9 and 11 which analyzed the economics of two and three platform development confirmed that in 183 meters (600 feet) of water adding more platforms with correspondingly larger field sizes still would not yield a 15 percent rate of return.

The implication of this finding is startling. If the initial production rate is no higher than 2500 b/d, and development proceeds as assumed in this study, oil discovered in 183 meters (600 feet) of water could not be recovered fast enough to earn a 15 percent hurdle rate. No matter how large the oil field, the revenue stream would not justify development if the operator required a 15 percent return on his investment.

Table 7-14 shows the effect on oil recovery, investment cost and internal rate of return of increasing the initial production rate from 2500 b/d to 7500 b/d. The amount of oil that can be recovered in twenty years -- given the assumptions about industry development practices described in Appendix C -- increases by 515 million barrels. At $12.00 per barrel this increases the revenue received over the 20-year period by $6.18 billion, or 147 percent. Investment costs rose 36 percent to accommodate platform equipment to handle the increased throughput, increased pipeline cost and an increased share of shore terminal costs. For a 500 MMb field, the higher initial productivity increases the return on investment from 17.5 percent to 23.5 percent.

TABLE 7-14

COMPARISON OF INVESTMENT COST AND OIL RECOVERY
FOR DIFFERENT INITIAL PRODUCTION RATES

Initial Production Rate (Per Well)	Mid-Range Investment Cost[1] ($ Million) 1978)	Amount Of Oil That Can Be Recovered in 20 Years (MMB)	Internal Rate of Return on 300 MMB Oil Field (%)	Internal Rate of Return on 500 MMB Oil Field (%)
2500 B/D	$507.9	350	?6.2	17.5
7500 B/D	$691.6	865	19.0	23.5
Percentage Change	200%	1 47%	17.3%	34. 3%

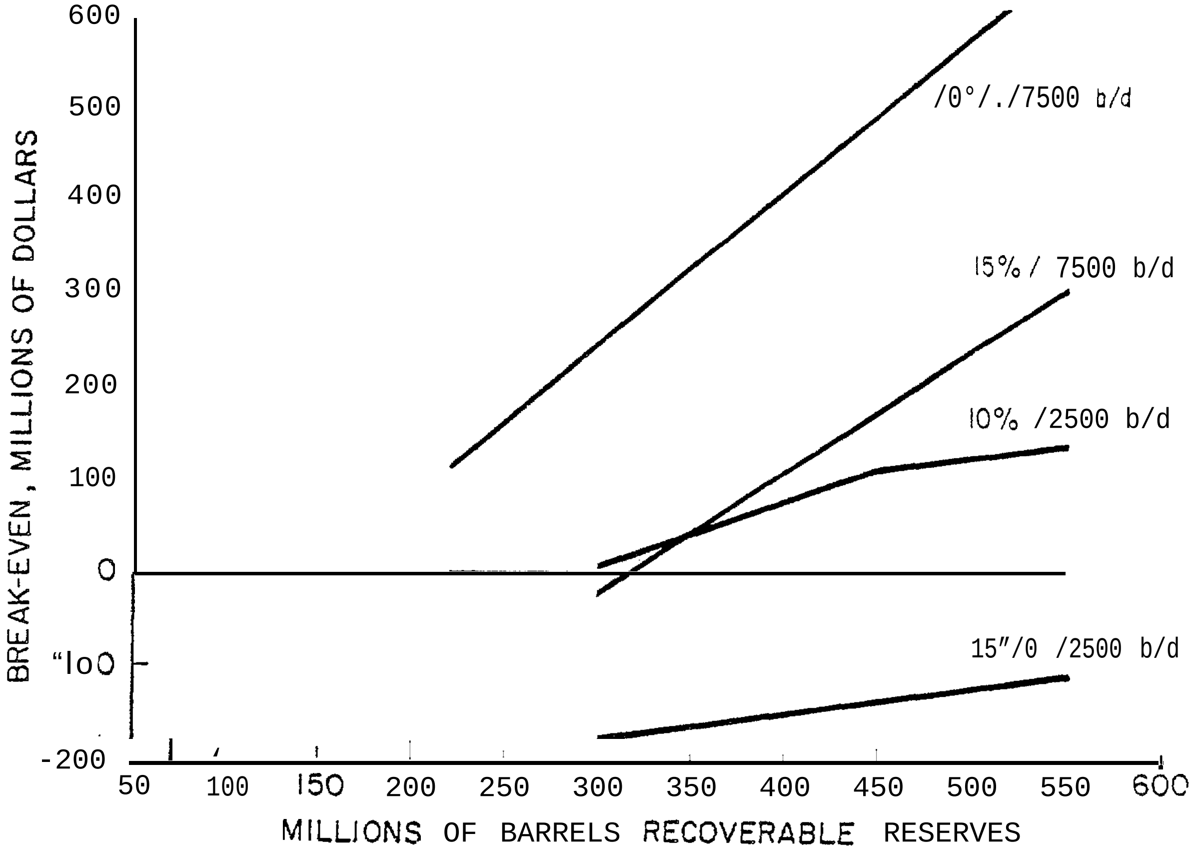
Source: Based on estimated Costs in Appendix B.

1 Forty producing wells in 91 meters (300 feet) water depth. The lower production rate shares one-half of pipeline cost and 15.5 percent of shore terminal cost. The upper production rate requires more invest-ment in deck equipment, supports the entire pipeline cost and pay 45 percent of shore terminal cost. Shore terminal cost is proportionate to share of capacity at peak throughput.

Figures 7-47 and 7-48 show the impact on minimum field size for development of increasing the initial production rate to 7500 b/d.

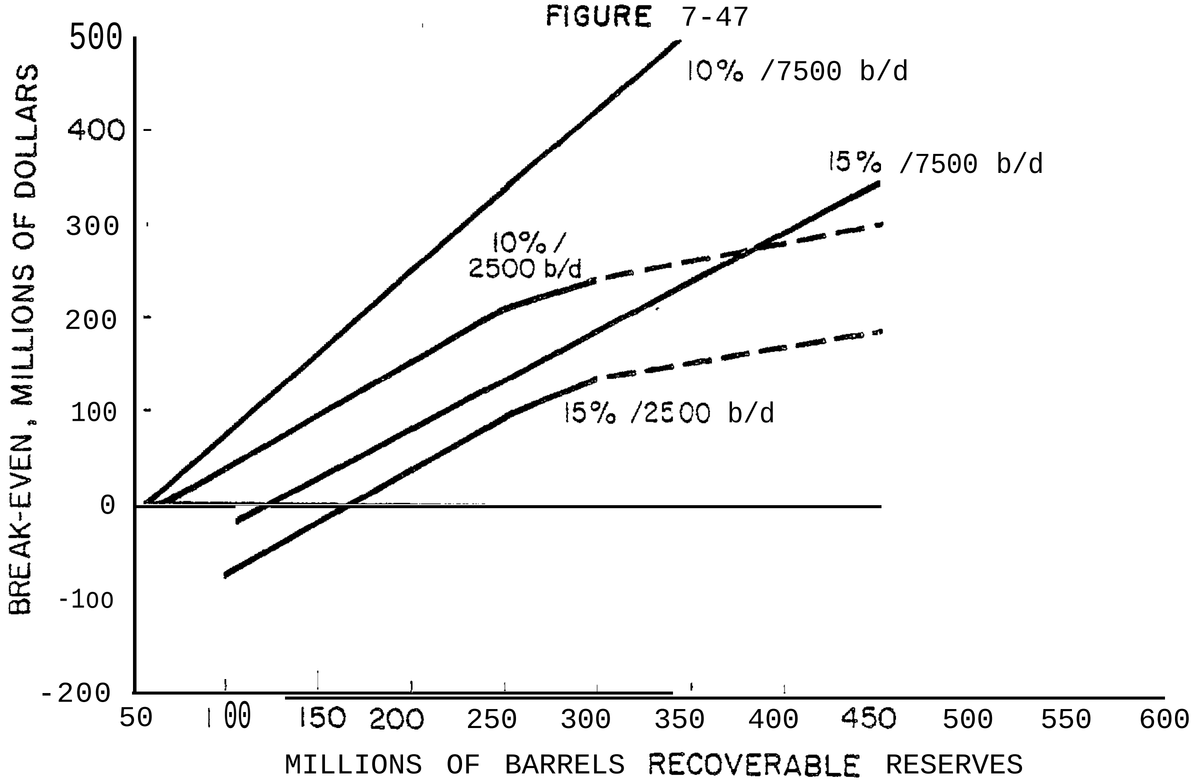
The figures contrast the break-even curves for the single steel platform in 91 and 183 meters (300 and 600 feet) water depth assuming 2500 b/d initial productivity with the same systems assuming 7500 b/d productivity. With 7500 b/d initial production rate, production from oil fields in 183 meters (600 feet) of water will earn the 15 percent hurdle rate. The minimum field size for development at 15 percent is 320 million barrels.

In 91 meters (300 feet) of water the increased initial production rate changes the minimum field size for development at 15 percent from 215 million barrels to 175 million barrels. Table 7-15 summarizes the effects of increased productivity on minimum field size for development.



183 m (600 FT) WATER DEPTH

FIGURE 7-47



91m (300 FT) WATER DEPTH

FIGURE 7-48

EFFECT OF PEAK PRODUCTION RATE ON NET PRESENT VALUE
OF DEVELOPMENT: 2500 b/d VERSUS 7500 b/d
SINGLE PLATFORM SHARING ONE-HALF OF
80 KILOMETER (50 MILE) PIPELINE TO SHORE TERMINAL

TABLE 7-15

EFFECT OF INCREASED PRODUCTION RATE ON MINIMUM FIELD SIZE FOR DEVELOPMENT

Initial Production Rate (Per Well)	91 Meters (300 Feet) Million Barrels		183 Meters (600 Feet) Million Barrels	
	10%	15%	10%	15%
2500 B/D	120	215	290	Not Economic
7500 B/D	105	175	160	320

Source: Dames & Moore Calculation

8.0 IDENTIFICATION OF SKELETAL SCENARIOS AND SELECTION OF DETAILED SCENARIOS

8.1 Introduction

The cases that were economically screened in Chapter 7.0 were selected as reasonably representative of (a) current production technologies in deep water storm-stressed environments, (b) field sizes likely to justify development within the resource levels defined by the U.S. Geological Survey, (c) probable reservoir characteristics (well productivity, depth, etc.), and (d) anticipated ranges of water depths and distances to shore of possible oil and gas discoveries in the western Gulf of Alaska.

Since there is an infinite number of permutations of field size, production technologies and discovery situations (water depth, distance to shore, geographic location) which have been demonstrated to be economically viable under the assumptions of this analysis, it is necessary to limit the number of possible developmental options at each level of resource discovery (five percent probability resource level, statistical mean resource level, no commercial resources) through application of some basic assumptions and determination of the key parameters governing potential impacts on the Alaskan economy and environment.

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

- A number of skeletal petroleum development scenarios derived from the technology, resource and discovery permutations are identified through application of assumptions and impact parameters.

- Selection by staff of the Bureau of Land Management, Alaska OCS Office of a skeletal scenario for each resource level.

- Detailing of the equipment, materials, facilities and manpower requirements and scheduling of each selected scenario (five percent probability resource level, statistical mean resource level, no commercial resources found).

8.2 Resource Assumptions

To formulate a set of skeletal scenarios, some basic resource assumptions are required. These include: (a) an allocation of the U.S. Geological Survey estimated oil and gas resources between the three sub-basins of the western Gulf of Alaska Tertiary province, (b) definition of the field sizes comprising the total resources within each sub-basin, (c) the location and geographic distribution (dispersion) of the individual fields, and (d) an allocation of the U.S. Geological Survey gas resource estimate between associated and non-associated gas. It should be emphasized that some of the resource assumptions have been, in part, selected for the need to explore impact potential. They have been explained in detail in Chapter 3.0 and Appendix C. The resource assumptions implicit in the skeletal scenarios identified on Tables 8-1 through 8-6 are:

- Eighty percent of the oil and gas resources are located in the Albatross Basin and the remaining 20 percent are located in the Tugidak Basin.
- Field size distribution is arbitrary, but all fields correspond to the minimum economic field size or larger,
- All the fields specified are economic under the assumptions and parameters of the economic analysis (Chapter 7.0 and Appendix C).
- The minimum field size is dictated by the results of the economic analysis (Chapter 7.0).
- Field locations are not specified in the skeletal scenarios;

TABLE 8-1

5% PROBABILITY RESOURCE LEVEL
CASE NO. 1: MAXIMUM ONSHORE IMPACTS: OIL AND ASSOCIATED GAS PRODUCTION ONLY

Basin	Field Size		Production System	Platforms No./Type[1]	Number of Production Wells	Peak Production		Water Depth		Distance to Shore Terminal[2]		Pipeline Diameter (inches)	
	Oil (MMBBL)	Gas[4] (BCF)				Oil (MB/D)	Gas (MMCF/D)	meters	feet	kilometers	miles	Oil	Gas
Albatross	500	--	Steel platforms with shared trunkline to shore	2 S	80	192	--	61-91	200-300	32-56	20-35	--	--
Group 1	250	--	Steel platform with shared trunkline to shore	1 S	80	192	--	61-91	200-300	32-56	20-35	8-3C	--
	200	--	Steel platform with shared trunkline to shore	1 S	40	96	--	61-91	200-300	32-56	20-35	--	--
Tugidak	250	--	Steel platform with no storage, offshore loading	1 S	40	65	--	61-91	200-300	--	--	--	--
Portlock	--	--	--	--	--	--	--	--	--	--	--	--	--

[1] S = Steel, C = Concrete

[2] Shore terminal for Albatross is Ugak Bay area.

[3] Group 1 fields share a pipeline to Ugak Bay: peak throughput, 384 MB/D.

[4] A low gas-oil ratio or non-commercial associated gas is implicit - associated gas is assumed to be used as platform fuel and reinjected see text).

TABLE 8-2

5% PROBABILITY RESOURCE LEVEL
CASE NO MINIMUM ONSHORE IMPACTS: OIL AND ASSOCIATED GAS PRODUCTION ONLY

Basin	Field Size		Production System	Platforms	Number of Production Wells	Peak Production		Water Depth		Distance to Shore Terminal[2]		Pipeline Diameter (inches)	
	Oil (MMBBL)	Gas[3] (BCF)		No./Type[1]		Oil (MB/D)	Gas (MMCF/D)	meters	feet	kilometers	miles	Oil	Gas
Al b	360	..	Concrete platform with offshore oil loading	1 S	40	96	--	61-91	200-300	32-56	20-3	--	--
	300	--	Concrete platform	1 C	40	96	--	61-91	200-300	--	--	--	--
	300	--	With storage and offshore loading	1 C	40	96	--	61-91	200-300	--	--	--	--
Tug	240	140	Steel platform	1 S	40	65	38[3]	61-91	200-300	--	--	--	--

[1] S = Steel, C = Concrete

[2] Ugak Bay area.

[3] A low gas-oil ratio or non-commercial associated gas is implicit - associated gas is assumed to be used as platform fuel and reinfected

TABLE 8-3

5% PROBABILITY RESOURCE LEVEL

CASE MAXIMUM AND MINIMUM ONSHORE IMPACTS: NON-ASSOCIATED GAS ONLY

Basin	Field Size		Production System	Platforms	Number of Production Wells	Peak Production		Water Depth		Distance to Shore Terminal[2]		Pipeline Diameter inches	
	Oil (MMBBL)	Gas (BCF)		No./Type[1]		Oil (MB/D)	Gas MMCF/D)	meters	feet	kilometers	miles	Oil	Gas
Albatross	--	1200	Steel platform with shared gas pipeline to shore	1 S	8	--	192	61-91	200-300	32-56	20-35	--	6-18
		800	Steel platform with shared gas pipeline to shore	1 S	8	--	192	61-91	200-300	32-56	20-35	--	--
		800	Steel platform with shared gas pipeline to shone	1 S	8	--	192	61-91	200-300	32-56	20-35	--	--
Tugidak	--	700	Not produced - uneconomic	--	--	--	--	--	--	--	--	--	--

[1] S = Steel, C = Concrete

[2] Ugak Island area.

TABLE 8-4

STATISTICAL MEAN RESOURCE LEVEL
CASE NO MAXIMUM AND MINIMUM IMPACTS: OIL AND ASSOCIATED GAS PRODUCTION

Basin	Field Size		Production System	Platforms	Number of Production Wells	Peak Production		Water Depth		Distance to Shore Terminal[2]		Pipeline Diameter (inches)	
	Oil (MMBBL)	Gas[3] (BCF)		No. /Type[1]		Oil (MB/D)	Gas (MMCF/D)	meters	feet	kilometers	miles	Oil	Gas
Albatross	160	--	Steel platform with no storage offshore loading	1 S	40	65	--	61	200	--	--	--	--
Tugidak	--	--	--	--	--	--	--	--	--	--	--	--	--
Portlock	--	--	--	--	--	--	--	--	--	--	--	--	--

[1] S = Steel, C = Concrete

[2] Ugak Bay area

[3] A low gas-oil ratio or non-commercial associated gas is implicit - associated gas is assumed to be used as platform fuel and reinfected.

Note: The oil and gas resources of the western Gulf of Alaska as estimated by the U. S.G. S. at the statistical mean level (200 mmbbl oil, 700 bcf gas), when allocated 20 percent to the Tugidak Basin, 80 percent to the Albatross, and 0 percent to the Portlock Basin, result in one economic oil field in the Albatross Basin. The remainder of the oil is uneconomic and cannot be produced under the technological conditions as assumptions of this analysis.

TABLE 8-5

HIGH INTEREST LEASE SALE

Basin	YEAR AFTER LEASE SALE 1		2		3	
	tie. of Rigs	No. of Wells	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells
Albatross	2	4.8	2	4.8	1	1.4
Tugidak	1	2.4	1	2.4	1	1.2
Portlock	--	--	--	--	--	--
TOTALS	3	7.2	3	7.2	2	2.6

TOTAL WELLS = 17

TABLE 8-6

LOW INTEREST LEASE SALE

Basin	YEAR AFTER LEASE SALE					
	1		2		3	
	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells
Albatross	2	4.8	1	2.4	1	0.8

TOTAL WELLS = 8

in the detailed scenarios described in Chapter 9.0 fields have been located on known structures (see second note above) when sufficient geologic data has been available.

- There is no allocation of the gas resource between non-associated and percent associated.[1]

The U.S. Geological Survey estimates of recoverable oil and gas resources are by definition economically recoverable (see Miller et al., 1975, U.S. Geological Survey Circular 725). This explicitly means that all the oil and gas in the U.S. Geological Survey estimates is discovered and produced. In the case of natural gas with offshore conversion to LNG unlikely the gas has to be transported to shore. Due to the geographic isolation of the Gulf of Alaska, lack of gas markets and transportation network, onshore conversion to LNG and shipment to lower 48 markets (which has been assumed in this analysis) or use as petrochemical feedstock by a plant onshore are the only options for market of the gas. A gas pipeline over 322 kilometers (200 miles) long linking Kodiak field(s) with existing and/or planned LNG plants in Upper Cook Inlet is not believed to be economically feasible. This has significant implications with respect to onshore development on Kodiak, especially if the gas resources occur in one or more adjacent fields.

8.3 Onshore Development Potential

The identification of a set of skeletal scenarios has to recognize that there are two basic parameters governing the potential impacts on the Alaskan economy, environment, and local communities: the amount of the resource and its location. To these factors a third can be added: the production and transportation system to be utilized in offshore oil and gas development.

---

(1) At the direction of the BLM staff at the 5 percent resource level, scenarios depicting oil production only or non-associated gas production only were developed. Therefore, no allocation of the gas resource between associated and non-associated was made. In the oil production scenarios, the implicit assumption is made that there is a low gas-oil ratio and/or the associated gas is non-commercial.

Allocation of the oil and gas resources (80:20) to two geographically separate areas -- the Albatross Basin and the Tugidak Basin -- means that it is unlikely that oil and gas will be brought to shore in the Tugidak Basin or even economic (as occurs at the statistical mean resource level).

There is insufficient available geologic data on the Kodiak Tertiary Province to identify prospects (structures) for the location of the hypothetical discoveries. Consequently, distribution of the fields (identified in Chapter 9.0) is arbitrary. However, the alternate oil development cases at the five percent resource level presented in Tables 8-1 and 8-2 reflect -- other factors being equal -- contrasting field distributions and production systems.

The production and transportation systems selected are to a great extent dependent on the amount and location of the resource. The larger the field size and/or the closer together the individual fields the greater the proportion of oil production that may be brought to shore and, therefore, the greater the onshore development. Conversely, the smaller the individual field sizes and/or the more dispersed the individual fields the greater the proportion of oil that may be produced offshore directly to tankers and, therefore, the lesser the onshore development.

The minimum economic field size (under the assumptions of this study and anticipated conditions of the Kodiak Shelf water depths, etc.) is on the order of 150 to 200 million barrels depending upon the production system and rate of return required (see Table 7-l). This factor coupled with the total resource estimate of 960 million barrels at the five percent recoverability level for the Albatross Basin means that under the umbrella of the U.S. Geological Survey resource estimates a few large fields comprise the total resource. Since the minimum economic field size is smaller for shared pipeline/shore terminal systems, some fields that would be marginal prospects in isolation become developable in proximity to other fields. Thus, economics would have to in part dictate the distribution of fields if economic (as the U.S. Geological Survey estimates imply) oil is postulated.

8.4 Skeletal Scenario Options

Given the considerations discussed above (Sections 8.2 and 8.3), skeletal scenarios were selected that were representative of a range of onshore development potential varying field sizes, field distributions and production systems. The larger the fields and/or the more closely spaced the fields, other factors being equal, the greater the proportion of total oil production assumed to be brought to shore. Similarity, the shallower the water in which the fields are located and/or the closer the fields are to shore the more likely that production will be brought to shore. It is recognized, of course, that other factors, such as comparability of crudes, unitization agreements etc., will influence the destination of production and sharing of facilities.

The skeletal scenario options in Tables 8-1 and 8-2 were selected to demonstrate what we believe represent maximum and minimum onshore impacts of offshore oil and associated gas development at the five percent level of resource discovery. Table 8-4 shows the maximum and minimum impacts of oil and associated gas development at the statistical mean resource level . At the statistical mean resource level (200 mmbbl oil, 700 bcf gas), the oil and gas resources when allocated 20 percent to the Tugidak Basin and 80 percent to the Albatross Basin result in one economic oil field in the Albatross Basin. The remainder of the oil is uneconomic and cannot be produced under the technological conditions and assumptions of this analysis. Consequently, there are no alternatives to the case identified in Table 8-4.

The gas resources as indicated by the U.S. Geological Survey are by definition economically recoverable. This explicitly means that all gas discovered goes to shore and is converted to marketable LNG. Thus, the minimum and maximum onshore impacts are identical at the five percent resource level. Therefore, no alternative skeletal scenarios are presented for non-associated gas production at the five percent resource level.

The non-associated gas scenario for the five percent resource level identified in Table 8-3 at the request of BLM staff represents a non-associated gas only scenario to be detailed separately from the selected oil scenario at the five percent resource level. (In the scenarios for the northern Gulf of Alaska, the non-associated gas production was treated cumulatively with the oil and associated gas production.) Because the non-associated gas scenario is treated separately, the assumption has been made that the total gas resource estimated by the U.S. Geological Survey will be non-associated. The principal reason far detailing a gas-only scenario is the fact that the Kodiak Tertiary Province may be gas prone rather than oil prone with the possibility that only non-associated gas will be found.

At the statistical mean resource level, the gas resource is too small to be economic.

Two exploration scenarios have been identified reflecting high interest and low interest in the lease sale, Tables 8-5 and 8-6 respectively.

In summary, the skeletal scenario options for the western Gulf of Alaska (Kodiak) are restricted by resource economics and the relatively small estimated resources (in the context of resource economics). Essentially, the only option is at the five percent resource level of oil discovery. The maximum onshore impact case (Table 8-1) assumes all oil production in the Albatross Basin is brought to shore in a single, trunk line from three closely spaced fields; a single small field in the Tugidak Basin produces through offshore loading to tankers. The alternate case (Table 8-2) assumes all oil production in both basins is offshore-loaded to tankers and implicitly indicates that the fields are too widely dispersed in the sale area, too small and/or too distant from shore to justify pipeline(s) to shore, shore terminal(s) and sharing of facilities.

8.5 Scenarios Selected for Detailing

After review of the skeletal scenario, options and consideration of their developmental implication, staff of the Bureau of Land Management, Alaska OCS Office selected the following skeletal scenarios for detailed analysis and description:

Five Percent Probability Resource Level - Oil Production Only

Case No. 1, Table 8-1

Five Percent Probability Level - Gas Production Only

Case No. 1, Table 8-3

Statistical Mean Resource Level - Oil Production Only

Case No. 1, Table 8-4

Exploration Only (No Commercial Resources)

Case No. 1, Table 8-5

9.0 DETAILED (SELECTED) SCENARIOS

9.1 Introduction

This chapter describes in detail those scenarios selected by BLM staff for the no commercial resource, five percent probability and statistical mean resource levels of the U.S. Geological Survey estimates as allocated according to the resource assumptions defined in Chapter 3,0. (Figure 9-1 shows the location of the study area.)

The exploration and development schedules are based upon the assumption that OCS lease sale No. 46 is held in 1980 and that exploration starts the year following the sale, i.e. 1981. In all the development schedules, therefore, Year 1 is 1981.

It should be-emphasized that the scenarios described in this chapter are hypothetical. Furthermore, the field developments shown are simplified examples of what is normally the result of a complex set of development decisions. Significant qualitative contrasts in crudes and gas are not, for example, examined or accommodated in these scenarios. Unitization agreements are assumed. Because of the lack of geologic data, our assumed field sizes and field distribution may not conform to geologic" reality of possible future discoveries. These and other factors have to be kept in mind when reviewing the scenario descriptions.

With minimal geologic data, location of discovery sites becomes arbitrary. The areas of "high" industry interest indicated in the Kodiak OCS Lease Sale (No. 46) draft environmental impact statement (U.S. Department of the Interior, 1976) include large portions of the middle and northern Albatross Bank. The tracts on the middle Albatross Bank lie east of the central portion of Kodiak Island, those on the northern Albatross Bank for the most part lie east of Afognak Island and the southern tip of the Kenai Peninsula. In general, discoveries on potential lease tracts in the middle Albatross Bank will be in shallower water and closer to shore than finds on the northern Albatross Bank. Potential pipeline landfalls and shore terminal sites for fields on the

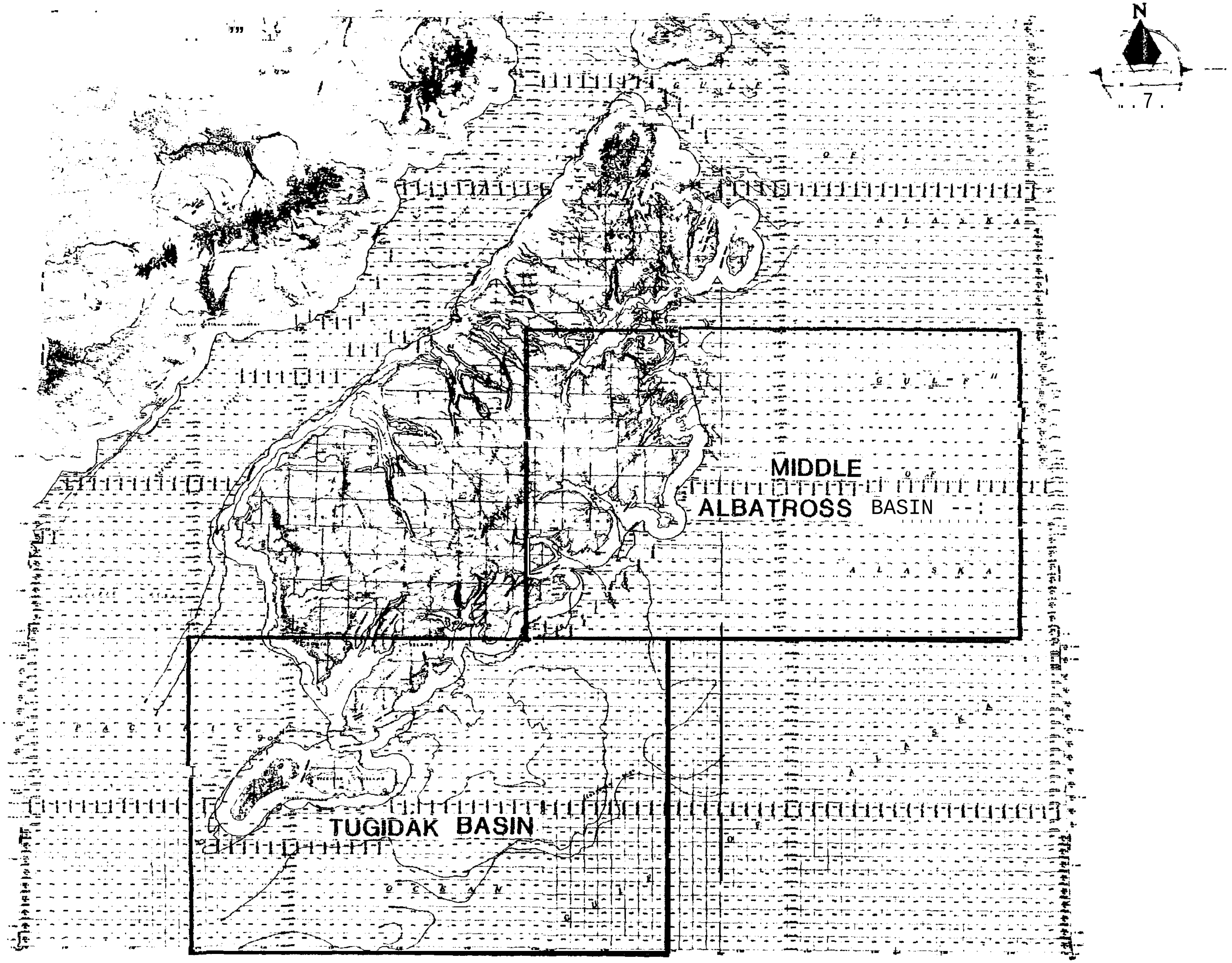


FIGURE 9-1

WESTERN **GULF** OF ALASKA, **LOCATION OF STUDY** AREA middle Albatross Bank lie along the central Kodiak Island coast while those for fields on the northern Albatross Bank lie along the northeast coast of Kodiak Island and east coast of Afognak Island. Woodward-Clyde (1977) made assumptions of northern and middle Albatross Bank finds in their analysis of potential terminal" sites for Kodiak Shelf petroleum discoveries.

The locational and impact alternatives, therefore, mainly concern these two regions. After consideration of these factors and the exigencies of the resource economics the study team opted for discovery locations on the middle Albatross Bank.

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

- An exploratory effort consistent with the postulated resources at an assumed rate of discovery which has been sustained historically in some other offshore areas (a high discovery ratio is assumed for the five percent resource level and more modest success ratio for the statistical mean resource level).

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

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

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

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

Once a discovery date has been defined for each of the fields comprising the total resource, the field development schedules defined in each scenario are based on the assumptions given in Appendix B which are consistent with schedules in other offshore areas, principally the North Sea. The scenario production profiles are described in Appendix B.

9.2 Environmental Setting of the Scenarios

9.2.1 Oceanography

The regional oceanography for the western Gulf was discussed in Section 4.3.1 which describes overall conditions within the Gulf of Alaska. The purpose of this section is to describe more site specific oceanographic conditions of the postulated exploration area and discovery leases located close to the coast of Kodiak Island. Oceanographic features particularly relevant to this area are described below.

Tidal information for the gulf of Alaska has been compiled from NOS data in the Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska (Brewer et al., 1977). Table 9-1 shows the annual average of the diunal range for selected locations on Kodiak and adjacent islands.

With the exception of Larsen Bay, which is situated well within Uyak Bay on the western side of the big island, these ranges reflect the continuous reduction in range to the southwest from the mainland. Larsen Bay is somewhat anamolous probably reflecting local physiography.

TABLE 9-1

ANNUAL AVERAGE OF DIUNAL RANGES FOR KODIAK AND ADJACENT ISLANDS (Source: Brewer et al., 1977)

Location	Range Meters	(Feet)
Red Fox Bay	4.2	(13.7)
Larsen Bay	4.2	(13.7)
Kodiak	2.6	(8.5)
Sitkinak Lagoon	2.3	(7.5)

The preponderance of the water current information adjacent to the Kodiak Island complex consists of geostrophic estimates, e.g., Thompson et al, (1936) and Fauorile (1970). The direct wind driven component has also considered by Searby (1969). Nearshore, however, the currents are primarily tidally generated and largely dependent on local conditions. Kodiak and nearby islands display complex coastlines with narrow straits occurring between islands, deep, fjord-like bays separated by jutting headlands. These features can interact with the tidal currents to generate turbulent and often hazardous navigational situations.

Anticipated wave climates for the Gulf have been discussed in Section 4,3.1. The normal wave pattern is modified by the highly variable bottom topography. Possible hazardous conditions may be found near headlands or over shoals where wave energy tends to be concentrated. In addition, the combination of tidal currents and waves can present potential dangerous conditions. Alternatives to conducting operations within and laying pipelines through such areas should be carefully considered.

The entire coastline of the Gulf of Alaska is susceptible to tsunamis generated by seismic activity. Such waves can be extremely damaging to coastal facilities as witnessed by the aftermath of the Good Friday Earthquake in 1964. The Kodiak Island complex was particularly impacted by tsunamis generated from that earthquake.

Ice floes or large ice blocks produced by "calving" of glaciers fronting coastlines should not pose hazards for marine terminals or shipping. No glaciers intersect the coast on Kodiak Island and the area is sufficiently south to avoid ice buildup on the surface. Superstructure icing must be considered as a possible hazard to the smaller work boats (AEIDC, 1974, p.22). This is due to specific combinations of wind, water and air temperatures. The Climatic Atlas (AEIDC/Institute of Economic, Government Research, 1977) has reproduced a nomograph for forecasting icing conditions at the sea surface. Examination of this graph indicates that severe conditions are not required to produce very heavy icing.

This section has described those oceanographic factors that could have direct and significant impact on site specific problems. We have not attempted to estimate the maximum wave height that could reasonably be considered as a design wave -- nor have we tried to estimate the magnitude of tidal currents within the area -- these are highly variable and depend largely on local conditions. We have pointed out phenomena that do occur in this area and to which concern should be given. Efforts to expand the present data base undoubtedly will proceed development of this area.

9.2.2 Geologic Hazards

Site specific geologic hazard data for the Kodiak area is extremely limited. Most of the data available is inferred or approximated. Bearing this in mind the discussion that follows summarizes the geologic hazards for the two main areas where offshore development has been postulated to occur -- the middle Albatross Basin and Tugidak Basin.

The middle Albatross Basin area is bisected by two troughs, the Chiniak trough to the north and the Kiliuda trough on the south. The bottom sediments within this area are either well consolidated sediments, glacial outwash and moraines or bedrock. Because of the absence of unconsolidated sediments the probability of slumps and slide occurrence is low and associated impacts to petroleum exploration and development operations is therefore minor.

The major geologic hazard, aside from the ever present seismic risks, is faulting. The minimal data available delineates several faults running parallel to Kodiak Island. Pipelines from production platforms may be impacted by faults that cross the mouth of Ugak Bay. However, this problem cannot be directly avoided by route relocation because these faults traverse the full length of southeastern Kodiak Island. Faulting will have to be considered, along with potential seismicity, in design criteria for production platforms, LNG plants, oil terminals and pipelines.

Tugidak Basin is bordered on the north by Sikinak trough and on the south by Chirikof Island. The sediments are almost entirely consolidated mixed gravels and sand, with scattered glacial deposits. Data for the Tugidak Basin is virtually non-existent, therefore fault locations, slump and slide locations or even potential locations are impossible to predict.

A BLM report (AEIDC/Institute of Social, Economic, Government Research, 1974, The Western Gulf of Alaska, A Summary of Available Knowledge) summarizes the glacial activity that occurred in the western Gulf during the Pleistocene. This has produced many overstepped slopes. These features can be sites of landslides especially if not managed correctly during construction of onshore facilities. Such slopes often front bays around the Kodiak Island areas. Landslides within these bays could generate local tsunamis that should be considered as potential hazards.

9.2.3 Biology

The offshore platforms southeast of Ugak Bay specified in the five percent and statistical mean scenarios are located on Albatross Bank which is noted for its production of fish and shellfish. Domestic commercial fishing in the area occurs for king and tanner crab, scallops, and halibut. Foreign fisheries exploit several species of bottomfish. The middle Albatross area is particularly important as spawning and rearing habitat for king crab and rearing habitat for tanner crab (ADF&G, 1977). In addition, sea birds, fur seals and several species of whales utilize the vicinity for foraging. All of the above resources and the associated fishing activities occur over a large area and it is unlikely that the presence of several isolated platforms would have a significant detrimental impact. However, an oil spill within this sensitive area and possibly involving the east coast of Kodiak Island could have potentially greater impacts than in most other offshore locations. Operations would need to be conducted with extreme care.

The offshore region east of Tugidak Island also supports important resources including king, tanner and dungeness crabs, shrimp and halibut. The area has been designated as "vital" spawning and rearing habitat for king crab (ADF&G, 1977). The potential for detrimental impact due to oil spills is high in this location and would be increased further if Tugidak and Sitkinak Islands became involved in petroleum development because of large concentrations of harbor seals and lesser numbers of sea lions, sea otters and sea birds. Operations, particularly offshore loading, would need to be carefully conducted.

Undersea pipelines running from the platforms in the middle Albatross Bank area into Ugak Bay would probably have little impact on marine organisms, but, again, the potential impact from oil leaks would be high, particularly near the coast or within the bay. Pipelines, if not buried or trenched, could create an inconvenience for offshore trawl fisheries and for the purse seine salmon fishery that operates within the outer portion of Ugak Bay.

Ugak Bay and the adjoining coastline support rich biological assemblages typical of the east coast of Kodiak Island. Ugak Island, just outside the bay, is a hauling area for seals and sea lions and Gull Point, at the other side of the bay entrance, supports a sea bird nesting colony and a sea lion hauling area. More important resources within the bay include salmon, high concentrations of harbor seals, wintering sea birds, occasional whales, crabs and shrimp. Portions of the coastline are important habitat for Sitka blackmailed deer and brown bear. Numerous streams used by anadromous fish species enter the bay (ADF&G, 1977; Science Applications, Inc., 1978), An oil and gas shore terminal in the north central portion of the bay (corresponding with site #10, Woodward-

Clyde, 1977) would probably have relatively less impact than other site locations providing that siting was done carefully. Saltery Cove, immediately west of the suggested terminal site, contains important resources (salmon streams, razor clams, waterfowl, archeological sites) and should be avoided. Woodward-Clyde (?977) rated the site as moderate in environmental sensitivity in relation to other Kodiak sites.

Increased marine traffic within Ugak Bay and on Albatross Bank would result from the development. Marine traffic zoning might be implemented to protect resources and fishing grounds.

9.3 Exploration Only Scenario

The exploration only scenario assumes that no commercial oil and/or gas resources are discovered. Industry interest is high and is principally centered in the Albatross Basin. A high level of exploratory activity characterizes the exploration program due to a number of promising "shows". However, the promise is never realized and only small non-commercial hydrocarbon deposits are found. Exploration terminates after the fourth year with a total of 17 wells drilled (see Table 9-2).

9.3.1 Tracts and Location

No tracts are specified in this scenario. The total of wells drilled (17) indicates that 17 of the leased tracts are drilled (the assumption has been made that no more than one well is drilled per tract), 11 in the Albatross Basin and six in the Tugidak Basin. Several of the larger structures are explored with two or even three wells, thus the total number of prospects examined is somewhat less than the" total number of wells drilled.

9.3.2 Schedule

The exploration schedule, presented in Table 9-2, shows that exploration commences in the first year after the lease sale, and terminates in the third year after discouraging results.

TABLE 9-2

EXPLORATION SCHEDULE - EXI%ORATION ONLY SCENARIO

	Year After Lease Sale					
	1		2		3	
Shelf	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells
Albatross	2	4.8	2	4.8	1	1.4
Tugidak	1	2.4	1	2.4	1	1.2
Portlock						
Totals	3	7.2	3	7.2	2	2.6

Total Wells = 17

9.3.3 Facility Requirements

Exploration in the western Gulf of Alaska will be mainly conducted by semi-submersible drill rigs, perhaps supported by drill ships in the summer, since the range of water depths [61 to 198 meters (200 to 650 feet)] in which most of the prospects are located is best suited to these rigs. The number of rigs involved in the exploration program is given in Table 9-2.

As discussed in Chapter 6.0, the principal exploration support base will be Seward with Kodiak performing a minor role.

9.3.4 Manpower Requirements

The manpower requirements associated with the exploration program are presented in Tables 9-3, 9-4 and 9-5.

9.4 Five Percent Probability Resource Level Scenario - Oil Only

This scenario is illustrated in Figures 9-2 and 9-3. A summary description of this scenario, including field sizes, is provided in Table 9-6.

9.4.1 Resources

The five percent probability resource level scenario represents a high find case of resource discovery but with only a 1 in 20 chance that that amount of resource will be discovered. The scenario postulates that only oil is discovered and that associated gas is non-commercial and used to fuel the platforms and reinfected.

The total reserves discovered and developed are:

	Oil (MMbbl)
Albatross Basin	950
Tugidak Basin	250

TABLE 9-3

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS - EXPLORATION ONLY SCENARIO
(NUMBER OF PEOPLE)

	JANUARY					JULY					PEAK	
	OFFSHORE		ONSHORE		JANUARY	OFFSHORE		ONSHORE		JULY		
YEAR AFTER LEASE SALE	ONSITE	OFFSITE	ONSITE	OFFSITE	TOTAL	ONSITE	OFFSITE	ONSITE	OFFSITE	TOTAL	MONTH	TOTAL
1	246.	207.	39*	15.	507.	271.	207.	41.	15.	534.	5	561.
2	246.	207.	39 .	15.	507.	271.	207.	41.	15.	534.	5	561.
3	164.	138.	26.	10.	338.	25.	0.	2.	0.	27..	5	365.

TABLE 9-4

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY - EXPLORATION ONLY SCENARIO
(ONSITE NAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	2191.	230.	0.	0.	936.	252.	0.	3127.	482.	3609.
2	2191.	230.	0.	0.	936.	252.	0.	3127.	482.	3609.
3	747.	78.	0.	o*	312.	84.	o.	1059.	162.	1221.

TABLE 9-5

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY - EXPLORATION 0HL% SCENARIO
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	302.	180.	0.	0.	0.	0.	0.	0.	0.	0.	175.	2016.	0.	0.	0.	936.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	0.	468.
2	ONSITE	302.	180.	00	0.	0.	0.	0.	0.	0.	0.	175.	2016.	0.	0.	0.	936.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	0.	468.
3	ONSITE	102.	60.	0.	0.	0.	0.	0.	0.	0.	0.	75.	672.	0.	0.	0.	312.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	672.	0.	0.	0.	156.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 9-5 (Cont.)

LIST OF TASKS BY ACTIVITY

ONSHORE

Activity

1 Service Bases (Onshore Employment which would include all onshore administration, service base operations, rig and platform service)

- Task 1 - Exploration Well Drilling
- Task 2 - Geophysical Exploration
- Task 5 - Supply/Anchor Boats for Rigs
- Task 6 - Development Drilling
- Task 7 - Steel Jacket Installations and Commissioning
- Task 8 - Concrete Installations and Commissioning
- Task 11 - Single-leg Mooring System
- Task 12 - Pipeline-Offshore, Gathering, Oil and Gas
- Task 13 - Pipeline -Offshore, Trunk, Oil and Gas
- Task 23 - Supply/Anchor Boats for Platform
- Task 24 - Supply /Anchor Boats for Lay Barge
- Task 27 - Longshoring for Platform
- Task 28 - Longshoring for Lay Barge
- Task 33 - Maintenance and Repairs for Platform and Supply Boats
- Task 37 - Longshoring for Platform (Production)

2 Helicopter Service

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

Construction

3 Service -

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

4 Pipe Coating

- Task 15 - Pipe Coating

5 Onshore Pipelines

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

6 Terminal

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

7 LNG Plant

- Task 17 - LNG Plant

8 Concrete Platform Construction

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

9 Oil Terminal Operations

- Task 36 - Terminal and Pipeline Operations

10 LNG Plant Operations

- Task 38 - LNG Operations

OFFSHORE

Activity

11 Survey

- Task 2 - Geophysical and Geological Survey

12 Rigs

- Task 1 - Exploration Well

13 Platforms

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

14 Platform Installation

- Task 7 - Steel Jacket Installation and Commissioning
- Task 8 - Concrete Installation and Commissioning
- Task 11 - Single-Leg Mooring System

15 Offshore Pipeline Construction

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

16 Supply /Anchor/Tug Boat

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

TABLE 9-6

5% PROBABILITY RESOURCE LEVEL - OIL PRODUCTION ONLY

Basin	Field Size: Oil (MMBBL)	Field Size: Gas[4] (BCF)	Production System	Platforms No./Type[1]	Number of Production Wells	Peak Production: Oil (MB/D)	Peak Production: Gas MMCF/D)	Water Depth: meters	Water Depth: feet	Distance to Shore Terminal[2]: kilometers	Distance to Shore Terminal[2]: miles	Pipeline Diameter (inches): Oil	Pipeline Diameter (inches): Gas
Albatross	500	--	Steel platforms with shared trunkline to shore	2 S	80	192	--	61-91	200-300	32-56	20-35	--	--
Group 1	250	--	Steel platform with shared trunkline to shore	1 S	80	192	--	61-91	200-300	32-56	20-35	28-30[3]	--
	200	--	Steel platform with shared trunkline to shore	1S	40	96	--	61-91	200-300	32-56	20-35	--	--
Tugidak	250	--	Steel platform with no storage, offshore loading	1S	40	65	--	61-91	200-300	--	--	--	--
Portlock	--	--	--	--	--	--	--	--	--	--	--	--	--

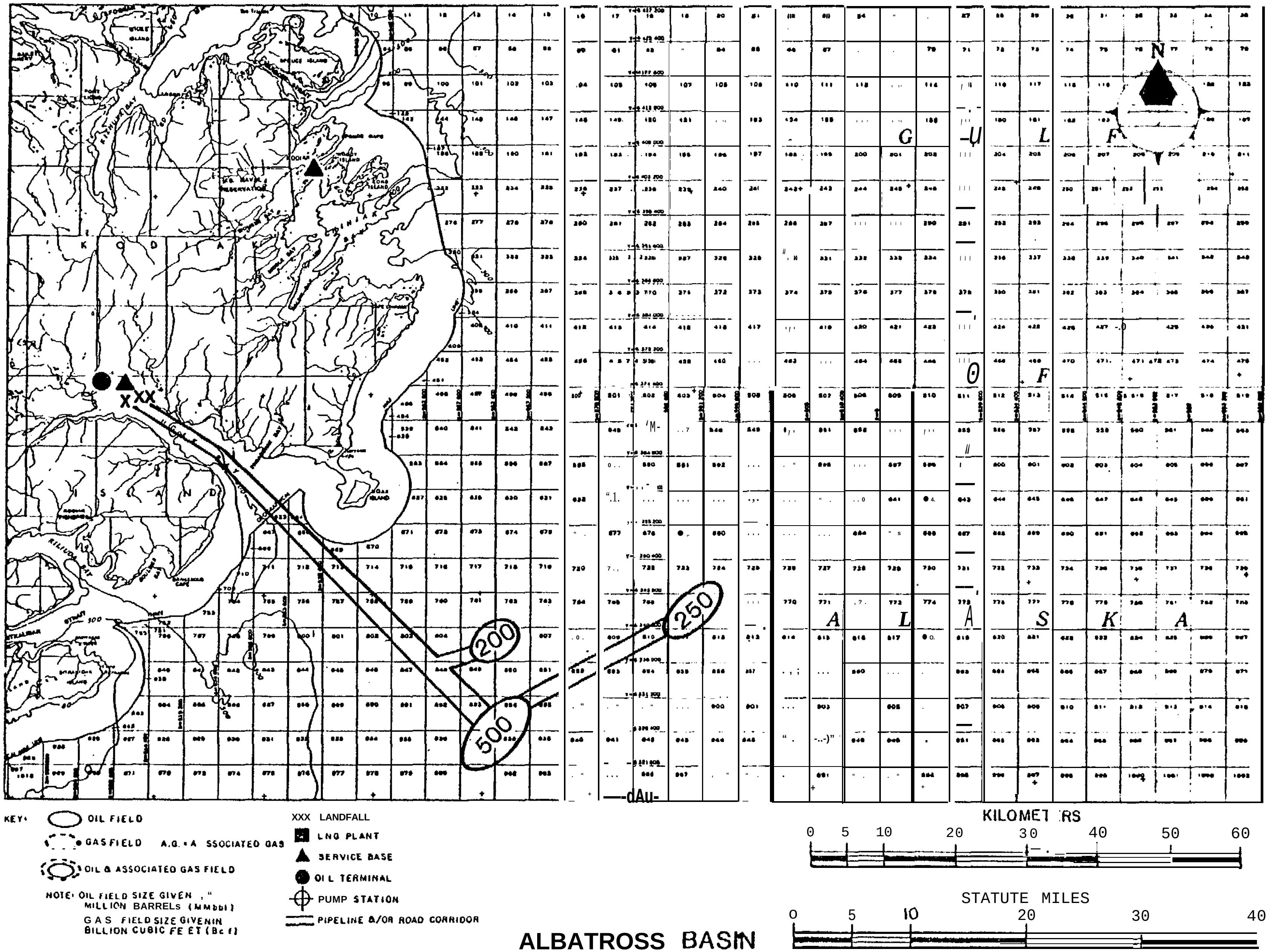
[1] S = Steel, C = Concrete

[2] Shore terminal for Albatross is Ugak Bay area.

[3] Group 1 fields share a pipeline to Ugak Bay: peak throughput, 384 MB/D.

[4] A low gas-oil ratio or non-commercial associated gas is implicit - associated gas is assumed to be used as platform fuel and reinjected (see text).

OIL - 5% PROBABILITY RESOURCE LEVEL SCENARIO

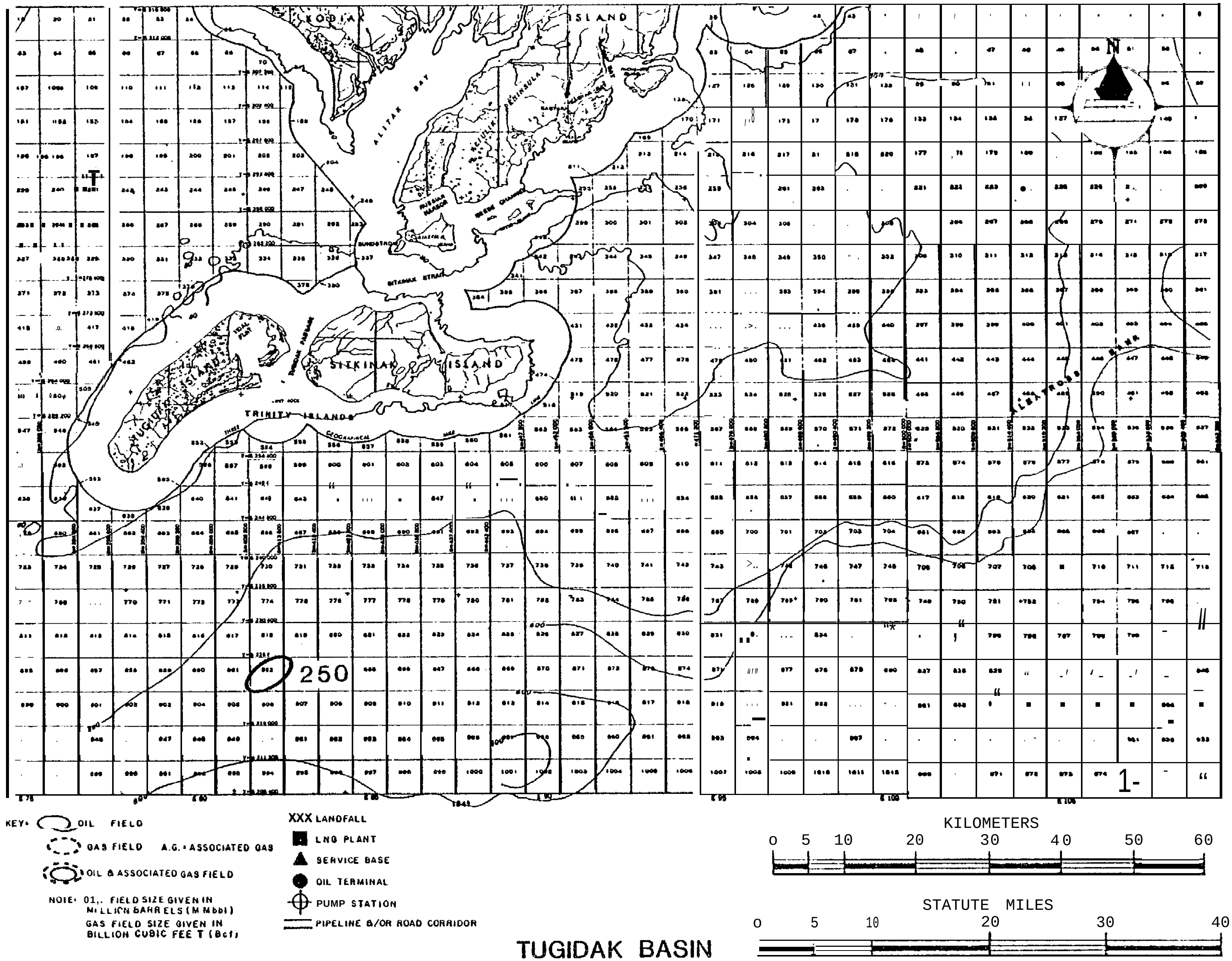


ALBATROSS BASIN

FIELD AND ONSHORE SITE LOCATIONS

FIGURE 9-3

OIL - 5% PROBABILITY RESOURCE LEVEL SCENARIO



TUGIDAK BASIN

FIELD AND ONSHORE SITE LOCATIONS

This scenario assumes that only oil and associated gas are discovered. The associated gas reserves are too small to economically justify production and are, therefore, used to power the platforms and reinfected.

9.4.2 Tracts and Location

As shown in Table 9-7 total productive acreage is 34,285 involving a total of 5.9 lease tracts.

9.4.3 Exploration, Development and Production Schedule

Exploration, development and production schedules are shown on Tables 9-8 through 9-15. Four commercial oil discoveries are made over a period of five years commencing in the second year after the lease sale (Table 9-9). Exploration peaks in Year 4 when 11 exploratory wells are drilled (Table 9-8).

Field development commences in Year 5 following the decision-to-develop the first discovery (a 500 mmbbl reserve oil field). The first production platform is installed in Year 6 and the last in Year 9 (Table 9-11). Construction schedules of the major onshore facilities are shown in Table 9-12.

Oil and gas production schedules are given in Table 9-11 which indicates that oil production commences in Year 10 after the lease sale and gas in Year 8.

9.4.4 Facility Requirements

The major portion of the oil reserves discovered off Kodiak Island are found in three fields located within 48.3 kilometers (30 miles) of each other on the middle Albatross Bank in water depths of 61 to 91 meters (200 to 300 feet). The proximity of the fields to each other and their discovery within three years of each other permits their development in tandem and their sharing of a trunk pipeline to shore and oil terminal.

TABLE 9-7

5% PROBABILITY RESOURCE LEVEL SCENARIO - OIL ONLY
FIELDS AND TRACTS

Basin	Oil (mmbbl)	FIELD SIZE Acres	Hectares	Tracts	Tract Nos.[1,2]
Albatross	500	14,286	5,714	2.5	937, 938, 961, 893, 891
	250	7,143	2,857	1.2	810, 811, 766, 767, 768, 723, 724
	200	5,714	2,286	1.0	805, 806, 761, 762
Tugidak	250	7,142	2,857	1.2	86?, 862, 863
TOTALS		34,285	13,714	5.9	

[1] Includes all tracts and/or portions of tracts comprising surface expression of field in total area not exceeding number of tracts indicated in previous column.

[2] BLM protraction diagram numbers.

TABLE 9-8

EXPLORATION SCHEDULE FOR EXPLORATION AND DELINEATION WELLS - OIL - 5% RESOURCE LEVEL SCENARIO

Shelf	Well Type	Year After Lease Sale						4		5				7								Well Totals
		Rigs	Wells[3]	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	
Albatross	Exp.[1]	1	2	2	6	2	4	3	5	2	3	1	3					-		-		23
	Del.[2]						2		3		2											7
Tugidak	Exp.							1	3	1	3	1	1	1	1					-		8
	Del.										-		2									2
Total		1	2	2	6	2	6	4	11	3	8	2	6	1	1							40

[1]In this high find scenario a success rate of one significant discovery for every seven exploration wells is assumed. To date, this success rate has been sustained, for example, in the North Sea in the period 1968-1977 (Her Majesty's Stationary Office, 1978). This compares with a 10 percent success rate in U.S. offshore areas in the past 10 years (Tucker, 1978).

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

[3]An average completion time of four to five months per exploration/delineation well is assumed or 2.4 to 3 wells Per rig Per Year.

Source: Dames & Moore

TABLE 9-9

TIMING OF DISCOVERIES - OIL - 5% RESOURCE LEVEL SCENARIO

Year After Lease Sale	Type	Reserve Size		Location	Water Depth	
		Oil (mmbbl)	Gas (bcf)		Meters	(feet)
2	Oil	500	--[1]	Albatross	61-91	(200-300)
3	Oil	200	--[1]	Albatross	61-91	(200-300)
4	Oil	250	--[1]	Albatross	61-91	(200-300)
5	Oil	250	--[1]	Tugidak	61-91	(200-300)

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

Source: Dames & Moore

TABLE 9-10

FIELD PRODUCTION SCHEDULE - OIL - 5% RESOURCE LEVEL SCENARIO

Shelf	Field		Peak Production		Year After Lease Sale			
	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	Years of Production
Albatross	500	--	192	--	8	22	11	15
	200	--	96	--	9	20	11	12
	250	--	96	--	10	24	12-13	15
Tugidak	250	--	65	--	11	30	13-15	20

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

Source: Dames & Moore

TABLE 9-11

PLATFORM INSTALLATION SCHEDULE - 5% OIL RESOURCE LEVEL SCENARIO

Field		Year After Lease Sale											
Oil (MMBBL)	Gas (BCF)	1	2	3	4	5	6	7	8	9	10	11	12
500			*		D		Δs	Δs					
200				*		D.		Δs					
250					*		D		As				
250						*		D		Δs			
Totals							1	2	1	1			

* = Discovery; D = Decision to Develop; Δs = Steel Platform Installation

Notes:
1. Platform installation is assumed to be June in each case.
2. Platform "installation" includes module lifting, hook-up and commissioning.
3. Steel platforms in water depths < 91 meters (<300 feet)- are fabricated and installed within 48 months of construction start up; steel and concrete platforms in water depths 91 meters plus (300 feet) plus are constructed and installed within 36 months of fabrication start up.

Source: Dames & Moore

TABLE 9-12

MAJOR FACILITIES CONSTRUC ION SCHEDULE 5% OIL RESOURCE LEVEL SCENARI°

Source: &

TABLE 9-13

MAJOR SHORE FACILITIES START UP DATE - 5% OIL RESOURCE LEVEL SCENARIO

Facility	Year After Lease Sale	
	Start Up Date[1]	Shut Down Date[2]
Oil Terminal	8	24

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

Source: Dames & Moore

TABLE 9-14

DEVELOPMENT WELL DRILLING SCHEDULE - 5% OIL RESOURCE LEVEL SCENARIO

Field	Oil (MMBBL)	Gas (BCF)	Platforms Nos.	Platforms Type[1]	No.[2] of Drill Rigs Per Platform	Total No. of Production Wells[4]	Start of Drilling Month	Year After Lease Sale - No. Wells Drilled[3] 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Albatross	500	--	1	S	2	40	July						Δ	8	16P	16	4			W							
		--	1	S	2	40	July							Δ	8	16P	16	16 4			W						
	200	--	1	S	2	40	July							Δ	8	16P	16	16 4			W						
	250	--	1	S	2	40	July								A	8	16P	16	4			W					
Tugidak	250	--	1	S	2	40	July									Δ	8	16	16	4			W				

[1]S = Steel

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

[3]Drilling progress is assumed to be 45 days per development well per drilling, i.e. eight wells per year.

[4]Gas or water reinjection wells etc.; well allowances are assumed to be one well for every 10 production wells for oil fields.

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

P = Production starts; assumed to occur when first 16 wells are completed, i.e., two years after platform is installed if two drill rigs are used.

Δ = Platform installed; assumed to be June.

Source: Dames & Moore

TABLE 9-15

PIPELINE CONSTRUCTION SCHEDULE - OIL - 5% RESOURCE LEVEL SCENARIO
KILOMETERS (MILES) CONSTRUCTED BY YEAR

Pipeline Diameter (Inches) Oil		Water Depth Meters	Water Depth (feet)	Year After Lease Sale 1	2	3	4	5	6	7	8	9	10	11
Offshore	28-30	0-91	(0-300)							76 (47.3)				
	14-16	76-91	(250-300)							4.0 (2.5)				
	14-16	76-91	(250-300)								33 (20.5)			
	14-16	76-91	(250-300)								4.2 (2.6)			
Subtotal										80 (49.8)	37.2 (23.1)			
Onshore	28-30	--	--							1.6 (1.0)				
		--	--											
Subtotal										1.6 (1.0)				
Total										82 (50.8)	37 (23.1)			

Source: Dames & Moore

A medium-sized oil terminal designed to handle the anticipated peak production of 384,000 barrels per day is constructed on the north shore of Ugak Bay, the closest, most suitable deep water port location (see Chapter 6.0). The terminal completes stabilization of the crude, recovers valuable LPG, treats tanker ballast and provides storage for approximately four million barrels of crude. There are two loading jetties (one for crude and one for crude/LPG) for tankers destined for the U.S. West Coast.

Only one economic field is discovered in the Tugidak Basin with reserves of about 250 million barrels. The operator decides that there are insufficient reserves to support a pipeline to shore and tanker terminal. An offshore loading production system using a single SPM and employing "dedicated" tankers is selected. A single steel platform with no storage capability is selected; the incremental cost of providing storage is deemed not to compensate for the increased production capability.

Facilities at the ports of Seward and Kodiak are expanded for construction support in the development of the Kodiak fields. The steel platforms and modules are fabricated on the U.S. West Coast and towed to Alaska by barge.

Facility requirements and related construction scheduling are summarized in Tables 9-8 through 9-15.

9.4.5 Manpower Requirements

The manpower requirements for this scenario are presented in Tables 9-16 through 9-18.

9.5 Five Percent Probability Resource Level Scenario - Non-Associated Gas Only

This scenario assumes discoveries of non-associated gas only. The scenario is illustrated in Figures 9-4 and 9-5. A summary description of this scenario is provided in Table 9-19.

TABLE 9-16

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS - 5% PROBABILITY RESOURCE LEVEL SCENARIO
OIL PRODUCTION ONLY
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHONE ONSITE	JANUARY ONSHONE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	82.	69.	13.	5.	169.	82.	69.	13.	5.	169.	5	196.
2	164.	138.	26.	10.	338.	189,	138.	28.	10.	365.	5	392.
3	164.	138.	26.	10.	338.	189.	138.	28.	10.	365.	5	392.
4	328.	276.	5.2.	20.	676.	378.	276.	56.	20.	730.	5	757.
5	246.	207.	173.	30.	656.	296.	207.	847.	103.	1453.	6	1453.
6	164.	138.	76.	15.	393.	668.	577.	440.	53.	1739.	12	1989.
7	561.	508.	725.	81.	1876.	1884.	1723.	870.	90.	4567.	7	4567.
8	1070.	991.	520.	127.	2708.	1857.	1732.	315.	104.	4008.	7	4008.
9	899.	853.	191.	94.	2037.	1658.	1561.	283.	109.	3611.	7	3611.
10	1179.	1121.	221.	104.	2625.	1375.	1311.	242.	109.	3037.	7	3037.
11	896.	872.	180.	104.	2052.	980.	950.	189.	109.	2228.	6	2228.
12	980 .	950.	189.	109.	2228.	980.	950.	189.	109.	2228.	1	2228.
13	888.	858.	185.	109.	2040.	888.	858.	185.	109.	2040.	1	2040.
14	704.	674.	177.	109.	1664.	704.	674.	177.	109*	1664.	1	1664.
15	612.	582.	173.	109.	1476.	612.	582.	173.	109.	1476.	1	1476.
16	520.	490.	169.	109.	1288.	520.	490.	169.	109.	1288.	1	1288.
17	520.	490.	169.	109.	1288.	520.	490.	169.	109.	1288.	1	1288.
18	520.	490.	169.	105.	1288.	520.	490 •	169.	10'3.	1288.	1	1288.
19	520.	490.	169.	109.	1288.	520.	490.	169.	109.	1288.	1	1288.
20	520.	490.	169.	109.	1288.	520.	490.	169.	109.	1288.	1	1288.
21	500.	470.	161.	109.	1240.	416.	392.	152.	104.	1064.	1	1240.
22	416.	392.	152.	104.	1064.	416.	392.	152.	104.	]064.	1	1064.
23	376.	352.	136.	104.	968.	208.	196.	118.	94.	616.	1	968.
.24	208.	196.	34.	10.	448.	208.	196.	34 •	10*	448.	1	448.
25	188.	176.	26.	10.	400.	104.	98.	17.	5.	224.	1	400.
26	104.	98.	17.	5.	224.	104.	98.	17.	5.	224.	1	224.
27	104.	98.	17.	5.	224.	104.	98.	17.	5.	224.	1	224.
28	104.	98.	17.	5.	224.	104.	98.	17.	5*	224.	1	224.
29	104.	98.	17.	5.	224 .	104.	98.	17*	5.	224.	1	224.
30	104.	98.	17.	5.	224.	104.	98.	17.	5*	224.	1	224.

TABLE 9-17

ONSITE MANPOWER REQUIREMENTS BY INDUSTR% - 5% PROBABILITY RESOURCE LEVEL SCENARIO
01 L PRODUCT ION ONLY
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	610.	64.	0*	0*	260.	70.	0.	870.	134.	1004.
2	1494.	156.	0.	0.	624.	168.	0.	2118.	324.	2442.
3	1494.	156.	0.	0.	624.	168.	0.	2118.	324.	2442.
4	2963.	310*	0.	0.	1248.	336.	0.	4211.	646.	4857.
5	2216.	232.	0.	5628.	936.	252.	0.	3152.	6112.	9264.
6	1494.	156.	2800.	4(I 75.	1177.	427.	0*	5471.	4658.	10129.
7	977.	104.	91s0.	8030.	2044.	423.	0.	12171.	9057.	?1228.
8	3192.	288.	8600.	1775.	1828.	1885.	0.	13620.	3948.	17568.
9	6576.	504.	5600.	350.	1418.	1760.	0.	13594.	2614.	16208.
10	9144.	648.	2800.	175.	1069.	1654.	0.	13013.	2477.	15490.
11	10680.	720.	0.	0.	660.	1503.	0*	11340.	2223.	13563.
12	11040.	720.	0.	0.	720.	1548.	0.	11760.	2268.	14028.
13	9840.	576.	96.	96.	720.	1548.	0*	10656.	2220.	12876.
14	7440.	288.	288.	298.	720.	1548.	0.	8448.	2124.	10572.
15	6240.	144.	384.	384.	720.	1548.	0.	7344.	2076.	9420.
16	5040.	0.	480.	480.	720.	1548.	0.	6240.	2028.	8268.
17	5040.	0.	480.	480.	720.	1548.	0.	6240.	2028.	8268.
18	5040.	0.	480.	480.	720.	1548.	0.	6?40.	2028.	8268.
19	5040.	0.	480.	480.	720.	1548.	0.	6240.	2028.	8268.
20	5040.	0.	480.	480.	7,?0.	1548.	0.	6240.	2028.	8268.
21	4392.	0*	364.	384.	636.	1485.	0.	5412.	1869.	728] .
22	4032.	0.	384.	384.	576.	1440.	0.	4992.	1824.	6816.
23	2736.	0.	192.	192.	408.	1314.	0.	3336.	1506.	4842.
24	?016.	0.	192.	192.	288.	?16.	0.	2496.	408.	2904.
25	1368.	0.	96.	96.	204.	1s3.	0.	1668.	249.	1917*
26	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
27	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	]452.
28	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
29	1008.	0.	96.	96.	144.	Ion.	0.	1248.	204.	1452.
30	1008.	0.	96.	96.	144.	108.	0*	1248.	204.	1452.

TABLE 9-18

YEARLY NANPOWER REQUIREMENTS BY ACTIVITY - 5% PROBABILITY RESOURCE LEVEL SCENAR1O
OIL PRODUCTION ONLY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	84.	50.	0.	o*	0.	u*	0.	0.	0.	0.	50.	560.	0.	0.	0.	260.
	OFFSITE	0.	50.	0.	0.	0.	0.	0.	0.	0.	0.	0.	560.	0.	0.	0.	130.
2	ONSITE	.204.	1200	o*	0.	0.	o*	0.	0.	0.	0.	150.	1344.	0.	0.	0.	624.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1344.	0.	0.	0.	312.
3	ONSITE	204.	120.	0.	0.	0.	0.	0.	0.	0.	0.	150.	1344.	0.	0.	0.	6.24.
	OFFSITE	o*	120.	0.	0.	o*	0.	0.	o*	0.	o*	0.	1344.	0.	0.	0.	312.
4	ONSITE	406.	240.	0.	0.	0.	0.	0.	0.	0.	0.	275.	2688.	o*	o*	0.	1248.
	OFFSITE	0.	240.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2608.	o*	o*	0.	624.
5	ONSITE	304.	Afro.	5628.	0.	o*	0.	0.	0.	0.	0.	200.	2016.	o.	0.	0.	936.
	OFFSITE	0.	180.	619.	0.	o.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	0.	46a.
6	ONSITE	603.	155.	o*	0.	0.	3900.	0.	0.	0.	0.	150.	1344.	0.	2800.	0.	1177.
	OFFSITE	o*	155.	o*	0.	0.	429.	0.	0.	0.	0.	0.	1 344.	0.	2800.	0.	588.
7	ONSITE	1512.	145.	0.	350.	0.	7050.	0.	0.	0.	0.	25.	280.	672.	8400.	750.	2044.
	OFFSITE	12.	145.	0.	38.	0.	775.	0.	0.	0.	0.	o*	280.	672.	8400.	750.	1022.
8	ONSITE	1570.	145.	o*	175.	0.	1050.	o*	0.	1008.	0.	0.	0.	3192.	8400.	200.	1828.
	OFFSITE	3.	]45.	0.	19.	o*	115.	0.	0.	1008.	0.	0.	0.	3192.	8400.	200.	914.
9	ONSITE	1406.	200.	0.	o*	o.	0.	0.	0.	1008.	0.	0.	0.	6576.	5600.	0.	1418.
	OFFSITE	o*	200.	0.	o.	0.	0.	0.	0.	1008.	0.	0.	0.	6576.	5600.	0.	709.
10	ONSITE	1219.	250.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	9144.	2800.	0.	1069.
	OFFSITE	0.	250.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	9144.	2800.	0.	534.
11	ONSITE	940.	275.	0.	o*	0.	0.	0.	0*	1008.	0.	0.	0.	10680.	0.	0.	660.
	OFFSITE	0.	275.	0.	o.	0.	0.	o*	0.	1008.	0.	o*	0.	10680.	0.	0.	330.
12	ONSITE	960 .	300.	0.	0.	0.	0.	o.	0.	1008.	0.	o.	0.	11040.	o*	0.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	10U8.	0.	0.	0.	11040.	o.	0.	360.
13	ONSITE	912.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	9840.	0.	0.	720.
	OFFSITE	0.	300.	0.	0.	o*	0.	0.	0*	1008.	0.	0.	0.	9840.	0.	0.	360.
]4	ONSITE	816.	300.	0.	0.	o.	0.	o.	o.	1008.	0.	0.	0.	7440.	o*	0.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	7440.	o.	0.	360.
15	ONSITE	768.	300.	0.	0.	0.	0.	I-J.	0.	1008.	0.	0.	0.	6240.	0.	9.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	o.	0.	1008.	0.	0.	0.	6240.	0.	0.	360.

** SEE ATTACHELI KEY OF Activities

TABLE 9-18 (Cont.)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	720.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	360.
17	ONSITE	720.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	360.
18	ONSITE	720.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	360.
19	ONSITE	720.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	360.
20	ONSITE	720.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	720.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5040.	0.	0.	360.
21	ONSITE	596.	265.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4392.	0.	0.	636.
	OFFSITE	0.	265.	0.	0.	0.	0.	0.	0.	1008.	00	0.	0.	4392.	0.	0.	318.
22	ONSITE	576.	240.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4032.	0.	0.	576.
	OFFSITE	0.	240.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4032.	0.	0.	288.
23	ONSITE	328.	170.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	2736.	0.	0.	408.
	OFFSITE	0.	170.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	2736.	0.	0.	204.
24	ONSITE	288.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	144.
25	ONSITE	164.	85.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1368.	0.	0.	204.
	OFFSITE	0.	85.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1368.	0.	0.	102.
26	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
27	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
28	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
29	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
30	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 9-18 (Cont.)

LIST OF TASKS BY ACTIVITY

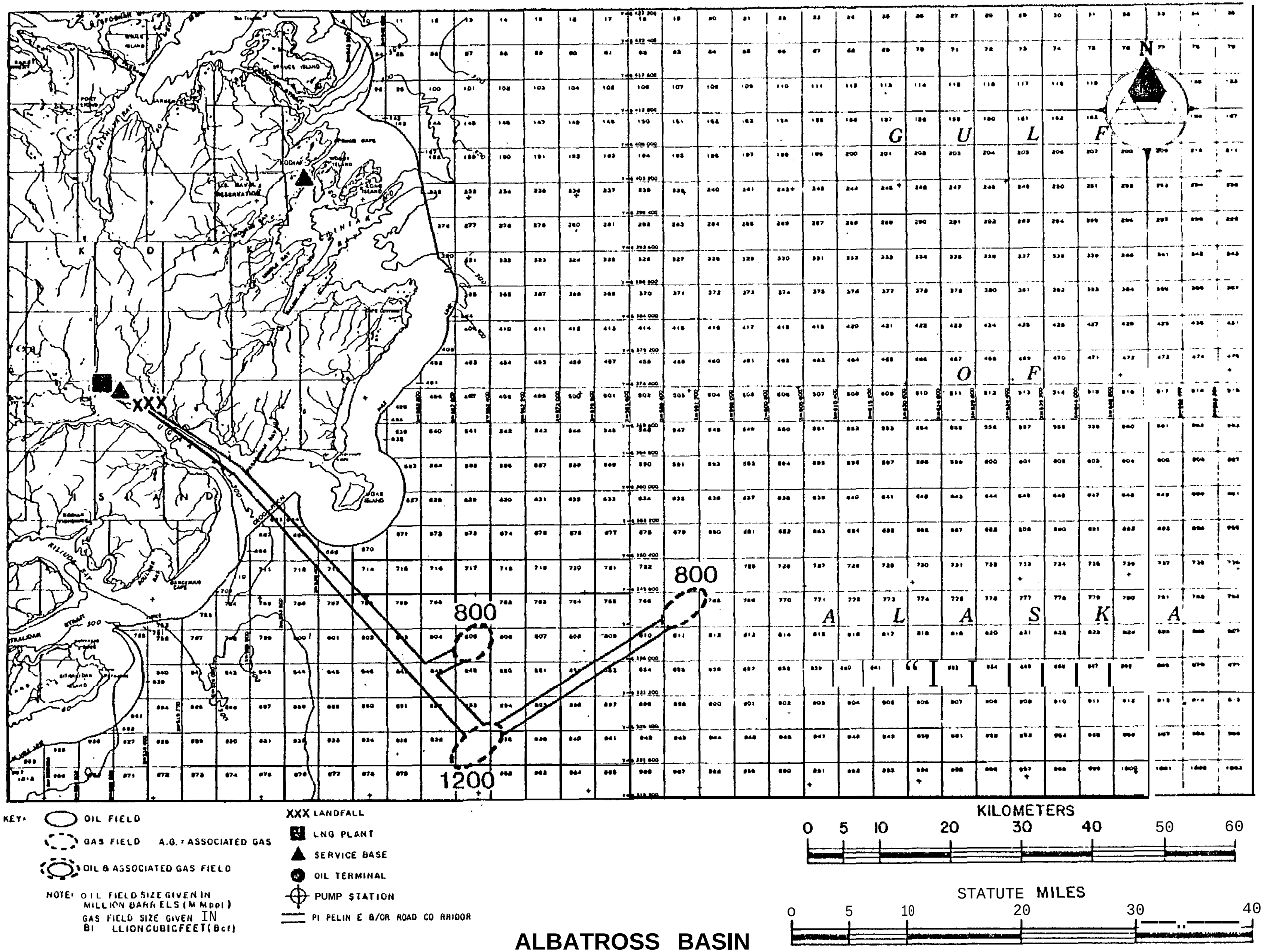
ONSHORE

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

OFFSHORE

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

NON-ASSOCIATED GAS - 5% PROBABILITY RESOURCE LEVEL SCENARIO

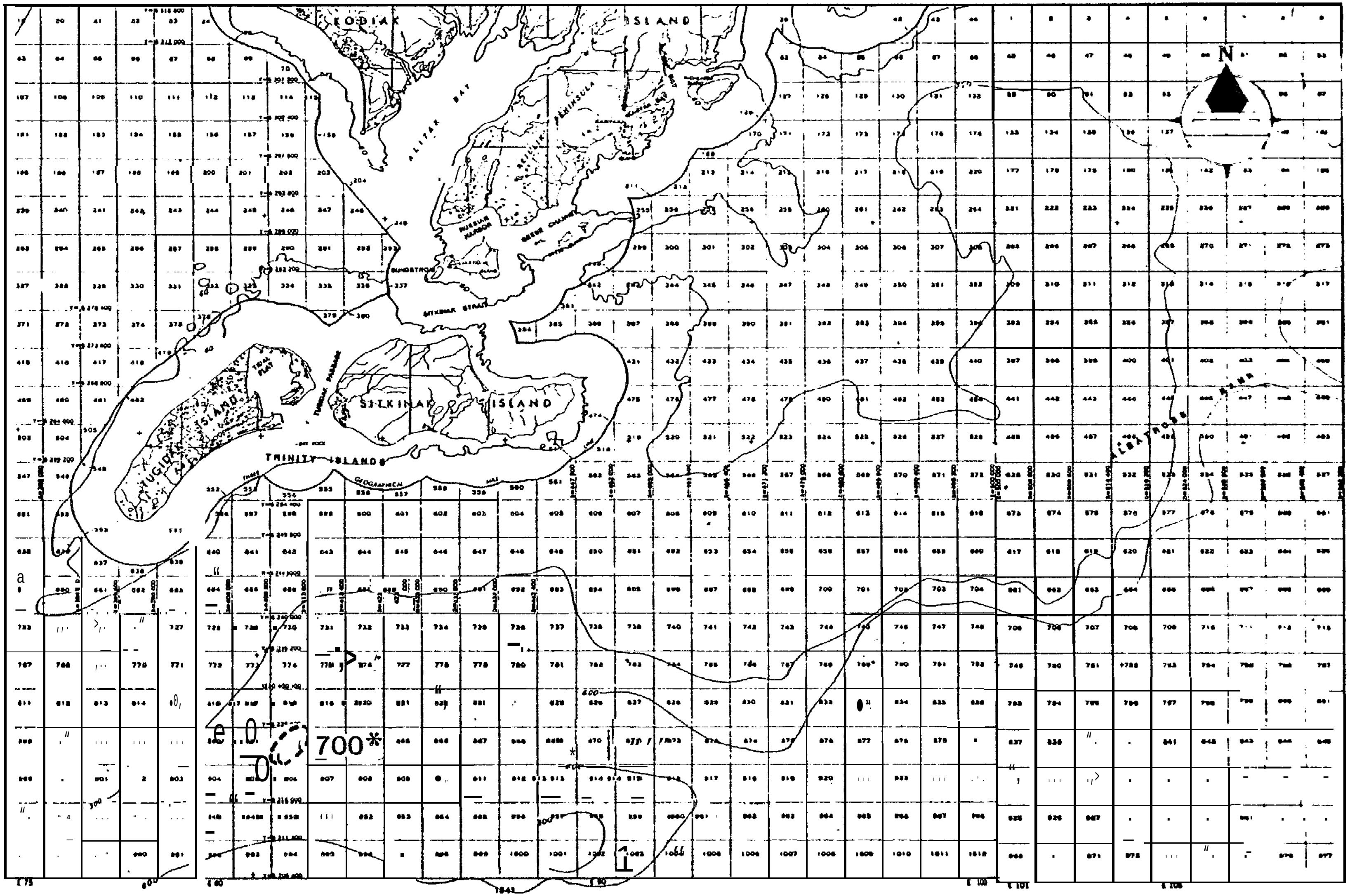


ALBATROSS BASIN

FIELD AND ONSHORE SITE LOCATIONS

FIGURE 9-5

NON-ASSOCIATED GAS - 5% PROBABILITY RESOURCE LEVEL SCENARIO



KEY: OIL FIELD

GASFIELD 4.0. , ASSOCIATED GAS

OIL & ASSOCIATED GAS FIELD

NOTE: OIL FIELD SIZE GIVEN IN MILLION BARRELS (MMbbl)
GAS FIELD SIZE GIVEN IN BILLION CUBIC FEET (Bcf)

XXX LANDFALL

LNG PLANT

SERVICE BASE

OIL TERMINAL

PUMP STATION

PIPELINE &/OR ROAD CORRIDOR

* NON COMMERCIAL

KILOMETERS
0 5 10 20 30 40 50 60

STATUTE MILES
0 5 10 20 30 40

TUGIDAK BASIN

FIELD AND ONSHORE SITE LOCATIONS

9.5.1 Resources

The five percent probability resource level scenario for non-associated gas represents a high find case of resource discovery. The total resources discovered and developed[1] are:

Basin	Gas - Non-Associated (Bcf)
Albatross	2,800
Tugidak[1]	700

9.5.2 Tracts and Locations

The productive acreage and tracts in this scenario are given in Table 9-20.

9.5.3 Exploration, Development and Production Schedule

Exploration, development and production schedules are shown on Tables 9-21 through 9-28. Three commercial and one non-commercial gas fields are discovered over a period of four years commencing in the second year after the lease sale (Table 9-22). Field development occurs in Year 3 following the decision to develop the first discovery (a 1,200 bcf non-associated gas field). The first production platform is installed in Year 4, a second in Year 5 and the last in Year 6 (Table 9-24). Gas production commences in Year 6 (Table 9-23).

9.5.4 Facility Requirements

Facility requirements and related construction scheduling are summarized in Tables 9-19 through 9-28.

The major portion of the gas reserves discovered off Kodiak Island are found in three fields located within 48 kilometers (30 miles) of each

(1) The gas resources, even though they may be found in a single field, are uneconomic and are not developed.

TABLE 9-19

5% PROBABILITY RESOURCE LEVEL SCENARIO - NON-ASSOCIATED GAS ONLY

Basin	Field Size: Oil (MMBBL)	Field Size: Gas (BCF)	Production System	Platforms No./Type[1]	Number of Production Wells	Peak Production: Oil (MB/D)	Peak Production: Gas MMCF/D)	Water Depth: meters	Water Depth: feet	Distance to Shore Ter[illegible]nal[2]: kilometers	Distance to Shore Ter[illegible]nal[2]: miles	Pipeline Diameter (in[illegible]es): Oil	Pipeline Diameter (in[illegible]es): Gas
Albatross	--	1200	Steel platform with shared gas pipeline to shore	1 s	8	--	192	61-91	200-300	32-56	20-35	--	[illegible]- 18
		800	Steel platform with shared gas pipeline to shore	1 s	8	--	192	61-91	200-300	32-56	20-35	--	--
		800	Steel platform with shared gas pipeline to shone	1 s	8	--	192	61-91	200-300	32-56	20-35	--	--
Tugidak	--	700	Not produced - uneconomic	--	--	--	--	--	--	--	--	--	--

[1] S = Steel , C = Concrete

[2] Ugak Island area.

TABLE 9-20

5% PROBABILITY RESOURCE LEVEL SCENARIO
NON-ASSOCIATED GAS ONLY
FIELDS AND TRACTS

Basin	Non-Associated Gas (Bcf)	FIELD SIZE			Tract Nos.[1] [2]
		Acres	Hectares	Tracts	
Albatross	1200	5,714	2,286	1.0	936, 937, 938, 893, 894
	800	3,810	1,524	.7	805, 761
	800	3,810	1,524	.7	766, 767, 768, 723, 724
Tugidak	700[3]	2,000	800	.4	861, 862, 818
TOTALS	3500	15,334	6,134	2.8	

[1] Includes all tracts and/or portions of tracts comprising surface expression of field in total area not exceeding number of tracts indicated in previous columns.

[2] BLM protraction diagram numbers.

[3] Non-commercial.

TABLE 9-21

EXPLORATION SCHEDULE , EXPLORATION AND DELINEATION WELLS - NON-ASSOCIATED GAS-5% RESOURCE LEVEL SCENARIO

Shelf	Well Type	Year After Lease Sale: 1 Rigs	1 Wells[3]	2 Rigs	2 Wells	3 Rigs	3 Wells	4 Rigs	4 Wells	5 Rigs	5 Wells	6 Rigs	6 Wells	7 Rigs	7 Wells	8 Rigs	8 Wells	9 Rigs	9 Wells	10 Rigs	10 Wells	Well Totals
Albatross	Exp.[1]	1	2	2	6	2	4	3	5	2	3	1	2	-	-	-	-	-		-		22
	Del.[2]				-		2		2		2		-		-		-					6
Tugidak	Exp.			.	-			1	3	1	3	1	1	1	1	-	-	-		-		8
	Del.				-				-				2		-		-					2
Totals		1	2	2	6	2	6	4	10	3	8	2	5	1	1	-	-	-		-	-	38

[1] In this high find scenario a success rate of approximately one significant discovery for every seven exploration wells is assumed. To date, this success rate has been sustained, for example, in" the North-Sea in the period 1968 -1977 (tier Majesty's Stationary Office, 1978). This compares with a 10 percent success rate in U.S. offshore areas in the past 10 years (Tucker, 1978).

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

[3] An average completion rate of four to five months per exploration/delineation well is assumed or 2.4 to 3 wells per rig Per year with an average total well depth of 13,500 feet.

Source: Dames & Moore

TABLE 9-22

TIMING OF DISCOVERIES - NON-ASSOCIATED GAS 5% RESOURCE LEVEL SCENARIO

Year After Lease Sale	Type	Reserve Size		Location	Water Depth	
		Oil (mmbbl)	Gas (bcf)		meters	feet
2	Gas	--	1200	Albatross	61-91	200-300
3	Gas	--	800	Albatross	61-91	200-300
4	Gas	--	800	Albatross	61-91	200-300
5	Gas	--	700	Tugidak	61-91	200-300

Source: Dames & Moore

TABLE 9-23

FIELD PRODUCTION SCHEDULE - NON-ASSOCIATED GAS 5% RESOURCE LEVEL SCENARIO

	Field		Peak Production		Year After Lease Sale			
Shelf	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	Years of Production[1]
Albatross	--	1200	--	192	6	26	7-18	21
	--	800	--	192	7	21	9-16	15
	--	800	--	192	8	22	10-17	15
Tugidak	--	700[1]	--	--	--	--	--	--

[1] Not economic, insufficient reserves to support an LNG system.

Source: Dames & Moore

TABLE 9-24

PLATFORM INSTALLATION SCHEDULE - NON-ASSOCIATED GAS
5% RESOURCE LEVEL SCENARIO

Field		Year After Lease Sale											
Oil (MMBBL)	Gas (BCF)	1	2	3	4	5	6	7	8	9	10	11	12
--	1200		*		As								
.-	800			*		As							
--	800				*		As						
Totals					1	1	1						

* = Discovery; D = Decision to Develop; As = Steel Platform Installation.

Notes:
1. Platform installation is assumed to be June in each case.
2. Platform "installation" includes module lifting, hook-up and commissioning.
3. Steel platforms in water depths <91 meters (300 feet) are fabricated and installed within 48 months of construction start up; steel and concrete platforms in water depths 91 meters (300 feet) plus are constructed and installed within 36 months of fabrication start up.

Source: Dames & Moore

TABLE 9-25

MAJOR FACILITIES CONSTRUCTION SCHEDULE - NON-ASSOCIATED GAS 5% RESOURCE LEVEL SCENARIO

Facility[1]/Location	Peak Throughput		Year After Lease Sale											
	Oil (MBD)	Gas (MMCFD)	1	2	3	4	5	6	7	8	9	10	11	12
Kodiak LNG Plant	--	576												
Kodiak Construction Support Base	--	--												

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

Source: Dames & Moore

TABLE 9-26

MAJOR SHORE FACILITIES START UP DATE - 5% NON-ASSOCIATED GAS
RESOURCE LEVEL SCENARIO

Facility	Year After Lease Sale	
	Start Up Date[1]	Shut Down Date[2]
Kodiak LNG Plant	6	26

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

Source: Dames & Moore

TABLE 9-27

DEVELOPMENT WELL DRILLING SCHEDULE - NON-ASSOCIATED GAS - 5% RESOURCE LEVEL SCENARIO

Field		Platforms		No.[2] of Drill Rigs Per Platform	Total No. of Production Wells	Start of Drilling	Year After Lease Sale - No. of Wells Drilled[3]																			
Oil (MMBBL)	Gas (BCF)	Nos.	Type[1]			Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
--	1200	1	S	1	16	July				Δ	2	4P	4	4	2		W									
--	800	1	S	1	8	July					Δ	2	4P	2				W								
--	800	1	S	1	4	July						Δ	2	4P	2				W							

[1] S = Steel

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

[3] Drilling progress is assumed to be 90 days per development well per drilling, i.e. four wells per year.

[4] Gas or water reinjection wells etc. ; well allowances are assumed to be one well for every 10 production wells for oil fields.

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

P = Production starts

Δ = Platform installed

Source: Dames & Moore

TABLE 9-28

PIPELINE CONSTRUCTION SCHEDULE - 5% NON-ASSOCIATED GAS RESOURCE LEVEL SCENARIO
KILOMETERS (MILES) CONSTRUCTED BY YEAR

	Pipeline Diameter (Inches) Gas	Water Depth Meters	Water Depth (feet)	Year After Lease Sale 1	2	3	4	5	6	7	8	9	10	11
Offshore	26-28	0-91	(0-300)					76 (47.3)						
Offshore	14-18	76-91	(250-300)					4.0 (2.5)	33 (20.5)					
Offshore	14-18	76-91	(250-300)						4.2 (2.6)					
Subtotal								80 (49.8)	37.2 (23.1)					
Onshore	26-28	-- --	-- --					1.6 (1.0)						
Subtotal								1.6 (1.0)						
Total								82 (50.8)	37 (23.1)					

Source: Dames & Moore

other on the middle Albatross Bank about 80 kilometers (50 miles) southeast of the city of Kodiak in water depths of 61 to 91 meters (200 to 300 feet). The proximity of the fields to each other and their discovery within three years of each other permits their development makes a shared trunk pipeline to shore and LNG plant economically feasible.

A medium-sized LNG plant designed to process the anticipated peak gas production of nearly 600 mmcfd is constructed on the north shore of Ugak Bay, the closest, most suitable deep water port location (see Chapter 6.0). A single loading jetty serves a fleet of three LNG tankers which rotate between Alaska and the U.S. West Coast.

A fourth gas field discovered in the Tugidak Basin is deemed uneconomic and is too distant from the other gas fields to share facilities.

Field construction support bases are located at Seward and Kodiak. The steel jacket platforms and topside modules are fabricated on the U.S. West Coast and transported by barge to the fields.

9.5.5 Manpower Requirements

The scenario manpower estimates and related wage bill are presented on Tables 9-29 through 9-31.

9.6 Statistical Mean Probability Resource Level Scenario

This scenario is illustrated in Figure 9-6. A summary description is provided in Table 9-32.

9.6.1 Resources

The statistical mean probability resource level represents a medium find case of resource discovery. The total reserves discovered and developed are:

TABLE 9-29

JANUARY , JULY AND PEAK MANPOWER REQUIREMENTS - 5% PROBABILITY RESOURCE LEVEL SCENARIO
NON-ASSOCIATED GAS ONLY
(NUMBER OF PEOPLE)

	JANUARY					JULY					PEAK	
YEAN AFTER	OFF SHORE		ONSHORE		JANUARY	OFFSHORE		ONSHORE		JULY		
LEASE SALE	ONSITE	OFFSITE	ONSITE	OF FSITE	TOTAL	ONSITE	OFFSITE	ONSITE	OFFSITE	TOTAL	MONTH	TOTAL
1	82.	69.	13.	5.	169.	82.	69.	13.	5.	169.	5	196.
2	164.	138.	26.	10.	338.	189.	138.	28.	10.	365.	5	392.
3	164.	138.	160.	25.	487.	189.	138.	992.	116.	1435.	7	1435.
4	328.	276.	692.	90.	1386.	857.	71s.	1238.	148.	2959.	8	3047.
5	807.	715.	994.	122.	2638 .	1607.	1383.	644.	83.	3718.	7	3718.
6	579.	513.	140.	75.	1308.	1103.	967.	206.	85.	2361.	7	2361.
7	637.	578.	142.	75.	1433.	695.	643.	144.	75.	1558.	7	1558.
8	336.	324.	96.	7(').	826.	280.	268.	90.	70.	708.	1	826.
9	280.	268.	90.	70.	708.	168.	156.	78.	70.	472.	1	708.
10	168.	156.	78.	70.	472.	168.	156.	78.	70.	472.	1	472.
11	188.	176.	86.	70.	520.	188.	176.	86.	70.	520.	1	520.
12	208.	196.	94.	70.	568.	208.	196.	94.	70.	568.	1	568.
13	228.	216.	102.	70.	616.	228.	216.	102.	70.	616.	1	616.
14	228.	216.	102.	70.	616.	228.	216.	102.	70.	616.	1	616.
15	228.	216.	102.	70.	616.	228.	216.	102.	70.	616.	1	616.
16	228.	216.	102.	10.	616.	228.	216.	102*	70.	616.	1	616.
17	228.	216.	102.	?0.	616.	228.	216.	102.	70.	616.	1	616.
18	228.	216.	102.	70.	616.	312.	294.	111.	75.	792.	7	792.
19	312.	294.	Ill.	75.	792.	312.	294.	111.	75.	792.	1	792.
20	312.	294.	111*	75.	792.	312.	294.	111.	7s.	792.	1	792.
21	.312.	294.	111.	?5.	792.	312.	294.	111.	75.	792.	1	792.
22	292.	274.	103.	75.	744.	208.	196.	94.	70.	568.	1	744.
23	188.	1?6.	86.	70.	520.	188.	176.	86.	70.	520.	1	5.20.
24	188.	176.	86.	70.	520.	188.	176.	86.	70.	520.	1	520.
25	188.	176.	86.	?0.	520.	188.	176.	86.	70.	520.	1	520.
26	188.	175.	26.	10.	400.	188.	176.	26.	10.	400.	1	400.

TABLE 9-30

ONS ITE MANPOWER REQUI REMENTS BY INDUSTRY - 5% PROBABIL ITY RESOURCE LEVEL SCENARIO
NON-ASSOCIATED GAS 0HL%
(ONS ITE MAN-MONTHS)

YEAR AFTER LEASE SALE	PETROLEUM OFFSHORE	PETROLEUM ONSHORE	CONSTRUCTION OFFSHORE	CONSTRUCTION ONSHORE	TRANSPORTATION OFFSHORE	TRANSPORTATION ONSHORE	MFG ONSHORE	ALL INDUSTRIES OFFSHORE	ALL INDUSTRIES ONSHORE	TOTAL
1	722.	76.	0.	0.	312.	84.	0*	1034.	160.	1194.
2	1494.	156.	0.	0.	624.	168.	0.	2118.	324.	2442.
3	1494.	156.	(1.	7868.	624.	168.	0*	2118.	8192.	10310.
4	2938.	308.	2800.	11855.	1801.	595.	0.	7s39.	12758.	20297.
5	3.249.	342.	5510.	6032.	2609.	923.	0.	11368.	7297.	18665.
b	2909.	262.	4120.	445.	1887.	693.	720.	8916.	2120.	11036.
7	3281.	212.	1960.	122.	899.	414.	720.	6140.	1468.	7608.
8	3408.	180.	0.	0.	288.	216.	720.	3696.	1116.	4812.
9	2400.	72.	0.	0.	288.	216.	720.	2688.	1008.	3696.
10	1728.	0.	0.	0.	288.	216.	720.	2016.	936.	2952.
11	1872.	0.	96.	96.	280.	216.	720.	2256.	1032.	3288.
12	2016.	0.	192.	192.	288.	216.	720.	2496.	1128.	3624.
13	2160.	0.	288.	288.	288.	216.	720.	2736.	1224.	3960.
14	2160.	0.	288.	288.	288.	216.	720.	2736.	1224.	3960.
15	2160.	0.	288.	288.	288.	216.	7'20.	2736.	1.224.	3960.
16	2160.	1').	288.	288.	288.	216.	720.	2736.	1224.	3960.
17	2160.	0.	288.	288.	288.	216.	720.	2736.	1224.	3960.
18	2592.	0.	288.	288.	360.	270.	720.	3240 *	1278.	4518.
19	3024.	0.	288.	288.	43%*	324.	720.	3744.	1 332.	5076.
20	3024.	0.	288.	288.	432.	324.	720.	3744.	1332.	5076.
21	3024.	0.	288.	288.	432.	324.	720.	3744.	1332.	5076,
22	2448.	0.	192.	192.	360.	270.	720.	3000.	1182.	4182.
23	1872.	0.	96.	95.	288.	216.	720.	2256.	1032.	3288.
24	1872.	0,	96.	96.	288.	216.	720.	2256.	1032.	3288.
25	187.?.	0.	96.	94.	288.	216.	720.	2256.	1032.	3288.
26	1872.	0.	96.	96.	288.	216.	0.	2256.	312.	2568.

TABLE 9-31

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY- 5% PROBABILITY RESOURCE LEVEL SCENARIO
NON-ASSOCIATED GAS ONLY
(MAN -MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	b	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	100.	60.	o*	0.	0.	0.	0.	0.	0.	0.	50.	672.	0.	0.	0.	312.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	672.	0.	0.	(1.	1s6.
2	ONSITE	204.	120.	0.	0.	0.	0*	0.	0.	0.	o*	150.	1344*	0.	0.	0.	624.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	o*	0.	1344.	0.	0.	0.	312.
3	ONSITE	204.	120.	5628.	0.	0.	0*	2240.	o*	0.	o.	150.	1344.	0.	0.	0.	624.
	OFFSITE	0.	120.	619.	0.	0.	0.	246.	o*	0.	0.	o*	1344.	0.	0.	0.	312.
4	ONSITE	803.	275.	o*	0.	0.	0.	11680.	o.	0.	0.	250.	2688.	0.	2800.	0.	1801.
	OFFSITE	0.	275.	0.	0.	0.	0.	1285.	0.	0.	0.	0.	2688.	o*	2800.	0.	900.
5	ONSITE	1342.	325.	0.	350.	0.	o.	5280.	0.	0.	0.	225.	2688.	336.	4760.	750.	2609.
	OFFSITE	12.	325.	0.	38.	0.	0.	581.	0.	0.	0.	o*	2688.	336.	4760.	750.	1304.
6	ONSITE	1000.	225.	0.	175.	o*	0.	0.	o*	0.	720.	125.	1344.	1440.	3920.	200.	1887.
	OFFSITE	3.	225.	0.	19.	o.	0.	0.	o*	n.	720.	0.	1344.	1440.	3920.	200.	943.
7	ONSITE	598.	150.	0.	0.	0.	o*	0.	o*	0.	720.	25.	280.	2976.	1960.	0.	899.
	OFFSITE	0.	150.	0.	0.	0.	0.	0.	o.	0.	720.	0.	280.	2976.	1960.	n*	449.
8	ONSITE	276.	120.	0.	0.	0.	o*	0.	o*	0.	720.	0.	0.	3408.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	o.	0.	0.	0.	720.	0.	0.	3408.	o*	0.	144.
9	ONSITE	168.	120.	0.	0.	0.	0.	0.	o*	0.	720.	0.	0.	2400.	o.	0.	288.
	OFFSITE	o.	120.	0.	0.	0.	0.	0.	o.	0.	720.	0.	0.	2400.	o*	0.	144.
10	ONSITE	96.	120.	0.	0.	0.	0.	0.	o*	0.	720.	0.	0.	1728.	o.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	o.	0*	720.	0.	0.	1728.	0.	0.	144.
11	ONSITE	192.	120.	0.	0.	0.	0.	n.	0.	0.	720.	0.	0.	1872.	0.	0.	288.
	OFFSITE	0.	120.	o*	0.	0.	0.	o.	0.	0.	720.	0.	0.	1872.	o*	0.	144.
12	ONSITE	288.	120.	o*	0.	o*	0.	0.	0.	0.	720.	0.	0.	2016.	o.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	o*	0.	720.	0.	0.	2016.	0.	0.	144.
13	ONSITE	384.	120.	0.	0.	0.	0.	0.	o.	0.	720.	o*	0.	2160.	o*	0.	288.
	OFFSITE	0.	120.	0.	cl.	0.	0.	l-).	0.	0.	720.	o.	0.	2160.	o.	0.	144.
14	ONSITE	384.	120.	0.	0.	0.	0.	0.	0.	0.	720.	1-1.	o*	2160.	0.	n.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	o*	0.	720.	0.	o.	2160.	0.	0.	144.
15	ONSITE	384.	120.	0.	0.	0.	0.	0.	o.	0.	720.	0.	0.	2160.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2160.	0.	0.	144.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 9-31 (Cont.)

YEAR	ACTIVITY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	384.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2160.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2160.	0.	0.	144.
17	ONSITE	384.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2160.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2160.	0.	0.	144.
18	ONSITE	408.	150.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2592.	0.	0.	360.
	OFFSITE	0.	150.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2592.	0.	0.	180.
19	ONSITE	432.	180.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	3024.	0.	0.	432.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	3024.	0.	0.	216.
20	ONSITE	432.	180.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	3024.	0.	0.	432.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	3024.	0.	0.	216.
21	ONSITE	432.	180.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	3024.	0.	0.	432.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	3024.	0.	0.	216.
22	ONSITE	312.	150.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2448.	0.	0.	360.
	OFFSITE	0.	150.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	2448.	0.	0.	180.
23	ONSITE	192.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1872.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1872.	0.	0.	144.
24	ONSITE	192.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1872.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1872.	0.	0.	144.
25	ONSITE	192.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1872.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	720.	0.	0.	1872.	0.	0.	144.
26	ONSITE	192.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1872.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1872.	0.	0.	144.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 9-31 (Cont.)

LIST OF TASKS BY ACTIVITY

ONSHORE

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

OFFSHORE

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

TABLE 9-32

STATISTICAL MEAN RESOURCE LEVEL SCENARIO

Basin	Field Size Oil (MMBBL)	Field Size Gas[3] (BCF)	Production System	Platforms No./Type[1]	Number of Production Wells	Peak Production Oil (MB/D)	Peak Production Gas (MMCF/D)	Water Depth meters	Water Depth feet	Distance to Shore Terminal[2] kilometers	Distance to Shore Terminal[2] miles	Pipeline Diameter (inches) Oil	Pipeline Diameter (inches) Gas
Albatross	160	--	Steel platform with no storage offshore loading	1 S	40	65	--	61	200	--	--	--	--
Tugidak	--	--	--	--	--	--	--	--	--	--	--	--	--
Portlock	--	--	--	--	--	--	--	--	--	--	--	--	--

[1] S = Steel, C = Concrete

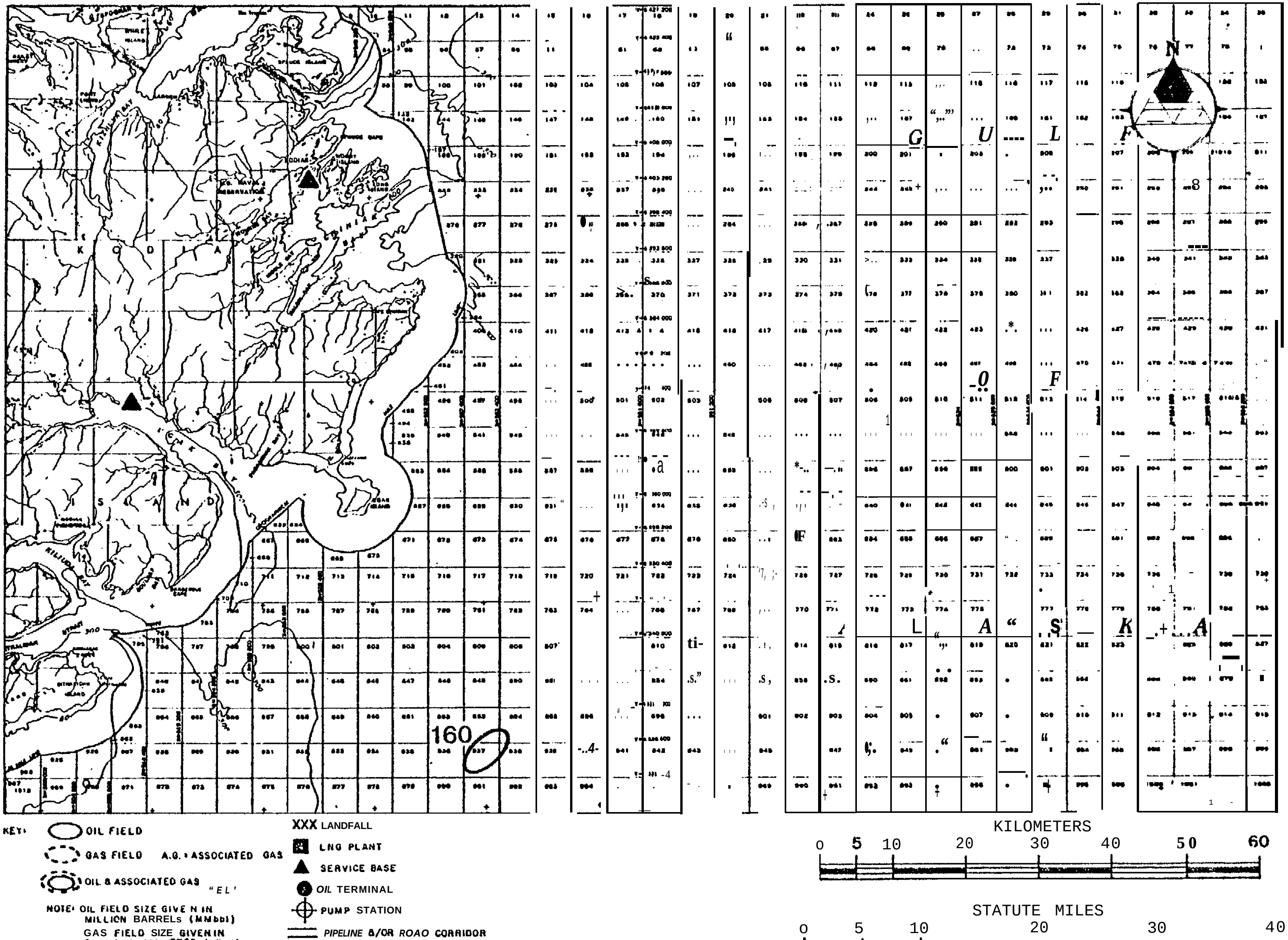
[2] Ugak Bay area

[3] A low gas-oil ratio or non-commercial associated gas is implicit - associated gas is assumed to be used as platform fuel and reinfected.

Note: The oil and gas resources of the western Gulf of Alaska as estimated by the U. S.G. S. at the statistical mean level (200 mmbbl oil, 700 bcf gas), when allocated 20 percent to the Tugidak Basin, 80 percent to the Albatross, and O percent to the Portlock Basin, result in one economic oil field in the Albatross Basin. The remainder of the oil is uneconomic and cannot be produced under the technological conditions as assumptions of this analysis.

FIGURE 9-6

OIL-STATISTICAL MEAN RESOURCE LEVEL SCENARIO



ALBATROSS BASIN

FIELD AND ONSHORE SITE SITE LOCATIONS

	Oil (MMbbl)	Associated Gas (bcf)	Non-Associated Gas (bcf)
Albatross Basin	160	--	--

(The oil and gas resources of the western Gulf of Alaska as estimated by the U.S. Geological Survey at the statistical mean level (200 mmbbl oil, 700 bcf gas) when allocated 80 percent to the Albatross Basin, 20 percent to the Tugidak Basin result in one economic oil field in the Albatross Basin. The remainder of the oil and all the gas are uneconomic and cannot be produced under the technological and economic assumptions of this analysis. Furthermore, to be economic all the oil would have to be found in a single field as indicated in this scenario.)

9.6.2 Tracts and Location

The productive acreage and tracts of the single field specified in this scenario are given in Table 9-33.

9.6.3 Exploration, Development and Production Schedule

Exploration, development and production schedules are shown on Tables 9-34 through 9-39. Only one commercial oil discovery is made in three years of exploration. The discovery is made in the first year after the lease sale (Table 9-35), the decision to develop is made in Year 3, the single steel platform is installed in Year 5 (Table 9-37) and production commences in Year 7.

9.6.4 Facility Requirements

The only commercial discovery made is located on the middle Albatross Bank about 50 miles southeast of the city of Kodiak in a water depth of about 200 feet. The reserves (160 mmbbl) are insufficient to justify a pipeline to shore and shore terminal. An offshore loading system using a single steel platform producing to an SPM and "dedicated" tankers is selected. The platform has no storage capacity since the increased production afforded by storage is not deemed to offset the incrementsl investment in a storage buoy.

TABLE 9-33

STATISTICAL MEAN RESOURCE LEVEL SCENARIO - OIL
FIELDS AND TRACTS

	Field Size			
	Acres	Hectares	Tracts	Tract Nos.[1]
Oil (mmbbl)				
160	4,571	1,828	.8	893, 894, 837, 838
Total	4,571	1,828	.8	

[1]Tracts listed include all tracts that are nvolved in the surface express" on of an oil and/or gas field. In some cases on'.y portions (a corner, etc.) of a tract are involved. However, the entire tract is-listed above. (See Figure 9-6 for exact tract location and portion involved in surface of field.)

TABLE 9-34

EXPLORATION SCHEDULE FOR EXPLORATION AND DELINEATION WELLS - OIL - STATISTICAL MEAN RESOURCE LEVEL SCENARIO

Shelf	Well Type	Year After Lease Sale 1		2		3		4		5		6		7		8		9		10		Well Totals
		Rigs	Wells[3]	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	
Albatross	Exp.[1]	2	5	2	4	1	3															12
	Del.[2]				2																	2
Total		2	5	2	6	1	3	-	-			-	-	-	-	-	-	--	--	--	--	14

[1]Based on U.S. historic offshore exploration data, a success rate of approximately 10 percent of exploration wells drilled for each discovery has been assumed in this table (see Tucker, Oil and Gas Journal, August 14, 1978).

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

[3]An average completion time of four to five months per exploration/delineation well is assumed or 2.4 to 3 wells per rig per year.

Source: Dames & Moore

TABLE 9-35

TIMING OF DISCOVERIES - STATISTICAL MEAN RESOURCE LEVEL SCENARIO

Year After Lease Sale	Type	Reserve Size		Location	Water Depth (feet)
		Oil (mmbbl)	Gas (bcf)		
1	Oil	160	--	Albatross	200

Source: Dames & Moore

TABLE 9-36

FIELD PRODUCTION SCHEDULE - OIL STATISTICAL MEAN RESOURCE LEVEL SCENARIO

	Field		Peak Production		Year After Lease Sale			
Shelf	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	Years of Production
Albatross	160	--	65	--	7	20	9-10	13

Source: Dames & Moore

TABLE 9-37

PLATFORM INSTALLATION SCHEDULE - STATISTICAL MEAN OIL RESOURCE LEVEL SCENARIO

Field			Year After Lease Sale											
	Oil (MMBBL)	Gas (BCF)	1	2	3	4	5	6	7	8	9	10	11	12
Albatross	160	--	*		D		As							

TABLE 9-38

MAJOR FACILITIES CONSTRUCTION SCHEDULE - OIL - STATISTICAL MEAN RESOURCE LEVEL SCENARIO

Facility/Location	Peak Throughput		Year After Lease Sale											
	Oil (MBD)	Gas (MMCFD)	1	2	3	4	5	6	7	8	9	10	11	12
Kodiak Construction Support Base														

Source: Dames & Moor-e

TABLE 9-39

DEVELOPMENT WELL DRILLING SCHEDULE - OIL-STATISTICAL MEAN RESOURCE LEVEL SCENARIO

Field		Platforms		No.[2] of Drill Rigs Per Platform	Total No. of Production Wells	Other Wells[4]	Start of Drilling Month	Year After Lease Sale - No. of Wells Drilled[3]																			
Oil (MMBBL)	Gas (BCF)	Nos.	Type[1]					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
160	--	1	S	2	40	4	July					Δ	8	16P	16	4			W								

[1] S = Steel

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

[3] Drilling progress is assumed to be 45 days per development well per drilling, i.e. eight wells per year.

[4] Gas or water reinfection wells etc. ; well allowances are assumed to be one well for every 10 production wells for oil fields.

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

P = Production starts.

Δ = Platform installed.

Source: Dames & Moore

Kodiak is used as the construction support base and field operation center. The single steel platform and topside modules are fabricated on the U.S. West Coast and transported to Alaska by barge.

9.6.5 Manpower Requirements

The scenario manpower estimates and related wage bill are presented on Tables 9-40 through 9-42.

TABLE 9-40

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS - STATISTICAL MEAN RESOURCE LEVEL SCENARIO
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	164.	138.	26.	10.	338.	189.	138.	28.	10.	365.	5	365.
2	164.	138.	26.	10.	338.	189.	138.	28.	10.	365.	5	392.
3	82.	69.	13.	5.	169.	107.	69.	15.	5.	196.	5	196.
4	0.	0.	134.	15*	149.	0.	0.	804.	88.	892.	6	892.
5	0.	0.	0.	o.	0.	359.	319.	48.	5.	73.?.	12	968.
6	471.	431.	60.	5.	968.	694.	643.	85.	5.	1427.	5	1427.
7	112.	112.	12.	0.	236.	196.	190.	21*	5.	412.	7	412.
8	196.	190.	21.	5.	412.	196.	190.	21.	5.	412.	1	412.
9	196.	190.	21.	5.	412.	196.	190.	21.	5.	412.	1	412.
10	196.	190.	21.	5.	412.	195.	190.	21.	5.	412.	1	412.
11	196.	190.	21.	5.	412.	84.	78.	9.	5.	176.	1	412.
12	104.	98.	17.	5.	224.	104.	98.	17.	5*	224.	1	224.
13	104.	99.	17.	5.	224.	104.	98.	17.	5*	224.	1	224.
14	104.	98.	11.	5.	224.	104.	90.	17.	5.	224.	1	224.
15	104.	98.	17.	5.	224.	104.	98.	17.	5.	224.	1	224.
16	104.	98.	17.	5.	224.	)04.	98.	]7.	5.	224.	1	224.
17	104.	98.	17.	5.	224.	104.	98.	17.	5*	224.	1	224.
18	104.	98.	17.	5.	224.	104.	98.	17.	5*	224.	1	224.
19	104.	99.	17.	5.	224.	84.	78.	9.	5.	176.	1	224.
20	0,	0.	0.	0.	0,	o*	o.	0.	0.	0.	0	0.

TABLE 9-41

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY - STATISTICAL MEAN RESOURCE LEVEL SCENARIO
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFF SHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	1469.	154.	0*	0.	624.	168.	0.	2093.	322.	2415.
2	1494.	156.	0.	0.	624.	168.	0.	2118.	324.	2442.
3	741.	78.	0.	0.	312.	84.	0.	1059.	162.	1221.
4	0e	0.	0.	5628.	0*	0.	0*	0.	5628.	5628.
5	112.	12.	1960.	122.	553.	217.	n.	2625.	351.	2976.
6	1344.	144.	3160.	272.	691.	217.	o.	5195.	633.	5826.
7	1776.	144.	0.	0.	72.	54.	0.	1848.	198.	2046.
8	2208.	144.	0*	0.	144.	108.	0.	2352.	252.	2604.
9	2208 .	144.	0.	0.	144.	108.	0.	2352.	252.	2604.
10	2208.	144.	0.	0.	144.	108.	0.	2352.	252.	2604.
11	1424.	60.	0.	0.	144.	108.	0.	1568.	168.	1736.
12	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
13	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
14	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
15	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
16	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
17	1008.	0.	96 .	96.	144.	108. ,	0*	1248.	204.	1452.
18	1008.	0.	96.	96.	144.	108.	0.	1248.	204.	1452.
19	936.	0.	48.	48.	144.	108.	0.	1128.	156.	1284.
20	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TABLE 9-42

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY - STATISTICAL MEAN RESOURCE LEVEL SCENARIO
(MAN-MONTHS)

YEAR/ACTIVITY			2	3	4	5	6	7	8	9	10		2	3	4	5	6 **
1	ONSITE	202.	20.	0.	0.	0.	0.	0.	0.	0.	0.	25.	-344.	0.	0.	0.	24.
	OFFSITE	0.	20.	0.	0.	0.	0.	0.	0*	0.	0*	0.	-344.	0.	0.	0.	12.
2	ONS TE	204.	120.	0.	0.	0.	0.	0.	0.	0.	0.	50.	134.	0.	0.	0.	624.
	OFFS TE	0.	120.	0.	0.	0.	0.	0.	0.	0.	0.	0.	134.	0.	0.	0.	312.
3	ONSITE	[illegible]	60.	0.	0.	0.	0.	0.	0.	0.	0.	75.	672.	0.	0.	0.	312.
	OFFSITE	0.	60.	0.	0.	0.	0*	0.	0.	0.	0.	0.	672.	0.	0.	0.	156.
4	ONSITE	0.	0.	5628.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	OFFSITE	0.	0.	619.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
5	ONS TE	3 6.	35.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.	960.	0.	553.
	OFFS TE	0.	35.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2*	960.	0.	276.
6	ONSITE	598.	35.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1344.	3-60.	0.	691.
	OFFSITE	0.	35.	0.	0.	0.	0 *	0.	0.	0.	0.	0.	0.	1344.	3-60.	0.	345.
7	ONSITE	166.	30.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	-776.	0.	0.	72.
	OFFSITE	0.	30.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	-776.	0.	0.	36.
8	ONSITE	92.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2208.	0.	0.	44.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2208.	0.	0.	72.
9	ONSITE	192.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2208.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0*	0*	0*	0.	0.	0.	2208.	0.	0.	72.
10	ONSITE	92.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2208.	0.	0.	44.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2208.	0.	0.	72.
	ONSITE	08.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	424.	0.	0.	4.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	424.	0.	0.	2.
.2	ONSITE	4.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	44.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
3	ONSITE	44.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	08.	0.	0.	144.
	OFFSITE	0.	60.	0*	0.	0.	0.	0 *	0 0	0.	0.	0.	0.	08.	0.	0.	72.
14	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1 08.	0.	0.	4.
	OFFSITE	0.	60*	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	2.
15	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 3 42 Cont.

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	1	12	3	14	5	16 **
16	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
17	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
18	ONSITE	144.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	72.
19	ONSITE	96.	60.	0.	0.	0.	0.	0.	[illegible]	0.	0.	0.	0.	936.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	[illegible]	0.	0.	0.	0.	936.	0.	0.	72.
20	ONSITE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	OFFSITE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 9-42 (Cont.)

LIST OF TASKS BY ACTIVITY

ONSHORE

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

OFFSHORE

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

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GLOSSARY AND ABREVIATIONS

bbl	Barrels
$/bbl	Dollars per barrel
BTU	British Thermal Unit
DHC	Exploration drilling costs for the tract
EMV	Expected mean value
EMVT	Expected mean value of a tract
Intangible Investments	Development expenditures that can be expensed for tax purposes.
LPG	Liquified Petroleum Gas
Mcf	Thousand cubic feet
MMBTU	Million British Thermal Units
NPV	Net present value of producing a certain field with specified technology over a given time period
NPVD	Net present value of a tract, given discovery
OCSEAP	Outer Continental Shelf Environmental Assessment Program
Operating Cost	Annual operation costs
P	Probability of discovery
PV	Present value operator to continuously discount all cash flows with value of money
Price	Wellhead price
Production	Annual production uniquely associated with a given field size, a selected production technology, and number of wells
r	Discount Rate, or Value of Money
RVP	Reid Vapor Pressure

Roya l ty	Royalty rate
SIC	Standard Industrial Classification
Tangible Investments -	Development investments depreciated over life of production
Tax	Tax rate
Tax Credits	The sum of investment tax credits (ITC) plus depreciation tax credits (DTC) plus intangible drilling costs tax credits (IDC)

APPENDIX A

APPENDIX A

PETROLEUM GEOLOGY

I. Introduction

The Kodiak Tertiary province occupies the continental shelf of the , Western Gulf of Alaska extending approximately from Montague Island on the northeast to Chirikof Island on the southwest. On the basis of sparse geophysical data, the Kodiak Tertiary province has been divided into three sub-basins. The Albatross Basin is between 40 and 60 km (25 to 37 miles) in width. It extends along the OCS parallel to the south-east coast of Kodiak Island for a distance of over 500 km (310 miles) from Sitkinak Island on the south, northeastward to the area south of Montague Island.

The Tugidak Basin encompasses Tugidak and Chirikof Islands and covers an area of about 70 km (44 miles) wide and 150 km (93 miles) long. The small Portlock Basin off the north end of Kodiak island is about 60 km (37 miles) across.

The area of industry interest and proposed leasing for OCS lease sale No. 46 lies between about 56° N latitude and 60° N latitude in water depths generally less than 200 meters (650 feet) covering an area of approximately 6,600 square kilometers (2,550 square miles).

The purpose of the petroleum geology review is to provide the geologic parameters and assumptions necessary for the economic analysis of Western Gulf of Alaska (Kodiak) petroleum resources (see Chapter 3.0). The review included an analysis of the published literature and available geophysical data. The principal references include Von Huene, et al., (1976), Capps (1937), McGee (1972), Moore (1967), and Bruns, et al., (1977).

For a description of the regional geology and resource potential, and a summary of the available data, the reader is referred to U.S.G.S. Open-File Report 76-325 (Von Huene, et al., 1976).

II. Seismic Data

The only available seismic coverage of this area consisted of a multi-channel, common-depth-point (CPD) survey made by the U.S. Geological Survey in 1975 (Bruns, 1977). No interpretive information has yet been published on this survey. .

Coverage in the area of interest includes one traverse line and cross lines at approximately 56 kilometers (30 nautical miles) spacing. Validity for the approximate limits of the Tugidak and Albatross Basins can be determined from this data. Large areas of wedge-out and other stratigraphic possibilities for traps appear to be present along the margins of the basins; a great deal of faulting and some anticlinal and synclinal folding are noted on the seismic sections.

That some or several prospective structures are present can only be surmised on the basis of present data. Because of the sparcity of present coverage, however, the locations and aerial extent of possible closed anticl inal structures cannot be determined.

III. Geophysical Data

Between 1972 and 1977, the petroleum industry performed about 122.5 crew months of geophysical work in the Gulf of Alaska. U.S. Geological Survey data upon which this report is based, amounts to an estimated 3 to 5% of this amount.

IV. Petroleum Potential

Between May and October 1977, three joint-company stratigraphic tests were drilled along the central part of the Albatross Basin. Total depths were from 2,596 meters (8,517 feet) to 3,188 meters (10,460 feet). Presumably the tests were located in synclinal areas. No data is yet available on these wells.

The upland areas adjacent to the Western Gulf of Alaska Tertiary Province contain no known oil seeps and the Upper Tertiary sedimentary sequence is not similar to that of the onshore Northern Gulf of Alaska Basin nor the Cook Inlet Basin.

Upper Tertiary outcrops found along the eastern coast of Kodiak Island are both marine and non-marine in character. These rocks overlay basement rocks of pre-Tertiary age. Based on outcrop evidence alone, the Western Gulf area may possibly be more conducive to the generation and accumulation of gas rather than oil.

V. Published Resource Estimates

The latest U.S. Geological Survey estimates of recoverable oil and gas resources in the Western Gulf of Alaska are presented in Open-File Report 76-325 (Von Huene, et al., 1976). These are:

	95% Probability	5% Probability	Statistical Mean
Oil (billions of barrels)	0	1.2	0.2
Gas (trillions of cubic feet)	0	3.5	0.7

The probability of no oil or gas in commercial quantities is 60%,

VI. Structural Geology

Albatross Basin

Available seismic data suggests this basin may be divided into several discontinuous arches or sub-basins. The western shoreward side of the basin appears to be formed by a steeply dipping faulted and deformed zone that may be a major crustal boundary. This zone could serve as either a barrier or a passageway to oil and gas migrating from the deeper sedimentary basin to the east.

Several large longitudinal anticlines and synclines appear to be present but. specific areas of closure cannot be defined on the basis of present data.

The depth of the sedimentary section is very uncertain; however, deeper portions of the basin appear to be as thick as 6,000 meters (19,685 feet) .

Tugidak Basin

This basin appears to contain sedimentary rocks to a maximum depth of about 7 km (23,000 feet). Local pronounced thinning of the strata against the flanks of the basin suggest possible stratigraphic traps.

Some broad anticlines are present but potential areas of closure cannot be determined with available data.

Portlock Basin

Very little is known about this basin and no seismic coverage is available. There appears to be at least 1,000 meters (3,281 feet) of uncompacted sediments overlying more dense sedimentary rock. On regional aspects alone, this basin may have pre-Tertiary basement rocks at relatively shall depths.

For lack of more positive evidence, the basin is not considered significantly prospective for oil or gas at this time.

VII. Resource Allocation and Estimates

The U.S. Geological Survey estimates of recoverable oil and gas resources (Von Huene, eta?., 1976) have been allocated to the three basins comprising the Kodiak Tertiary Province as shown in Table A-1. The productive acreage required for recoverable reserves of 50,000 bbl/acre for giant fields and 20,000 bbl/acre for small fields is given in Table A-2.

TABLE A-1

ALLOCATION OF U.S. GEOLOGICAL SURVEY RESOURCE Estimates BY BASIN -- wEsTERN GULF OF ALASKA (KODIAK)

Basin	Percentage of Total Resource	Estimated Reserves			
		Five Percent Probability		Statistical Mean Probability	
		Oil (Bbbl)	Gas (tcf)	Oil (Bbbl)	Gas (tcf)
Albatross	80	0.96	2.8	0.16	0.56
Tugidak	20	0.24	0.70	0.04	0.14
Portlock	--	--	--	--	--
Totals		1.2	3.5	0.20	0.70

[1]U.S. Geological Survey Open-File Report 76-325 (Von Huene et al., 1976).

TABLE A-2

PRODUCTIVE ACREAGE REQUIRED -- WESTERN GULF OF ALASKA

Basin	Resource Probability	Estimated Reserves Oil (Bbbl)	Gas (tcf)	Total Productiv Acreage Required @ 50,000 bbl/acre	@ 20,000 bbl/acre
A batross	5%	0.96	2.8	19,200	48,000
	Statistical Mean	0.16	0.56	3,200	8,000
Tugidak	5%	0.24	0.70	4,800	12,000
	Statistical Mean	0.04	0.14	800	2,000
Portlock	--	--	--	--	--

VIII. Summary

There is no producing field analog or sufficient geologic data to establish with any certainty assumptions on reservoir and hydrocarbon characteristics of possible Western Gulf of Alaska (Kodiak) discoveries. Available geophysical coverage is insufficient to locate or estimate the aerial extent of possible closed anticlinal structures. The U.S.G.S. notes that the most nearby analogous basins are probably the adjoining Eastern Gulf of Alaska Tertiary Province (also referred to as the Northern Gulf of Alaska) and the Western most Oregon-Washington basin, including the offshore (Von Huene, et al., 1976, p. 25).

APPENDIX B

APPENDIX B - PETROLEUM DEVELOPMENT COSTS

I. Introduction

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

Predictions on the costs of petroleum development in frontier areas such as the Gulf of Alaska (which has only experienced exploration to date) 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. North Sea petroleum development serves to a considerable extent as both a technology and economic model for this analysis although significant economic, geographic and environmental contrasts with the Gulf of Alaska have to be acknowledged and accommodated in the analysis.

The cost data presented in this study are based on published literature, interviews with government agencies, oil companies and construction companies (including those involved in the North Sea development). The North Sea cost data base includes the "North Sea Service" of Wood, Mackenzie & Co. which monitors North Sea petroleum development and conducts economic and financial appraisals of North Sea fields. The Wood, Mackenzie & Co. reports provide a breakdown and scheduling of capital cost investments for each North Sea field. A. D. Little, inc. (1976) have estimated petroleum development costs for the various U.S. OCS areas, including the Gulf of Alaska, and have identified the costs of different technologies and the various components {platforms, pipelines, etc.) of field development. The results of the A. D. Little study have also been produced in a text by Mansvelt Beck and Wiig (1977).

Gulf of Mexico data has provided the basis for several economic studies of offshore petroleum development (National Petroleum Council, 1975; Kalter, Tyner and Hughes, 1975). Gulf of Mexico cost data has been extrapolated to provide cost estimates in more severe operating regions through the application of a cost factor multiplier. For example, Gulf of Alaska cost estimates for exploration and development have been developed using cost factor multipliers of 1.8 (exploration) and 2.8 (development) as defined by Kalter, Tyler and Hughes (1975). This approach has been used in this report when North Sea data has not been applicable or when a comparison has been required among estimates. The pipeline cost estimates (Table B-l), for example, were made by review of recently published Gulf of Mexico data (Oil and Gas Journal, August 14, 1978) to which a cost factor was applied. The factored cost estimates were then compared with North Sea pipeline cost estimates (obtained from a number of sources) and modified accordingly.

Other important cost data sources include occasional economic reports in the Oil and Gas Journal and American Petroleum Institute (API) statistics on drilling costs. Some of the technology references cited in Chapter 4.0 contain cost estimates of the various offshore facilities and equipment. A problem with some of the cost data, especially estimates contained in technology references, is that they do not precisely specify the component costed. Thus a reference to a platform quoted to cost $100 million may not specify whether the estimate refers to fabrication of the substructure, fabrication and installation of the substructure, or the completed structure including topside modules. Another problem is that the year's dollars (1975, 1976, etc.) to which the cost estimate is related is often not specified.

All the cost figures cited in Tables B-1 through B-12 are given in 1978 dollars. Cost figures from the various sources have been inflated to 1978 dollars using United Kingdom and United States petroleum industry indices. For North Sea cost data a modified U.K./U.S. index has been used.

Estimation of steel platform fabrication costs (Table B-1) was assisted by plotting costs of North Sea platforms vs. water depth on log-log paper and conducting a regression analysis on the data. This was done because a geometric increase in platform fabrication costs with water

TABLE B-1

PLATFORM FABRICATION COST ESTIMATES

Platform Type	Water Depth Meters (Feet)	Cost. $ Millions 1978 Medium Value[3]
Converted Semi Submersible	30.5 (loo)	30
	91 (300)	30
	183 (600)	30
Steel Jacket	30.5 (loo)	30
	91 (300)	54
	183 (600)	283.5
Concrete Gravity[2]	30.5 (100)	.-
	91 (300)	120.4
	183 (600)	298

Sources: Wood, Mackenzie & Co., 1978, A.C). Little, Inc., 1976; Bendiks, 1975; Peat, MarWick, Mitchell & Co., 1975; Dames & Moore.

[1] Costs are for conversion of semi-submersible rig only; the economic analysis assumes rig is leased during the life of the field (i.e. , on operating cost).

[2] Concrete platforms are assumed to not be feasible in water depths of less than 200 feet.

[3] A medium (most likely) value is given here. In the economic analysis a low estimate 25% less than this value and a high estimate of 40% greater than this value were investigated. Explanation of this range is presented in the text.

TABLE B-2

PLATFORM INSTALLATION COST ESTIMATES[1]

Platform Type	Cost $ Millions 1978 Medium Value[2]
Converted Semi-Submersible	27.6
Steel Jacket	88.5
Concrete Gravity	55

Sources: Wood, Mackenzie & Co., 1978; A. O. Little, Inc., 1976; Dames & Moore.

[1] Platform "installation" includes site preparation, tow out, setdown, pile driving (if steel jacket), module lifting, facilities hookup, etc.

[2] See Note No. 3, Table B-1

TABLE B-3A

PLATFORM EQUIPMENT AND FACILITIES
COST ESTIMATES OIL PRODUCTION

Platform Type	Peak Capacity Oil (MBD)	Cost $ Millions 1978 Medium Value[2]
Converted	< 25	22.5
Semi-Submersible	25-50	38.8
	50-100	50
Steel Jacket	< 25	22
	25-50	50
	50-100	60
	> 100	90.6
Concrete Gravity[1]	< 25	--
	25-50	--
	50-700	71.3
	> 100	106.3

Sources: Wood, Mackenzie & Co., 1978; A. D. Little, Inc., 1976.

[1] It is assumed that concrete platforms are not justified for small fields (low throughput).

[2] See Note No. 3, Table B-1.

TABLE B-3B

PLATFORM EQUIPMENT COST ESTIMATES
ASSOCIATED GAS PRODUCTION

Platform Type	Peak Capacity[1] Oil (MBD)	Incremental Cost for Associated Gas Production $ Millions 1978 Medium Value[3]
Converted[4] Semi-Submersible	--	--
Steel Jacket	< 25	2.3
	25-50	5
	50-100	6
	> 100	9
Concrete Gravity	< 25	--
	25-50	--
	50-100	i'
	> 100	10

Sources: Wood, Mackenzie & Co., 1978; Dames & Moore

[1] In the scenario development it is assumed that oil is the primary product.

[2] Generally, when oil is the primary product, the incremental cost of producing associated gas (excluding pipelines and shore terminals) is small; therefore, a 10% increase in platform equipment costs has been assumed for the production of associated gas (see Table 3A).

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

[4] Associated gas is assumed not to be produced from floating platforms and other systems which offshore-load oil,

TABLE B-3C

PLATFORM EQUIPMENT AND FACILITIES COST ESTIMATES
NON-ASSOCIATED GAS PRODUCTION

Platform Type	Peak Capacity Gas (MMCFD)	Cost $ Millions 1978 Medium Value[1]
Steel Jacket	< 200	15
	200-500	25
	500-1000	45
	1000-1500	70
Concrete Gravity	< 200	--
	200-500	--
	500-1000	60
	1000-1500	90

Sources: Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1976; Dames & Moore.

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

TABLE B-4

DEVELOPMENT WELL COST ESTIMATES

Well Type	Cost $ Millions 1978 Medium Value[1]
Development Well (Each)	3.3
Incremental Cost for Subsea Completed Well (Each)	4.7

Sources: Wood, Mackenzie & Co., 1978; API, 1978; Gruy Federal, Inc., 1977; Bendiks, 1975; Dames & Moore.

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

TABLE B-5

SINGLE POINT MOORING BUOY (SPM)[1]
COST ESTIMATES

	Cost $ Millions 1978 Medium Value[2]
Each	55

Sources: Wood, Mackenzie & Co., 1978; Bendiks, 1975.

[1] This estimate relates to several different designs known by different acronyms (SPM, ESLBM, etc.).

[2] See Note No. 3, Table B-1.

TABLE B-6

FLOWLINE[1] COST ESTIMATES

	Cost $ Millions 1978 Medium Value [2]
Incremental Costs Per Development Well	4.75

[1] The cost are only applicable to production systems utilizing subsea completed wells.

[2] See Note No. 3, Table B-1.

TABLE B-7A

MARINE PIPELINE COST ESTIMATES

Diameter (Inches)	Average Cost Per Mile $ Millions 1978 Medium Value[1]
30-36	2.5
20-29	1.3
10-19	0.8
< 10	0.5

Sources: Wood, Mackenzie & Co., 1978; O'Donnell, 1976; Eaton, 1977; Oil and Gas Journal, August 14, 1978; Offshore, July, 1977; Darnes & Moore.

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

TABLE B-76

ONSHORE PIPELINE COST ESTIMATES

Diameter (Inches)	Average Cost Per Mile $ Millions 1978 Medium Value[1]
30-36	1.0
20-29	.600
10-19	.400
< 10	.170

Source: Oil and Gas Journal, August 14, 1978.

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

TABLE B-8

OIL TERMINAL[1] COST ESTIMATES

Peak Throughput (MBD)[2]	Total Cost $ Millions 1978 Medium Value[3]
≈250	250
≈ 500	450
650	535
750	600

Sources: Wood, Mackenzie & Co., 1978; Duggan, 1978; Cook Inlet Pipeline Co., 1978.

[1] The terminals costed here are assumed to perform the following functions: pipeline terminal (for offshore lines), crude stabilization, LPG recovery, tanker ballast treatment, crude storage (sufficient for about 10 days production), and tanker loading for crude transshipment to the lower '48.

[2] There is a cost index which equates facility cost with daily bbl capacity - the terminal costs cited here range from $500 to $1000 per daily bbl capacity.

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

TABLE B-9

LNG SYSTEM FACILITY AND EQUIPMENT COST ESTIMATES[1]

Facility/Equipment	Cost $ Millions ?978 Medium Value[2]
Liquefaction Plant (200 MMCFD) and Marine Terminal	514
each additonal 200 MMCFD	155
LNG Tankers (2)	435
Regasification Plant (Lower '48)	150
each additional 200 MMCFD	6

Sources: Pacific Alaska LNG, 1977; Oil and Gas Journal, August 18, 1975.

[1] Field development costs (platforms, wells, pipelines, etc.) are not included in this table.

[2] See Note No. 3, Table 5-1.

TABLE B-10

MISCELLANEOUS COST ESTIMATES

In the economic analysis 5% of total field development costs (including pipelines and terminals) have been added to the total field development costs for miscellaneous capital expenditures that cannot be readily classified (e.g., flare booms). This cost is based on a review of North Sea field development costs.

TABLE B-II

ANNUAL FIELD OPERATING COST ESTIMATES

	$ Millions 1978
1 Platform Field	25-35
2 Platform Field Pipeline-Terminal	70
3 Platform Field Pipeline-Terminal	100

Sources: Wood, Mackenzie & Co., 1978; A.D. Little, inc., 1976; Gruy Federal, Inc., 1977.

TABLE B-12

EXAMPLE OF TABLES USED IN ECONOMIC ANALYSIS

A. SCHEDULE OF CAPITAL EXPENDITURES FOR FIELD DEVELOPMENT - SINGLE CONCRETE PLATFORM WITH STORAGE , OFFSHORE LOADING

Facility/Activity	Year After Decision to Develop - Percent of Expenditure					
	1	2	3	4	5	6
Platform Fabrication	35	45	20			
Platform Equipment	45	45	10			
Platform Installation			100			
Development Wells[1] 36			5	44	44	11
48			4	33	33	30
SPM			50	50		
Miscellaneous			33	33	34	

Source: Based on analysis of expenditures of North Sea projects.

[1]Example presented is for 36 and 48 wells based on assumption of two rigs working at a completion rate of 45 days per well per rig; for different numbers of wells the expenditures are prorated approximately at the assumed completion rate. If fewer than 36 wells are required, then only one rig is assumed to be working.

B. SCHEDULE OF CAPITAL COST EXPENDITURES - SINGLE STEEL OR CONCRETE PLATFORM, PIPELINE TO SHORE, SHORE TERMINAL[1]

Facility/Activity	Year After Decision to Develop - Percent of Expenditure					
	1	2	3	4	5	6
Oil Pipeline (10 miles) 16 Km	30	70				
(25 miles) 40 Km	30	70				
(50 miles) 80 Km	25	60	15			
(80 miles) 129 Km	25	60	15			
Terminal	5	40	40			

Source: Based on analysis of expenditures of North Sea projects.

[1] Instructions - this table added to a table such as Example A (above) with deletion of SPM provides schedule of cost flows for oil field produced by a single platform with pipeline to shore and shore terminal.

depths has been reported (Bendiks, 1975; Lovegrove, 1976). A reasonable fit was obtained, and cost ranges for steel jacket platforms, at various water depths, were defined and compared with independent data.

It should be emphasized that in reality field development costs will vary considerably even for fields with similar recoverable reserves, production systems and environmental setting. Some of the important factors in this variability are reservoir characteristics, quality of the hydrocarbon stream, distance to shore, proximity of other fields, and lead time (from discovery to first production). The available cost data is insufficient to provide all these economic sensitivities. 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 buyers or sellers market. Similarly, offshore construction costs will be influenced by lease rates for construction and support equipment (lay barges, derrick barges, tugs, etc.) which will vary according to the level of offshore activity nationally or internationally.

Offshore field development costs are often quoted in terms of cost per barrel of daily peak production. These costs range from about $2,500 per barrel of maximum production to over $11,000 for North Sea fields currently under development (Lovegrove, 1976; Enright, 1978). The field development costs screened in this report fall within this range (see Chapter 7.0).

Review of the cost data enabled definition of low, medium, and high values for the various petroleum facilities and equipment. Based on this review a low estimate of 25 percent less than the mid-range (medium) value and a high estimate of 40 percent greater than this value were selected and used for economic screening.

II. Methodology

The cost tables presented in this appendix were the basic input-s in the economic analysis. Each case analyzed was essentially defined by reserve size, production technology and water depth. To cost a particular case the economist took the required cost components (field facility and equipment components) from Tables B-1 through B-n using a building block approach; in some cases a facility or equipment item was deleted or substituted.

The cost components of each case are then scheduled as indicated in the examples presented in Table B-12. The schedules of capital cost expenditures are based upon typical North Sea development schedules. They are expressed as a percentage of the total expenditures for that item (platform fabrication, development well etc.) by year in the development schedule.

111. Exploration and Field Development Schedules

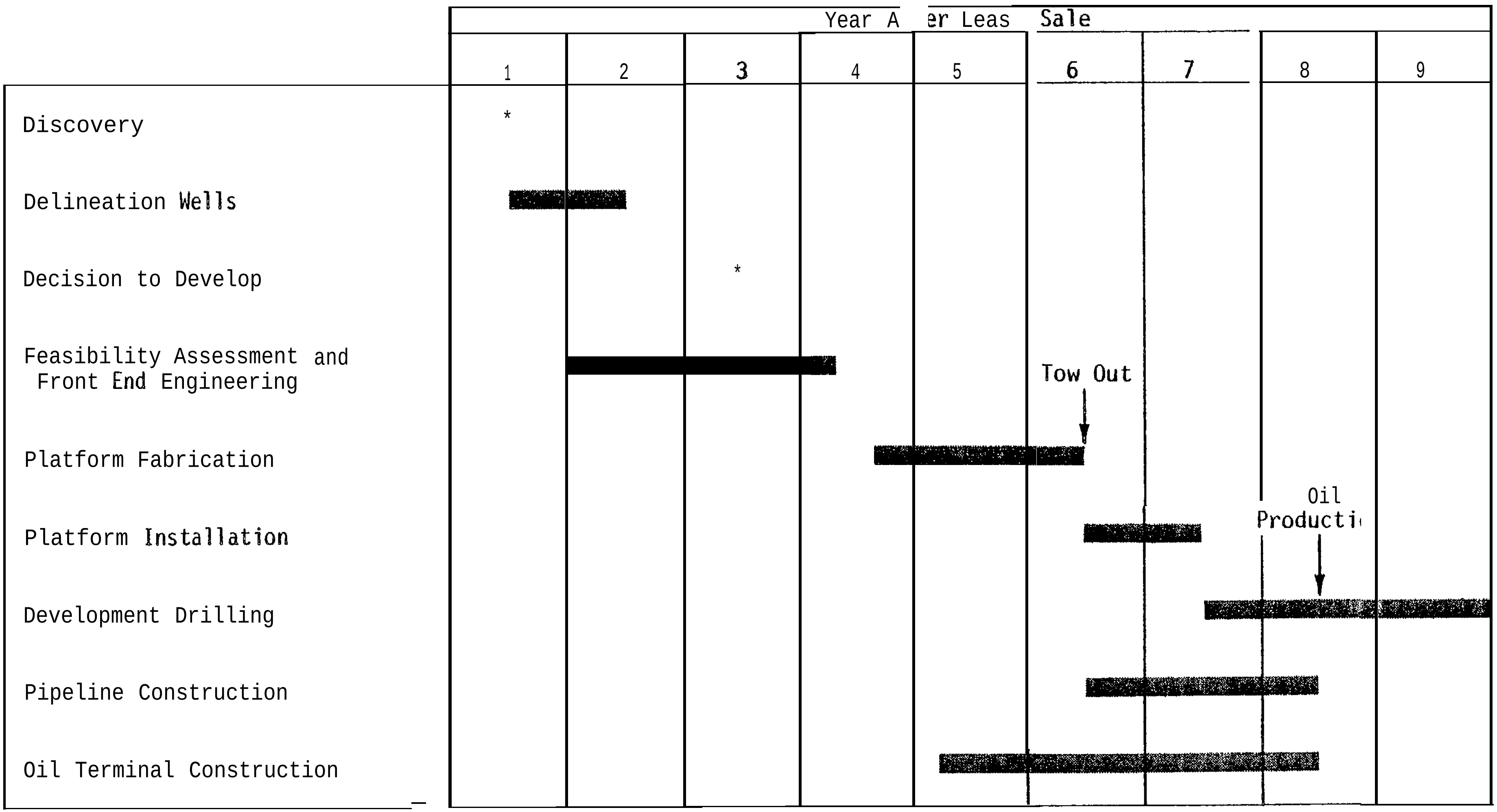
This appendix discusses the assumptions made in defining the exploration and field development schedules contained in Sections 9.3, 9.4, and 9.5. These schedules are basic inputs into the economic analysis (scheduling of investments) and manpower calculations (facilities construction schedule).

To simplify these analyses a number of scheduling assumptions were made based upon review of petroleum technology (Chapter 4.0) and petroleum development in comparable environments, principally the North Sea.

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. The sequence of events in field development from time of discovery to start-up of production involves a number of steps commencing with field appraisal, development planning and construction. The appraisal process involves evaluation of the geologic data obtained (see Figure B-2) from the discovery well, followed by a decision to drill delineation (appraisal) wells to obtain additional geologic/reservoir information for reservoir engineering. There is a trade-off between additional delineation wells to obtain more reservoir data (to more closely predict reservoir behavior and production profiles) and the cost of the drilling

FIGURE B-1

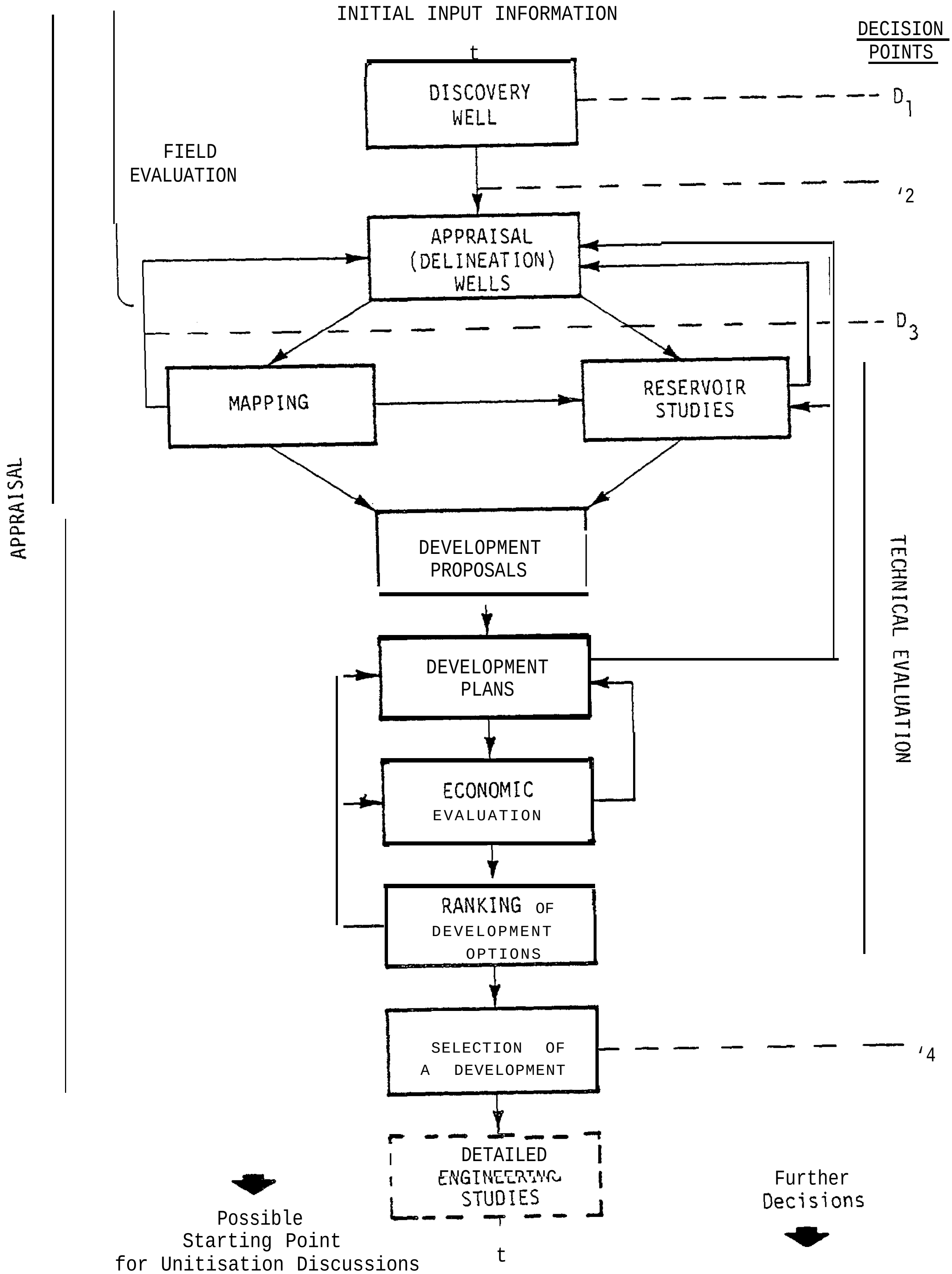
EXAMPLE OF MEDIUM-SIZED FIELD COMPLETION SCHEDULE
SINGLE STEEL PLATFORM, OIL PIPELINE TO SHORE, SHORE TERMINAL[2]



Source: Dames & Moore

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

FIGURE B-2



THE APPRAISAL PROCESS

Source: Birks (1978)

investment. Using the results of the geological and reservoir engineering studies, a set of development proposals are formulated. These would also take into account locational and environmental factors such as meteorology"ic and oceanographic conditions. The development proposals involve preliminary engineering feasibility with consideration of the number and type of platforms, pipeline vs. offshore loading, processing requirements, etc.

As illustrated in Figure B-2, the development proposals are screened for technical feasibility and other sensitivities, reducing them to a small number to be examined as development plans. These are further screened for technical, environmental and political feasibility. An economic analysis of these plans is conducted similar to that conducted in this study. In the economic evaluation, facilities, equipment and operating expenditures are costed and expenditures and income scheduled. A ranking of development plans according to economic-merit is then possible and weighed accordingly with technical, environmental and political factors to select a development plan for subsequent engineering design. The feasibility appraisal process is complete. At this time, the operator will make a preliminary go, no-go decision.

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

The field development and production plan will then have to pass regulatory agency scrutiny and approval. In the United Kingdom, for example, the operator has to submit his plan to the Department of Energy for approval. The department reviews the plan with respect to consistency with national and local economic, environmental planning, and energy policy. In the United States the operator will have to submit an environmental report together with the proposed development and production plan to the U.S. Geological Survey in accordance with U.S. Geological Survey Regulation S250.34-3 Environmental Reports presented in the Federal Register, Vol. 43, No. 19, Friday, January 27, 1978.

In terms of the effect upon the development schedule, delays due to regulatory agency review, environmental requirements, etc. can not be predicted with accuracy for possible Gulf of Alaska discoveries. The time that may elapse from discovery to decision to develop is field specific and also difficult to predict as is the number of delineation wells required to assess the reservoir. However, these factors are accommodated in this report by the schedule assumptions cited below.

With the decision to develop final design of facilities and equipment commences and contracts placed with manufacturers, suppliers, and construction companies. Significant investment expenditures commence at this time. Front-end engineering and design would take from one to two years following decision to develop, depending upon the facility/equipment. Design and fabrication of the major field component -- the drilling and production platform would take about three years for a large steel jacket such as Chevron's North Sea Ninian Southern Platform (Hancock, White and Hay, 1978). Onshore fabrication of a steel jacket platform will vary from about 12 to 24 months depending upon size and complexity of the structure (Antonakis, 1975). An additional seven months of offshore construction will be required for pile driving, module placement and commissioning. Construction of a concrete gravity platform inshore will take from 21 to 32 months, a schedule which includes inshore deck and module placement.

A critical part of offshore field development is scheduling as much offshore work in the summer "weather window" and timing of onshore construction to meet deadlines imposed by the weather window. In the Gulf of Alaska, like the North Sea, platform tow-out and installation will occur in early summer, May or June, to permit maximum use of the weather window. If the weather window is missed or the platform is installed in late summer, costly delays up to 12 months in length could result.

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

Development well drilling will commence as soon as is feasible after platform installation. If regulations permit, the operator may elect to commence drilling while offshore construction is still underway even though interruptions to construction activities on the platform occur during "yellow alerts" in the drilling process (Allcock, personal communication, 1978). The operator has to weigh the economic advantages of early production vs. delays and inefficiencies in platform commissioning. Development drilling will generally commence late in the year of platform installation (assuming early summer tow-out) on concrete gravity platforms (i. e. three to four months after tow-out) and from 6 to 12 months after tow-out in 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.

For floating units with subsea-completed wells, development drilling can commence in year one of the field development schedule using a conventional semi-submersible drill rig. All the wells are ready for hookup to the platform when the floating production platform arrives on station, 24 to

36 months after development drilling commences (Bendiks, 1975). The field development schedule of a floating production system, such as the Argyll and Buchan fields in the North Sea, will be from 36 to 48 months. The floating production platform is towed out, hooked up and commissioned in the last year of the development schedule.

IV. Scheduling Assumptions

Based upon a review of technology data and industry experience, the following assumptions have been made on exploration and field development scheduling (see field development schedules in Chapter 9.0 and economic assumptions in Appendix C).

- Exploration commences the year following the lease sale (i.e. 1981); all schedules relate to 1981 as Year 1.

- An average completion rate of four to five months per exploration/ delineation well is assumed or 2.4 to 3 wells per rig per year with an average total well depth of 4,115 meters (13,500 feet).

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

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

- 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 water depths less than 91 meters (300 feet) are fabricated and installed within 24 months of construction start-up; steel and concrete platforms in water depths 91 meters (300 feet} plus are constructed and installed within 36 months of fabrication start-up.

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

- Development drilling is assumed to commence about four months following tow-out for concrete platforms and 12 months following tow-out for steel jacket platforms; for floating systems, development wells are assumed completed prior to platform tow-Out.

- Platforms sized for 36 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 36 well slots are assumed to have one drill rig operating during development well drilling.

- Drilling progress is assumed to be 45 days per oil development well per drilling rig, i.e. eight wells per year and 90 days per gas development well per drilling rig, i.e. 4 wells per year (the difference reflecting contrasting depths postulated for oil and gas reservoirs).

- Production is assumed to commence when about one-half of the development wells have been drilled.

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

- Oil terminal and LNG plant construction takes between 24 and 36 months depending on design throughput.

APPENDIX C

APPENDIX C

METHODS AND ASSUMPTIONS OF THE ECONOMIC MODEL AND THE ANALYSIS

I. The Objective of the Analysis

One objective of the economic analysis is to evaluate several likely oil and gas production technologies suitable for conditions in the Gulf of Alaska and the minimum field sizes required to justify each technology at various water depths.

This analysis is different from the calculation of a lease bonus. In that procedure, the potential net present value of discovery calculated for a particular tract to be leased is multiplied by the probability of that discovery and then adjusted for the cost of exploratory dry holes multiplied by the probability of a dry hole. This procedure yields an expected mean value (EMV) of economic rent, or surplus above the minimum required profit, of the tract. Some part of this can become the bonus bid based on other strategic considerations. Equation No. 1 summarizes the calculation of the expected mean value of the economic rent of a tract.

Equation No. 1: $EMV_T = (p)\,(NPV_D) - (1-P)\,(DHC)$

Where:

EMV_T	=	expected mean value of a tract
NPV_D	=	net present value of the tract, given discovery
DHC	=	the exploratory drilling costs for the tract
P	=	the probability of discovery

Geology is the driving force of the lease bonus calculation. The net present value of the tract, given discovery, (NPV_D), hinges on the geologic assessment of the size of reserves. The probability of discovery hinges on the geologic assessment of the presence of factors that may cause hydrocarbons to be present. The lease bonus analysis emphasizes, therefore, exploration risk.

The analysis of this report focuses attention on the engineering technology required to produce reserves under the harsh conditions of the Gulf of Alaska and emphasizes the risks due to the uncertainties in the cost of that technology. Sensitivity and Monte Carlo procedures are used in the analysis to allow for the uncertainty in the costs of technology and the uncertainty in the price of the oil and gas.

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

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

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

II. The Model and the Solution Process

11.1 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 data flow and analytical logic are illustrated in Figure 1-1 in Chapter 1, Introduction. The following equation shows the relationships among the variables in the solution process of the model .

Equation No. 2: $NPV = \Big[[\text{Price} \times \text{Production} \times (1\text{-Royalty}) - \text{Operation Costs}]$
$\cdot(1\text{-Tax}) + [\text{Tax Credits}]$
$- [\text{Tangible Investments} + \text{Intangible Costs}]\Big] \times PV$

Where: NPV	=	net present value of producing a certain field with specified technology over a given time period
Pv	=	present value operator to continuously discount all cash flows with value of money, r
Price	=	wellhead price
Production	=	annual production uniquely associated with a given field size, a selected production technology, and number of wells
Royalty	=	royalty rate
Operating Cost	=	annual operation costs
Tax	=	tax rate
Tax Credits	=	the sum of investment tax credits (ITC) plus depreciation tax credits (OTC) plus intangible drilling costs tax credits (IDC)
Tangible Investments	=	development investments depreciated over life of production
Intangible Investments	=	Development expenditures that can be expensed for tax purposes.

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

This analysis assumes that these costs are covered by the firm's earnings from its successful portfolio of exploration investments.[1]

Excluding exploration costs and bonus payments and the time for these activities leaves out a great deal of money and several years of discounting future revenues. The minimum field sizes to justify exploration and development with a specified technology is significantly larger than the minimum field size to justify development given a discovered and delineated field.

Since 1973 the industry has spent over $4.0 billion on lease bonuses in OCS areas, $560 million of which was spent in the April 1976 Gulf of Alaska lease sale. The results have been dismal and expensive: 18 dry holes in the Mafia Dome, no discoveries; 11 dry holes, one discovery off southern California; 11 dry holes, no discoveries in the Gulf of Alaska; about nine dry holes in the Baltimore Canyon and one Texaco well with some indication of petroleum. AAPG data show that, in fact, the industry has had a success rate of only 4.3 percent for offshore wildcats for the six years 1971-1976.

Dry holes in the Gulf of Alaska have cost between $10 to $21 million each. If the industry has to explore for five years, as it did in the North Sea, to find the oil the U.S. Geological Survey estimates is present in the Gulf of Alaska, exploration could be an extremely costly adventure. Excluding exploration costs from the analysis focuses attention on the problems related to production technology and its impacts on Alaska rather than exploration problems.

The model does not include a term for salvage of equipment at the end of production. The assumption is made that the cost of removal of all

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(1) Assuming that "sunk" costs are covered by the successful portfolio of exploration investments implies that the upstream operations of vertically integrated companies must account for their profit and loss without reliance on downstream earnings. For non-vertically integrated exploration and production companies there is no alternative.

equipment and of 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 model assumes that the cost of removal will be offset by the value of the salvage.

11.2 Solution

Equation No. 2 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. 2 are not known. The technologies that have been developed for the North Sea have not been tested in the Gulf of Alaska or cost-estimated in the United States (see Appendix B). Thus, upper, lower, and mid-range values have been estimated for the critical variables of Equation No. 2 and are used in the solution process.

Both sensitivity analysis and Monte Carlo simulation are used in the solution process of Equation No. 2. 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.

This analysis relies more on sensitivity analysis than Monte Carlo simulation because:

- Knowing the boundaries of potential outcomes in most cases is sufficient;
- The information gained about the probability distribution using Monte Carlo simulation exceeds the requirements of the analysis in most of the cases analyzed.

Equation No. 2 together with sensitivity and Monte Carlo techniques allows several approaches to the solution process.

Equation No. 2 can be solved, given a field size and a selected technology, to show the relationship between the NPV of production and different values for:

- The value of money;
- Prices;
- Operating costs;
- Tangible investment costs;
- Intangible drilling costs.

Alternatively, the model can be solved given field size, 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 show how the previously calculated rate of return changes with different values for:

- Prices;
- Operating costs;
- Tangible investment costs;
- Intangible drilling costs.

Iterative solutions of Equation No. 2, given prices and a selected technology, can be used to determine the minimum size field to justify completion at various values of money. Sensitivity analysis can be used to show how changes in the values for the four items above change minimum economic field size.

III. The Assumptions

111.1 Value of Money

The minimum field size calculation is extremely sensitive to the value of money, r, used to discount the cash flows in Equation No. 2. Dames & Moore has specified that 10-15 percent brackets the real rate of return after tax in constant 1978 dollars that winning bidders will be willing to accept to develop a field.

John Lohrenz, economist for USGS, recently published two papers (1978a; 1978b) that indicate the oil industry, has, in fact, earned 9.5 percent internal rate of return on a group of 839 offshore oil and gas leases issued prior to 1963. Production and wells drilled through 1976 are included in his data. Removing the bonus paid for these properties from the investment base, Lohrenz reports they earned 14.3 percent. Lohrenz included inflation of both revenues and costs in this analysis; thus the 9.5 percent return can be considered similar to, but slightly overstating a "real" rate of return calculated in constant dollars. The investment base in Lohrenz's data is fixed at the point in time it is made and not inflated thereafter; but revenues continue to inflate. To the extent his investment base is dominated by more recent (inflated) investments rather than older (uninflated) investments, there is lesser or greater overstatement of the "real" rate of return implicit in his 9.5 percent. We are unable to assess the overstatement; but judge it to be no more than 10 percent of reported rate of return. This would lower his findings to a "real" 8.6 percent or 12.9 percent without the bonus.

Lohrenz's two studies report actual earned rates of return of each lease. Of the 839 offshore leased properties in his data set, 519 were non-producers. Thus, the 9.5 percent return earned by the entire group was earned by only 38 percent of the properties. Actual earned rates of return differ from expected rate of return used by oil companies to screen projects for capital allocation. Expected rates of return, or hurdle rates as they are called, anticipate some losses and are set at a level sufficiently high to allow the resulting historically observable rate of return on the entire portfolio of investments to meet given management objectives. These will differ firm-to-firm; thus, hurdle rates will differ firm-to-firm.

In consultation with BLM economists and major oil company economic analysts, and relying on Lohrenz's data as a reference point, 10-15 percent in constant 1978 dollars is adopted as the hurdle rates that will bracket most company hurdle rates for development of a known field in the Gulf of Alaska. Notice that if inflation is expected to be 6 percent, 10-15 percent in constant dollars is equivalent to 16.6 to 21.9 percent in current dollars. A recent, similar, study used a 15 percent constant dollar value of money in its base case with 10 percent and 25 percent for sensitivity (Gruy Federal, 1977). The A.D. Little report also used 15 percent in its base case with 10-25 percent sensitivity; but these appear to be in current dollars and the assumed inflation rate is not apparent (A. D. Little, 1976).

111.2 Inflation

The analysis is constructed in 1978 dollars. This constant dollar assumption implies that the existing relationship between prices and costs will remain constant, that oil and gas prices and the costs of their exploitation will inflate at the same rate between now and the period of exploration and development in the 1980's. Since ?974, however, the costs of finding and producing oil and gas have risen faster than oil prices as shown by Table C-1. If this trend continues -- and our constant 1978 dollar assumption implies it will not -- minimum field sizes for development will be larger than our analysis shows.

111.3 Prices

111.3.1 Oil Prices

The oil price is assumed to be $12.00 per bbl at the well-head. Sensitivity and Monte Carlo runs specify upper and lower limits of $15.00 and $11,00.

The logic of $12.00 oil is pegged to the economic valuation of North Slope crude but acknowledges that some yet undiscovered crude from the Gulf of Alaska may be qualitatively superior to the North Slope crude. Twelve dollars is the approximate average of the three cases analyzed below.

TABLE C-1

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

	Year	Oil Prices[1]	Gas Prices[2]	IPAA Drilling Cost Per Foot[3]	Oil Field Machinery & Tools[4]
	1974	100	100	100	100
	1975	116.0	138.9	114.9	124.4
	1976	119.8	188.3	124.6	137,9
	1977	130.0	266	137.3	149.9
Annual Rate of Growth:	'74 to '77	9.1%	38. 6%	11 .2%	14.5%

Sources:

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

111.3.1.1 General Background

It now seems likely that North Slope crude will remain surplus on the West Coast and will be trans-shipped inland either via the canal or the proposed El Paso pipeline throughout the 1980's and beyond. If U.S. regulations change, North Slope crude may be shipped to Japan in exhange for some other crude shipped to the East Coast, but this is unlikely.

111.3.1.2 Current Value of North Slope Crude: Case I

Under current economics, North Slope crude is worth between $10.50 and $11.00 at Valdez. This assumes that a barrel of North Slope replaces a barrel of Arab Light on the Gulf Coast and that the quality differential between the crudes is $0.50. The quality differential will vary among refiners; $0.50. per barrel is a reasonable valuation. The analysis is given below:

Value of North Slope Crude on Gulf Coast

	$/BBL
Arab Light Laid-In ($12.70 + $1.00 Trans)	$13.70
Less quality differential	- (.50)
Equals value of North Slope crude on Gulf Coast	$13.20
Less Trans From L.A. to Gulf Coast	-(1.50)
Equals value of North Slope crude in L.A.	$11.70
Less Trans from Valdez to L.A.	-(1.00)
Equals value of North Slope crude at Valdez	$10.70

111.3.1.3 Value of North Slope Crude Exchanged with Japan for Arab Light Delivered to the Gulf Coast: Case II

An exchange with Japan would raise the value of North Slope crude at Valdez. The value of a barrel of North Slope crude at Valdez would equal the quality adjusted laid-in value of Arab Light (or whatever crude is accepted in exchange) less freight from Valdez to Japan.

Should the regulations change to allow this, a critical issue would be whether the Alaska crude must move in expensive U.S. flagships to Japan.

This analysis can be stated as follows:

North Slope Crude Exchange

	$/BBL
Arab Light On Gulf Coast	$13.70
Less Quality Adjustment	(.50')
Less Trans Valdez to Japan at World Scale (est.) -	(1.20,)
Equals Value of North Slope Crude at Valdez --	$12.00

(Note: If oil must move in U.S. flagships, North Slope crude is worth between $10.50 - $11.00).

111.3.1.4 Value of Some Crude From Alaska That Replaces Sumatran Light Delivered to Los Angeles: Case 111

There is no explicit reason to assume that some new crude from the Gulf of Alaska will be similar to North Slope crude. Should it be a low-sulfur crude, it would remain on the West Coast and back out a barrel of Indonesian crude. (Arab Light is 1.8 percent S; North Slope crude is 0.95 percent S; Sumatran Light is 0.07 percent S.) Sumatran Light lays into L.A. at about $14.50. If the new Gulf of Alaska crude replaced a barrel of Sumatran Light, it would be worth approximately $13.00 - $13.50 at point of shipment in Alaska.

111.3.2 Gas Prices

The compromise gas bill currently in Congress (summer, 1978) would allow new gas at the wellhead to sell for $1.97 per MMBTU in 1978. This is approximately equal to $12.00 per bbl oil on a BTU basis. Even if the bill does not pass, new gas from frontier areas will eventually have to be priced on a par with oil. By the early 1980's, Dames & Moore assumes that regulations will change to allow gas to be priced at an equivalent $2.00 per million cubic feet (mcf) in 1978 dollars.

Sensitivity of ± $0.25 is used in the analysis.

All natural gas produced in the Gulf of Alaska will have to be converted to LNG for shipment to market.[1] According to public financial documents filed by Pacific Alaska LNG Associates (1977), they plan to convert natural gas to LNG delivered to Los Angeles for $3.89 in 1978 dollars. Pacific Alaska's "Summary of Cost of Service," shows they plan to pay $1.66 per mcf for purchased Cook Inlet gas. They intend to convert gas into LNG for $2.23/mcf in 1978 dollars. Assuming $2.00 as the price of gas delivered to an Alaskan LNG plant, plus Pacific Alaska's conversion costs, implies that LNG will lay into Los Angeles for $4.23 per mcf in 1978 dollars.

Dames & Moore makes no prediction about late 1980's LNG market values. Since Pacific Alaska is going ahead with their plant, this analysis assumes that LNG delivered for $4.23 per mcf is economic.

III.4 Effective Income Tax Rate and Royalty Rate

Federal taxes on corporate income now stand at 48 percent of taxable income. Dames & Moore assumes revenues from Gulf of Alaska development would be incremental and taxable after the usual industry deductions indicated below. Tracts are in federal OCS. No state or local tax applies.

(1) This assumption reflects the geographic isolation of the Gulf of Alaska from existing or planned gas transmission systems (e.g., the Alcan Gas Pipeline) and markets for natural gas. (A spur pipeline to the Alcan line, assuming spare capacity in that line, would be from 150 to 200 miles long and would have to tranverse the Chugach or St. Elias Mountains).

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

111.5 Tax Credits Depreciation and Depletion

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

111.6 Fraction of Investment As Intangible Costs

Dames & Moore assumes that expenses will be written off as intangible drilling costs to the maximum extent permissible by law. Thirty percent of investment totals are considered to be intangible expenses. Expenses incurred before production are carried forward until production begins and then expensed against revenue. The 30 percent fraction is consistent with an industry rule-of-thumb and the Gruy Federal report (Gruy Federal, 1977).

111.7 Investment Schedules

Appendix B describes in detail the timing of the flows of investment funds for various production systems. This discussion emphasizes the impacts of the investment flows on the calculated values of the model.

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.

Typical investment schedules for the various production technologies are:

- Six years for the typical 16- to 24-well gas platform and pipeline to shore in 91 meters (300 feet) or less water depth; seven years if greater than 91 meters (300 feet).

- Six years for the typical 24 to 40 producing-well oil platform in 91 meters (300 feet) or less water depth; seven years at greater than 91 meters (300 feet).

- Seven years for a 2-platform oil field in 91 meters (300 feet) or less; or eight years at greater than 91 meters (300 feet) water depth.

- Eight years for a 3-platform oil field in 91 meters (300 feet) or less; or nine years at greater than 91 meters (300 feet).

Oil production is assumed to begin when the platform is in place and the first 16 wells are completed. (Production timing is discussed below in Section IV.) Pipeline and shore investments required far completion are assumed to be completed before production begins,

Both tangible and intangible investment costs are entered into the model as lower, mid-range and upper limits. The lower limit is derived from calculations and is estimated to be 75 percent of mid-range. The upper limit, also derived from calculations, is estimated to be 140 percent of the mid-range. 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 also was used over these ranges of values.

111.8 Operating Costs

Annual operating costs are assumed to be constant on a per platform basis and not to vary with production. Thus, as production declines over time, the cost per barrel rises. Average operating cost per barrel over the life of the field is higher than average operating cost at peak capacity.

Annual operating costs are entered as a range of values. Values used in millions of dollars a year are:

	Low	Mid	Upper
• Floating Production Systems	$20	$ 25	$ 35
• Single Platform Systems	25	25	35
• Two Platform Systems	50	35	50
• Three Platform Systems	75	100	140

Per bbl operating costs were calculated for the production systems analyzed in this report. Most of the systems clustered around $1.00 per bbl at peak production and $2.00 per bbl on lifetime average production.

Gas operating costs clustered around $0.48 permcf at peak; $0.60 per mcf on average.

IV. Production Characteristics That Affect the Economic Analysis

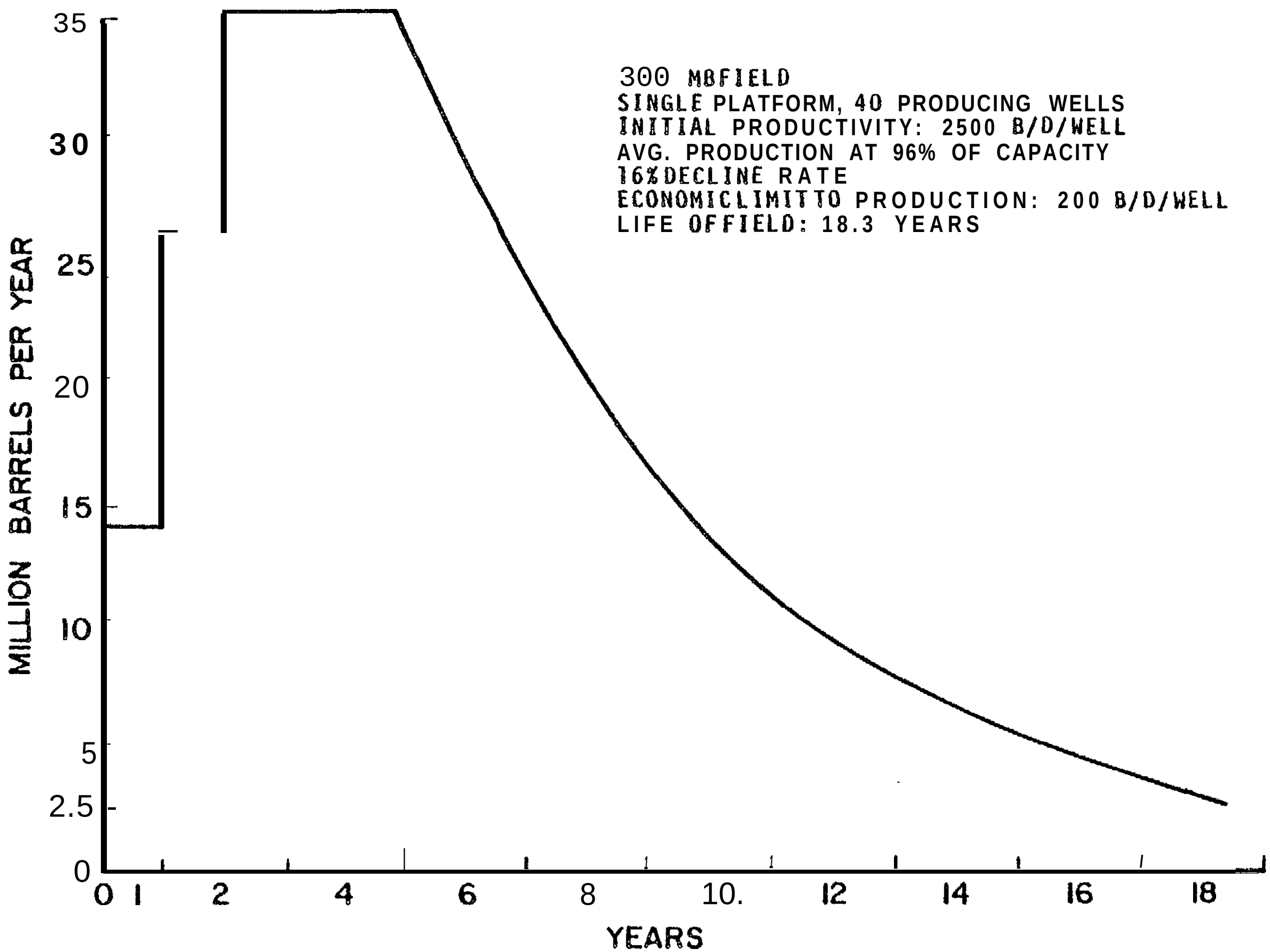
IV.1 Timing, Initial Productivity and Decline

The timing of production start-up varies with the construction delays associated with different production systems, for either oil or gas, numbers of platforms and wells, number of drilling rigs per platform, and water depth. In view of the high investment cost of production in the Gulf of Alaska, production is assumed to start as early as possible. See Figure C-1 for a typical production profile.

IV.1.1 Oil

IV.1.1.1 Timing

For the typical platform with two drilling rigs and 40 producing wells (oil or oil and associated gas), producing wells come on-stream in three groups over a 3-year period beginning with the sixth year after development begins in water depths up to 91 meters (300 feet) and beginning



TYPICAL PRODUCTION PROFILE

FIGURE C-1

with the seventh year at depths above 91 meters (300 feet).[1] Production rises to peak in the eighth or ninth year depending on water depth and is assumed to begin an exponential decline after 45 percent of the recoverable reserves are produced.[2] Between 65 - 70 percent of recoverable reserves are produced within the first 40 percent of the life of the field. Enhanced recovery procedures are assumed to be used over the last 60 percent of the life of the field to maintain a stable exponential decline.

IV.1.1.2 Initial Production Rate

Initial productivity per well is assumed to be 2500 barrels per day (bpd). Since well productivity is related to thickness by Darcy's equation (Newendorp, 1975), assuming a reasonably high initial productivity is tantamount to assuming that reservoirs found in the Gulf of Alaska will be reasonably thick. For a field to be economic in the Gulf of Alaska it must have recoverable reserves in excess of 100 MMbbl. It is not unreasonable to assume, therefore -- given the USGS estimate of recoverable reserves -- that an economic field will have a thick pay zone and be intrinsically productive.

IV.1.1.3 Platform Capacity and Field Decline

Platforms are assumed to be sized to hold up to 40 producing wells and eight service wells. Maximum production per platform is therefore 100,000 bpd. Full capacity systems described in Chapter 4.0 are assumed

(1) Water depth and production schedule are related insofar as platform fabrication and installation for fields in water depths of up to 300 feet are assumed to take about two years, and about three years for fields in water depths of over 91 meters (300 feet). This is because platform size (and hence fabrication time) is in part related to water depth.

(2) This is a somewhat conservative assumption in that some industry analysts suggest as much as 50 percent of reserves would be produced before decline begins. However, all fields are different; assuming either 45 percent or 50 percent does not mean some yet-to-be discovered oil field in the Gulf of Alaska will decline according to our assumption -- or any other.

to produce at 96 percent of capacity. Offshore loading systems with no storage are assumed to produce 65 percent of the time. Production decline rates vary as a function of production system, reserves recovered per well, and the assumed initial productivity rate of 2500 bpd well.

IV.1.2 Non-Associated Gas

The typical non-associated gas platform with one drilling rig begins production with four wells in the fifth year after development begins in water depths up to 91 meters (300 feet) and in the sixth year at water depths greater than 91 meters (300 feet). Production steps up with four completions per year until peak is reached with eight or 16 wells and then continues flat until 75 percent of recoverable reserves are produced. Production then begins an exponential decline.

Initial productivity is assumed to be 25 mmcfd per well. Gas platforms are assumed to house fewer wells than oil platforms. Eight or 16 gas wells per platform are assumed for the typical field sizes in the development scenarios. Maximum platform production, therefore, is either 200 or 400 mmcfd. Platforms are assumed to produce 96 percent capacity.

IV.2 Well Spacing and Recoverable Reserves Per Acre:

IV.2.1 General

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

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

The first item governs how the oil or gas flows. We have fixed initial production rates by assumption. Reservoir depth determines the maximum area which can be produced from a platform, assuming that a deviated well can be drilled to an angle of up to 50 degrees from the vertical; Table C-2 shows that the maximum area that can be reached from a single

TABLE C-2

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

Depth of Reservoir in Meters	(Feet)	Maximum Area Produced Sq. Kilometers	(Sq. Miles)	(Acres)
1,524	5,000	7.8	3.0	1,920
2,286	7,500	18.0	7.0	4,480
3,048	10,000	32.4	12.5	8,000
3,810	12,500	50.5	19.5	12,480
4,572	15,000	72.5	28.0	17,920

Note: Maximum angle of deviation assumed to be 50 degrees.

Source: Dames & Moore Estimate

platform ranges from three to 28 square miles, assuming the depth ranges from 1,524 to 4,572 meters (5,000 to 15,000 feet).

In view of the extreme cost of installing and maintaining platforms in the Gulf of Alaska, it is necessary to minimize their number. All other factors being equal, a shallow field with a thin pay reservoir covering many square miles and requiring several platforms to produce is less economic in the Gulf of Alaska than a field of equal reserves, with a deep and thick payzone, which can be produced from a single platform.

The number of wells required to produce a field differs for oil and gas and varies as a function of reservoir characteristics, including initial production rate. Initial production rates assumed are 2500 bpd per well for oil and 25 mmcfd for gas.

IV.2.2 Oil

It can be shown that reservoir characteristics -- porosity, permeability, connate water, driving mechanism, etc. -- together define the recoverable reserves per acre, which is thus a good proxy in place of more technical functional relationships for determining the number of wells required to produce a field, given its initial production rate.

The Arthur D. Little report (1976) indicated that recoverable reserves range as high as 300,000 barrels per acre in the extremely productive fields of the North Sea and as low as 5000 barrels per acre in the Gulf of Mexico. The Dames & Moore Beaufort Sea report (1978) indicated that recoverable reserves at Prudhoe Bay are about 50,000 barrels per acre and adopted as a reasonable range 20,000 to 50,000 barrels of oil per acre for the Beaufort Sea.

The A.D. Little report indicated that well spacing for the Gulf of Mexico fields ranged between 40-202 hectares (100-500 acres) per well as a function of initial well productivity and recoverable reserves per acre. Well spacing in the North Sea ranged between 40-808 hectares (100-2,000 acres) per well (A. D. Little, 1976, p. III-25). The Dames &

Moore Beaufort Report indicated that well spacing for the Beaufort region may be expected to range between 80-160 acres per well, based on expected Prudhoe plans (Dames & Moore, 1978b, p. 188-189).

In columns 6 and 7 of Table C-2, we have calculated the upper and lower limit well spacing implied for the Gulf of Alaska, assuming 40 wells maximum per platform and 20,000 and 50,000 barrels per for the hypothetical fields from the Gulf of Alaska development scenarios.

In all cases but the single platform, 40-well, 400-MMbbl -field well spacing is less than 500 acres per well. Most of the fields and well combinations on Table C-3 will allow well spacing between 40-131 hectares (100-325 acres) per well. Industry practices suggest that it is not unreasonable to expect that economic field sizes will allow well-spacing that falls within the limits shown on Table C-3.

The last column of Table C-3 shows the area implied by the upper and lower limits of barrels of reserves per acre and number of wells that a producing platform must be able to cover. Oil fields in the Gulf of Alaska are not expected to be found much below 3,810 meters (12,500 feet). Thus, a single platform could not reasonably be expected to produce an area larger than 50.5 square kilometers (19.5 square miles). At the low value -- 20,000 barrels per acre -- single platform production systems are sufficient to produce fields up to about 250 MMbbl. But the low estimate of recoverable reserves per acre is less reasonably associated with these "giant" fields, beyond 100 MMbbl, than some greater amount closer to 50,000 barrels per acre. It is not unreasonable to expect -- given the USGS estimates of economically recoverable reserves in the Gulf of Alaska and the economic necessity to minimize the number of platforms -- that the economically recoverable reserves will be found in reservoirs that will allow well spacing and area coverage from one to three platforms as shown on Table C-3.

TABLE C-3

FIELD SIZES, PRODUCTION PROFILES AND WELL SPACING -- OIL

Field Size (MB)	No. of Wells	Production Profile: Years Before Decline	Production Profile: Decline Rate	Production Profile: Total Production Life (Years)	Well Spacing (Acres Per Well): At 20 M/B Per Acre	Well Spacing (Acres Per Well): At 50 M/B Per Acre	Lifetime Reserves Produced Per Well (MB)	Area of Field Produced Per Platform: Sq. Kilometers	Area of Field Produced Per Platform: (Sq. Miles)
Offshore Loading Systems With No Storage									
160	40	4	.217	12.6	200	80	4.0	32.4 - 13	(12.5 - 5)
200	40	4.7	.172	15.8	250	100	5.0	40.4 - 16.2	(15.6 - 6.25)
250	40	5.6	.140	20.0	312.5	125	6.25	50.5 - 20.2	(19.5 - 7.8)
300	40	6.5	.118	23.0	375	150	7.50	60.6 - 24.4	(23.4 - 9.4)
Full-Time Production Systems									
160	30	3.6	.233	11.9	266	106	5.33	32.4 - 13	(12.5 - 5.0)
200	40	2.2	.253	10.7	250	100	5.00	40.4 - 16.2	(15.6 - 6.25)
300	40	4.4	.163	18.3	375	150	7.5	60.6 - 24.4	(23.4 - 9.4)
350	40	5.4	.154	20.3	437.5	175	8.75	70.7 - 28.2	(27.3 - 10.9)
400	40	6.0	.136	23	500	200	10.0	80.9 - 29.8	(31.25 - 11.5)
400	80	4.0	.259	12.3	250	100	5.0	40.4 - 16.2	(15.6 - 6.25)
500	80	4.6	.208	15.2	312.5	125	6.25	50.5 - 20.2	(19.5 - 7.8)
750	80	6.2	.144	22.2	375	150	9.375	60.6 - 24.4	(23.4 - 9.4)
750	120	5.1	.210	15.8	312.5	125	6.25	40.4 - 16.2	(15.6 - 6.25)
1000	120	6.1	.159	20.4	416	166	8.33	67.3 - 26.9	(26.0 - 10.4)

Source: Dames & Moore Estimate

IV.2.3 Non-Associated Gas

The 1976 Little report showed that non-associated gas recoverable reserves per acre in the Gulf of Mexico varied between 50 and 200 mmcf and between 50 and 500mmcf in the North Sea (A. D. Little, 1975). Initial well productivities ranged between 10 and 80 mmcfd in these two areas.

Gas and gas reservoir characteristics allow much larger well spacing than oil fields. Furthermore, in frontier areas demand forces rather than reservoir characteristics tend to limit the rate of gas extraction and thus the number of producing wells. In the North Sea initial well spacing was shown by the A. D. Little report to be as large as 2,020 hectares (5,000 acres) per well. The demand for gas from the North Sea is currently satisfied with reasonably wide spacing. As demand grows, wells will fill in to boost production.

Columns 6 and 7 of Table C-4 show the upper and lower limit of gas well spacing that is implied for the hypothetical non-associated gas fields for the Gulf of Alaska development scenarios. These range between 168 and 420 hectares (416 and 1,040 acres) per well. All gas from the Gulf of Alaska must be converted to LNG to get to market. In view of the speculative nature of LNG at the costs suggested by Pacific Alaska Associates in Section 111.3.2 of this Appendix, we assume that gas production is more likely to be limited by demand forces rather than reservoir characteristics. Thus, well spacing in the range of 259 hectares (640 acres), which is bracketed by our assumed upper and lower limits, is a reasonably conservative estimate.

No fields larger than 3.0 trillion cubic feet (tcf) are assumed in the scenarios. Gas platforms may reasonably be expected to be able to produce a larger area in the Gulf of Alaska because gas reservoirs are expected to occur deeper than oil reservoirs. It is not unreasonable to expect -- given the U.S. Geological Survey estimates of economically recoverable gas reserves in the Gulf of Alaska and the economic necessity to minimize the number of platforms -- that the economically recoverable

TABLE C-4

FIELD SIZES, PRODUCTION PROFILES AND WELL-SPACING -- GAS

Field Size (BCF)	No. of Wells	Production Profile		Total Production Life	Well Spacing (Acres Per Well)		Lifetime Reserves Produced Per Well (BCF)	Area of Field Produced Per Platform	
		Years Before Flat	Decline Rate		At 120 MCF Per Acre	At 300 MCF Per Acre		(Sq. Kilometers)	(Sq. Miles)
1000	8	11.2	.19	17.8	1040	416	125	33.6-13.5	(13 - 5.2)
2000	16	12.2	.218	20.7	1040	416	125	67.3-27	(26 -10.4)
3000	24	18.1	.23	17.8	1040	416	125	50.5-20.2	(19.5- 7.8)[1]

[1] 2-4 Well Platforms

Source: Dames & Moore Estimates

reserves will be found in reservoirs which will allow well spacing and area of coverage from one or two, 8-well to 16-well platforms as shown on Table C-4.

V. Economies of Scale and Per Barrel Development Costs

Economies of scale are a function of required investment to develop a field and the total recoverable reserves produced over the life of the field.

The per barrel development cost for fields of different sizes given a level of investment can be calculated after a technique suggested by Adelman.

The production profile for oil assumed in the model is equal to Q_T

Where: For Oil:

$$Q_T = N_1 q_{t_1} + N_2 q_{t_2} + \underset{'3}{\Sigma} N_3 q_t + {}_3 \frac{N_3 q_{t_4}}{a} \left(1-e^{-N_3 a t_4}\right) \qquad (1)$$

Where:

T = $t_1 + t_2 + t_3 + t_4$, total years of production

‘1 = First year of production with 16 oil wells or four gas wells

‘2 = Second year of production with 30 oil wells or eight gas wells

t_2' = Third year of gas production with 12 gas wells, if appropriate

t_2'' · Fourth year of gas production with 16 gas wells, if appropriate

t_2''' = Fifth year of gas production with 20 gas wells, if appropriate

‘3 = Period of flat production of 40 oil wells or maximum number of gas wells

‘4 = Period of declining production = T - $(t, + t_2 + t_3)$

‘1 = 16 wells

‘2 = 30 wells

‘3 = 40 wells -- maximum

q = b(365 x 2500 b/d), peak annual production rate, where b = capacity utilization -- 96 percent

a = Decline rate for field

Let I_0 = The present value of all investments over the life of the field

Thus ,

$$I_0 = PV \sum_{t=1}^{T} (I_t e^{-rt}) \qquad (2)$$

For each level of investment there is an associated production profile dependent on the total recoverable reserves. Given total investment and total recoverable reserves, the investment per barrel to develop a field can be calculated.

Let c = The per barrel development costs

$$I_0 = \int_0^T (c\, q_t\, e^{-rt}\, dt) \qquad (3)$$

Where:

q_t = Annual production of oil in year t, given total recoverable reserves

r = The discount rate

Equation (3) can be solved given investment, I_0, and various levels of total recoverable reserves -- the integral of q_t over T (the life of the field) -- to see how oil produced from various field sizes affects the per barrel development cost, c.

Substituting Equation (1) into (3):

$$I_0 = c[(N_1 q_{t_1} + N_2 q_{t_2} + \sum_{t_3} N_3 q_{t_3}) + \frac{N_3 q_{t_4}}{a} (1-e^{-N_3 a t_4})]\ e^{-rt} \qquad (4)$$

Simplifying and combining, this is equal to:

$$I_0 = c[(N_1q_{t_1} + N_2q_{t_2} + \Sigma_{t_3} N_3q_{t_3})\ e^{-rt} \bullet [\frac{1-e^{-(N_3a+r)t_4}}{a+r}]\ N_3q_{t_4}] \quad (5)$$

Since production at peak ($N_3q_{t_4}$) does not begin to decline until some number of years into the future, the last term must be discounted further to show that decline does not begin until the end of time, t_3. Define $e^{-rt'_3}$ as the factor to discount the production over the declining years.

Where:

t'_3 = Last year of flat production

For reasonable values of N_3, a, r, and t_4, $e^{(-N_3a+r)t_4}$ approaches zero and the last term becomes $(1/a + r)(N_3\ q_{t_4})e^{-rt'_3}$.

$$I_0 = c\ [(N_1q_{t_1} + N_2q_{t_2} + \Sigma_{t_3} N_3q_{t_3})e^{-rt} + (1/a+r)(N_3q_{t_4})e^{-rt'_3}] \quad (6)$$

The expression in the brackets of Equation (6) is equivalent to an expression Adelman refers to as the "present barrel equivalent" of the flow of annual oil production, qt. That is, if the oil could be produced all at once in one big glob, the quantity defined by the expression in the brackets represents the present barrel equivalent of total reserves recovered over the life of the field. Its per barrel development cost, c, is the equivalent to the present value at discount rate, r, of the investment costs divided by the present barrel equivalent of the whole stream of output.

Equation (6) can be rearranged to solve for c, the per barrel development costs :

$$c = \frac{I_o \ (a+r)}{(N_1 q_{t_1} + N_2 q_{t_2} + N_3 q_{t_3}) \ e^{-rt_3} + (N_3 q_{t_4}) \ e^{-rt'_3}} \qquad (7)$$

Equation (7) will be solved for fields of various sizes given the level of investment required to develop the field to examine the effects of economies of scale on per barrel development costs of oil or gas.