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PART 2 of 2

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM

BEAUFORT SEA BASIN PETROLEUM DEVELOPMENT SCENARIOS FOR THE FEDERAL OUTER CONTINENTAL SHELF

INTERIM REPORT

PREPARED FOR

BUREAU OF LAND MANAGEMENT

ALASKA OUTER CONTINENTAL SHELF OFFICE

December 1977

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 is an interim report designed to provide preliminary petroleum development data to the groups working on the Alaska OCS Socioeconomic Studies Program. The assumptions used to generate offshore petroleum development scenarios are subject to revision. A review of concerns and criticisms of some of the assumptions, and conditions under which alternative assumptions might provide a more accurate projection basis, is given in Appendix A. Specifically, the most significant concerns are the exploration activity assumptions found in Section 3.3 and Tables 3-4 through 3-9.

3. The units presented in this report are metric with American equivalents except for units used in standard petroleum practice. These are barrels (42 gallons, oil), cubic feet (gas), pipeline diameters (inches), wel 1 casing diameters (inches) and wel l spacing (acres).

4. Since this analysis was conducted two important petroleum-related events have occurred in Alaska. Jurisdiction of Naval Petroleum Reserve No. 4 (NPR-4) has been transferred from the Department of the Navy to the Department of the Interior becoming National Petroleum Reserve-Alaska (NPR-A) and the Alcan (Northwest) pipeline proposal has been selected to transport Prudhoe Bay gas to lower 48 markets.

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
Beaufort Sea Basin Petroleum Development Scenarios for the Federal Outer Continental Shelf, Interim Report

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December 1977

FOREWARD

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 local 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 Director, Socioeconomic Studies Program, Alaska OCS Office, P. O. Box 1159, Anchorage, Alaska 99510.

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INTRODUCTION

PURPOSE

In order to analyze the socioeconomic and environmental impacts of Beaufort Sea petroleum exploration, development and production, it is necessary to make reasonable predictions of the nature of that development. Petroleum development scenarios serve that purpose by providing a "project description" for the impact analysis.

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 the 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 the most economically and technically feasible based upon available estimates of oil and gas resources of the Beaufort Sea.

SCOPE

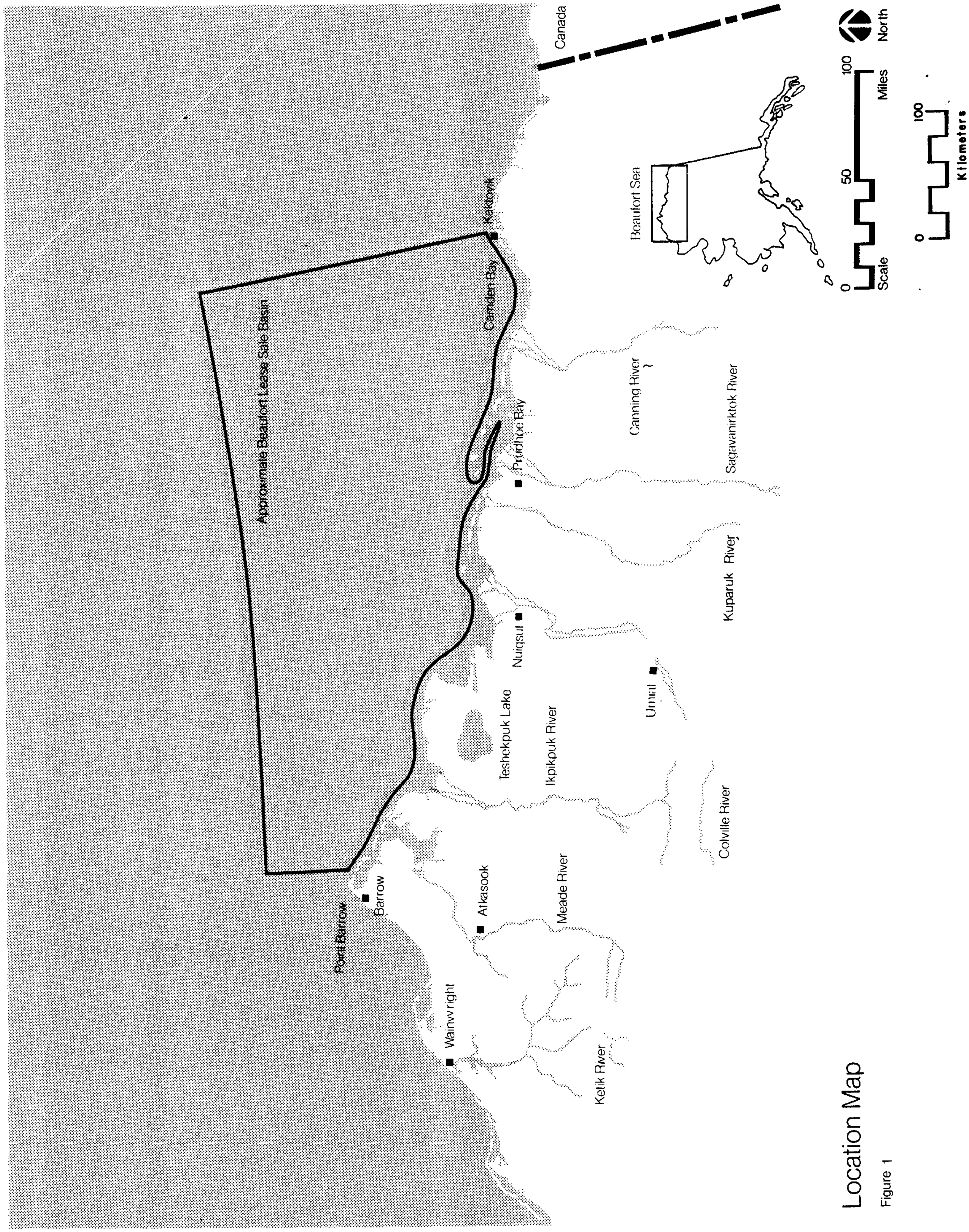
The petroleum development scenarios formulated in this report are for the proposed federal lease sale area located in the Beaufort Sea. Although this area has yet to be precisely defined and the tracts that will ultimately be leased are unknown, the lease area considered in this report encompasses that portion of the Beaufort Sea located between Barter Island (144° W) and Point Barrow (156° W) and extending seaward from the three mile limit to about the 20 m (60-foot) isobath. The significance of 20 m (60-foot) isobath is that it is the water depth believed to be the limit of present or imminent technology for exploratory drilling and production. This is because the 20 m (60-foot) isobath marks the approximate landward boundary of significant ice movement and encroachment of the seasonal and polar pack ice. The study area is shown in Figure 1, Location Map.

The area of the Beaufort Sea within the three mile limit comes under the jurisdiction of the State of Alaska and will be the location of a state or state-federal lease sale. Such a lease sale, which will probably occur before a federal sale, is not considered in this analysis. Moreover future petroleum developments in National Petroleum Reserve - Alaska (NPR-A), which is currently being evaluated by an exploratory drilling program, are not fully evaluated in this report; nor are they directly considered in the economic analysis. The reason for this exclusion is that future study efforts will expand the scenario scope to include all North Slope development; this report is therefore interm in nature.

This report does, however, consider the Prudhoe Bay development, Alyeska pipeline and the proposed Arctic Gas, Northwest and El Paso gas pipeline projects, which provide important economic data relevant to the analysis*.

The basis of this report is the U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources of the Beaufort Sea between the 0 and 200 m isobaths as described in Circular 725 (Miller et al.,

*Subsequent to completion of this study the Northwest (Alcan) gas pipeline project has been selected by President Carter and approved by Congress and the Arctic Gas and El Paso proposals have been withdrawn.



Location Map

Figure 1

1975). These estimates, which include the lease area under considerations in this report, are:

	Probability 95%	5%	Statistical Mean
Oil (billion of barrels)	0	7.6	3.28
Gas (trillions of cubic feet)	0	19.3	8.2

For the federal OCS lease sale discussed in this report, the following estimates of undiscovered recoverable oil and gas resources have been made by the U.S. Geological Survey (Grantzet al., 1976):

Oil (billions of barrels)	Oto 3.9
Gas (trillions of cubic feet)	Oto 9.9

These approximate the 5 and 95 percent probability levels.

METHODOLOGY

As stated above, the construction of the petroleum development scenarios is based upon the building block of the U.S. Geological Survey resource estimates. The initial scenario construction in Chapter II generates 15 scenarios based upon one of five unique levels of reserve concentration distributed in three arbitrarily chosen geographic locations (east, central and west) of the Beaufort Sea.

The technical framework of the scenarios established in Chapter II is based upon the technology review presented in Chapter I. That review describes available and potential Arctic petroleum technology in the context of the dominant environmental constraints (sea ice, permafrost, etc). The technical assumptions and related cost data also rely significantly on Alyeska experience and the proposed gas pipeline projects. Each of the 15 scenarios is subject to a parametric economic analysis which sequentially applies a range of economic variables (parameters) to the initial set of 15 scenarios. For each unique combination of parametric values (i.e. level of required investment, tax status, desired rate of return, transportation tariff, etc.) a determination is made of the required market price and minimum field size for commercial development. The process used for the economic analysis is shown schematically in Figure 3-1.

Criteria are established that permit the selection of the four scenarios to be elaborated in detail in Chapter IV. The criteria include: (1) the need for representation of all three geographical areas and four levels of reserves among the selected scenarios, (2) economic feasibility of both oil and gas development as determined by the economic framework of Chapter III, and (3) representation of the "maximum development" scenario with respect to the impacts of development on the physical and social environment. These criteria are sequentially applied to the fifteen scenarios, resulting in a unique set of four that meet all the above conditions.

Each of the selected scenarios is then described in detail in Chapter IV according to locational factors, facilities, equipment and manpower requirements. Scenario scheduling is presented and described for exploration, development, production and shutdown phases of petroleum development.

REGIONAL SETTING

To appreciate the physical setting of the petroleum region and potential OCS lease sale area discussed in this report, a brief description of the major physical features of the North Slope and Alaskan Beaufort Sea is appropriate. The petroleum region and adjacent OCS lease sale area are located within the Arctic Coastal Plain physiographic region which for the most part is a smooth plain that rises gradually from the Arctic Ocean coast to an elevation of 180 m (600 feet) in the foothills of the Brooks Range (Warhaftig, 1965). Located north of the Arctic circle, the American section of the Beaufort Sea extends from Demarcation Point (69° 40'N, 141° 00'W) at the Canadian border to Point Barrow (71° 25'N, 153° 30'W) in the west, a distance of approximately 610 km (380 miles).

The shoreline is also characterized by low relief with coastal bluffs generally less than 3 m (10 feet) high. The Arctic Coastal Plain can be subdivided into two sections: the Teshepuk section which is a flat-lying lake-dotted plain, and the White Hills section, east of the Itkillik River, which is diversified by scattered groups of low hills. The coastal plain is at its narrowest near the Canadian border [about 18 km (11 miles)] and widens significantly westward toward Point Barrow where it is about 180 km (110 miles) across. Most of the coastal plain is underlain by unconsolidated silts and sands with some clays and gravels which comprise the predominantly marine Gubik Formation of Quaternary Age (Black, 1964). These deposits, which are up to 45 m (150 feet) thick, unconformably overlie Mesozoic sediments (shales, mudstones, sandstones) west of the Colville River and Tertiary rocks east of the river.

The coastal plain is underlain by continuous permafrost up to 610m (2,000 feet) thick. The continuous permafrost coupled with the low relief result in the generally poor drainage and the development of patterned ground, thermokarst features and ice-cored mounds such as pingos. One of the most unique features of the coastal plain is the thousands of lakes which cover an area of approximately 435,000 square km (168,000 square miles); many of these lakes are oriented with their long axes a few degrees west of north.

Drainage on the coastal plain is predominantly north to the Arctic Ocean with the major rivers having their headwaters in the Brooks Range. The Colville is the largest of these rivers being over 690 km (430 miles) long and draining about 30 percent of the Arctic Slope. West of the Colville the rivers on the coastal plain are generally shallow, poorly-integrated and have meandering channels. In contrast, the rivers east of the Colville generally exhibit braided patterns and have numerous gravel and sand bars interspersed with continuously shifting channels.

An important result of these contrasts is the regional availability of sand and gravel. West of the Colville River, which intercepts much of the drainage and coarse sediments from the Brooks Range, gravel and sand are in short supply whereas east of the Colville many of the rivers originate in the Brooks Range and transport coarse sediment. The most significant hydrologic characteristics of the coastal plain are the virtual cessation of flow during the winter, the concentration of most of the season’s flow in a short period of time, and the inclusion of large amounts of ice in river flow usually during peak discharge (Walker, 1973).

The Beaufort Sea coastline is varied comprising such features as beaches, barrier islands, barrier bars, spits, lagoons, dunes and river deltas (Hartwell , 1973). Low but steep sea bluffs in many places are under active retreat as a result of a combination of thermal and wave erosion during the short summer open-water season.

The continental shelf of the American Beaufort Sea is narrow [no more than 95 km (59 miles) wide] and terminates at the edge of the continental slope in water depths of 45 to 70 m (150 to 220 feet). The shelf remains shallow for considerable distances offshore; at Harrison Bay, for example, the 20 m (60-foot) isobath lies as much as 73 km (45 miles) offshore. The waters in the eastern American Beaufort get deep much more quickly; the 20 m (60-foot) isobath at Camden Bay, for example, lies only 18 km (11 miles) from shore.

More detailed information on the physical features and environment of the North Slope and Beaufort Sea are available in such comprehensive references as Alaskan Arctic Tundra (Britton, 1973), The Alaskan Arctic Coast (Arctic Institute of North America, 1974) and The Coast and Shelf of the Beaufort Sea (Reed and Sater, 1974).

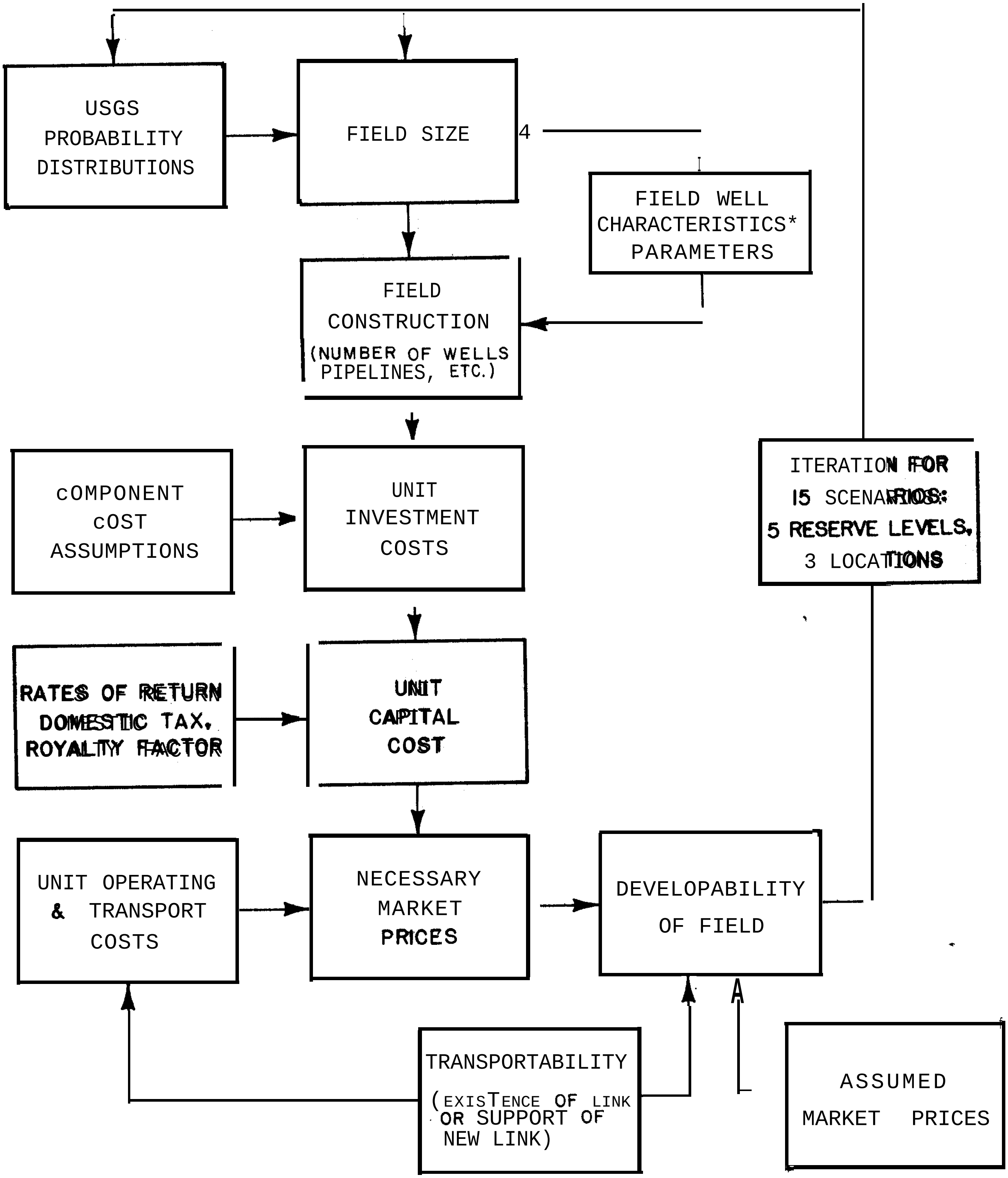
CHAPTER III

ECONOMIC ANALYSIS

3.1 INTRODUCTION

This chapter of the report is devoted to an analysis of the economic feasibility of the 15 petroleum development scenarios developed thus far for the Beaufort Sea OCS lease-sale area. To the technical and developmental assumptions that were discussed in the preceding chapter, this part of the report will add assumptions regarding cost, financial objectives, and taxation in order to determine the required market price and minimum field size needed to justify the development. A generalized flow sheet of the logic of the analysis is shown in Figure 3-1.

In general, three major economic concepts are employed throughout the analysis: (1) all unit costs, prices, etc. are stated in terms of constant 1975-76 dollars, i.e., average 1975-76 price, such that they are presumed to escalate in direct relation to the general level of U.S. inflation, (2) comparisons regarding economic feasibility are all referenced to a single point in time, the start of production, such that all investment required for development is escalated forward to this point in time and all revenues and production costs are "discounted" backwards to the same point in time, (3) many of the variables are not fixed uniquely by assumption, but rather are given a range of values, such that the analysis can be termed "parametric" in nature. Determination of the required market prices, for example, are carried out for all of the following variables:



LOGIC FLOW SHEET

FOR THE ECONOMIC ANALYSIS

FIGURE 3-1

Variables: Parameters Analyzed

- Reserve Size: 3.5 Bbbl, 2.3 Bbbl, 1.4 Bbbl, 0.4 Bbbl
- Location of Discovery: east, central, west
- Exploration Activity: optimistic, cautious
- Investment Cost: high, low
- Effective Producer Tax Rate: 35%, 10%
- Desired Rate of Return: 25%, 20%, 15%, 10%, 5%
- Gas Transportation Tariff: new line; high, primary, low tariff on shared existing line
- Most Feasible Market Price: $12, $13, $14 per barrel for oil, and $6, $7 per unit (2.5 mcf) for gas (constant 1975-76 dollars)
- Limit Market Price: $17 per barrel for oil and $10 per unit for gas (constant 1975-76 dollars)

3.2 CAPITAL COST ASSUMPTIONS

The capital cost assumptions used in developing the investment requirements for each scenario are summarized in Table 3-1. They have been prepared with both a high and low set of values. The high values

TABLE 3-1

CAPITAL COST ASSUMPTIONS FOR THE

BEAUFORT SEA OCS SCENARIOS

(price base: millions of 1975-76 dollars)

CAPITAL EQUIPMENT	ESTIMATED COST (millions of dollars)	
	Low	High
Tract Costs (each)	5	10
Exploration Platforms:		
Gravel/Reinf. Earth Islands (each)	8	15
Drillships/Rigs (each) (1)	3	11
Ice/Earth-Ice Islands (each)	2	5
Production Platforms:		
Gravity Structures @ 15m (50 ft.) (each) (2)	35	65
Gravity Structures @ 6m (20 ft.) (each)	20	40
Gravel Island @ 4.5-5m (15-25 ft.) (each)	15	30
Exploratory Wells (each):		
First 6 per exploratory region	10	15
Remainder	5	8
Production Wells (each):		
First 20 per field group	8	10
Remainder, including development wells:	3	6
Processing Equipment (per MBD Capacity) (3)	0.5	0.7
Gas Plant (per 100 mmcfd) (4)	10	14

TABLE 3-1

(Cont.)

	Low	High
Transportation:		
Barges (each)	0.7	1.2
Supply Vessels (each)	0.2	0.2
Supply Tractors (each)	0.1	0.1
Harbor (each)	4	6
Crew Base (each)	8	12
Roads:		
Long Roads per kilometer (per mile) (5)	0.22 (0.35)	0.25 (0.4)
Short Roads per kilometer (per mile)	0.16 (0.25)	0.19 (0.3)

	Low Cost Flow Rate in MMBD			High Cost Flow Rate in MMBD		
	(.1-.4)	(.4-1.0)	(1.0+)	(.1-.4)	(.4-1.0)	(1.0+)
Oil Pipelines:						
Offshore per kilometer (per mile)	5 (8)	5 (8)	6.2 (10)	5 (8)	5.6 (9)	7.5 (12)
North Slope per kilometer (per mile)	4.3 (7)	5 (8)	5.6 (9)	4.3 (7)	5.6 (9)	6.8 (11)

Gas Pipelines per kilometer (per mile): Estimated at 70% of oil pipeline costs for equivalent flow rates.

Footnotes:

(1) High range for drilling unit based upon annual charge; average of 1.5 wells per year.

(2) Gravity structure is a generic term for al 1 bottom resting structures (i.e. monopods) that are currently in the con-ceptual design stage. Meters (feet) refers to water depth.

(3) Includes all processing equipment: oil/water separation, desanding, H2S stripping, turbines, etc., as well as a share of crew quarters.

TABLE 3-1

(Cent.)

Footnotes:

(4) Shares a portion of the cost of platform crew quarters with processing equipment.

(5) Long roads incur increased hauling costs for the transport of construction materials.

correspond to current experience; they have been extrapolated from estimates of return on Prudhoe Bay oil, construction costs on the Alyeska line, estimated construction costs for the Arctic, Northwestern, and El Paso gasline projects, and reported expenditures of Canadian projects. The low estimates were arbitrarily extrapolated from the high estimates by assuming lower labor costs, economies of scale, and improvements in scheduling. With regard to the latter, labor and machine productivity is not likely to be improved, but schedule productivity gains may be assumed from reductions in downtime, better parts scheduling, improvements in logistical coordination, etc.

Although the high cost values reflect more closely the demonstrated frontier costs in Arctic exploration, and could be assumed to be the "most likely", the lower cost range may reflect more closely industry expectations of cost which might be achieved in field groups of over a billion barrel reserve units.

3.3 EXPLORATION COSTS* (See Appendix A)

For the purposes of scenario analysis, exploration costs are limited to three major cost components:

*Significant concerns have been expressed about the exploration activity assumptions contained in this section. Specifically, there is concern that the number of exploratory drilling platforms constructed and exploratory wells drilled is significantly overstated. Another concern is the timing of exploratory platform construction and well drilling expenditures which are believed to be somewhat extended. The reader is referred to a discussion of the alternate interpretations contained in Appendix A.

- purchase of offshore tracts
- construction of exploratory platforms
- drilling of exploratory wells

The number of tracts purchased is generally dependent upon the level of anticipated discovery, whereas the level of exploratory activity is generally dependent upon the rate and level of actual discovery, such that exploratory success in an area will lead to further drilling. Two levels of hypothesized exploratory activity ("high" and "low") are shown in Table 3-2 for each of the assumed reserve levels (building blocks) used throughout the analysis. The rationale for considering the high exploration variant is that it could result from optimism generated by events outside the boundaries of the Beaufort OCS lease-sale area. If significant finds occur in state waters, or adjacent onshore areas prior to the Beaufort lease sale, then it is conceivable that Beaufort bidding and drilling activities could be stimulated accordingly--bidding levels even more than drilling activity. Without the corollary assumption of external stimulation, the higher exploratory activities would not be expected for scenario construction. As stated in Chapter II, only a limited number of the purchased tracts will be ultimately explored as a result of the accumulating knowledge of geological structures within the lease-sale area. Each explored tract is assumed to require 2.5 exploratory wells, drilled either from one platform, or from successive wells from mobile or temporary platforms. Multiplying the assumed number of tracts, platforms, and wells by the high and low capital cost assumptions from Table 3-1, will yield the total exploration costs as shown in Table 3-4.

TABLE 3-2

HYPOTHETICAL EXPLORATION ACTIVITY

Reserve Level Building Block (Billions of Barrels)	Exploration Activity	Number of Tracts Purchased	Explored	Held
3.5	High	60	40	20
2.3	High	60	40	12
	Low	40	20	8
1.4	High	25	16	8
	Low	15	12	8
0.7	High	20	10	3
	Low	6	4	2
0.4	High	20	8	2
	Low	6	4	2
0	High	30-40	4	0
	Low	6	2	0

TABLE 3-3

SUMMARY OF EXPLORATORY

UNIT COSTS*
($1975** per barrel oil and 2.5 mcf gas)

Reserve Level	Exploratory Level	Cost Level Low	Cost Level High
3.5 Bbbl	High	$0.45	$0.82
2.3 Bbbl	High	0.68	1.25
	Low	0.38	0.74
1.4 Bbbl	High	0.45	0.87
	Low	0.33	0.60
0.7 Bbbl	High	0.67	1.21
	Low	0.27	0.48
0.4 Bbbl	High	1.07	1.95
	Low	0.48	0.84

*Detailed derivations in Table 3-4
**10-year span from tract purchase to start of revenue

TABLE 3-4

EXPLORATION COSTS BY RESERVE LEVEL, ACTIVITY LEVEL, AND COST LEVEL ($Millions-1975-76)

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
3.5 Bbbl High Cost, High Activity	60 Tracts @ $10	$600	9.5	$ 1246
	40 Platforms	328	7.5	473
	8 gravel @ $15			
	8 rigs @ $11			
	24 ice @ $5			
	100 Wells	842	6.5	1156
	6 @ $15			
	94 @ $8			
				$ 2875
	UNIT COST $0.82/bbl			
3.5 Bbbl Low Cost, High Activity	60 Tracts @ $5	$300	9.5	$ 623
	40 Platforms	144	7.5	208
	8 gravel @ $8			
	16 rigs @ $3			
	16 ice @ $2			
	100 Wells	530	6.5	728
	6 @ $10			
	94 @ $5			
				$ 1559
	UNIT COST $0.45/bbl			
2.3 Bbbl High Cost, High Activity	60 Tracts @ $10	$600	9.5	$1246
	40 Platforms	328	7.5	473
	8 gravel @ $15			
	8 rigs @ $11			
	24 ice @ $5			
	100 Wells	842	6.5	1156
	6 @ $15			
	94 @ $8			
				$ 2875
	UNIT COST $0.45/bbl			

TABLE 3-4 (Cont.)

EXPLORATION COSTS BY RESERVE LEVEL, ACTIVITY LEVEL, AND COST LEVEL ($Millions-1975-76)

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
2.3 Bbbl High Cost, Low Activity	40 Tracts @ $10	$400	9.5	$ 831
	20 Platforms	186	7.5	268
	4 gravel @ $15			
	4 rigs @ $11			
	12 ice @ $5			
	50 Wells	442	6.5	607
	6 @ $15			
	44 @ $8			
				$ 1706

UNIT COST $0.74/bbl

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
2.3 Bbbl Low Cost, High Activity	60 Tracts @ $5	$300	9.5	$ 623
	40 Platforms	144	7.5	208
	8 gravel @ $8			
	16 rigs @ $3			
	16 ice @ $2			
	100 Wells	530	6.5	728
	6 @ $10			
	94 @ $5			
				$ 1559

UNIT COST $0.68/bbl

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
2.3 Bbbl Low Cost, Low Activity	40 Tracts @ $5	$200	9.5	$ 415
	20 Platforms	72	7.5	77
	4 gravel @ $8			
	8 rigs @ $3			
	8 ice @ $2			
	50 Wells	280	6.5	384
	6 @ $10			
	44 @ $5			
				$ 876

UNIT COST $0.38/bbl

TABLE 3-4 (Cont.)

EXPLORATION COSTS BY RESERVE LEVEL, ACTIVITY LEVEL, AND COST LEVEL ($Millions-1975-76)

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
1.4 Bbbl High Cost, High Activity	25 Tracts @ $10	$250	9.5	$ 519
	16 Platforms	144	7.5	208
	4 gravel @ $15			
	4 rigs @ $11			
	8 ice @ $5			
	40 Wells	362	6.5	497
	6 @ $15			
	34 @ $8			
				$ 1224
	UNIT COST $0.87/bbl			
1.4 Bbbl High Cost, Low Activity	15 Tracts @ $10	$150	9.5	$ 312
	12 Platforms	100	7.5	144
	4 gravel @ $15			
	8 ice @ $5			
	30 Wells	282	6.5	387
	6 @ $15			
	24 @ $8			
				$ 843
	UNIT COST $0.60/bbl			
1.4 Bbbl Low Cost, High Activity	25 Tracts @ $5	$125	9.5	$ 260
	16 Platforms	40	7.5	58
	8 rigs @ $3			
	8 ice @ $2			
	40 Wells	230	6.5	316
	6 @ $10			
	34 @ $5			
				$ 634
	UNIT COST $0.45/bbl			

TABLE 3-4 (Cont.)

EXPLORATION COSTS BY RESERVE
LEVEL, ACTIVITY LEVEL,
AND COST LEVEL
($Millions-1975-76)

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
1.4 Bbbl Low Cost, Low Activity	15 Tracts @ $5	$75	9.5	$ 156
	12 Platforms	36	7.5	52
	8 rigs @ $3			
	4 ice @ $2			
	30 Wells	180	6.5	247
	6 @ $10			
	24 @ $5			
				-r-m---
	UNIT LOST $0.33/bbl			
0.7 Bbbl High Cost, High Activity	20 Tracts @ $10	$200	9.5	$ 416
	10 Platforms	70	7.5	101
	2 gravel @ $15			
	8 ice @ $5			
	25 Wells	242	7 . 5	332
	6 @ $15			
	19 @ $8			
				$ 849
	UNIT COST $1.21/bbl			
0.7 Bbbl High Cost, Low Activity	6 Tracts @ $10	$60	9.5	$ 125
	4 Platforms	30	7.5	43
	1 gravel @ $15			
	3 ice @ .$5			
	10 Wells	122	6.5	167
	6 @ $15			
	4 @ $8			
				$ 335
	UNIT COST $0.48/bbl			

TABLE 3-4 (Cont.)

EXPLORATION COSTS BY RESERVE LEVEL, ACTIVITY LEVEL, AND COST LEVEL ($Millions-1975-76)

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
0.7 Bbbl Low Cost, High Activity	20 Tracts @ $5	$100	9.5	$ 208
	10 Platforms	32	7.5	46
	2 gravel @ $8			
	8 ice @ $2			
	25 Wells	155	6.5	212
	6 @ $10			
	19 @ $5			
				$ 466

UNIT COST $0.67/bbl

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
0.7 Bbbl Low Cost, Low Activity	6 Tracts @ $5	$30	9.5	$ 62
	4 Platforms	14	7.5	20
	1 gravel @ $8			
	3 ice @ $2			
	10 Wells	80	6.5	110
	6 @ $10			
	4 @ $5			
				$ 192

UNIT COST $0.27/bbl

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
0.4 Bbbl High Cost, High Activity	20 Tracts @ $10	$200	9.5	$ 416
	8 Platforms	60	7.5	86
	2 gravel @ $15			
	6 ice @ $5			
	20 Wells	202	6.5	277
	6 @ $15			
	14 @ $8			
				$ 780

UNIT COST $1.95/bbl

TABLE 3-4 (Cont.)

EXPLORATION COSTS BY RESERVE
LEVEL, ACTIVITY LEVEL,
AND COST LEVEL
($Millions-1975-76)

LEVEL	BASE CALCULATION (Units @ Cost/Unit)	BASE COST	ESCALATION TIME (Years)	FINANCIAL COST
0.4 Bbbl High Cost, Low Activity	6 Tracts @ $10	$ 60	9.5	$ 125
	4 Platforms	30	7.5	43
	1 gravel @ $15			
	3 ice @ $5			
	10 Wells	122	6.5	167
	6 @ $15			
	4 @ $8			
				$ 335
	UNIT COST $0.84/bbl			
0.4 Bbbl Low Cost, High Activity	20 Tracts @ $5	$100	9.5	$ 208
	8 Platforms	28	7.5	40
	2 gravel @ $8			
	6 ice @ $2			
	20 Wells	130	6.5	178
	6 @ $10			
	14 @ $5			
				$ 426
	UNIT COST $1.07/bbl			
0.4 Bbbl Low Cost, Low Activity	6 Tracts @ $5	$30	9.5	$ 62
	4 Platforms	14	7.5	20
	1 gravel @ $8			
	3 ice @ $2			
	10 Wells	80	6.5	110
	6 @ $10			
	4 @ $5			
				$ 192
	UNIT COST $0.48/bbl			

It should be noted that the exploration costs in Table 3-4 (as well as the investment requirements in the following section) are stated in terms of "financial cost", which is the value of a specific "sunk" investment escalated in time to the start-up of production (about 10 years after the lease sale). An investment, for example, made 9.5 years before it receives a return (cash flow resulting from production), has lost 9.5 years of potential interest. Thus, the financial cost reflects the sunk cost (base cost as shown in the table), plus an "opportunity cost", and the latter is determined by compounding a given interest rate over the period of lost opportunity. The investment in tracts is made 9.5 years before production, and is assumed to have an interest cost of 8 percent per year; thus, the financial cost equals the base cost times $(1.08)^{9.5}$. All the other investment costs in the table involve construction, in which it has been assumed to be cheaper to build now than in the future (by an assumed 3 percent per year); thus although there is an opportunity "loss" of 8 percent, there is a "savings" of 3 percent, yielding a net interest of 5 percent. Therefore, the financial cost of investing in exploration platforms 7.5 years (average) before production startup is equal to the base cost times $(1.05)^{7.5}$. All costs are stated in constant dollars. The assumption that construction costs increase at 3 percent per year reflects an estimate that they will escalate at 3 percent faster than general inflation levels (the rate of the GNP deflator). The purpose of the escalation is to provide a common reference point in time for financial comparison with the future revenues and costs of the project which are discounted to the year of initial production.

For convenience, the unit exploration costs (per barrel oil and per 2.5 mcf gas) have been summarized for all of the permutations (5 reserve levels, 2 cost levels, 2 activity levels) in Table 3-3. From this table, it can be seen that the unit costs for low (cautious) exploration activity generally fall within a band of $0.40 to $0.80 per unit reserve located; the band limits correspond to the low and high component costs.

Exploratory costs are charged as an expense that reflects the entire pool of exploration activities of the oil producer, and are not amortized directly by the individual field that incurs them. Exploratory costs thus enter the cost base used to determine the relation between market price and return on investment indirectly through the tax status of an oil producer. Consequently, since exploration costs are not a direct determinant in the decision to develop a field after the discovery has been made, they will not be reflected further in the analysis of the economic feasibility of the scenarios. The assumptions regarding the tax status of oil producers will be discussed in the section entitled "Investment Framework" (Section 3.5).

3.4 INVESTMENT REQUIREMENTS FOR FIFTEEN SCENARIOS

Tables 3-5 through 3-9 represent five sets of tables, one set for each reserve level (building block), which: (a) summarize the major developmental

TABLE 3-5A

DEVELOPMENT SUMMARY - 3.5 BILLION BARREL RESERVE

FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 large	1.2	4	3	140	22
2 medium	0.8	2	2	85	72
	0.6	2	2	75	10
4 small	0.3	1	2	50	8
	0.2	1	1	30	8
	0.2	1	1	30	8
	0.2	1	1	30	8
	3.5	12	12	440	76

Max, output, 1.1 MMBD, 1.3 bcfd

Tracts held 20

TABLE 3-5B

HIGH COST INVESTMENT REQUIREMENTS FOR 3.5 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)			490	5.5	641
Gravity Structures @ 15m (50 ft.)		2 @ $65			
Gravity Structures @ 6m (20 ft.)		6 @ $40			
Gravel Islands @ 4.5m (15 ft.)		4 @ $30			
Production Wells (each)		60 @ $10	600	4.5	747
		380 @ $ 6	2,280	2.5	2,576
Development Wells (each)		76 @ $6	456	2.5	515
Processing equipment (MBD)		1,100 @ $ 0.7	770	0.5	789
Gas Plant (100 mmcfd)		13 @ $14	182	0.5	187
Offshore Oil Lines kilometers (miles)	EAST	113 @ $ 4.9 (70 @ $ 8)	560	1.5	603
	CENTRAL	113 @ $ 4.9 (70 @ $ 8)	560	1.5	603
	WEST	169 @ $ 4.9 (105 @ $ 8)	840	1.5	904
Onshore Oil Lines kilometers (miles)	EAST	145 @ $ 6.8 (90 @ $11)	990	2.5	1,118

TABLE 3-5B (Cont.)

HIGH COST INVESTMENT REQUIREMENTS FOR 3.5 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION{ TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 6.8 (24 @ $11)	264	1.5	298
	WEST	274 @$ 6.8 (170 @ $11)	1,870	2.5	2,113
Gas Lines (kilometers) (miles)	EAST	)	1,085		1,205
	CENTRAL	) @ 70% of) oil lines	577		631
	WEST	)	1,348		2,112
Roads (kilometers) (miles)	EAST	145 @ $0.25 (90 @ $0.4)	36	5.5	47
	CENTRAL	39 (?$0.19 (24 @ $0.3)	7	5.5	9
	WEST	274 @ $0.25 (170 @ $0.4)	68	5.5	89
Harbor, Base camp (each)		1 @ $40	40	5.5	52
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9-5}$

TABLE 3-5C

LOW COST INVESTMENT REQUIREMENTS FOR 3.5 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)			250	5.5	327
Gravity Structures @ 15m (50 ft.)		2 @ $35			
Gravity Structures @ 6m (20 ft.)		6 @ $20			
Gravel Islands @4.5m (15 ft.)		4 @ $15			
Production Wells		60 @ $ 8	480	4.5	598
		380 @ $ 3	1,140	2.5	1,288
Development Wells (each)		76 @ $ 3	228	2.5	254
Processing Equipment (MBD)		1,100 @ $ 0.5	550	0.5	564
Gas Plant (100 mmcfd)		13 @ $10	130	0.5	133
Offshore Oil Lines (kilometers) (miles)	EAST	113 @ $ 4.9 (70 @ $ 8)	560	1.5	603
	CENTRAL	113 @ $ 4.9 (70 @ $ 8)	450	1.5	603
	WEST	169 @ $ 4.9 (105 @ $ 8)	840	1.5	904
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5.6 (90 @ $ 9)	810	2.5	915

TABLE 3-5C (Cont.)

LOW COST INVESTMENT REQUIREMENTS FOR 3.5 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 5.6 (24 @ $ 9)	216	1.5	232
	WEST	274 @ $ 5.6	1.530	2.5	1,728
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	959	2.5	641
	CENTRAL		543	1.5	585
	WEST		1,659	2.5	1,842
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	42
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.16 (170 @ $ 0.25)	60	5.5	78
Harbor, Base camp (each)			22	5.5	29
Booster Station (each)	WEST only		6	5.5	8

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X (1 .08)9.5

TABLE 3-6A

DEVELOPMENT SUMMARY - 2.3 BILLION BARREL RESERVE

FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 large	1.2	4	3	140	22
2 medium	.6	2	2	75	10
	.3	1	2	50	8
2 small	.2	1	1	30	8
	2.3	8	8	295	48

Max, output, 0.7 MMBD Oil

0.9 bcfd Gas

Tracts held 12-16

TABLE 3-66

HIGH COST INVESTMENT REQUIREMENTS FOR 2.3 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)			325	5.5	426
Gravity Structures @ 15m (50 ft.)		1 @ $65			
Gravity Structures @ 6m (20 ft.)		5 @ $40			
Gravel Islands @ 4.5m (15 ft.)		2 @ $30			
Production Wells (each)		40 @ $10	400	4.4	498
		255 @ $ 6	1,530	2.5	1,730
Development Wells (each)		48 @ $ 6	288	2.5	325
Processing Equipment (MBD)		700 @ $ 0.7	490	0.5	502
Gas Plant (100 mmcfd)		9 @ $14	126	0.5	129
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	46 @ $ 5 (60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5.6 (90 @ $ 9)	810	2.5	915

TABLE 3-6B (Cont.)

HIGH COST INVESTMENT REQUIREMENTS FOR 2.3 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 5.6 (24 @ $ 9)	216	1.5	232
	WEST	274 @ $ 5.6 (170 @ $ 9)	1,530	2.5	1,730
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	791		881
	CENTRAL		375		403
	WEST		1,410		1,850
Roads (kilometers) (miles)	EAST	145 @ $ 0.25 (90 @ $ 0.4)	36	5.5	47
	CENTRAL	39 @ $ 0.19 (24 @ $ 0.3)	7	5.5	9
	WEST	113 @ $ 0.25 (70 @ $ 0.4)	68	5.5	89
Harbor, Base camp (each)		7 @ $40	40	5.5	52
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE 3-6C

LO° COST INVESTMENT REQUIREMENTS FOR 2.3 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)			165	5.5	216
Gravity Structures @ 15m (50 ft.)		1 @ $35			
Gravity Structures @ 6m (20 ft.)		5 @ $20			
Gravel Islands @ 4.5m (15 ft.)		2 @ $15			
Production Wells (each)		40 @ $ 8	320	4.5	399
		255 @ $ 3	765	2.5	864
Development Wells (each)		48 @ $ 3	144	2.5	163
Processing Equipment (MBD)		700 @ $ 0.5	350	0.5	359
Gas Plant (100 mmcfd)		9 @ $10	90	0.5	92
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	96 @ $ 5 (60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5 (90 @ $ 8)	720	2.5	813

TABLE 3-6C (Cont.)

LOW COST INVESTMENT REQUIREMENTS FOR 2.3 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 5 (24 @ $ 8)	192	1.5	207
	WEST	168 @ $ 5 (105 @ $ 8)	840	2.5	949
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	728		810
	CENTRAL		358		385
	WEST		924		1,030
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	42
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.22 (170 @ $ 0.35)	60	5.5	78
Harbor, Base camp (each)			22	5.5	29
Booster Station (each)	WEST only		6	5.5	8

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE 3-7A

DEVELOPMENT SUMMARY - 1.2 to 1.5 BILLION BARRELS RESERVE

	FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
I.	1 large	1.1	4	3	130	20
	2 small	0.2	1	1	30	8
		0.2	1	1	30	8
		1.5	6	5	190	36

Tracts held 9 - 12

Max Output, 1.5 MMBD Oil; 0.6 bcfd Gas

	FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
II.	1 medium	0.8	2	2	100	15
	1 small	0.4	2	2	60	10
		1.2	4	4	160	25

Tracts held 6 - 8

Max output 0.4 MMBD Oil; 0.46 bcfd Gas

III. Scenario Composite: 1.4 billion BBL

3 units, 5 platforms, 16 exploration platforms, 180 production wells;

30 development wells.

Max output: 0.45 MMBD: 0.5 bcfd Gas

TABLE 3-76

HIGH COST INVESTMENT REQUIREMENTS FOR 1.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)			215	5.5	282
Gravity Structures @ 15m (50 ft.)		1 @ $65			
Gravity Structures @ 6m (20 ft.)		3 @ $40			
Gravel Islands @ 4.5m (15 ft.)		1 @ $30			
Production Wells (each)		40 @ $10	400	4.5	498
		140 @ $ 6	840	2.5	949
Development Wells (each)		30 @ $ 6	180	2.5	203
Processing Equipment (MBD)		450 @ $ 0.7	315	0.5	323
Gas Plant (100 mmcfd)		5 @ $14	70	0.5	72
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	96 @ $ 5 (60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5.6 (90 @ $ 9)	810	2.5	915

TABLE 3-7B (Cont.)

HIGH COST INVESTMENT REQUIREMENTS FOR 1.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 5.6 (24 @ $ 9)	216	1.5	232
	WEST	274 @ $ 5.6 (170 @ $ 9)	1,530	2.5	1,730
Gas Lines (kilometers) (miles)	EAST	@ 70 % of oil lines	791		881
	CENTRAL		375		403
	WEST		1,410		1,850
Roads (kilometers) (miles)	EAST	145 @ $ 0.25 (90 @ $ 0.4)	36	5.5	47
	CENTRAL	39 @$ 0.19 (24 @ $ 0.3)	7	5.5	9
	WEST	113 @ $ 0.25 (70 @ $ 0.4)	68	5.5	89
Harbor, Base camp (each)		1 @ $40	35	5.5	46
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X (?.08)$^{9''5}$

TABLE 3-7C

LOW COST INVESTMENT REQUIREMENTS FOR 1.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each			110	5.5	144
Gravity Structures @ 15m (50 ft.)		1 @ $35			
Gravity Structures @ 6m (20 ft.)		3 @ $20			
Gravel Islands @ 4.5m (15 ft.)		1 @ $15			
Production Wells (each)		40 @ $ 8	320	4.5	399
		140 @ $ 3	420	2.5	474
Development Wells (each)		30 @ $ 3	90	2.5	102
Processing Equipment (MBD)		450 @ $ 0.5	225	0.5	231
Gas Plant (100 mmcfd)		5 @ $10	50	0.5	51
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	96 @ $ 5 (60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5 (90 @ $ 8)	720	2.5	813

TABLE 3-7C (Cont.)

LOW COST INVESTMENT REQUIREMENTS FOR 1.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 5 (24 @ $ 8)	192	1.5	207
	WEST	168 @ $ 5 (105 @ $ 8)	840	2.5	949
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	728		810
	CENTRAL		358		386
	WEST		924		1,030
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	41
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.22 (170 @ $ 0.35)	60	5.5	78
Harbor, Base camp (each)			8	5.5	24
Booster Station (each)	WEST only		6	1.5	6

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base x $(1.08)^{9.5}$.

TABLE 3-8A

DEVELOPMENT SUMMARY - 0.7 BILLION BARREL RESERVE

FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 medium	0.7	2	2	90	13

Tracts held 2 - 3

Max output, 0.2 MMBD Oil; 0.3 bcfd Gas

TABLE 3-8B

HIGH COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)			95	5.5	124
Gravity Structures @ 15m (50 ft.)		1 @ $65			
Gravel Islands @ 4.5m (15 ft.)		1 @ $30			
Production Wells (each)		20 @ $10	200	4.5	249
		70 @ $ 6	420	2.5	474
Development Wells (each)		13 @ $ 6	78	2.5	88
Processing Equipment (MBD)		200 @ $ 0.7	140	0,5	144
Gas Plant (100 mmcfd)		3 @ $14	42	0.5	43
Offshore Oil Lines (kilometers) (miles)	EAST	32 @ $ 5 (20 @ $ 8)	160	1.5	172
	CENTRAL	32 @ $ 5 (20 @ $ 8)	160	1.5	172
	WEST	32 @ $ 5 (20 @ $ 8)	240	1.5	258
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712

TABLE 3-8B (Cont.)

HIGH COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	181
	WEST	274 @ $ 4.3 (170 @ $ 7)	1,190	2.5	1,340
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	553		619
	CENTRAL		230		248
	WEST		1,000		1,120
Roads (kilometers) (miles)	EAST	145 @ $ 0.25 (90 @ $ 0.4)	36	5.5	47
	CENTRAL	39 @ $ 0.19 (24 @ $ 0.3)	7	5.5	9
	WEST	274 @ $ 0.25 (170 @ $ 0.4)	68	5.5	89
Harbor, Base camp (each)		1 @ $40	35	5.5	46
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE 3-8C

LOW COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)			50	5.5	66
Gravity Structures @ 15m (50 ft.)		1 @ $35			
Gravel Islands @ 4.5m (15 ft.)		1 @ $15			
Production Wells (each)		20 @ $ 8	160	4.5	199
		70 @ $ 3	210	2.5	237
Development Wells (each)		13 @ $ 3	39	2.5	44
Processing Equipment (MBD)		200 @ $ 0.5	100	0.5	103
Gas Plant (100 mmcfd)		3 @ $10	30	0.5	31
Offshore Oil Lines (kilometers) (miles)	EAST	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	CENTRAL	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	WEST	48 @ $ 5 (30 @ $ 8)	240	1.5	259
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712

TABLE 3-8C (Cont.)

LOW COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	181
	WEST	274 @ $ 4.3 (170 @ $ 7)	1,190	2.5	1,340
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	553		620
	CENTRAL		230		248
	WEST		1,001		1,119
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	41
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.22 (170 @ $ 0.35)	60	5,5	78
Harbor, Base camp (each)			18	5.5	24
Booster Station (each)	WEST only		6	1.5	6

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE 3-9A

DEVELOPMENT SUMMARY - 0.4 BILLION BBL RESERVE

FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 small	0.4	2	1	50	10

Tracts held 2

Max output, 0.1 MMBD Oil; 0.15 bcfd Gas

TABLE 3-9B

HIGH COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - $ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms each)		@ $40	30	5.5	52
Production Wells (each)		20 @ $10	200	4.5	249
		30 @ $ 6	180	2.5	203
Development Wells (each)		10 @ $ 6	60	2.5	68
Processing Equipment (MBD)		100 @ $ 0.7	70	0.5	72
Gas Plant (100 mmcfd)		2 @ $14	28	0.5	29
Offshore Oil Lines (kilometers) (miles)	EAST	32 @ $ 5 (20 @ $ 8	160	.5	172
	CENTRAL	32 @ $ 5 (20 @ $ 8	160	.5	172
	WEST	48 @ $ 5 (30 @ $ 8)	240	1.5	258
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	81
	WEST	274 @ $ 4.3 (170 @ $ 7)	1,190	2.5	1,340

TABLE 3-9B (Cont.)

HIGH COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	553		619
	CENTRAL		230		247
	WEST		1,000		1,120
Roads (kilometers) (miles)	EAST	145 @ $ 0.25 (90 @ $ 0.4)	36	5.5	47
	CENTRAL	39 @ $ 0.19 (24 @ $ 0.3)	7	5.5	9
	WEST	274 @ $ 0.25 (170 @ $ 0.4)	68	5.5	89
Harbor, Base camp (each)		1 @ $40	40	5.5	52
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE 3-9C

LOW COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Production Platforms (each)		1 @ $20	20	5.5	26
Production Wells (each)		20 @ $ 8	160	4.5	200
		30 @ $ 3	90	2.5	102
Development Wells (each)		10 @ $ 3	30	2.5	34
Processing Equipment (MBD)		100 @ $ 0.5	50	0.5	51
Gas Plant (100 mmcfd)		2 @ $10	20	0.5	21
Offshore Oil Lines (kilometers) (miles)	EAST	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	CENTRAL	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	WEST	48 @ $ 5 (30 @ $ 8)	240	1.5	259
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	181
	WEST	274 @ $ 4.3 (170 @ $ 7)	1,190	2.5	1,340

TABLE 3-9C (Cont.)

LOW COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST*
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	553		620
	CENTRAL		230		248
	WEST		1,001		1,119
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	41
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.22 (170 @ $ 0.35)	60	5.5	78
			16	5.5	21
			6	1.5	6
Harbor, Base camp (each)			16	5.5	21
Booster Station (each)	WEST only		6	1.5	6

*Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

requirements as described in Chapter II, (b) itemize the high cost investment requirements for the three geographic locations, and (c) itemize the low cost investment requirements for the same three locations. The investment requirements are obtained by multiplying the developmental requirements by the appropriate “unit costs”, which are the capital cost assumptions already detailed in Table 3-1.

Again, the base costs (expressed in constant 1975-76 dollars) have been escalated to the date of initial production at the rate of 5% per annum to reflect the “net opportunity loss” of capital over and above general inflation. A discussion of the rationale for this assumption was included in the preceding section on “Exploration Costs.”

From Tables 3-5 through 3-9, it can be seen that for any given building block, the itemized costs of development are independent of location, with the exception of pipelines and roads. Thus, each of 5 sets of investment tables (one for each reserve level) yields three geographically specific cost summaries. These are shown for each of the resulting 15 scenarios in the Summary Table 3-10.

The unit investment requirements (per barrel of oil or per 2.5 mcf of gas) for each of the fifteen scenarios are shown in Table 3-11. The unit totals were obtained by dividing the total investment figures of Table 3-11 by the appropriate reserve sizes. The unit investment for

TABLE 3-10

SUMMARY OF INVESTMENT REQUIREMENTS*
($Millions-1975-76)

		High Cost	Low Cost
West	3.5 Bbbl	$ 10,734	$ 7,753
	2.3 Bbbl	7,856	4,703
	1.4 Bbbl	6,521	4,004
	0.7 Bbbl	3,984	3,506
	0.4 Bbbl	3,528	3,257
Central	3.5 Bbbl	$ 7,048	$ 4,621
	2.3 Bbbl	4,650	3,066
	1.4 Bbbl	3,361	2,370
	0.7 Bbbl	1,778	1,310
	0.4 Bbbl	1,321	1,065
East	3.5 Bbbl	$ 8,480	$ 5,394
	2.3 Bbbl	5,858	4,131
	1.4 Bbbl	4,560	3,433
	0.7 Bbbl	2,718	2,250
	0.4 Bbbl	2,262	2,001

*Geographic cost summaries derived from Tables 3-5 through 3-9

Table 3-11

SUMMARY OF UNIT INVESTMENT REQUIREMENTS
($1975-76 per barrel oil, per 2.5 mcf gas)

		High Cost			Low Cost		
		Oil	Gas (2)	Total (1)	Oil	Gas (2)	Total (1)
West	3.5 Bbbl	2.28	.79	3.07	1.58	.64	2.22 (3
	2.3 Bbbl	2.42	1.00	3.42	1.48	.56	2.04 (3
	1.4 Bbbl	3.14	1.52	4.66	2.00	.86	2.86
	0.7 Bbbl	3.88	1.81	5.69	3.27	1.74	5.01
	0.4 Bbbl	5.77	3.05	8.82	5.18	2.96	8.14
Central	3.5 Bbbl	1.65	.36	2.01	1.04	.28	1.32
	2.3 Bbbl	1.66	.36	2.02	1.05	.28	1.33
	1.4 Bbbl	1.92	.48	2.40	1.30	.39	1.69
	0.7 Bbbl	1.98	.56	2.54	1.40	.48	1.88
	0.4 Bbbl	2.45	.85	3.30	1.90	.77	2.67
East	3.5 Bbbl	1.89	.53	2.42	1.25	.29	1.54
	2.3 Bbbl	1.98	.57	2.55	1.33	.47	1.80
	1.4 Bbbl	2.43	.83	3.26	1.76	.69	2.45
	0.7 Bbbl	2.79	1.09	3.88	2.19	1.02	3.21
	0.4 Bbbl	3.88	1.78	5.66	3.30	1.70	5.00

(1) Obtained by dividing total investment requirements shown in Table 3-10 by appropriate field sizes.

(2) Gas allocated 10% of shared costs

(3) Unit price variation reflects utilization of offshore lines assumed in scenaric

gas was obtained by adding the total investment requirements for the gas plant and gas lines, plus an arbitrary allocation of 10 percent of the “shared” investment (platforms, wells, roads, harbor and base camp), and then dividing by the total reserves. Subtracting the unit investment requirements for gas from the total unit investment yielded the unit investment requirements for oil.

Examination of Table 3-11 reveals a number of significant cost relationships. First, the unit costs tend to increase as the hypothetical reserve levels decrease, since there are fewer “units” over which to amortize fixed investment. Second, the unit costs for any given reserve level are uniformly lowest in the central location and highest in the western location, with the eastern location always falling in the intermediate position. This latter relationship is a reflection of the relative distances to the central interconnection near Prudhoe Bay, with the west averaging 274 kilometers (170 miles), the east 145 kilometers (90 miles), and the central location 39 kilometers (24 miles). In fact, the relative investment requirements are closely proportional to the length of connecting pipeline since pipeline investment represents such a large proportion of total cost. Pipeline investment as a percentage of total investment is roughly 50 percent in the western and eastern locations (always greater in the west) and roughly 33 percent in the central location.

Table 3-12 represents a summary of the recalculated unit investment requirements for oil for these scenarios with insufficient gas reserves

TABLE 3-12

UNIT OIL INVESTMENT REQUIREMENTS
FOR SCENARIOS WITH INSUFFICIENT
GAS RESERVES FOR DEVELOPMENT*
($1975-76 per barrel oil)

Scenario Location	Reserve Level	High Cost Investment	Low Cost Investment
West	2.3 Bbbl	$ 2.47	NA
	1.4 Bbbl	3.20	NA
	0.7 Bbbl	3.95	$3.33
	0.4 Bbbl	5.88	5.26
East	0.7 Bbbl	2.86	2.24
	0.4 Bbbl	3.97	3.37

* Oil carries total burden of investment -- gas production facilities excluded and shared costs reapplied to oil investment requirements.

to warrant development. It was found in the parametric market price analysis (see upcoming section entitled "Required Market Price") that the gas for these scenarios would have to sell for more than $10/unit (greater than $4.00/mcf) to justify the required investment, and that such a market price (in constant dollars) would exceed the feasible market limit as determined by the research staff. Consequently, the unit investment requirements for oil for these particular scenarios was then recalculated by: (1) removing the costs for the gas plant and gas lines, (2) reapplying the 10 percent gas allocation of shared investment for such items as platforms, wells, roads, harbor and base camp to the total oil investment, and (3) dividing by the appropriate reserve size.

3.5 INVESTMENT FRAMEWORK

3.5.1 Introduction

Thus far, the analysis has developed the unit investment requirements for the fifteen scenarios under both high cost and low cost assumptions. Moreover, the investments have been escalated to the point in time of initial production, which has been assumed to take place approximately 10 years after the lease sale. As stated previously, this date is the single reference point in time against which all future revenues and costs are ultimately compared in the determination of economic feasibility. The analysis will now shift its focus toward these future revenues and costs, as well as the analytical framework by which the economic comparison can be made.

The investment requirements for each scenario are statements of the total capital investment needed to bring the Beaufort Sea OCS oil and gas to the point of interconnection with Alyeska and the proposed natural gas pipeline. As such, subtracting the cost of transportation from Prudhoe Bay to the assumed market (i.e. Los Angeles), as well as the costs of operating the oil and gas fields (i.e. labor, supplies, etc.), from an assumed market price (i.e. West Coast delivered crude) will yield the return on the scenario investment. This return is a "stream" of money arriving in the future, whose rate of flow may be constant or variable, and which must be "brought back" in time to the point of investment. This process is called "discounting" and is developed more fully in the next few pages of this report. The return on fixed investment will determine the attractiveness of the investment to a profit making body. This description can be summarized as follows:

Market Price

Less: Transportation Cost:

Alyeska Pipeline

Tanker to West Coast

Less: Oil Field Operating Costs

Less: Royalty (1/6) to Federal Government

Equals: Return on Fixed Investment: a future "stream" of money to be discounted at a given rate-of-return

Similar generalized equations could be stated for natural gas moving to market through the proposed trans-Canadian pipeline.

The analysis now proceeds to assign specific values (or a range of parametric values) to the four major elements in the generalized equation above: market price, transportation cost, field operating cost and return on investment.

3.5.2 Market Price

No specific market price levels have been assigned; rather, the next major section of the report is devoted to a parametric analysis of the required market prices needed to achieve a desired rate of return, given an assumed tax status, transportation tariff, and level of investment.

The presumed market for the Beaufort Sea OCS oil is southern California, which in 1976 supported a price level of $13/barrel. Midwestern markets in the same time period supported market prices of nearly $14/barrel. Since all costs and revenues in this analysis are stated in terms of constant 1975-76 dollars, the only justification for presuming acceptance of market prices above the $13-14/barrel (constant 1975-76 dollars) level is that oil prices will rise faster than general inflation. No such assumption has been made in this analysis, although the required market prices of up to $17/barrel (constant 1975-76 dollars) have been included in order to explore the economic feasibility of the scenarios under a full range of future contingencies.

U.S. Interstate gas prices are currently regulated at $1.44/mcf, which corresponds to prices of the order $4/unit (2.5 mcf/unit). A market level of $6-7/unit (constant 1975-76 dollars) is perhaps more realistic for the Beaufort OCS scenarios as it is comparable to the basis of delivery for the proposed gas pipeline from the North Slope. Even higher levels are not implausible; an $8/unit market (constant 1975-76 dollars) corresponds to some currently requested allowances for imported gas. Again, to allow some latitude in the analysis for the possibility of future escalation in gas prices (in real dollars), required market prices of up to $10/unit were included in the parametric analysis.

3.5.3 Present Worth Factors

Return on fixed investment represents revenue that will be derived subsequent to the start of production, money that will flow to the investor as a “time-revenue stream” over a 20-year period. As such, its value must be brought back (reduced through discounting) to the time of initial production, at a desired rate of return. This rate of return is a subjective assessment of the investors’ options, historical practice, and preference for risk; and several incremental rates between 5 percent and 25 percent will be evaluated in the subsequent analysis of required market price.

The future stream of oil and gas revenues assumed in this analysis are a direct function of the production profiles depicted in Chapter II, which were drawn from the H.K. van Poollen studies (Section 2.3.3). For oil, the assumed production curve reaches a maximum in years 2 through 7, and thereafter falls off exponentially; thus, the total revenue stream tends to “return” to the investor relatively rapidly. Conversely, the gas production profile can be represented by a “flat” curve with production (and therefore the “return” of the revenue stream) maintained at a constant level for years 3 through 20.

It is conventional practice to evaluate a potential investment, or to compare various investment options, through an analysis of the “present worth” of the future stream of revenues and costs . Present worth is the “value” today of $1.00 received in a future year, a value diminished (discounted) by an assumed rate of annual interest over the intervening years. Conversely, it is that amount today that if invested at the assumed compounded annual interest rate would equal $1.00 in the future year. In this analysis, the discounted cash flow is treated by simultaneously calculating (integrating) the present worth of the revenue and cost streams relative to the start of production; separate discounting of revenues and costs (normal discounted cash flow procedure) was not carried out as costs and revenues were presumed to be proportional. As such, the presumption implies that all costs and revenues are concurrent; that is, that the revenues derived from selling a barrel of oil and the associated costs of producing the barrel of oil occur at the same time.

This is certainly true for transportation costs, which represent the bulk of costs for North Slope oil; but is only an approximation for field operating costs. The major changes to be considered in operating cost are the unit-cost increases toward the end of the life of the field. Because this is the period that is most strongly discounted, and because operating costs are only minor portions of total cost, the influence of this approximation is negligible.

Table 3-13 shows the present worth factors used in the economic analysis of the Beaufort Sea OCS scenarios. The present worth factors can be used to take a future stream of money and bring it back into today's purchasing power. Multiplying future revenue by the present worth factor gives its investment potential at the start of production. Conversely, dividing the required investment (escalated to the start of production) by the present worth factor gives the future revenue that must be generated (over the given time period and at a given interest rate) to justify the investment.

It should be noted that the present worth factors have been calculated for two assumed after-tax rates: an effective tax rate of 35 percent and an effective tax rate of 10 percent. The former is a typical domestic tax rate for an oil company with nominal deductions; the latter for an oil company with substantial deductions. Exploration costs

TABLE 3-13

SUMMARY OF PRESENT WORTH FACTORS

	Rate of Return	Present Worth Factors: 20 year Pretax	After 10% Tax	After 35% Tax
Factors for Oil Development	5%	.75	.73	.66
	10%	.59	.56	.47
	15%	.48	.45	.36
	20%	.40	.37	.29
	25%	.34	.32	.24
Factors for Gas Development (Years 3-20)	5%	.60	.572	.476
	10%	.40	.364	.246
	15%	.28	.248	.173
	20%	.20	.181	.121
	25%	.16	.138	.090
Factors for Delayed Gas Development (Years 21-38)	5%	.2450	.2144	.1252
	10%	.0677	.0547	.0340
	15%	.0208	.0154	.0041
	20%	.0070	.0049	.0010
	25%	.0028	.0017	.0003

Factors for Interstate Pipeline Projects

Pretax Return	18 yr	20 yr	22 yr	24 yr	26 yr	28 yr
7%	.56	.53	.50	.48	.45	.43
10%	.46	.43	.40	.37	.35	.33

generally make up a substantial portion of the Deductions taken by an oil producer. For this reason, the exploration costs, which were calculated earlier, are not employed directly in the analysis; but rather are reflected indirectly through the effective tax rates. The effective rates assumed for the analysis, 10 percent and 35 percent, respectively, provide an "envelope" around the estimated industry average. The nominal domestic tax rate for the oil industry is estimated at around 28 percent, although this figure is not verifiable. The only verifiable rate (Chase Manhattan Bank, 1977) is that the average total tax rate for the oil industry, which includes foreign taxes, is in excess of 50 percent.

Only after-tax rate of return to the invester is carried out in the analysis of required market prices. By implication, the total return on investment must include enough revenue to cover income tax and still yield the desired after-tax return. For example, if an invester desires 25 percent, and he has an effective tax rate of 35 percent, then the total return required is:

$$= \frac{\text{After-Tax Rate}}{(1\text{-Effective Tax Rate})}$$

$$\text{Total Return} = \frac{25\%}{(1-.35)} = 38.5\%$$

3.5.4. Transportation Costs

3.5.4.1 Oil Transportation Costs

The delivery system used in the economic analysis is a pipeline to the south of Alaska with subsequent tanker transport to southern California entry. For the purposes of scenario analysis, an estimate of the tariff on the Alyeska system has been utilized. If Alyeska is expanded to 2 MMBD by 1980, through the use of additional pump stations, then by 1986-87, the production curve from a 9.6 billion barrel reserve will begin to decline. By 1990, Alyeska will have an excess capacity of 1 MMBD, a level fully adequate to absorb the oil from any of the scenarios in question.

The costs of transferring oil from the point of interconnection with Alyeska near Prudhoe Bay to the U.S. West Coast can be estimated as the sum of two components:

o Pipeline Tariff, which includes:

  capital costs (investment amortization, and interest or profit from which income taxes can be drawn)

  operating costs (energy, labor, and ad valorem taxes or duties for a pipeline across Alaska)

o Tanker Costs, which include terminal charges not covered in the pipeline tariff.

The estimated pipeline tariff used in the analysis is $4.50/barrel (constant 1975 dollars); the figure was drawn from projections provided by the Oil and Gas Journal (June 7, 1976). More recent estimates of eventual transport costs for Prudhoe Bay oil range from $6 - $6.50/barrel (Wall Street Journal, April 15, 1977). The latter figure represents a 6 percent annual escalation between 1975 and 1978, and is well within the framework of economic assumptions. Scale effects on unit cost with different volumes of flow and distance have not been considered in the analysis but could be included as percentage changes where desired. Such effects may not all be negative with increasing flow volumes. For example, the unit operating cost for pushing the Alyeska line to 2 million b/d may be higher. However, similar pipeline operating costs for a North Slope to Nome link would be lower because of the lesser distance.

Nome is mentioned as an alternative port, site both in the specific sense, and in the generic sense, as any port northward of the Aleutian chain. All of this area has difficult sea and ice conditions, but a recent study (Arctic Institute of North America, 1973) indicated that Nome could be maintained as a year-round port with ice breakers.

The costs of tanker transport between southern Alaska and southern California have been estimated in the analysis at $0.90 per barrel (constant 1975 dollars). This is within the range of published estimates. Tanker charges were estimated by Arthur D. Little, Inc. (1976) at $3.00

to $6.50 per long ton ($0.40 to $1.00 per barrel) for U.S. flag carriers from the Gulf of Alaska to Long Beach, California. Transport costs were projected at $0.80 to $1.00 per barrel for the Valdez - Long Beach link by the Oil and Gas Journal (June 7, 1976). The assumed transport charge of $0.90 per barrel from south Alaska covers the loading, unloading, and terminal costs to the point of entry (P.O.E.) market that are not included in the pipeline tariff. Fluctuations of costs with throughput, and projected improvements in average tanker fleet productivity will be ignored for purposes of the Beaufort Sea scenario analysis. Transport costs from the Nome area to southern California are estimated to be about 10 percent greater than from the Gulf of Alaska, about $1.00 per barrel (1975 dollars).

3.5.4.2 Gas Transportation Costs

The Beaufort Sea OCS gas is assumed to be transported either by a trans-Canada route, or by tanker to the U.S. West Coast*. The tanker route requires liquefaction of the gas, with subsequent regasification at the port of entry (U.S. West Coast).

The transportation costs for gas are considered parametrically in 1975 dollars. Based upon published estimates of the proposed Arctic and El Paso gas line systems, costs of $1.65 to $1.85/mcf would be involved in

*At the time of writing, a decision had not been reached on selection of one of the three gas pipeline transportation proposals for Prudhoe Bay gas. Subsequently, the Alcan (Northwest) proposal has been approved by the President and Congress.

transporting gas in systems of 2.5 to 3.0 billion cubic feet per day over a 26-year life (corresponding to reserves of 24 to 29 tcf). This range is used as the primary gasline tariff in the analysis. In addition, a low tariff of $1.25 to $1.40/mcf, and a high tariff of $1.95 to $2.10/mcf were considered to provide information on the sensitivity of market price to tariff levels. The high tariff range corresponds to a line with costs of $10 to $12 billion and reserve levels of 20 to 24 tcf. The low tariff range corresponds to systems of $6 to $7 billion and reserve levels of 28-30 tcf. The low range should not be considered to correspond to achievable cost performance.

The gas line tariffs used in the analysis imply that the Beaufort OCS reserves can be transported without delay along with those gas reserves already committed to the proposed lines. The Prudhoe Bay reserves of 24 tcf require a capacity of 2.5 bcfd over 26 years. An additional flow of 0.5-1.0 bcfd could be accommodated in the same diameter pipe by increasing the system pressure.

It is conceivable that gas reserves other than those in the Beaufort OCS lease-sale area will be discovered first and will contract for the expanded capacity in the proposed gas lines (up to 10 tcf additional capacity). In such a case, the Beaufort OCS gas would have to be transported by a second line. This contingency has been explored in the analysis, and the appropriate tariffs have been calculated for a system with an 18-year life. For the largest reserve level (3.5 Bbbl oil, 8.7-

9.0 tcf), a tariff of \$2.60-\$2.90/mcf has been determined for a \$7.5-\$8.7 billion system in the following manner.

$$\text{Gas Tariff} = \frac{\text{system investment}}{\text{Reserve Size}} + \text{system unit operating cost}$$

$$= \frac{\$8.7 \times 10^9}{8.5 \times 10^9 \text{ mcf}} \left(\frac{1}{.46}\right) + \$0.65/\text{mcf} = \$2.92/\text{mcf},$$

where

.46 is the present worth factor of an 18-year pipeline, 10 percent return (10 percent is based upon the pass through of bonded interest cost rather than the regulated 7 percent return rate). \$0.65/mcf is the assumed operating costs of the Arctic line in 1975 dollars.

Gas is used as an energy source for transport in both overland and LNG modes. Consequently, some shrinkage of the supply will occur. This shrinkage has not been considered directly in the analysis. At the eventual market, there will be an adjustment in the "real" market price, relative to the "parametric" markets used in the analysis to account for the appropriate shrinkage.

3.5.4.3 Transportation Cost for Delayed Gas

In considering the various gas transport systems which could be projected as available for the Beaufort Sea OCS production, it has been noted that saturation of the proposed delivery systems might occur, as a result of unforeseen production volumes in Prudhoe Bay and elsewhere which could be committed to the system before the Beaufort production were to begin. Such saturation might occur despite the ability of the proposed systems to provide capacity expansions. If the line were saturated, and if the Beaufort Sea OCS explorations were to be only moderately successful, (i.e. insufficient amounts to warrant a second line), then the reserves would have to await delayed delivery.

An estimate of the returns available from delayed production of the gas is given in the market price analysis section to follow. The returns are predicated upon "bargain" pipeline tariffs ($0.10 to 0.25/mcf which would result from the purchase of a used line some 20 years in the future). These returns indicate that the delay does not necessarily mean the resource would be economically lost, rather only that the available rates of return would be lowered to the present field developer. Delayed production of gas reserves is considered as a "worst case" assumption that is used to illustrate a situation creating maximum impact in terms of project length. The indicated rates of return are only approximate lower bounds since they were extrapolated from the development costs as shown in Table 3-14. A more complete analysis would have to explore:

- o The timing of the gas pipeline and gas plant investment
- o The potential acquisition and conversion of the oil connecting line

- 0 Partial gas production during the delay period

- 0 Sale of the gas rights for future delivery to a secondary investor, such as a utility, and the appropriate prices.

Except for the alternative of converting an oil line at bargain costs, the above options do not have any potential for increasing rates of return above those indicated from immediate gas production. It is also to be noted here that the given returns for delayed gas are dependent upon delivery in a “used” transport system, i.e., upon bargain interstate tariffs.

From the present worth factors for delayed gas, it can be seen that the market level (in constant dollars) to increase the rate of return from 5 percent to 10 percent must increase by greater than a factor of four. It is evident that production delay is costly, and that no investor could be expected to profit by holding the gas for delayed delivery.

3.5.5 Field Operating Costs

The field operating costs for producing oil from the Beaufort Sea reservoirs with a water drive has been estimated at $1.00 per barrel from discussions with industry personnel (Alaska Oil and Gas Association, 1977). Similarly the field operating costs for gas have been estimated at $0.08 per mcf. ($0.20/unit, where a unit uquals 2.5 mcf). Several

TABLE 3-14A

REQUIRED MARKET PRICE[1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas[2])

	High Tax Producer Desired Rate of Return on Investment[3]					Low Tax Producer Desired Rate of Return on Investment[3]				
	25%	20%	15%	10%	5%		20%	15%	10%	5%
3.5 Bbbl East High Cost Investment										
Oil via Alyeska[4]	15.85	14.22	12.70	11.23	9.84	13.49	12.53	11.44	10.45	9.51
Gas via:										
New Line	-	-	-	9.84	8.59	-	-	9.81	9.00	8.36
Shared Existing Line										
High Tariff	-	-	6.76	7.67	6.42	9.69	8.59	7.64	6.83	6.19
Primary Tariff	-	9.59	8.01	6.92	5.67	8.94	7.84	6.89	6.08	5.44
Low Tariff	-	8.59	7.01	5.92	4.67	7.94	6.84	5.89	5.08	4.44
3.5 Bbbl East Low Cost Investment										
Oil via Alyeska[4]	12.65	11.57	10.57	9.59	8.67	11.09	10.45	9.73	9.08	8.45
Gas via:										
New Line	-	-	9.26	8.66	7.98	9.77	[illegible].17	8.65	[illegible]	7.86
Shared Existing Line										
High Tariff	8.95	7.96	7.09	6.49	5.81	7.60	7.00	6.48	6.04	5.69
Primary Tariff	8.20	7.21	6.34	5.74	5.06	6.85	6.25	5.73	5.29	4.94
Low Tariff	7.20	6.21	5.34	4.74	4.06	5.85	5.25	4.73	4.29	3.94

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

- Blanks n table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14B

REQUIRED MARKET PRICE (1) FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas(2))

	High Tax Producer Desired Fate of Return on Investment (3)					Low Tax Producer Desired Rate of Return on Investment (3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
3.5 Bbbl Central High Cost Investment										
Oil via Alyeska (4)	14.65	13.23	11.90	11.90	9.40	12.59	11.75	10.80	9.94	9.11
Gas via:										
New Line			9.75	9.01	8.61		9.64	8.99	9.44	8.01
Shared Existing Line										
High Tariff	9.88	8.65	7.58	6.84	5.99	8.21	7.47	6.82	6.27	5.84
Primary Tariff	9.13	7.90	6.83	6.09	5.24	7.46	6.72	6.07	5.52	5.09
Low Tariff	8.13	6.90	5.83	5.09	4.24	6.46	5.72	5.07	4.52	4.09
3.5 Bbbl Central Low Cost Investment										
Oil via Alyeska (4)	11.60	10.70	9.87	9.06	8.29	10.30	9.77	9.17	8.63	8.11
Gas via:										
New line			9.19	8.62	7.96	9.68	9.21	8.60	8.17	7.84
Shared Existing Line										
High Tariff	8.81	7.86	7.02	6.45	5.79	7.51	6.94	6.43	6.00	5.67
Primary Tariff	8.06	7.11	6.27	5.70	5.04	6.76	6.19	5.68	5.25	4.92
Low Tariff	7.06	6.11	5.27	4.70	4.04	5.76	5.19	4.68	4.25	3.92

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit forgas)

TABLE 3-14C

REQUIRED MARKET PRICE[1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas[2])

	High Tax Producer Desired Rate of Return on Investment (3)					Low Tax Producer Desired Pate of Return on Investment (3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
3.5 Bbbl West High Cost Investment										
Oil via Alyeska (4)	17.80	15.83	14.00	12.22	10.55	14.95	13.79	12.48	11.29	10.13
Gas via:										
New Line					9.24				9.85	8.91
Shared Existing Line										
High Tariff				8.93	7.07		-	8.90	7.68	6.74
Primary Tariff			9.81	8.18	6.32		9.57	8.15	6.93	5.99
Low Tariff			8.81	7.18	5.32		8.57	7.15	5.93	4.99
3.5 Bbbl West Low Cost Investment										
Oil via Alyeska (4)	14.30	12.94	11.67	10.43	9.27	12.33	11.52	10.61	9.79	9.00
Gas via:										
New line					8.85				9.36	8.59
Shared Existing Line										
High Tariff			9.52	8.20	6.68	-	9.32	8.18	7.1?	6.42
Primary Tariff			8.77	7.45	5.93	9.90	8.57	7.43	6.44	5.67
Low Tariff		9.68	7.77	6.45	4.93	8.90	7.57	6.43	5.44	4.67

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost.

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14D

REQUIRED MARKET PRICE (1) FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas (2))

	High Tax Producer Desired Rate of Return on Investment (3)					Low Tax Producer Desired Rate of Return on Investment (3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
2.3 Bbbl East High Cost Investment										
Oil via Alyeska (4)	16.30	14.59	13.00	11.46	10.00	13.83	12.82	11.68	10.64	9.65
Gas via:										
New Line	-	-	-	-	-	-	-	-	-	-
Shared Existing Line										
High Tariff	-	-	9.13	8.04	6.79	-	8.96	8.01	7.20	6.56
Primary Tariff	-	9.64	8.06	6.97	5.72	8.99	7.89	6.94	6.13	5.49
Low Tariff	-	8.59	7.01	5.92	4.67	7.94	6.84	5.89	5.08	4.44
2.3 Bbbl East Low Cost Investment										
Oil via Alyeska (4)	13.05	11.30	10.83	9.80	8.82	11.39	10.71	9.95	9.25	8.59
Gas via:										
New line	-	-	-	-	-	-	-	-	-	-
Shared Existing Line										
High Tariff	8.47	8.33	7.46	6.86	6.18	7.97	7.37	6.85	6.41	6.06
Primary Tariff	7.40	7.76	6.39	5.79	5.11	6.90	6.30	5.78	5.34	4.99
Low Tariff	6.35	6.21	5.34	4.74	4.06	5.85	5.25	4.73	4.29	3.94

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

- Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14E

REQUIRED MARKET PRICE [1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas(2))

	High Tax Producer Desired Rate of Return on Investment [3]					Low Tax Producer Desired Rate of Return on Investment [3]				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
2.3 Bbbl Central High Cost Investment										
Oil via Alyeska [4]										
Gas via:										
New Line	Equivalent to 3.5 Bbbl Central for									
Shared Existing Line	both High Cost and Low Cost Investment									
High Tariff										
Primary Tariff										
Low Tariff										
2.3 Bbbl Central Low Cost Investment										
Oil via Alyeska [4]										
Gas via:										
New line										
Shared Existing Line										
High Tariff										
Primary Tariff										
Low Tariff										

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for cil, $10/unit for gas)

TABLE 3-14F

REQUIRED MARKET PRICE[(1)] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas[(2)])

	High Tax Producer Desired Rate of Return on Investment[(3)]					Low Tax Producer Desired Rate of Return on Investment[(3)]				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
2.3 Bbbl West **High Cost Investment**										
Oil via Alyeska[(4)]	18.75	16.62	14.63	12.71	10.89	15.66	14.41	12.99	11.69	10.46
Gas via:										
New Line										
Shared Existing Line										
High Tariff										
Primary Tariff										
Low Tariff										
2.3 Bbbl West Low **Cost Investment**										
Oil via Alyeska[(4)]	13.80	12.52	11.33	10.18	9.09	11.95	11.20	10.35	9.57	8.83
Gas via:										
New Line										
Shared Existing Line										
High Tariff			9.33	8.18	6.86		9.16	8.16	7.30	6.62
Primary Tariff		9.93	8.26	7.11	5.79	9.25	8.09	7.09	6.23	5.55
Low Tariff		8.88	7.21	6.06	4.74	8.30	7.04	6.04	5.18	4.50

Required Market Price in excess of $10/unit for gas in all cases. Therefore, unit investment for oil drawn from Table 3-12 rather than 3-11.

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14G

REQUIRED MARKET PRICE(1) FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas(2))

	High Tax Producer Desired Rate of Return on Investment(3)					Low Tax Producer Desired Rate of Return on Investment(3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
1.4 Bbbl East										
High Cost Investment										
Oil via Alyeska(4)	18 55	16.46	14.50	12.60	10.82	15.51	14.28	12.68	11.61	10.39
Gas via:										
New Line	-	-	-	-	-	-	-	-	-	-
Shared Existing Line										
High Tariff	-	-	-	9.50	7.54	-	-	9.47	8.19	7.19
Primary Tariff	-	-	-	8.43	6.47	-	9.88	8.40	7.12	6.12
Low Tariff	-	-	9.46	7.75	5.79	-	9.20	7.72	6.44	5.44
1.4 Bbbl East										
Low Cost Investment										
Oil via Alyeska(4)	15.20	13.68	12.27	10.39	9.60	13.00	12.11	11.09	10.17	9.29
Gas via:										
New line	-	-	-	-	-	-	-	-	-	-
Shared Existing Line										
High Tariff	-	-	-	8.82	7.19	-	-	8.79	7.72	6.90
Primary Tariff	-	-	9.17	7.[illegible]5	6.12	-	8.35	7.72	6.65	5.83
Low Tariff	-	-	8.49	7.07	5.44	9.70	8.27	7.04	5.97	5.15

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

\- Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14H

REQUIRED MARKET PRICE [1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per *barrel oil and* per 2.5 mcf gas(2))

	High Tax Producer Desired Rate of Return on Investment (3)					Low Tax Producer Desired Rate of Return on Investment (3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
1.4 Bbbl Central High Cost Investment										
Oil via Alyeska (4)	16.00	14.34	12.80	11.30	9.89	13.60	12.63	11.52	10.51	9.56
Gas via:										
New Line										
Shared Existing Line										
High Tariff			8.78	7.79	6.66	9.62	8.63	7.77	7.05	6.46
Primary Tariff		9.14	7.71	6.72	5.59	8.55	7.56	6.70	5.98	5.39
Low Tariff		8.46	7.03	6.04	4.91	7.87	6.88	6.02	5.30	4.71
1.4 Bbbl Central Low Cost Investment										
Oil via Alyeska (4)	12.90	11.78	10.73	9.72	8.76	11.28	10.62	9.87	9.19	8.54
Gas via:										
New line										
Shared Existing Line										
High Tariff	-	9.32	8.16	7.35	6.43	9.84	8.04	7.34	6.74	6.27
Primary Tariff	9.58	8.25	7.09	6.28	4.87	7.77	6.97	6.27	5.67	5.20
Low Tariff	8.90	7.57	6.41	5.60	4.68	7.09	6.29	5.59	4.99	4.52

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}(6/5)$ + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile *years* 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-141

REQUIRED MARKET PRICE (1) FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas(2))

	High Tax Producer Desired Rate of Return on Investment (3)					Low Tax Producer Desired Rate of Return on Investment (3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
1.4 Bbbl West High Cost Investment										
Oil via Alyeska (4)		19.64	17.07	14.57	12.22	18.40	16.78	14.93	13.26	11.66
Gas via:										
New Line										
Shared Existing Line										
High Tariff	Required Market Price in excess of $10/unit for gas in all cases. Therfore, unit investment for oil drawn from Table 3-12.									
Primary Tariff										
Low Tariff										
1.4 Bbbl West Low Cost Investment										
Oil via Alyeska (4)	16.65	14.88	13.23	11.63	10.13	14.09	13.05	11.87	10.79	9.77
Gas via:										
New line		-	-							
Shared Existing Line										
High Tariff		-	-							
Primary Tariff		-	-	8.53	6.50			8.49	7.17	6.13
Low Tariff										

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}(6/5)$ + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14J

REQUIRED MARKET PRICE[1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas[2])

	High Tax Producer Desired Rate of Return on Investment[3]					Low Tax Producer Desired Rate of Return on Investment[3]				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
0.7 Bbbl East High Cost Investment										
Oil via Alyeska[4]	-	18.23	15.93	13.70	11.60	17.13	15.68	14.03	12.53	11.10
Gas via:										
New Line										
Shared Existing Line										
High Tariff	Required Market Price in excess of $10/unit for gas in all cases. Therefore, unit investment for oil drawn from Table 3-12.									
Primary Tariff										
Low Tariff										
0.7 Bbbl East Low Cost Investment										
Oil via Alyeska[4]	17.60	15.67	13.87	12.12	10.47	14.80	13.66	12.37	11.20	10.06
Gas via:										
New line										
Shared Existing Line										
High Tariff	Required Market Price in excess of $10/unit for gas in all cases. Therefore, unit investment for oil drawn from Table 3-12.									
Primary Tariff										
Low Tariff										

Footnotes

(1) $\frac{\text{Required Investment (6/5)}}{\text{Present Worth Factor}}$ + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14K

REQUIRED MARKET PRICE(1) FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas(2))

	High Tax Producer Desired Rate of Return on Investment(3)					Low Tax Producer Desired Rate of Return on Investment(3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
0.7 Bbbl Central High Cost Investment										
Oil via Alyeska(4)	16.30	14.59	13.00	11.46	10.00	13.83	12.82	11.68	0.64	9.64
Gas via:										
New Line										
Shared Existing Line										
High Tariff	-	-	9.33	8.12	6.86	-	9.16	8.16	7.30	6.62
Primary Tariff	-	9.93	8.26	7.11	5.79	9.26	8.09	7.09	6.23	5.55
Low Tariff	-	9.25	7.58	6.43	5.11	8.57	7.41	6.41	5.55	4.97
0.7 Bbbl Central Low Cost Investment										
Oil via Alyeska(4)	13.40	12.19	11.07	9.37	8 95	11.65	10.94	10.13	9.40	8.70
Gas via:										
New line	-	-	-	-	-	-	-	-	-	-
Shared Existing Line										
High Tariff	-	-	8.78	7.79	6.66	9.62	8.63	7.77	7.05	6.46
Primary Tariff	-	9.14	7.71	6.72	5.59	8.55	7.56	6.70	5.98	5.39
Low Tariff	-	8.46	7.03	6.04	4.91	7.87	6.88	6.02	5.30	4.71

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

\- Blanks in table refer to market prices too high for consideration ($17/barrel for cil, $10/unit for gas)

TABLE 3-14L

REQUIRED MARKET PRICE [1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas [2])

	High Tax Producer Desired Rate of Return on Investment [3]					Low Tax Producer Desired Rate of Return on Investment [3]				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
0.7 Bbbl West										
High Cost Investment										
Oil via Alyeska [4]			19.57	16.49	13.58		19..21	16.93	14.86	12.89
Gas via:										
New Line										
Shared Existing Line										
High Tariff	Required Market Price in excess of $10/unit for gas in all cases. Therefore, unit investment for oil drawn from Table 3-12.									
Primary Tariff										
Low Tariff										
0.7 Bbbl West										
Low Cost Investment										
Oil via Alyeska [4]			17.50	14.90	12.45		17.20	15.28	13.54	11.87
Gas via:										
New line										
Shared Existing Line										
High Tariff	Required Market Price in excess Of $10/unit for gas in all cases. Therefore, unit investment for oil drawn from Table 3-12.									
Primary Tariff										
Low Tariff										

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14M

REQUIRED MARKET PRICE [1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas(2))

	High Tax Producer Desired Rate of Return on Investment (3)					Low Tax Producer Desired Rate of Return on Investment (3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
0.4 Bbbl East										
High Cost Investment										
Oil via Alyeska [4]										
Gas via:										
New Line										
Shared Existing Line										
High Tariff										
Primary Tariff										
Low Tariff										
0.4 Bbbl East										
Low Cost Investment										
Oil via Alyeska [4]										
Gas via:										
New line										
Shared Existing Line										
High Tariff										
Primary Tariff										
Low Tariff										

Equivalent to 0.7 Bbbl West for both High Cost and Low Cost Investment

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil,$10/unit for gas)

TABLE 3-14N

REQUIRED MARKET PRICE [1] FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas[2])

	High Tax Producer Desired Rate of Return on Investment [3]					Low Tax Producer Desired Rate of Return on Investment [3]				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
0.4 Bbbl Central High Cost Investment										
Oil via Alyeska [4]	18.65	16.54	14.57	12.65	10.85	15.53	14.35	12.93	11.66	10.43
Gas via:										
New Line										
Shared Existing Line										
High Tariff				9.60	7.59			9.56	8.25	7.23
Primary Tariff				8.53	6.52		9.82	8.49	7.18	6.16
Low Tariff			9.60	7.85	5.84		9.34	7.81	6.50	5.48
0.4 Bbbl Central Low Cost investment										
Oil via Alyeska [4]	15.90	14.26	12.73	11.25	9.85	13.53	12.56	11.47	10.47	9.52
Gas via:										
New line										
Shared Existing Line										
High Tariff				9.21	7.39			9.18	7.99	7.07
Primary Tariff			9.72	8.14	6.32		9.48	8.11	6.92	6.00
Low Tariff			9.04	7.46	5.64		8.80	7.43	6.24	5.32

Footnotes

(1) $\frac{\text{Required Investment}}{\text{Present Worth Factor}}$ (6/5) + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective 10% tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

TABLE 3-14P

REQUIRED MARKET PRICE (1) FOR BEAUFORT SEA OCS SCENARIOS
($1975-76 per barrel oil and per 2.5 mcf gas (2))

	High Tax Producer Desired Rate of Return on Investment (3)					Low Tax Producer Desired Rate of Return on Investment (3)				
	25%	20%	15%	10%	5%	25%	20%	15%	10%	5%
0.4 Bbbl West High Cost Investment										
Oil via Alyeska (4)										17.09
Gas via:										
New Line										
Shared Existing Line										
High Tariff	Required Market Price in excess of $10/unit for gas in all cases. Therefore, unit investment for oil drawn from Table 3-12.									
Primary Tariff										
Low Tariff										
0.4 Bbbl West Low Cost Investment										
Oil via Alyeska (4)								19.00	19.09	16.97
Gas via:										
New line										
Shared Existing Line										
High Tariff	Required Market Price in excess of $10/unit for gas in all cases. Therefor-, unit investment for oil drawn from Table 3-1?.									
Primary Tariff										
Low Tariff										

Footnotes

(1) $\frac{\text{Required Investment (6/5)}}{\text{Present Worth Factor}}$ + Transportation Cost + Field Operating Cost

(2) Excludes exploration cost

(3) After tax return: high tax producer with effective 35% tax rate
low tax producer with effective [illegible] tax rate

(4) Oil profile years 1-20; gas profile years 3-20

Blanks in table refer to market prices too high for consideration ($17/barrel for oil, $10/unit for gas)

diverse factors, such as gas reinfection, volume economies, the degree of gas treatment necessary, the degree of solution gas in the oil, etc., are ignored by using a unit fixed price for field operating costs. The field operating costs typically rise over the life of the field, and are a strong determinant in setting the eventual abandonment date of the field. The fixed cost estimates indicated here are compatible averages in fixed dollars for a field of the assumed production profile and field life. With the postulated delay of gas production for twenty years, the field operating costs could be expected to be high. Because of the discount in future values for downstream revenues and costs, the analysis is relatively insensitive to cost differences of this nature, and no attempt has been made to incorporate them.

3.6 REQUIRED MARKET PRICE FOR 15 SCENARIOS: A PARAMETRIC ANALYSIS

Tables 3-14A through 13-14P show the 1975-76 constant dollar market prices per unit (per barrel oil and per 2.5 mcf gas) that are required under the uniquely fixed conditions of the parametric variables that are used in analyzing each scenario. The variables include: reserve size, location of discovery, level of investment, tax status, desired rate of return, and the tariffs of the transportation systems used to transport the oil and gas south from Prudhoe Bay. It can be seen in Table 3-14A, for example, that a high-tax status oil producer (with an effective domestic tax rate of 35 percent) must sell his oil from a 3.5 Bbbl reserve in the eastern Beaufort, that was developed under high-cost investment conditions, into the southern California market for at least $14.22 per barrel (constant 1975 dollars) in order to achieve an after-tax return on investment of 20 percent. This same producer, given the same conditions, must sell his gas (transported at primary tariff) for at least $9.59 per unit (per 2.5 mcf) to achieve an after-tax return of 20 percent.

The blanks in the tab'les correspond to required market prices that the research team felt were too high to consider in the foreseeable future. For oil, the analysis was carried out only one step higher than the arbitrary cutoff of $17 per barrel (in constant 1975 dollars). For gas, market prices were not calculated above $10 per unit (per 2.5 mcf in constant 1975 dollars).

The prices in the tables were derived from the following formula:

$$RMP = \frac{RI}{PWF}(6/5) + TC + FOC$$

where

RMP = Required Market Price

RI = Required Investment (from Tables 3-11 and 3-12)

PWF - Present Worth Factor (from Table 3-13)

TC = Transportation Cost ($5.40/barrel for oil; gas tariffs as shown in Section 3.5.4.2)

FOC = Field Operating Costs ($1.00/barrel for oil, $0.20/unit for gas)

Royalty = 1/6 of wellhead prices

The tables provide required prices to meet a large array of financial conditions, all of which are plausible, though not all of which are equally probable. The text to follow is an attempt to focus on those aspects of the tables that correspond to the prevailing market conditions, notably the west coast market for oil of around $12-13/barrel (constant 1975 dollars), as well as the proposed delivery basis of the Arctic Gas and El Paso lines of $6-7/unit (2.5 mcf/unit, in constant 1975 dollars). The text has been arranged by the reserve levels corresponding to the 15 Beaufort Sea OCS scenarios under consideration.

3.6.1 3.5 Billion Barrel Reserve

Oil developed under high-investment conditions in the eastern Beaufort region can yield a 12 percent to 17 percent after-tax return to the investor in a $12/barrel market, and a 16 percent to 22 percent return in a $13/barrel market. Under low-investment conditions, the return jumps to 22 percent to 25 percent in a $12/barrel market, and exceeds 25 percent in a $13/barrel market. The ranges shown above, and in the text to follow, correspond to high and low effective tax rates, respectively.

For gas moving from the eastern Beaufort at the primary tariff (i.e. $1.65/mcf), the after-tax return in $6/unit market would be 6 percent to

10 percent if the required investment were high, and 12 percent to 17 percent if the required investment to develop were low. In a $7/unit market, the high investment case would yield a 9 percent to 14 percent after-tax return, which would climb to 18 percent to 25 percent under low investment conditions. Notably, a new, single purpose gas line would require an $8/unit market to yield a 5 percent to 7 percent after-tax return.

If the same size reserves were to be discovered in the central Beaufort region, the after-tax return on oil would climb by approximately 3 percent to 5 percent above that given for the same conditions stated above for the eastern region. For example, oil developed at high cost would yield a 15 percent to 22 percent return in a $12/barrel market. It should also be noted that the required prices are the same in the central Beaufort for the 2.3 billion barrel reserve scenarios as for the 3.5 billion barrel reserve level. As the scenarios were constructed, the assumed spread of offshore lines flattened out the scale economics normally expected from the larger field. This serves as a reminder of the great variability of conditions which may result offshore.

For gas moving from the central Beaufort under the primary tariff ($1.65/mcf), a return of 13 percent to 18 percent could be expected in $6/unit market given low cost investment requirements, and 9 percent to 14 percent given high costs investment requirements. As an alternative, selling the future gas rights for $6/unit for delayed delivery through a “used” line purchased for $0.10/mcf would yield a 5 percent to 8 percent return; if the line were purchased for $0.25/mcf the return would drop to 4 percent to 6 percent. In a $7/unit market, delayed delivery in a $0.10/mcf line would return 6 percent to 8 percent to the investor. In the central Beaufort, if OCS gas were transported through a new single purpose line (8.8 tcf only), it would return 5 percent to 7 percent to the investor in an $8/unit market.

For the western Beaufort region, given high development costs, a 3.5 billion barrel field could penetrate a $13/barrel oil market (1975 dollars) at more than a 15 percent return to the low-tax producer, and about 13 percent to the high-tax producer. In a $12/barrel market, the returns would be about 12 percent and 8 percent, respectively. On the other hand, if the development costs were low, the returns would be 20 percent to 25 percent in a $13/barrel market and 17 percent to 22 percent in a $12/barrel market.

Gas transported from the western Beaufort in a $6/unitmarket ($2.40/mcf) could achieve a 5 percent return for a low-tax producer if the delivery tariff did not exceed $1.65/mcf. For delivery charges of $1.90 to $2. 00/mcf, the gas could enter a $7/unit market ($2.80/mcf) with about a 4 percent to 7 percent return, and enter an $8/unit market ($3.20/mcf) with returns of 7 percent to 12 percent.

3.6.2 2.3 Billion Barrel Reserve

As mentioned previously, the required prices for oil and gas in the central Beaufort are the same in 2.3 Bbbl reserve case as in 3.5 Bbbl reserve case. Moreover, the gas returns for the 2.3 Bbbl central case could be achieved in the 2.3 Bbbl eastern case if a gas attachment could be made to a line passing through the area such as that originally proposed by Arctic Gas.

In the eastern Beaufort, oil developed at high cost could be delivered to a $12/barrel market with a 12 percent to 17 percent return, and with a 15 percent to 22 percent return in a $13/barrel market. For low cost development, the return is greater than 20 percent in a $12/barrel market and exceeds 25 percent in a $13/barrel market.

Similarly for the eastern Beaufort, gas transported at the primary tariff could return 6 percent to 9 percent in a $6/unit market if the costs of development were high, and 12 percent to 17 percent if the development costs were low. Delayed gas would return between 3 percent and 8 percent depending upon the cost of development and the purchase price of the used line.

In the western Beaufort region, if the development costs proved to be high, oil could be delivered to a $13/barrel market with an 11 percent to 15 percent return, and to a $12/barrel market with an 8 percent to 11 percent return. If the development costs proved to be low, the returns would range from 18 percent to over 25 percent.

Under the high-cost investment conditions, no gas can be developed in the western Beaufort at this reserve level. However, if National Petroleum

Reserve - Alaska should open up with a new gas line available for interconnection, the development costs could be reduced 160 kilometers ([100 miles] less to the presumed NPR-A location versus 274 kilometers [170 miles] to Prudhoe Bay) and the situations pertinent to the 2.3 Bbbl (5.5-6.0 tcf) central or eastern scenarios would apply. Under low-cost investment conditions, gas could be developed, and would yield a 5 percent to 8 percent return in a $6/unit market at the primary tariff. If the market were $7/unit, the return would climb to 10 percent to 15 percent. Delayed gas would return 3 percent to 7 percent after taxes.

3.6.3 1.4 Billion Barrel Reserve

In the eastern Beaufort region, oil developed at high cost could be delivered to a $13/barrel market with an 11 percent to 15 percent return. If the oil were to be produced at low cost, the return for the same market would climb to between 18 percent and 25 percent. Gas produced in the eastern region and transported at the primary tariff to a $6/unit market could achieve a 7 percent return under low cost investment conditions, and less than 5 percent under high cost development. In a $7/unit market, the return would be 7 percent to 12 percent and 6 percent to 9 percent, respectively, given low- and high-cost investment.

Oil transported from the central Beaufort would yield a return of 16 percent to 22 percent in a $13/barrel market if the cost of development were high, and over 25 percent if it were low. The respective rates in a $12/barrel market would be 12 percent to 17 percent and 21 percent to 25 percent. Gas delivered at the primary tariff ($1.65/mcf) to a $6/unit market would achieve a 15 percent to 20 percent return if the cost of development were low, and 11 percent to 17 percent if similar costs were found to be high. Delayed gas would return 5 percent to 8 percent.

In the western Beaufort, the return under high-cost development conditions in a $13/barrel market is 7 percent to 9 percent, climbing to 15 percent to 20 percent when low-cost conditions are assumed. If investment costs are high, gas is no longer developable given the 274 kilometer (170 mile) North Slope connection. This situation could be altered if a close line from NPR-A were available. Under low-cost investment conditions, the gas could be developed, and would return 7 percent to 9 percent in a $7/unit market.

3.6.4 0.7 Billion Barrel Reserve

In the eastern region, gas is no longer developable, unless a line along the route originally proposed by Arctic Gas could be tapped, making the North Slope gathering trunks shorter. Oil from the eastern region could achieve a 13 percent to 17 percent return in a $13/barrel market if the development costs were low, but only an 8 percent to 12 percent return if they were high.

In the central region, both oil and gas are developable. With high cost investment requirements, oil could be delivered to a $12/barrel market with a return of 12 percent to 17 percent to the investor; in a $13/barrel market the return increases to 15 percent to 21 percent. If the investment costs are low, the return for a $12/barrel market is 19 percent to 25 percent, and for a $13/barrel market is in excess of 25 percent. Gas transported at a primary tariff to $6/unit market would return 6 percent to 8 percent in the low cost case, and 7 percent to 10 percent in the high cost case. The delayed gas is becoming marginal--5 percent under the most favorable conditions.

In the western region, the low-cost oil would return 7 percent to 8 percent in a $13/barrel market, whereas the high-cost oil would return 5 percent or less. Gas is no longer developable at this reserve level in the western Beaufort.

3.6.5 0.4 Billion Barrel Reserve

Oil and gas development in the eastern region demonstrates the same economic profile as the 0.7 Bbbl-west scenario. No development is likely in the western region at the 0.4 Bbbl reserve level.

In the central region, high-cost oil will yield a return of 12 percent to 15 percent in a $13/barrel market, whereas under low-cost investment the return increases to 16 percent to 22 percent. Gas can be delivered at the primary tariff to a $7/unit market with a return of 7 percent to 10 percent.

3.7 MINIMUM FIELD DEVELOPMENT SIZE

Tables 3-15A through 3-15C show the minimum size fields (in billions of

TABLE 3-15A

MINIMUM FIELD DEVELOPMENT SIZES[1]
EASTERN LOCATION
(Billions of barrels of oil, trillions of cubic feet of gas)

	Market Price [2]	Desired Rate of After-Tax Return	High Cost Investment High Tax	High Cost Investment Low Tax	Low Cost Investment High Tax	Low Cost Investment Low Tax
OIL (Bbbl)	$ 13.00/bbl	25%			2.5 Bbbl	1.3 Bbbl
		20%		2.2 Bbbl	1.5	0.85
		15%	2.3 Bbbl	1.1	0.9	0.6
		10%	1.0	0.55	0.5	0.4
GAS (tcf)	$ 6.00/unit	20%				–
	(2.5 mcf)	15%		–		6.9 tcf
		10%			7.6 tcf	5.3
		5%	4.4 tcf	3.1 tcf	3.6	2.6
	$ 7.00/unit	25%		–		8.4 tcf
		20%				6.8
		15%		6.8 tcf	6.9 tcf	4.6
		10%	6.8 tcf	3.1	4.1	2.6
		5%	1.5	1.9	1.7	1.4

(1) Determined from trend curve plot of unit investment costs and field reserve sizes given an assumed market price, rate of return and tax category. Minimum field considered was 300 mmbbl, 0.8 tcf. Maximum field considered 3.5 Bbbl, 8.8 tcf.

(2) 1975-1976 dollars relative to $5.40 transport charge for oil, medium tariff for gas.

TABLE 3-15B

MINIMUM FIELD DEVELOPMENT SIZES[1]
CENTRAL LOCATION
(Billions of barrels of oil, trillions of cubic feet of gas)

	Market Price[2]	Desired Rate of After-Tax Return	High Cost Investment High Tax	High Cost Investment Low Tax	Low Cost Investment High Tax	Low Cost Investment Low Tax
OIL (Bbbl)	$ 13.00/bbl	25%	(3)	1.6 Bbbl	0.85 Bbbl	0.40 Bbbl
		20%	(3)	0.65	0.45	0.30
		15%	0.7 Bbbl	0.35	0.35	
		10%	0.35	0.30	0.30	
GAS (tcf)	$ 6.00/unit	20%				
		15%		4.5 tcf		3.9 tcf
		10%		2.4	3.9 tcf	1.55
		5%	1.4 tcf	1.1	1.2	1.0

(1) Determined from trend curve plot of unit investment costs and field reserve sizes given an assumed market price, rate of return and tax category. Minimum field considered was 300 mmbbl, 0.8 tcf. Maximum field considered 3.5 Bbbl, 8.8 tcf.

(2) 1975-1976 dollars relative to $5.40 transport charge for oil, medium tariff for gas.

(3) More than 3.5 Bbbl needed

TABLE 3-15C

MINIMUM FIELD DEVELOPMENT SIZES [1]
WESTERN LOCATION
(Billions of barrels of oil, trillions of cubic feet of gas)

	Market Price [2]	Desired Rate of After-Tax Return	High Cost Investment: High Tax	High Cost Investment: Low Tax	Low Cost Investment: High Tax	Low Cost Investment: Low Tax
OIL (Bbbl)	$ 13.00/bbl	20%			2.0 Bbbl	1.4 Bbbl
		15%		2.6 Bbbl	1.4	1.05
		10%	2.3 Bbbl	1.4	1.0	0.75
		5%	0.8	0.7	0.6	0.55
	$ 14.00/bbl	20%		3.1 Bbbl	1.4 Bbbl	1.15 Bbbl
		15%	3.5 Bbbl	1.8	1.2	0.9
		10%	1.5	0.9	0.8	0.6
		5%	0.65	0.55	0.5	0.5
GAS (tcf)	$ 7.00/unit	20%				7.8 tcf
	(2.5 tcf)	15%			8.0 tcf	6.3
		10%		8.8	6.3	3.8
		5%	5.3 tcf	4.0	3.0	2.5

(1) Determined from trend curve plot of unit investment costs and field reserve sizes given an assumed market price, rate of return and tax category. Minimum field considered was 300 mmbbl, 0.8 tcf. Maximum field considered 3.5 Bbbl, 8.8 tcf.

(2) 1975-1976 dollars relative to $5.40 transport charge for oil, medium tariff for gas.

barrels of oil, and trillions of cubic feet of gas) that are required to achieve a desired rate of after-tax return in the prevailing markets (i.e. oil selling at around $13 per barrel and gas at $6 to $7 per unit in constant 1975-76 dollars). Distinctions are made in the tables for high and low cost investment, as well as for high and low cost effective tax rates. The maximum field considered (3.5 Bbbl, 8.8 tcf) corresponds to the reserve level of the bonanza scenarios, and the blanks in the table represent minimum field sizes in excess of this cutoff volume. Table 3-15A shows, for example, that a high-tax status investor (effective domestic tax rate of 35 percent) who discovers oil in the eastern Beaufort region, and who anticipates high-cost development, must deliver at least 2.3 Bbbl of oil over the life of the field to a $13/barrel market (constant 1975-76 dollars) to obtain a 15 percent return. This same producer, under the same conditions must discover gas reserves of at least 6.8 tcf, and deliver them to a $7/unit market, in order to achieve a 10 percent return on his gas investment.

Comparison of the three tables clearly indicates the economic advantages of discovery in the central location. For example, under high-cost investment requirements and under high-tax conditions, the minimum size field needed to achieve a 10 percent return on investment is 0.35 Bbbl in the central location, 1.0 Bbbl in the eastern location, and 2.3 Bbbl in the western location. This is a direct consequence of the required length of pipeline to the interconnection with the Alyeska line. The sensitivity of return on investment to pipeline investment will be explored more fully in the next section.

The figures in Tables 3-15A through 3-15C were calculated by forming the trend curve plots of the data on required market prices, and then graphically interpolating them. These trend curve plots have not been included in this report.

3.8 Sensitivity Analysis

The scenario construction has formed a multivariable "window" of conditions under which development of the potential resources of the Beaufort may occur. Factors considered have been:

- The range of recoverable resources which may be found, expressed as a probability estimate by the U.S.G.S.

- The most likely end points of favorable field characteristics which would be expected in developable fields, based upon those for the Prudhoe Bay field. These were delivery curve, fill factor, and well spacing.

- A bracketing range of economic factors, including a high and low unit price for the various components of development, a range of rates of return, tax status of producers, optimistic to cautious levels of exploratory activity, gas transport tariffs, and market levels.

Factors not incorporated into the analysis have been:

- The scale, time progression, and other variations in field operating costs (not significant to the analysis here, but eventually critical to such questions as whether a field may be abandoned or converted to stripper operations at the end of the postulated 20-year recovery period).

- Scale and time variations in transport costs (their influence is relative to market level).

- Gas market adjustments for transport shrinkage.

The relative influence of the economic variables above can be explored by sensitivity analysis, computing the linearized differentials. The general form of the sensitivity analysis is shown below, as well as a numerical example carried out for the 0.7 Bbbl field in the western Beaufort region.

Tne cost model for the field is of the form, for a single commodity:

$$\Sigma\ a_i A_i = NRPZ,$$

where :

$a_i A_i$ are the number of field development components of type i, price A_i, each.

N = the number of reserve units available (i.e. Bbl of oil).

R = the royalty factor = 1 - royalty rate = 5/6

P = the present worth factor

Z = the unit money available for capital amortization.

Σ = market price minus operating and transport costs

In a given field, west, 700 MMB oil, one can then ask how much change in the field components (number of units and price per unit) is necessary to produce a 1 percent change in the rate of return. Differentiation of the general cost model gives:

$$\frac{\Delta A_i}{A\ P} = \frac{NRZ}{a_i} \quad \text{and} \quad \frac{A\ a_i}{\Delta\ P} = \frac{NRZ}{A_i}$$

Specific numbers corresponding to the 700 MMB-west scenario can now be applied. Under the low-cost investment conditions, it was found that:

a_1 = 322 kilometers (200 miles) of pipeline

‘1 = average cost of $4.96 million per kilometer ($7.99 million per mile) of pipeline

a_2 = 94 wells (without gas development)

‘2 = average cost per well of $7.95 million

R = 5/6

N = 700 million barrels of oil

z = $6.60 per barrel (in a $13/barrel market)

Also, from linear interpolation of the present worth table (oil development @ 35 percent effective tax rate), it can be seen that the necessary change in the present worth factor to go from a 7 percent to 8 percent rate of return is approximately:

$$\Delta P = -0.038$$

Given all the factors above, by straightforward substitution, one can calculate the necessary change in unit cost and total units (i.e. cost per kilometer [per mile] of pipeline, and total kilometers [miles] of pipeline) to go from 7 percent to 8 percent return:

$$\text{Unit Pipeline Cost Per Mile} = (-0.038)\ \frac{(6.6)(.83)(700 \times 10^6)}{200}$$

= - \$0.73 million per mile,
or - \$4.53 million per kilometer

which is $\frac{(.73)}{(7.99)} = 9.1\%$

$$\text{Miles of Pipeline System} = (-0.038)\ \frac{(6.6)(.83)(700. \times 10^6)}{7.99 \times 10^6}$$

= - 18.2 miles
or - 29.3 kilometers

which is also $\frac{(18.2)}{(200)} = 9.1\%$

Similarly, for wells, one can calculate the required change to increase the rate of return from 7 percent to 8 percent:

$$\text{Unit Cost Per Well} = (-0.038)\ \frac{(6.6)(.83)(700 \times 10^6)}{94}$$

= - \$1.55 million per well

which is $\frac{(1.55)}{(7.95)} = 19.5\%$

The interpretation of the sensitivity is <u>inverse</u> to the percentage changes. Therefore, it is easier to get a 1 percent improvement in net return from changing the pipeline costs than by changing the well costs, so that the pipeline connection is the more sensitive item.

One can also calculate the amount of royalty reduction (or gain) which would produce a change of 1 percent in net rate of return:

$$RP = \text{constant (for the given data)}$$

$$RAP + PAR = 0$$

$$\frac{AR}{\Delta P} = - \frac{R}{P}$$

At an 8 percent rate of return, P is about .58, so the increase in the royalty factor which would produce a point (1 percent) increase in the rate of return is about 5.4 percent. In the range of a 20 percent rate of return, P is about .3, and the change to produce a point difference" is only .01. Therefore, the increase in the royalty factor which would increase the rate of return one point is 2.8 percent.

The same format applies to net capital return and field size N:

$$\frac{AN}{\Delta P} = \frac{N}{P} \qquad \frac{\Delta Z}{\Delta P} = \frac{Z}{P}$$

Thus, the rate of return would be increased 1% if either:

$$\Delta N = \frac{700\text{x } 10^6}{.58} \quad (.038) = 46 \text{ MMB more oil were found,}$$

or:

$$\Delta Z = \frac{6.6}{.58} (.038) = 43¢$$ savings in operating costs, or conversely a 43¢ market gain were achieved.

At this point, it should be cautioned that linearized differential analysis is valid only for small changes.

The results for the tradeoff analysis indicate that the rate of return from a field is somewhat insensitive to changes in the number and unit cost of components when the return is low. However, as the rate of return increases, it becomes increasingly sensitive to the individual cost conditions.

The results also show that the unit pipeline cost for connecting the field to a transport system is a very sensitive cost item which will bite into the developability of Beaufort Sea petroleum fields. The cost estimation used in the analysis of the scenarios is based upon one-season laying of offshore lines and year-round laying of onshore lines. Alternatives considered were:

- directional drilling - too great a deviation distance for nearly all OCS areas.
- tunneling costs excessive
- winter offshore laying through the ice - insufficient experience to evaluate cost.

Of these alternatives, the latter is the only one which could have the potential for unit cost reductions below conventional or unconventional (reel barge) summer laying estimated here.

CHAPTER IV

SELECTED PETROLEUM DEVELOPMENT SCENARIOS

4.1 SCENARIO CONTEXT

The focus of this chapter is on the selection of four scenarios for detailed analysis: hypothezing the size and location of discovery, the chronology of major events, the manpower and facility requirements, and the issues and factors surrounding the selection of general onshore development zones. The locations of discovery are purely arbitrary; they reflect no knowledge of the potential resources, but rather are designed to provide the first step in a series of predictive tasks to evaluate the socio-economic implications of OCS petroleum development in Alaska.

This report, as stated in the beginning, is interim in nature. It explores the potential of the Beaufort OCS lease sale area in isolation from other anticipated petroleum activities on the North Slope. Subsequent work will attempt to interweave a future chronology of all petroleum-related events throughout the greater North Slope region. To bridge the gap toward the more expansive scope of future efforts, and to provide a context for scenario selection in this report, this chapter opens with a brief history of petroleum exploration on the North Slope, a brief discussion of the existing infrastructure along the Beaufort coast, and a brief discussion of the potential for down-stream processing of North Slope hydrocarbons, notably petrochemicals and refinery products. Subsequently, four scenarios will be selected for analysis on the basis of contrast and variation in reserve size, geography, and the type and level of impact potential, including the potential for "synergistic" development with other North Slope petroleum activities. Following the establishment of specific manpower assumptions and the general criteria for establishing onshore development zones, the four scenarios will be elaborated. The chapter closes with a brief comparison of the four scenarios with respect to manpower and general economics.

4.1.1 Historical Context of Petroleum Exploration in Northern Alaska

Oil seeps on the North Slope have long been known to the Eskimos and early Arctic explorers. Seepages have been reported at Skull Cliff, Cape Simpson, Fish Creek, Barter Island and Umiat. Modern interest in resources of the region began in 1901 with the first geologic traverse, and by 1923 there was sufficient data to indicate the possibility of oil deposits. In that year, Naval Petroleum Reserve No. 4 (NPR-4) was established by Executive Order No. 3797-A. Signed by President Harding, it put aside a 93,240 square kilometer (36,000 square mile) area on the western North Slope as a defense reserve under Navy jurisdiction. To evaluate the resources of NPR-4, the U.S. Geological Survey conducted a series of reconnaissance level surveys in the 1920's and 1930's that mapped the geology and geography, and evaluated the petroleum potential.

With the impetus of the Second World War and the need for additional oil reserves, the Navy in 1944 commenced a vigorous exploration and drilling program which was continued after the war under a private contract until close-out in 1953. The program completed 36 test wells, 44 core tests, more than 93,000 square kilometers (36,000 square miles) of seismic survey, 54,400 square kilometers (21,000 square miles) of reconnaissance geologic mapping and 67,300 square kilometers (26,000 square miles) of gravimetric survey. This work resulted in the discovery of nine oil and gas fields, none of which contains commercial reserves. The most extensive oil field is the Umiat field located in the south-eastern part of NPR-4 with 70 million barrels of recoverable reserves as estimated by the Navy. The second largest oil field is the Simpson Field with 12 million barrels of recoverable reserves. Discovered in 1949, the South Barrow Gas Field has estimated recoverable reserves as 25.2 billion cubic feet and presently supplies the village of Barrow and nearby Naval installations. Since 1949, nine wells have been drilled in the development of this gas field; and in order to meet increasing demand, two additional wells are planned. The Gubik Gas Field, located mostly outside NPR-4 on the Colville River east of Umiat, has estimated reserves of 295 billion cubic feet. An in-depth description of the 1944-53 exploration program of NPR-4 and adjacent areas is given by Reed (1958).

After the termination of the first NPR-4 exploratory program in 1953 no wells were drilled on the North Slope until 1963 when British Petroleum and other companies renewed exploration activities. Seven relatively shallow wells were drilled between 1963 and 1965, mainly in the vicinity of Umiat (Gryc, 1970). Like the original NPR-4 program, the new exploratory program concentrated on the relatively shallow Cretaceus sediments. Subsequent exploration moved northward toward the Colville Delta and Prudhoe Bay where deeper wells were drilled. In 1968, the 12th well, A.R.Co. Bay State No. 1, was drilled into the deeper Sadlerochit formation of Permo-Triassic age at Prudhoe Bay and became the discovery well. The Prudhoe Bay field is estimated to contain 9.6 billion barrels recoverable oil reserves and 24 trillion cubic feet recoverable gas reserves, which makes this discovery the largest single find in North America (International Petroleum Encyclopedia, McCaslin, cd., 1976). As a result, the Prudhoe Bay discovery has spurred significant interest in Arctic oil and gas exploration. With completion of the Trans-Alaska Pipeline in the summer of 1977, attention now shifts to the gas pipeline project and expansion of exploration on the North Slope and Beaufort Sea.

Exploratory drilling has continued on state leases on the fringes of Prudhoe Bay including a coastal strip that extends from the Arctic National Wildlife Range in the east to the Colville River delta in the west. In the spring of 1977, Union Oil completed an exploratory well from an ice island in the Beaufort Sea located five kilometers (three miles) west of Oliktok Point. Also in the winter of 1976-77 British Petroleum drilled an exploratory well from a gravel island just over a mile from shore in Prudhoe Bay.

The Prudhoe Bay discovery and the Arab oil embargo of 1973 caused renewed interest in NPR-4. In 1974, after Congress had made appropriations for the exploration of the Navy Petroleum Reserves, the Navy commenced an exploration and geophysical survey program (Department of the Navy, 1977). After additional congressional appropriations in 1975, the Navy awarded an operators contract to Husky Oil to continue the program. A step-out well, Iko Bay, was drilled 26 kilometers (16 miles) southeast of Barrow in 1975 to obtain additional gas reserves for the nearby village. Cape Halkett Well No. 1, located 160 kilometers (100 miles) east-southeast of Barrow was completed to a depth of 3,020m (9,900 feet) on March 24, 1975. On May 7, 1976, a second deep well, East Teshpuk No. 1, located on a small peninsula on the eastern shore of Teshepuk Lake, was completed to a depth of 3,250m (10,664 feet) after finding a non-commercial zone in Permo-Triassic and older formations. Five medium-depth exploratory wells are planned for the northeastern sector of NPR-4 in the winter of 1976-77.

Speculative estimates of the oil resources of NPR-4 have ranged as high as 100 billion barrels, but a recent study (Resource Planning Associates, 1976) presents a significantly less optimistic estimate of 5 billion barrels of recoverable liquid hydrocarbons (oil and gas condensates) and 14.3 trillion cubic feet of recoverable natural gas.

The proposed Beaufort Sea federal OCS lease sale area is believed to have a good potential for significant petroleum deposits (Grantz et al., 1976). The lease area is everywhere underlain by unmetamorphosed, mainly marine, sedimentary rocks. These formations or their correlative contain seeps and known petroleum accumulations onshore, including the giant Prudhoe Bay oil and gas field. Consequently, there are sufficient incentives to begin-exploration offshore in the Beaufort Sea which could conceivably prove to be the new American petroleum frontier. The probability of finding another Prudhoe Bay size field either on the North Slope or beneath the offshore waters of the Beaufort Sea is statistically remote. Nevertheless, commercial reserves in the Beaufort Sea OCS area remain a distinct possibility, and if developed in conjunction with other potential finds in state waters and/or onshore areas in NPR-4 and those adjacent to Prudhoe Bay, could conceivably justify another major transportation link to the south.

4.1.2 Existing Ports and Infrastructure Along the Beaufort Coast

OCS petroleum development in the Beaufort Sea will require the construction and operation of port staging areas close to productive fields. These staging areas could be built either in existing communities or independent of them.

This section describes the existing ports and other infrastructure in the communities of Barrow, Prudhoe Bay, and Kaktovik and their potential usefulness as OCS staging areas. The decision of industry either to capitalize upon these community facilities or to create new service bases will be based upon a consideration of factors contributing to efficient port operation; sheltered harbor, a terminal yard, airport, adequate roads to accommodate truck traffic, and proximity to an established community able to provide utilities, communications, labor force, supplies and other public services.

4.1.2.1 Prudhoe Bay

Prudhoe Bay was created in response to the increased level of oil-industry related activities begun in 1968; it lies four miles north of Deadhorse in the central Beaufort Sea region. The population of this area has fluctuated primarily in response to manpower requirements of the construction of the pipeline and has ranged from several hundred to more than several thousand persons.

The shallowness of the harbor at Prudhoe Bay makes it necessary to offload the seagoing barges at sea and lighter goods with smaller barges to the unloading dock. The port facilities, including dock and storage areas, were constructed in 1969, and are connected to the operating areas and the airstrip by road. Adjacent to the dock is a 10 hectare (25 acre) gravel pad storage area and a wide gravel causeway. Three heavy cranes are stationed at the dock, and four dock barges are placed at the end of the causeway to enlarge the unloading area.

Two airstrips serve the Prudhoe Bay-Deadhorse area. The airstrip at Deadhorse is State maintained and has a 1,524m (5,000 foot) runway. Improvements, including widening the airstrip and the installation of additional navigation aids, are scheduled. When completed, operations at the privately owned airport at Prudhoe Bay, which has a l,676m (5,500 foot) gravel runway, will be discontinued. The State maintins two helipads in the area, one at Deadhorse and the other at Prudhoe Bay. Each helipad has a 30m (100 foot) gravel landing strip. Next to the Deadhorse Airport is a warehouse, aircraft maintenance shop, the air terminal and a transient camp.

The base camps at Prudhoe Bay have full utilities service, including water supply, electricity and full sewage treatment facilities. The lands surrounding the oil facilities at Prudhoe Bay are all owned by the State of Alaska.

4.1.2.2 Barrow

Waters off the coast of Barrow are quite shallow, with a depth of about 2m (six feet) at 300m (1,000 feet) offshore, so that cargo vessels must anchor at least a mile out. With the exception of petroleum goods which come ashore through hoses, all freight is lightered to shore.

The frequency of marine transport is limited by the ice pack, which can encroach the shore even in summer and presents a constant danger to ships. Most vessels plan to arrive at Barrow in August or early September.

Air transport is the major means of moving goods in and out of Barrow, and is the sole means by which the populace travels to other distant communities. Barrow has three air facilities. The Wiley Post/Will

Rogers Memorial Airport is state owned. This facility, comprising 296 hectares (732 acres) of land south of Barrow, has a 1,980m (6,500-foot), asphalt-paved runway and instrument landing facilities. Wien Air Alaska provides daily, scheduled Boeing 737 jet service from Anchorage and Fairbanks. Local air taxi operators in Barrow provide intervillage passenger and freight service. A second airport is located immediately east of the Naval Arctic Research Laboratory (NARL). The airstrip is 1,524m (5,000 feet) long and has a steel-planked surface. The stated-owned helipad with a 15m (50-foot) runway is also located in Barrow.

Barrow has no city-wide water or sewer system. Barrow's water supply is a fresh water lake south of the city. Water is distributed by two private hauling companies. The only sewer facilities exist at the BIA, Bureau of Indian Affairs Public Health Service Hospital, and the U.S. Weather Bureau. Sewage generated by individual dwellings is disposed of by privies or honey buckets.

Electrical service in Barrow has recently been improved. In November 1976, the North Slope Borough received a new 2,710 kw gas turbine generator set. Excess capacity is expected to last several years.

Natural gas is the fuel source used to generate electricity and provide home heating. The U.S. Navy supplies gas to Barrow Utilities, Inc., which distributes it to city residents.

Telephone communications in Barrow improved early in 1977 when RCA Alaska Communications put into service a new satellite earth station.

The new system increased the number of long distance channels from 7 to 20. The earth station also carries private line circuits, including channels for the Public Broadcasting System, the Alaska Native Health Service, and teletype and telex customers. The earth station can be readily expanded to meet future traffic needs. Local phone service is provided by the General Telephone Company.

The government and service sectors employ well over half of the Barrow labor force. Many residents are either directly or indirectly dependent for employment upon the Naval Arctic Research Laboratory, the Weather Bureau Service, or local and borough units of government.

Acreage for industrial use within Barrow is limited to approximately two acres. No acreage is available outside city limits, as all property surrounding Barrow lies within Naval Petroleum Reserve No. 4. There are no current zoning ordinances in effect.

Gravel sources that will not accelerate beach erosion are limited. The State Commissioner of Environmental Conservation has strongly recommended that priorities be established for the use of existing limited deposits within economic distance of Barrow.

4.1.2.3 Kaktovik

Kaktovik is a village located on Barter Island east of Camden Bay with an estimated population of 150. Barter Island is also the site of the Bar-Main DEW Line station, the first station west of the Canadian border.

Marine transport facilities at Kaktovik are limited. Shallow water makes necessary the lightening of goods from offshore barges to the beach. A gravel road connects the offloading area with the village.

Kaktovik is dependent upon airplanes for passenger service and most freight transport. Wien Air Alaska provides twice weekly service from Fairbanks. The airport at Kaktovik is federally owned and consists of a 1,468m (4,817-foot) gravel runway and air terminal. Adjacent to the airport is heated storage space which houses equipment for rent including tractors, backhoes and augers.

Kaktovik has no city-wide water or sewer system. During the summer months water is hand carried in buckets to individual dwellings from a fresh water lake adjacent to the village. In winter, chips of ice are used as the water source. Honey buckets, collected and emptied annually, are used to contain sewage and solid waste.

Fuel oil, which is lightered to Kaktovik and stored in metal holding tanks and fuel bladders, is the energy source used to power the electrical generator as well as for home heating. Barrow Utilities, Inc., operates the electrical system at Kaktovik.

Kaktovik has no local telephone service. The village has several public phones used to place long distance calls, which are routed through Fairbanks.

The public sector is the major employer of Kaktovik residents. The North Slope Borough employs construction and maintenance workers. Jobs are also available at the Village Corporation and the DEW Line station.

Gravel for construction or maintenance is available at a borrow pit on the western tip of the island and from the Hula and Jago Rivers.

4.1.2.4 Other Locations

In the event that a decision is made to create a new service base rather than to expand the facilities at an existing community, one location which will likely receive detailed scrutiny is Lonely, a centrally located DEW Line station with a 1,585m (5,200 foot) airstrip (1,524m [5,000 feet] is usable), which can accommodate jets and C-130 Hercules cargo planes.

At the DEW Line station, about one kilometer (one-half mile) from Lonely, is a diesel fuel storage facility. Plans exist to increase capacity by constructing two additional steel fuel storage tanks during the summer of 1977. The diesel fuel is used to power turbine aircraft, drill rig operations, electric generator operations and other diesel powered equipment needed for Naval Petroleum Reserve No. 4 activities. The fuel is also used for home heating purposes. A pipeline system links the tanks with the barge transport area at Lonely as well as the airstrip. It is through this pipeline system that fuel can either be stored or carried to vehicles or planes for distribution.

During the winter months fuel is distributed by all-terrain vehicles to operating camps within an 80 kilometer (50-mile) radius of Lonely. If the operating camps are more than 80 kilometers (50 miles) distant, it is transported by plane. The DEW Line station also has two tanks holding gasoline which is used to power machinery with internal combustion engines.

At Lonely, an RCA transportable earth station is the primary means of communication linking field personnel with the outside world.

The Husky Oil Company, which holds a five-year contract to explore for oil, has recently constructed a 50-man base camp at Lonely to serve as a staging area for drilling operations.

4.1.3 Potential for Petrochemical and Related Development

No development of refineries or petrochemical industries can be expected as a direct result of Beaufort Sea OCS petroleum production.

The potential for refinery development in Alaska is limited to growth in state internal demand. This will be completely met by reserves within the state, regardless of whether the Beaufort OCS is determined to contain developable resources.

The outlook for petrochemical development in Alaska is limited to the recovery of natural gas liquids from petrogas production, and the availability of natural gas. Since these raw materials are in short supply as basic feedstock throughout the world, development of their recovery should be expected. However, the market potential does not exist in Alaska, but rather in the U.S. Gulf Coast and in the far east. The incentive for development would be expected to lie in reducing the base feedstock materials, such as ethane and propane, two intermediates which are denser and can be more economically transported.

The natural gas liquids (NGL) components do not at the present time appear to have potential for development of transportation systems separate from , those of natural gas. Thus the potential for intermediate petrochemicals will be dependent upon the path of natural gas transport. Environmental controls in Alaska are often cited as reducing the petrochemical outlook in Alaska; nevertheless, an ammonia/urea plant using natural gas from the Cook Inlet fields has been developed at Nikiski on the Kenai Peninsula. Unemployment levels projected for Alaska would also tend to favor acceptance of petrochemical industry where it is economically feasible.

Since the Beaufort Sea OCS cannot by itself be projected to support an additional gas transport system, it cannot be projected as providng a direct stimulus for petrochemical development. If such industry should otherwise be developed, then Beaufort Sea OCS production could be expected to support it.

The necessary reserves to support development of a new gas transport system have been indicated from the analysis here as 20-24 trillion cubic feet (tcf) for markets at the $6.00 per unit level ($2.40/mcf), and 9-10 tcf for markets at the $8.00 per unit level ($3.20/mcf). The bonanza scenario for Beaufort OCS development is at the threshold of the latter condition. In conjunction with other reserves which may be found in the North Slope or state waters, and which might not have committed transportation, Beaufort Sea OCS production could lead to development of a new gas transport system. In this case, it could also be termed as having contributory potential for the petrochemicals considered here. Again, a cautionary note with respect to these reserve sizes emphasizes that they are in 1975-76 constant dollars, without adjustments for delivery consumption.

In terms of the various proposed gas transmission routes being considered for delivery of the 24 tcf Prudhoe Bay gas reserves, the economic analysis in this report is neutral; all routes have been treated identically as falling within the “medium” tariff. For discoveries near Prudhoe Bay, i.e., Central Beaufort, all routes would be geographically equivalent. However, for eastern Beaufort discoveries, the route across the Arctic National Wildlife Refuge would shorten the connecting line costs (provided the gas could all enter the line in that area). Similarly, western Beaufort discoveries could be transported more economically if they were aggregated with sufficient undiscovered resources, such as those speculated for Naval Petroleum Reserve No. 4, that they would in combination support a new transmission system.

4.1.4 Native Interests

One of the most critical aspects of determining the social and economic effects of OCS activity is the interaction between oil and gas development and the evolving policies of the Alaska natives toward use of their lands. Those policies reflect both the very deep concern for the maintenance of the traditional subsistence activities and the opportunity to maximally benefit native residents of the Beaufort Sea Region through employment and corporate service agreements with the petroleum industry. The institution or vehicle for the evolution of the land use policies is the Alaska Native Claims Settlement Act (ANCSA).

This Act of the U.S. Congress mandated transfer of 16 million hectares (40 million acres) of Alaska's land to Native corporations at the regional and village level. In addition, a cash settlement of approximately $1 billion eventually is to be distributed through the corporations to the individual enrolled members. Not all monies are to be distributed to individuals; some .is retained by the corporations. The powers and obligations of the corporations are extremely complex and have been the source of much discussion, controversy and litigation. The roles of the various federal agencies (particularly the Department of Interior) have been a source of tensions as they, more than any other entity, must transfer land they had managed over to the Natives. For a much more complete discussion of the Alaska Native Claims Settlement Act, refer to Alaska Native Land Claims by Robert Arnold (1976), and the "Alaska

Native Management Report" a twice-monthly publication of the Alaska Native Foundations (ANF).

The petroleum development scenarios discussed in this Report most directly affect the Arctic Slope Regional Corporation, whose boundaries encompass most of the North Slope, south to the Brooks Range. This corporation, one of 13 created by ANCSA, is a for-profit entity, headquartered in Barrow. It encompasses eight (8) village colorations and one nonprofit corporation. The village corporations and their locations are (Selkregg, 1975):

Nunamiut Corporation, Anaktuvuk Pass
Atkasook Corporation, Atkasook/Mead River
Ukpeagvik Inupiat Corporation, Barrow
Kaktovik Inupiat Corporation, Kaktovik
Kuugpik Corporation, Nuiqsut
Tigara Corporation, Point Hope
Cully Corporation, Point Lay
Olgoonik Corporation, Wainwright

The non-profit regional corporation is also the regional governing body of the North Slope Borough. The unification of the Native non-profit entity and the regional general purpose government is unique and provides the non-profit entity with much greater access to programs and funds than if it were only a creation of ANCSA. With this greater access has come greater power in determining the direction of regional policies.

OCS activity is one of the present concerns which face the people of the North Slope and their various corporations. Much of the local capacity to respond and direct the OCS social and economic impact depends upon the specific programs, policies and constituent groups which are developing from the provisions of ANCSA. Of more immediate issue is the resolution of the land easement question. The title to the land conveyed to the Natives carries with it the provision of easements to enable the public access to navigable waters, lakes or federal facilities. (Secretarial Orders #2982 and #2987). The Arctic Slope Regional Corporation has brought suit against the Department of the Interior, (Arctic Slope Regional Corporation et al. vs. Kleppe) challenging specific easements and their legality. The cloudy issue of easements has seriously delayed conveyance of title to the Natives, although an inter"im agreement between the Arctic Slope and the Department of the Interior has been signed allowing conveyance of the majority of Native land. Nonetheless, the entire problem of the transfer of land from federal to Native jurisdiction has taken many years with both parties selecting the land which they feel is most critical to their particular needs. Federal selection (or withdrawal from consideration of conveyance to Natives) has centered on natural scenic and mineral resource criteria. The Natives have tended to select areas of crucial significance to subsistence activity and areas of potential mineral resource development. The regional corporation and the village corporations have each the right to select specific amounts of land.

Conflicts are very real between the desire to maintain many of the attributes of a subsistence lifestyle and the orientation to maximally profit from the development of Alaska's wealth of natural resources. Land which may have value in terms of subsistence activity may also be the site of petroleum development or a reservoir of oil. This conflict is clearly present today on the North Slope.

Eben Hobson, the Mayor of the North Slope Borough, is on record opposing Beaufort Sea OCS operations because of safety and environmental hazards. However, other Native groups are in favor of OCS development. The Arctic Slope Native Corporation is currently involved in developing roads and oil exploration platform pads for Naval Petroleum Reserve No. 4. Also, the corporation has signed contracts with three oil companies exploring for petroleum on the North Slope and the corporation is waiting for offshore development in the hopes of providing possible service business in connection with that development. Sale of gravel, for example, could become a significant Native or village activity. The village of Kaktovik has already begun analyzing its Alaska Native Claims Settlement Act (ANCSA) land withdrawls in terms of the gravel resources they contain.

4.2 SELECTION OF FOUR SCENARIOS

Thus far, the analysis has explored the economic feasibility of the 15 "skeletal" scenarios within the framework of the technical, developmental and economic assumptions established in Chapters II and III. At this point, the analysis narrows its focus to four of the fifteen scenarios;

and provides, for each of the four, a hypothetical chronology of development activities, manpower scheduling and facility requirements.

The selection process used in the analysis entails first the establishment of selection criteria, and secondly the application of these criteria to the fifteen scenarios. Although economic feasibility plays a major role in the screening process, it was born in mind by the research staff that economics do not dictate the location of oil; rather, the converse is true, that the location of offshore discovery will dictate economic feasibility. Although seemingly a subtle distinction, it is nevertheless critical to the scenario selection process. If one were to use a measure of economic attractiveness (i.e. rate of return on investment) as the sole means of scenario selection, it would imply that all of the scenarios were in fact actual discoveries and that the investor had the luxury of selecting among the full array of development options. In such a case, the investor would invariably choose the largest finds (i.e. the bonanza reserve level); and, because of the extreme sensitivity of his rate of return to pipeline investment (see Section 3.8), he would invariably give preference to the location with the shortest distance to the Prudhoe Bay interconnection (i.e. central scenario location). Consequently, to use the economics as developed in Chapter III as the only screening device would be to obviate the cardinal precept of scenario construction: the reality of the resource location and size is unknown, and can only be hypothesized prior to actual exploration and field delineation. Since the scenarios in questions are ultimately designed to provide speculative input to predictions of socioeconomic impacts resulting from future OCS development, and since the location and magnitude of the actual impacts remain unknown, the scenarios chosen should reflect the fullest range of possibilities. Consequently, the primary criteria for selection will emphasize the need for variation and contrast, both in terms of the size of discovered reserves and the location of discovery.

Other criteria will focus upon the relative economics of development, the joint development of oil and gas reserves, the potential for aggregating development with other North Slope discoveries, and "worst case" impacts with respect to the physical and social environment of the North Slope. In brief, the criteria established by the research team are as follows:

- Maximum variation and contrast among the four scenarios with respect to the scale and location of onshore impacts.

- One scenario corresponding to the U.S.G.S. low level of reserves (zero), one corresponding to the most likely level of reserves (0.7 Bbbl), one corresponding to the high level of reserves (2.3 Bbbl), and one corresponding to the bonanza reserve level (3.5 Bbbl).

- One scenario for each of the geographical extremes; that is, at least one in the western Beaufort, one in the eastern Beaufort and one in the central Beaufort regions.

- For each scenario, simultaneous development of both oil and gas reserves under the conditions of economic feasibility as calculated in Chapter III.

- One scenario representing the maximum development situation, with the potential for the greatest social and environmental impacts.

According to the first three criteria (the second and third of which are derivative of the first), the research staff is in effect searching for an "across-the-board" variation in each of two dimensions: a "horizontal" dimension corresponding to geographical location, and a "vertical" dimension corresponding to magnitude or the level of reserves. Since a large number of combinations can be "mixed and matched" that will fulfill these requirements, the selection process now becomes one of using the remaining criteria to select among the suitable combinations.

Before this is done, it should be noted that one set of scenarios, those corresponding to the U.S.G.S. low level of reserves, falls out by default, since it entails either no discovery or a discovery of insufficient resources to justify development. Consequently, the low-level reserve scenario will be one of exploration activities without subsequent oil and gas development. Although the criteria allow for this "exploration-only" scenario to be placed offshore from any of the three locations, the research staff felt it would be a more informative scenario with respect to impact analysis if the exploration activities were more widespread.

As a result, Scenario No. 1 was selected to be one of exploration activities ranging from Smith Bay in the west to Camden Bay in the east.

Only three scenarios therefore remain to be selected: a "mix and match" among the most likely, high, and bonanza reserve levels that are to be uniquely positioned with respect to the western, eastern and central Beaufort. Use of the fourth criteria (simultaneous oil and gas development) in conjunction with the findings of the economic analysis, will serve as the basis for the selection of the second scenario. Notably, both oil and gas will "go" in the eastern and western regions for both the high and bonanza reserve levels, as shown in Tables 3-14a and 3-14f.

However, examination of Table 3-14 (J,K,L) reveals that gas development is economically feasible for the "most likely" reserve level scenario (0.7 Bbbl) only for the central region; in the western and eastern regions the required market price exceeds the established cutoff of $10/unit (unit equals 2.5 mcf). Consequently, to meet the criteria of simultaneous oil and gas development, the "most likely" reserve level (0.7 Bbbl) must be located in the central Beaufort region offshore from Prudhoe Bay. This forms the basis for Scenario No. 2.

The selection process is now reduced to one of positioning the high and bonanza reserve levels with respect to the eastern and western locations. There are only two remaining combinations that are possible, since according to the first three criteria, the positioning of one reserve level in either of the two remaining locations automatically establishes the last scenario combination.

The final determination will be based upon the best criteria, that of establishing a "maximum development" situation whereby the potential impacts to the existing environment (physical, biological and man-made) can be analyzed with respect to the highest level of petroleum activities that can be reasonably anticipated. The greater the level of discovered reserves, the greater will be the levels of manpower and equipment required for petroleum development. In this sense, the 3.5 Bbbl (bonanza) reserve scenario represents the "maximum development" to be postulated in this analysis.

The remaining question is where to place the bonanza reserves in order to explore the "maximum development" impacts upon the environment and the existing socioeconomic system. A strong case can be made for either location. With respect to the environment, the eastern landfall would probably occur within the Arctic National Wildlife Range, and the western landfall within the province of the Naval Petroleum Reserve No. 4. These land-use designations strongly imply that the former is ecologically significant, whereas the latter is significant principally in terms of resource exploitation. Many would agree as such; nevertheless, a very strong case can be made that the western Beaufort region is as equally important and equally sensitive, in terms of the total ecosystem, as the eastern region, politics'l jurisdictions not withstanding.

With respect to the socioeconomic systems of the two areas, the need to analyze a "maximum development" situation can be argued for either the eastern or western locations. The eastern scenario would affect principally the village of Kaktovik on Barter Island which has a population of about 150 people. If one argues in the sense of "per-capita" change, then a "maximum development" scenario would logically fall into this region. Extending this arguement to the west, Barrow, which represents the largest population center on the Beaufort coast (a population several orders of magnitude greater than Kaktovik), might conceivably undergo less experiential change with respect to the individual lifestyles of its citizens than would be the case with Kaktovik. On the other hand, if one argues in the sense of absolute change rather than "per capita" change, the conclusion would be the opposite. Since Barrow possesses a significantly greater labor pool available for direct or indirect employment in nearby OCS development, the notion of total "enclave" development would be less likely there, and a greater amount of occupational and social interaction would ensue.

The potential for socio-political conflict might also be argued to be greatest in the western Beaufort. Native interests center on the use of their own lands. Traditional use of land for hunting and fishing, along with related concerns for conservation, will conflict with moves to exploit land for commercial, industrial and petroleum-related uses.

Opposition may take the form of lawsuits or political moves to stop development. Eben Hopson, the mayor of the North Slope Borough, is on record opposing Beaufort Sea OCS operations because of safety and environmental hazards. However, other Native groups are in favor of OCS development. The Arctic Slope Native Corporation is currently involved in developing roads and oil exploration platform pads for Petroleum Reserve No. 4. Also the corporation has signed contracts with three oil companies exploring for petroleum on the North Slope, and the corporation is waiting for offshore development in the hopes of providing possible service business in connection with that development.

Resolution of the choice for the location of the "maximum development" scenario was finally determined on the basis of the potential for aggregated gas development in the western region. As stated in Section 4.1.3, the gas associated with the bonanza reserve level is just below the threshold of justifying a new gas pipeline to the south in an $8/unit market (2.5 mcf/unit). Moreover, the potential for gas development in the nearby Naval Petroleum Region No. 4 appears favorable (see Section 4.1.1). Combining a recent conservative estimate (Resource Planning Associates, 1976) of the gas reserves in NPR-4 (14.3 tcf) with those for the bonanza reserve scenario (8.8 tcf) would elevate <u>total</u> gas reserves to the level needed to justify a new pipeline in a $6/unit market. (The latter is a delivered price corresponding to currently proposed gas pipelines.) Because of the potential for "synergistic" gas development in the west that could lead to still greater construction activity (another pipeline to the south), the potential for "maximum development" impacts appeared more probable in the western Beaufort location than in the eastern location. Consequently, it was decided to locate the bonanza reserve level offshore from Smith Bay. The high reserve was then accordingly placed in the east, near Camden Bay.

In summary, the four selected scenarios are as follows:

- Scenario No. 1 - Exploration only in all three geographical locations (western, central, and eastern Beaufort Sea) based on a low reserve estimate (95% probability).

- Scenario No. 2 - Development in Prudhoe Bay basedon a mode reserve estimate (50% probability).

- Scenario No. 3 - Development in Camden Bay based on a high reserve estimate (5% probability).

- Scenario No. 4 - Development in Smith Bay based on a bonanza reserve estimate (2% probability level).

4.3 MANPOWER ASSUMPTIONS

For each of the selected scenarios, the manpower requirements will be eventually projected by: year; phase (exploration, development, and production); activity (exploration platform construction, drilling, etc.); peak number of jobs; total man-months; and skill levels. To make these projections, a large number of assumptions have to be made; and this section of the report is devoted to a summary of the assumptions pertinent to manpower. When combined with the specific assumptions regarding -Facility requirements (number of wells, miles of pipeline, etc.), along with the construction/installation time table for these facilities, the complete manpower schedule for each scenario can be set out in detail.

Table 4-1 summarizes the manpower assumptions used in the analysis. For each discrete activity, such as the construction of an exploratory base camp, a typical time schedule for a single crew is specified. This time schedule represents actual on-site performance, with no provisions allowed for the hiring and relocation of personnel, delays in startup, critical parts supply, etc. Consequently, this schedule is termed “critical path”, and is quite unrealistic in terms of the actual time needed to complete a job. As a result, a “dilation factor” (multiplication factor) been assumed for each task that more closely approximates the realities of construction in an arctic environment. Consequently, if a single crew of 40 people can construct an exploratory base camp, it will require 400 man-months of effort:

$$\begin{aligned}\text{Total Man-months} &= \text{Critical Path} \times \text{Dilation Factor} \times \text{Crew Size} \\ &= 5 \times 2 \times 40 \\ &= 400\end{aligned}$$

If these same 40 men worked on a year-round basis, they should be able to complete the camp in approximately 10 months; however, since arctic construction activity is highly seasonal, the total man-months required might be stretched out over a two-year period. Thus, in the manpower schedules

TABLE 4-1

MANPOWER ASSUMPTIONS[1]

Job	Job Schedule (Months per Job per Crew): Critical Path(2)	Dilation Factor(3)	Crew Size (People per Crew)
Exploratory Base Camp Construction (each)	5	2.0	40
Production Base Camp Construction (each)	12-24(4)	1.5	40
Exploratory Platform Construction (each)	4	1.5-2.0	40
Exploratory Drilling (each)	4	2.0	40
Exploratory Drilling (each)	3	1.5-2.0	30
Production and Development Drilling (each)	2	1.1-1.5	30
Offshore Pipeline (mile)	.5-.7	1.5-2.5	120
Onshore Pipeline (mile)	.5-.7	1.7-2.5	120
Equipment Installation (each field)	12-30	1.0	75 (or less)
Base Camp Operation and Supply (each)	NA	NA	20-30 per block
Survey of Tract (each)	.2-.5	1.0	5
Transport Complement (total)	NA	NA	30 during construction 5-10 during operation
Platform Operation and Maintenance (each)	NA	NA	16

(1) Derived from unpublished working papers of Canadian Arctic Gas Pipeline Ltd. and judgments of the research staff.

(2) Typical (not average) months of actual on-the-job performance.

(3) Multiplication factor applied to critical path to adjust for delays due to hire, personnel transport, logistics, intra-job coordination, downtime. Factor tends to decline with larger jobs due to greater efficiencies and better coordination.

(4) Twenty four-month figure used in scenarios to account for road construction.

to be developed, the annual manpower requirements for each activity will be stated in term of the largest complement of workers at any given time during the year (peak jobs), and in terms of the total man-months of effort during that year.

Table 4-1 contains a range of values for some of the critical paths and dilation factors. As a general rule, it has been assumed that the dilation factors (i.e. measures of delay) will decrease with larger jobs (i.e. larger reserve levels) due to improvements in efficiency. Moreover, the factors related to the exploratory activites around Prudhoe Bay have been favorably weighted to reflect the use of the existing infrastructure. The specific values used in constructing the four scenario manpower schedules are shown in Table 4-2 (a supplement to Table 4-l).

Tables 4-3 and 4-4 show the skill level distribution pattern and the occupational distribution pattern, respectively, that will be employed in the manpower analysis. For each scenario, these profiles will be sequentially applied to the annual peak number of jobs for each activity (i.e. peak number of platform construction jobs in the third year following the lease award includes 25 jobs for semi-skilled technicians).

The manpower analysis for each scenario is stated in terms of required jobs, not employment. Due to rotation of personnel (normally 2-on and l-off), turnover of personnel, and limited productivity in the arctic environment, the number of people employed in any given year will be greater, roughly twice the number of jobs required. More specific relationships are shown in Table 4-5. Multiplying the number of jobs as

TABLE 4-2

SELECTED VALUES USED IN THE MANPOWER SCHEDULES
(supplement to Table 4-1)

	Scenario			
	No. 1	No. 2	No. 3	No. 4
Dilation Factors Used*				
Exploratory Platforms	1.5	1.5	2	2
Exploratory Drilling	1.5	1.5	2	2
Production Drilling	NA	1.2	1.15	1.1
Offshore Pipeline	NA	2.5	1.5	1.3
Onshore Pipeline	NA	2.5	2	1.7
Critical Path Used* (months per job per crew)				
Offshore Pipeline (miles)	NA	.7	.7	.7
Onshore Pipeline (miles)	NA	.7	.6	.6
Equipment Installation	NA	12	30	30

*For remaining activities refer to Table 4-1.

TABLE 4-3

MANPOWER DISTRIBUTION BY SKILL LEVEL[1]

Job/Activity	Skill Level[2] Skilled	Semi-Skilled	Unskilled
Platform, Harbor, Road Construction	10%	30%	60%
Drilling	24%	50%	26%
Pipeline Construction	21%	66%	13%
Processing Installation	50%	25%	25%
*Transport	20%	20%	60%
*Support Service/Supply	40%	35%	25%
*Operations and maintenance	40%	35%	25%
*Administrative, Regulatory, Personnel Support	45%	35%	20%

* Permanent operations.

(1) From published estimates of Canadian Arctic Gas Pipeline Ltd.

(2) Job titles within the skilled category include engineers, supervisors, foremen, mechanics, welders, aircraft personnel and technicians. Semi-skilled functions include clerical and supply workers, drivers, operators, and lower-grade technicians. Unskilled covers all other jobs.

TABLE 4-4

SKILL LEVEL DISTRIBUTION BY OCCUPATION*

Skilled	Percent of Work Force
Supervisory and Engineering	3.0%
Aircraft	3.0%
Maintenance Supervisory	1.5%
Foreman	1.5%
Mechanics	6.0%
Welders	4.5%
Technician, Chief or Supervisory	1.5%
Semi-Skilled	
Clerical and Supply	6.0%
Operators and Drivers	6.0%
Technicians	54. 5%
Unskilled	
Labor and Maintenance	12.5%
	100.0%

* Drawn from a construction plan of Canadian Arctic Gas Pipeline, Ltd. specifically applies to a distribution for a pipeline crew, but has been used as an approximation by the research staff of the occupational distribution for all activities for the purposes of scenario analysis.

TABLE 4-5

EMPLOYMENT FACTORS(1)

Job	Employment Multiplication Factor
Base Camp Construction	1.5
Base Camp Operation	1.5
Platform Construction	2 during exploration phase 3 during development production phases
Drilling	2.5
Pipelining	2-2.5(2)
Equipment Installation	1 (Jobs and Employment the same)
Surveying	1 (Jobs and Employment the same)
Local Transport	1.5
All Skilled Jobs	1.8
All Service Skilled Jobs	1.5-1.8
All Unskilled Jobs	2.5-3.0(3)

(1) Multiplication factor is applied to the job count to yield total direct employment. Typical rotation of personnel (2 on, 1 off) gives minimum factor of 1.5; values above this are based on the judgments of the research staff as to the productivity factor (i.e. standbys for workers unable to maintain a 10-hour shift in Arctic conditions) and the turnovers factor (i.e. dropouts). The employment factor tends to decrease for larger jobs as personnel problems stabilize.

(2) High for long pipeline jobs.

(3) High overall values reflect dropouts who are typically out-of-towners; factor for locals is closer to 1.5.

stated in the scenarios by the employment factors shown in the table give total direct employment. Direct employment excludes secondary or indirect employment, as well as suppliers, technical observers, and others who occasionally visit the work sites.

4.4 LOCATIONAL CRITERIA

The purpose of this section is to establish basic criteria for the siting of onshore facilities, which can be applied to the development requirements of the four selected scenarios in order to establish the most likely zones for development. These criteria will encompass the environmental considerations discussed in Section 1.5, including wildlife sensitivity, resource use and jurisdictional issues, as well the use of the existing infrastructure along the Beaufort coast as discussed in Section 4.1.2. The usefulness of these locational criteria is limited to the identification of development zones, rather than specific sites, because of the hypothetical and somewhat generalized nature of the scenario construction. The detailed analysis required for site-specific planning is beyond the scope of this report.

The following list of criteria is organized according to those considered to be of primary and secondary importance. The first category includes overriding concerns which will establish broad land-zones in which the development of base camps and pipelines is likely to take place. The second category helps clef"ine more specific areas within these zones.

4.4.1 Primary Locational Criteria

- Proximity to Offshore Production Field

  The most important requirement for base camp location is its proximity to the area of offshore development. Close proximity minimizes the running time of supply ships, over-ice vehicles and helicopters. This is especially important during periods of inclement weather or emergency. Close proximity also minimizes the length and therefore the investment requirements for offshore pipelines which have landfalls at the service base.

- Proximity to Deep Water

  Since the Beaufort Sea is shallow (the 20m [60-foot] isobath lies 16-18 kilometers [10-50 miles] offshore), depth of water close to shore is an important locational criteria for a port site. In general, the presence of shoal waters on the Beaufort Sea coasts necessitates lightening of freight from deep draft vessels to shore in barges that draw less than 2.5m (8 feet) of water. Other factors that are important in port site location include submarine topography, the type of bottom sediments, coastal erosion and near-shore sediment transport.

- Usefulness of Nearby Existing Facilities

  The usefulness of existing ports and airports during the exploration stage, and to a lesser extent, during the production stage is an important locational criteria. The potential for utilizing existing labor, roads, utilities, communications, specialized services, and public services at Prudhoe Bay, Barrow and other DEW Line military sites is directly related to their proximity to the offshore development fields.

- <u>Proximity to Prudhoe Bay</u>

  All oil reserves will be transported from the fields to landfalls at the base camp, and from there to the Alyeska pipeline. Prudhoe Bay would probably serve as a staging area for exploration and development in the central Beaufort Sea. Conceivably, petroleum exploration or development within 100 miles of Prudhoe Bay could utilize the facilities.

- <u>Sheltered Harbor</u>

  An adequate sheltered harbor in the general proximity of the development area is a major factor in locating the supply base. Barges will require protection from fall storms and the movement of sea ice. This will either require the construction of a jetty or causeway, or the location of the port in a protected, natural harbor, or inside a lagoon protected by offshore islands. Most port sites should be in the land-fast ice zone.

4.4.2 Secondary Locational Criteria

- Consideration of Environmentally Sensitive Areas
  Environmentally sensitive areas are an important consideration which could modify or dictate the construction schedule, as well as the siting of ports, base camps, offshore structures, pipeline causeways, and the movement of barges and other marine traffic. Consideration may have to be given to the location and timing of marine mammal and fish migrations. Onshore habitats, such as the dens of polar bears, the calving areas of caribou, and the nesting and molting sites of waterfowl, will have to be evaluated in the planning of ports and pipelines, and the timing of onshore construction. These marine and terrestrial wildlife resources are important with respect to the subsistence economies of the villages.

- Availability of Gravel and Water Resources The availability of exploitable gravel is important to petroleum development since it is used extensively for the construction of roads, airstrips, workpads, offshore drilling islands and pipeline causeways. One and one-half meter (five feet) thick gravel pads are the general rule in constructing facilities at Prudhoe Bay.

Regionally on the North Slope, gravel and coarse sand resources are limited west of the Colville River (see Section 1.5.2.1). This pattern is probably repeated offshore where sand and gravel bottom sediments are predominant east of the Colville River delta and are replaced by silts and clays west of the delta.

As indicated in Section 1.3.2, the availability of offshore gravel and sand will be an important factor in the selection of artificial islands for exploratory and production platforms. An important cost factor in the construction of such islands and onshore facilities will be the haul distance.

Gravel and sand availability will also be affected by the environmental impacts of their extraction. These concerns include:

- Siltation of fish spawning streams.
- Siltation in offshore fish habitats.
- Acceleration of erosion on beaches, river and coastal bluffs, barrier islands, and tundra surface.

Gravel availability would only be a significant locational factor if other factors were equal; rather the availability of gravel is an economic and environmental consideration. In some areas where gravel and sand are in short supply, alternate construction methods to economize on sand and gravel will have to be adopted and substitute materials used.

Water resource availability, discussed in Section 1.5.2.2, is a major concern in Arctic petroleum development since water is required in large quantities during every phase of petroleum development. The water supply problem on the North Slope is compounded by environmental problems of its withdrawal in some areas. These include:

- o Winter extraction from portions of rivers where fish winter.

- o Winter extraction from deeper lakes where fish winter.

Water resource availability would only be of significant locational factor if all other factors were equal.

- o <u>Jurisdictional Considerations</u>

  Although it is difficult to predict the importance of specific planning or regulatory activities established for such jurisdictions as State lands, the Naval Petroleum Reserve No. 4, or the Arctic National Wildlife Range, it can be assumed that these will influence the location, siting and routing of base camps, port sites, pipelines, etc.

- o <u>Political Considerations</u>

  The receptivity of existing communities to OCS development could be important, particularly in establishing exploratory base camps. The willingness of a community or operators of a facility to provide space and services in a timely manner for port and airport use, water and utilities supply, and communications could overcome other functional deficiencies with the location. Conversely, community resistance could mitigate otherwise sound criteria for facility location.

Although political considerations are important locational criteria, they are relatively intangible and extremely complex. Consequently, it was felt that an in-depth evaluation of the political issues and processes surrounding OCS development in the Beaufort Sea area was beyond the scope of this report.

o Facility Consolidation

With respect to industry, it has been assumed that a base camp would be established for a consortium of oil companies, although it is possible that some firms would prefer to develop a site for their sole use. Separate company base camps could be built to service their respective platforms in the same field.

o Consideration of Archaeological and Historical Sites

The location of important known historic and archaeologic sites may modify the location of pipelines, base camps, etc. (the major river valleys of the North Slope, in particular, are historically and archaeologically important). It can also be assumed, however, that archaeological surveys will be conducted as part of siting studies and add to existing knowledge.

4.5 SCENARIO NUMBER ONE

The first scenario under consideration, which corresponds to the U.S.G.S. low-level estimate of reserves (95% probability), entails simultaneous exploration offshore from Smith Bay, Prudhoe Bay and Camden Bay (eastern, central and western Beaufort, respectively). There are insufficient resources discovered to justify either oil or gas development.

4.5.1 Chronology of Major Events

In summary, the entire exploration phase covers a period of only four years subsequent to the lease-sale award. The results of this exploration prove sufficiently discouraging after four years that industry decides to cut its losses short and move its exploratory activities to a more favorable location; the fields are shut down and the base camps and platforms are abandoned.

The scenario begins with a moderately high level of optimism surrounding the lease-sale; speculation stimulated by discoveries in related geological structures in state waters and nearby onshore areas (unspecified in this interim analysis) lead to the purchase of some 20 tracts. Approximately one-half are offshore from Prudhoe Bay, with the remainder split equally between Smith Bay and Camden Bay. Arrangements are made to use the existing facilities at Prudhoe Bay as an exploratory base camp and operation of such begins in the first year following the lease sale. Simultaneously, construction begins on the base camps that will be used to support the exploratory activities in the western and eastern regions. Two crews (40 people per crew) are employed in the construction of these base camps, with one crew assigned to the west and one to the east.

The western base camp is completed within the first year, whereas construction of the eastern base camp carries over until some time in second year.

Exploration activities begin almost immediately after the lease-sale. In the first year, five survey teams (5 people per team) complete the geophysical data collection process that began prior to the lease-sale itself, as well as the required tract surveys. Eight tracts are eventually selected as the most favorable locations and construction begins within the first year on 5 exploratory platforms: two each in the land-fast ice zone of the western and central regions, and one similarly situated in the eastern region. Each of these platforms is constructed by a single crew of approximately 40 people.

Exploratory drilling begins in the second year with the completion of these 5 platforms. Meanwhile, the platform crews in the central and eastern areas are shifted to the remaining tracts selected for exploration, and construction begins on the additional platforms. By the end of the second year, seven exploratory wells have been completed (three in the west and four in the central region) without a successful field.

In the third year, all platform construction ceases, while drilling activities are stepped up in the central region and initiated in the eastern region. All together, some 10 exploratory holes are drilled and are found to be dry. Demobilization of the platforms on the unsuccessful tracts begins; it takes a single crew about one month per platform to remove the drill rigs and associated equipment. The abandoned gravel islands are left to the processes of natural erosion unless they pose a navigational hazard, or unless environmental regulations require their removal; ice islands (the majority) dissipate in the summer thaw.

By the fourth year, drilling activity has terminated in the western region and the base camp is either abandoned outright or sold as salvage. In the central and eastern regions, one and two additional wells are completed, respectively. No commercial resources are discovered, and discouragement finally leads to the decision to terminate all further exploratory activities in Beaufort Sea OCS lease-sale area.

A tabularized summary of the facilities required for scenario one, along with the schedule for their construction and installation are shown in Tables 4-6 and 4-7. The schedule separates the construction activities of the three regions.

4.5.2 Facility Requirements

The total facility requirements for scenario one include: 8 exploratory platforms, 20 wells, 2 base camps (excludes existing facilities at Prudhoe Bay), 42 barges, 70 trucks and tractors, and 14 aircraft. These figures are broken out for each of the three exploratory regions in Table 4-6.

An estimate of the total expenditures required to meet the exploratory program outlined by scenario one, including the cost of purchasing 20 tracts, is between $500 and $700 million.

TABLE 4-6

SCENARIO ONE DEVELOPMENT SUMMARY

Activities/Facilities	Requirements West	Requirements Central	Requirements East	Peak Number of Construction/ Drilling Crews West	Peak Number of Construction/ Drilling Crews Central	Peak Number of Construction/ Drilling Crews East
Tracts Explored	2	4	2	------- 5 survey teams ------		
Exploratory Platforms Constructed	2	4	2	2	2	1
Exploratory Wells Drilled	5	10	5	2	3	2
Base Camp/Harbor	1	*	1	1	0	1
Barges	12	18	12	NA	NA	NA
Trucks and Tractors	20	30	20	NA	NA	NA
Aircraft Complement	4	6	4	NA	NA	NA
Rotary	2	3	2			
Fixed Wing	2	3	2			

* Central uses Prudhoe Bay facilities.

TABLE 4-7

SCENARIO ONE
CONSTRUCTION AND INSTALLATION SCHEDULE

Exploratory Location	Year	Number of Completions: Platforms	Wells	Base Camp & Harbor
West	1			1
	2	2	3	
	3		2	
	4			
	Subtotal	2	5	1
Central	1			Uses Prudhoe Bay
	2	2	4	
	3	2	5	
	4		1	
	Subtotal	4	10	NA
East	1			
	2	2		1
	3		3	
	4		2	
	Subtotal	2	5	1
	TOTAL	8	20	2

4.5.3 Manpower Requirements

The peak number of jobs required to meet the exploratory objectives of scenario one rise from 375 jobs in year one to 530 jobs in year three; in the fourth year manpower requirements drop sharply to a level of 190 jobs, after which the program is terminated altogether. The manpower schedule for scenario one is summarized in Table 4-8 for each major activity (i.e. construction of platforms, drilling, etc.) with respect to the peak number of jobs in any given year, as well the total man-month requirements for each year. A comparison of peak jobs to total man-months reveals that the "average job" lasts for less than 6 months per year.

Manpower requirements reach a peak in the third year at a level of 530 jobs, of which nearly 80% are comprised of exploratory platform construction and drilling jobs. As mentioned in Section 4.3, total direct employment will be approximately twice the level of jobs, since the latter does not reflect rotation schedules, turnover, etc. Therefore, the total direct employment engendered by the assumptions of scenario one is in excess of 1,000 employees.

As shown in Table 4-9, roughly 40% of the job requirements will be for unskilled workers, 40% for semi-skilled, and 20% for skilled workers. The table also gives a breakdown for specific occupational categories.

TABLE 4-8

SCENARIO ONE
MANPOWER SCHEDULE
(Peak Number of Jobs)/ (Total Man-Month Requirements)

Activity	Year 1	Year 2	Year 3	Year 4
Base Camp Construction	80/600	40/200		
Base Camp Operation	10/100	20/200	20/200	10/100
Support and Supply	30/100	30/350	30/350	10/100
Exploratory Platform Construction	200/640	200/960	120/320	
Exploratory Platform Demobilization			210/160	60/80
Exploratory Drilling		180/945	210/1350	90/405
Local Transport	30/300	30/300	30/200	20/160
Survey	25/25			
TOTAL	375/1765	500/2955	530/2580	190/845

TABLE 4-9

SCENARIO ONE
MANPOWER DISTRIBUTION BY SKILLS
(Peak Number of Jobs)

Skilled Inventory	Year 1	2	3	4
Skilled Jobs				
Supervisor, Engineer	30	20	18	6
Aircraft	4	4	4	4
Foremen	6	14	15	10
Mechanics (craft)	20	32	35	9
Welders (certified)	10	16	18	8
Technicians (senior)	7	9	12	4
Skilled Subtotal	77	95	102	41
Semi-Skilled Jobs				
Clerical and Supply	17	37	40	20
Operators	65	85	75	25
Technicians	20	62	84	28
Semi-Skilled Subtotal	102	184	199	73
Unskilled Subtotal	196	221	229	76
TOTAL	375	500	530	190

4.5.4 Locational Factor Analysis

Exploration of the hypothetical western, central and eastern reserves will require the development of onshore facilities; the location of these facilities will primarily be determined by requirements for economy and efficiency of operations, but will also be influenced by locational criteria. The most important factor associated with the location of base camp facilities for exploration in the Beaufort Sea is the presence of support facilities at Prudhoe Bay. Although scenario one assumes the construction of base camps in both the west and east, recent discussions with officials at Prudhoe Bay (Featherstone, 1977) indicate that offshore exploration anywhere in the lease sale area could be supplied out of Prudhoe Bay. Prudhoe Bay facilities which could serve the application needs include: two operating airstrips, a heliport, port facilities, storage areas, gravel supplies, water supplies, communications facilities, supply and service companies, and emerging medical facilities. Drilling supplies and men could be airlifted daily from Prudhoe Bay to the off-shore platforms. If the exploration area was in close proximity to Prudhoe Bay, supply boats could be used in summer and over-ice tractors and trucks in winter.

If the Prudhoe Bay facilities should prove to be unavailable or uneconomic for exploration at the extremes of the Alaska Beaufort Sea, consideration would be given to other existing facilities in closer proximity to the offshore exploration area. A variety of facilites near the three hypothetical offshore reserves is discussed below. Each section begins with a description of the offshore area and important natural features in the vicinity.

4.5.4.1 Western Region

The hypothetical western exploration area includes 12 tracts (108 square miles) located north of Smith Bay, approximately 60 miles east of Barrow and 140 miles west of Prudhoe Bay. West of the Bay is Camp Simpson; to the east is Drew Point. Teshekpuk Lake, the largest fresh water lake in the Arctic, is located approximately 10 miles southwest of Drew Point.

Existing port and airport facilities in proximity to the western exploration region include the airport at Barrow and the DEW Line station at Lonely, approximately 15 miles east of Drew Point. Barrow may be limited in its potential to serve as an exploration support Base, because acreage for industrial use is extremely limited. Shallow water [2 m (6-foot) isobath lies 300 m (1,000 feet) offshore] off the coast of Barrow requires that cargo be transferred from vessels and lightered to shore.

Facilities at the DEW Line station at Lonely may provide more useful support to exploration in the western region. This station has a 1,525 m (5,000-foot) airstrip, fuel for electrical generation and heating, telecommunications facilities and an accessible port. In addition, a 50-man base camp has recently been constructed for support of exploratory drilling operations in Naval Petroleum Reserve No. 4.

The decision to utilize Prudhoe Bay or the facility at Lonely could involve such issues as the anticipated development potential of the offshore fields, the likelihood of year-round or winter exploration, and governmental limitations to the use of the Air Force station.

4.5.4.2 Central Region

The central region encompasses seven tracts, [about 155 square kilometers (60 square miles)], and ranges between 8 and 11 kilometers (5 and 7 miles) from the coastline. The block of tracts is approximately 40 kilometers (25 miles) at its closest point from the trans-Alaskan pipeline terminus at Prudhoe Bay. Lying between the block of tracts and the coastline is a 48 kilometer (30-mile) long chain of barrier islands which enclose Simpson Lagoon.

It is assumed that facilities near the camps of British Petroleum and Atlantic Richfield in Prudhoe Bay would serve this central area.

4.5.4.3 Eastern Region

The eastern exploratory region lies offshore from the Arctic National Wildlife Range in Camden Bay. The block of tracts extends approximately 64 kilometers (40 miles) west of Kaktovik to the delta of the Canning River. The center of the eastern region is approximately 145 kilometers (90 miles) east of the Prudhoe Bay and 48 kilometers (30 miles) west of Kaktovik.

Existing facilities for the possible support of exploration activities in the vicinity of Camden Bay are limited to Kaktovik and the proposed supply port for the proposed Alaska Arctic Gas pipeline. The facilities near Kaktovik include a 1,463 m (4,800-foot) runway and the communications' facilities at the Bar-Main DEW Line station. Nevertheless, the infrastructure and the existing facilities of the village area would be insufficient to meet the needs of an exploratory base camp.

A central Camden Bay port site was included in the Alaska Arctic Gas pipeline proposal as part of their construction requirements.

4.6 SCENARIO NUMBER TWO

The second scenario under consideration corresponds to the U.S.G.S. "most likely" estimate of recoverable reserves (0.7 Bbbl of oil and 1.8 tcf of gas) which are discovered offshore from Prudhoe Bay. At the time of discovery, industry conservatively projects future market prices at the time of initial production (10 years in the future) to be $14/barrel of oil and $7/unit (2.5 mcf/unit) for gas (constant 1975-76 dollars); other projections range considerably higher. Given the conservative projections, one high tax-status oil producer estimates his after-tax return on investment would be between 15% and 25%, depending on whether his investment costs run toward the high side or toward the low side (see Table 3-14k). Similarly, since contractual arrangements can be made to transport the gas to the south via the existing gas line (all of the currently proposed gas lines fall into the primary gas tariff), he estimates his return on investment for gas development would be in excess of 15%. His future need for refinery and petrochemical feedstocks are great, and the rate of return appears acceptable; consequently, the decision to develop the oil and gas fields is affirmed.

4.6.1 Chronology of Major Events

In summary, the exploration phase lasts for five years subsequent to the lease-sale award, and development of the field requires an additional five years. Oil production commences in the tenth year, and very quickly reaches a maximum annual output of 70 million barrels. Gas production begins in year 12 with an annual output in excess of 100 billion cubic feet. Although the flow rate of gas remains stable, the oil output begins to decline rapidly after the sixteenth year. By the thirtieth year, the annual oil output has dropped to 5 million barrels and the unit costs of operating the field are rising prohibitively. The decision is made to shut down the field and abandon the operations.

The scenario begins with a level of caution surrounding the lease-sale. Industry's geophysical and geological data indicate that the most favorable formations lie offshore from Prudhoe Bay, but are not expected to yield large commercial reserves. Only six tracts are purchased at an average cost of $5 million per tract. In the first year following the lease sale, two survey teams (5 men per team) complete the geophysical testing and identify the initial four tracts to be explored. Meanwhile, a single crew of 40 people has begun the construction of a small exploratory base camp and harbor; by preference or by the inability to gain immediate access to the existing facilities at Prudhoe Bay, a new location has been selected.

Construction of three exploratory platforms begins in the second year utilizing three independent crews of 40 people per crew; one is completed and the first exploration well is sunk. By the end of the second year, the exploratory base camp has been completed.

in the third year, three additional exploratory platforms are finished and rigged for drilling operations. By the end of the third year, three drilling crews are at work and two additional exploratory wells have been completed.

Drilling intensifies in the fourth year with five additional holes being punched. Oil and gas are discovered in two of the four tract locations which tend to confirm preliminary assessments of the geological structures; and a decision is made to abandon the two dry tracts without further search. Also, construction begins that will expand the exploratory base camp into a larger production base camp.

In the following year the harbor is opened for full-scale operations and work begins on the demobilization of the two artificial island platforms on the dry tracts. A few more exploratory wells are sunk in the successful areas to explore the reaches of the underlying deposit. Knowledge of the field is now sufficient that the most advantageous location for drilling can be determined, and construction of the first production platform gets underway.

By the end of the sixth year, all four exploratory platforms have been dismantled, and the equipment removed; the ice islands are simply abandoned, while the gravel islands are used principally as borrow sources for production platforms. The first production platform is completed and the workers are shifted to the second location. Manpower, employed in expanding the base camp and in the drilling operations has now reached a peak (160 jobs). Intensive efforts are made to delineate the extreme reaches of the oil-bearing structures and a number of producing wells are capped. Altogether, some 10 wells are completed in the sixth year. Onshore, preparation of the gravel pad for the laying of pipeline to the Alyeska interconnection has begun; a single crew of 120 is at work for up to eight months.

By the following year, two additional crews of 120 each are at work laying the offshore lines. Sixteen kilometers (ten miles) of line are laid from reel barges into trenches sufficiently deep to protect them from ice scour. These additional crews push the total manpower requirements for the year to a peak of 680 jobs. In the same year, 18 production wells are completed by the same four drill crews.

In the eighth year, the full production base camp is completed, along with 24 additional production wells, the remaining 16 kilometers (10 miles) of offshore line, and the first 24 kilometers (15 miles) of onshore line. Preparation of the gravel work pads and fabrication of the support members for the elevated hot oil line reduces the productivity of onshore pipelining to about 1 kilometer (2/3 of a mile) per month for a single crew of 120 people.

Preparations for the production phase are underway by the ninth year. The processing equipment is installed on one of the platforms, all pipeline construction is finished, and the lines are connected and hydraulically tested. Drilling activities continue unabated, and another 24 wells are completed.

In the tenth year, operations begin and 36 million barrels of oil are transported to the south. Manpower levels have fallen off rapidly with the completion of the pipelines. Nevertheless, drilling activities continue at the same pace, and drill crews now represent one-half of the base camp contingent. Another 24 wells are completed.

The next two years represent the final transition to the operational phase. Drilling activities are terminated, the gas plant is installed, and gas production begins a stable production flow of 105 billion cubic feet per year. Oil production peaks at 70 million barrels per year through the sixteenth year and then begins to fall off exponentially. By year 30, as measured from the lease-sale award, oil production has reached a level of 4 million barrels per year and consideration is given to the maintenance of stripper operations for another few years. The economics of secondary recovery are not justified by prevailing market conditions and shortly force the abandonment of the operations. Production rigs are dismantled and the base camp facilites are sold off, rented or maintained with a minimal staff. Disposition of the island platforms, in the case of the gravel island, is a question of legal stipulations to the lease-sale award, environmental regulations, navigational hazards they might pose, and the marketability of the gravel as a borrow source.

Much of the foregoing narrative is summarized in Tables 4-10, 4-11, and 4-12.

4.6.2 Facility Requirements

Total facility requirements for scenario two are given in Table 4-10, and are shown for each phase in the construction and installation schedule of Table 4-11. The exploration phase will entail the construction of a small base camp, a harbor, 4 platforms and 10 wells. During the development phase, requirements include: 2 production platforms, 76 wells, 40 kilometers (25 miles) of pipeline, and an enlarged base camp. Additional facility requirements after the stage of initial production will be minimal: more wells, bringing the total number of producing wells to 103, and a gas plant.

The total capital investment (excluding exploration costs) required to meet the developmental framework of scenario two is estimated between $1.3 and $1.8 billion. Oil and gas pipelines account for over 30% of the tota"l, and production wells for nearly 25%.

TABLE 4-10

SCENARIO TWO
DEVELOPMENT SUMMARY

Activity/Facilities		Total Requirements	Peak Number of Construction/Drill Crews
Tracts Explored		4	NA (2 survey teams)
Tracts Held		2	NA
Exploration Platforms Constructed		4	3
Production Platforms Constructed		2	2
Exploration Wells Drilled		10	3
Production Wells Drilled		103	4
Pipeline Kilometers (Miles) Layed		72 (45)	4
Offshore	32 (20)		
Onshore	40 (25)		
Base Camp/Harbor Constructed		1	1
Barges		24	NA
Trucks and Tractors		20	NA
Aircraft Complement		4	NA
Rota ry			
Fixed Wing			

TABLE 4-11

SCENARIO TWO
CONSTRUCTION AND INSTALLATION SCHEDULE

		Number of Completions				
				Pipeline Kilometers (Miles)		Other
Phase	Year	Platforms	Wells	Onshore	Offshore	Installations
Exploration	1	------------ Lease Award Year -------------				
	2	1	1			Exploratory Base Camp
	3	3	2			----
	4		5			----
	5	___	2			Harbor Open
	Subtotal	4	10	0	0	NA
Development	6	1	10			----
	7	1	18	-	16 (10)	----
	8		24	24 (15)	16 (10)	Production Base Camp
	9	___	24	16 (10)	-	Processing Equipment
	Subtotal	2	76	40 (.25)	32 (20)	NA
Production	10		24			----
	11		3			Gas Plant
	12-36	___				----
	Subtotal	0	27	0	0	NA
	TOTAL	6	113	40 (25)	32 (20)	NA

TABLE 4-12

SCENARIO TWO
PRODUCTION SCHEDULE

Year		Annual Output Oil (MMB)	Gas (tcf)
10		37	----
11		70	----
12		70	.105
13		70	.105
14		70	.102
15		70	.098
16		70	.098
17		52	.095
18		38	.095
19		31	.095
20		24	.095
21		21	.095
22		17	.095
23		14	.095
24		10	.090
25		7	.090
26		7	.090
27		7	.090
28		5	.090
29		5	.080
30	Stripper Operation	0.4	
31		0.3	
32		0.3	
33		0.3	
	TOTAL OUTPUT	700 MMB	1.750 tcf

4.6.3 Manpower Requirements

Total manpower requirements, as expressed in the peak number of jobs per year, climbs from an initial level of 80 jobs to a high of 680 jobs in the seventh and eighth years. This crest corresponds to the most active period of production drilling, as well as both offshore and onshore laying of pipeline. Pipeline employment is particularly significant, representing nearly 70% of the total job count. After the lines are installed the job count falls off sharply, finally stabilizing at an annual average of 56 jobs through the operational phase (years 11 through 30). A complete manpower schedule by activity, peak jobs, and total man-months is shown in Table 4-13.

As stated in Section 4.3, total direct employment is typically twice the number of jobs due to rotation schedules (i.e. 2-on, l-off), and turnover of personnel. Consequently, direct employment reaches a peak in years 7 and 8 of nearly 1,400 people. This figure excludes indirect and secondary employment, as well as suppliers and technical/managerial observers who visit the camps.

Manpower requirements for scenario two are shown by skill classification and occupation category in Table 4-14. In the early years, unskilled workers comprise nearly one-half of the labor force, whereas in the peak employment years (7 and 8) they account for less than 20%. This is due to the large number of semi-skilled technicians used for laying pipelines; in year 7 they account for more than one-third of the labor force.

Table 4-13

SCENARIO TWO
MANPOWER SCHEDULE
(Peak Number of Jobs)/ (Total Man-Months Required)

Activity	Year 1	2	3	4	5	6	7	8	9	10	11-30 (Year-Round Average Jobs)
Base Camp Construction	40/100	40/300		40/240	40/480	40/480	20/120	20/120			
Base Camp Operation & Supply		20/240	20/240	20/240	20/240	30/360	30/360	30/360	30/ 360	30/360	18
Exploration Platform Construction		120/480	120/480								
Exploration Platform Demobilization				80/60	80/120	40/60					
Exploration Drilling		30/135	90/270	90/675	30/270						
Production Platform Construction					80/400	80/240					
Production Drilling						120/1440	120/1440	120/1440	120/1440	120/1440	
Offshore Pipeline-Gas							120/1050	120/1050			
Offshore Pipeline-Oil							120/1050	120/1050			
Onshore Pipeline-Gas						120/930	120/1440	120/1440	120/1440		
Onshore Pipeline-oil						120/930	120/1440	140/1440	120/1440		
Equipment Installation									60/600	60/120	
Local Transport	30/180	30/360	30/360	30/360	30/360	30/360	30/360	30/360	.50/360	30/360	6
Survey	10/10										
Production Operation and Maintenance										32 Jobs	32
Total	80/290	240/1515	260/1350	260/1575	280/1870	580/4800	680/7260	680/7260	480/5640	772/2664	56

Table 4-14

SCENARIO TWO
MANPOWER DISTRIBUTION BY SKILLS
(Peak Number of Jobs)

Skills Inventory	Year 1	2	3	4	5	6	7	8	9	10	11-30 (Year-Round Average)
Skilled Jobs											
Supervisor, Engineer	6	8	12	12	8	19	26	26	25	16	6
Aircraft	4	4	4	4	4	4	4	4	4	4	1
Foremen	2	6	8	8	6	14	18	18	14	10	4
Mechanics (craft)	1	8	10	10	9	34	41	41	37	30	2
Welders (certified)	1	4	6	6	6	24	34	34	23	8	1
Technicians (senior)	6	8	8	8	8	21	26	26	24	34	8
Skilled Subtotal	20	38	38	48	41	116	149	149	127	102	22
Semi-Skilled Jobs											
Clerical and Adm.	4	12	14	14	12	36	50	50	32	20	8
Operators	10	16	22	22	28	67	86	86	59	32	4
Technicians, Mechanics	4	48	58	58	48	177	265	265	160	45	8
Semi-Skilled Subtotal	18	76	94	94	88	280	401	401	251	97	20
Unskilled Subtotal	42	126	118	118	151	184	130	130	102	73	14
Total Jobs at Peak	80	240	260	260	280	580	680	680	480	272	56

4.6.4 Location Factors

This section briefly describes the locational factors that may be important in the siting of offshore and onshore facilities in the central region near Prudhoe Bay. The evaluation is structured to identify the main locational criteria associated with the development and production phases of petroleum activities. These requirements include:

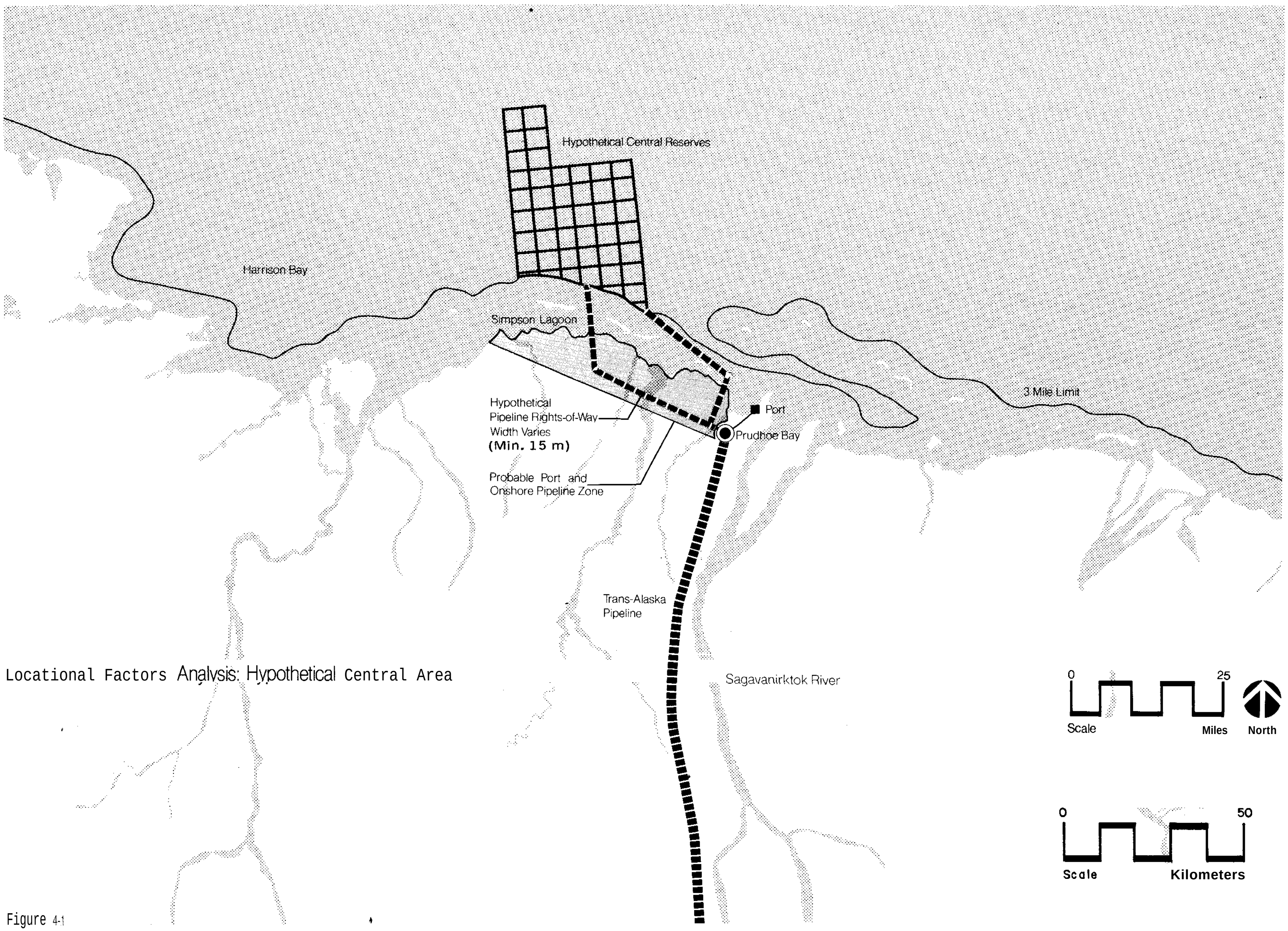
- The production base camp
- Offshore and onshore pipelines

Figure 4-1 illustrates the hypothetical location of reserves near Prudhoe Bay, and the zones in which port and pipelines may be located.

4.6.4.1 Production Base Camp

In contrast to the western and eastern locations the central reserves are situated close to an area of major petroleum development, Prudhoe Bay, which already has the major infrastructure requirements of a petroleum development staging area. Prudhoe Bay facilities include two operating airstrips, heliport, port, storage areas, communications, emergency medical services and camp accommodations. The port is situated on the eastern shore of Prudhoe Bay and has docks, storage areas, and cranes.

Since Prudhoe Bay is only 40 kilometers (25 miles) from the closest point of the hypothetical reserves, the primary locational factor will be in the proximity of Prudhoe Bay and the utilization and possible expansion of facilities; Prudhoe Bay is the staging point for continuing exploration of state leases at the fringes of the existing oil field. It is highly unlikely, therefore, that any new port sites would be developed.



Locational Factors Analysis: Hypothetical Central Area

Figure 4-1

Environmental concerns may not be as an important locational factor in the central area as they may be for the eastern and western areas because petroleum development has already occurred and much data is available on the biology and other environmental factors. Consequently, additional development in the Prudhoe Bay area can be accommodated with environmental comparability. Nevertheless, the increased demand on local resources, notably water and gravel, which is already a major concern in the Prudhoe Bay area, has to be taken into consideration in planning OCS operations.

4.6.4.2 Offshore and Offshore Pipelines

This scenario assumes that construction of a number of offshore pipelines converging at a pipe union facility, probably located at a coastline base camp. A single onshore pipeline of about 40 kilometers (25 miles) in length would be constructed from the landfall to the trans-Alaska pipeline to Prudhoe Bay. Figure 4-1 shows the zone in which pipelines may be constructed assuming a pipeline landfall somewhere between Oliktok Point in the west and Prudhoe Bay in the east. The zone encompasses a coastal strip, 16 to 24 kilometers (10 to 15 miles) in width, which is located on state land including current oil and gas leases. Routings in this area pass through portions of the existing oil field and precise alignments would in part be dictated by the location of existing feeder lines. Reserves located in the eastern portion of the lease tracts shown in Figure 4-1 may favor a direct predominantly offshore routing to Prudhoe Bay. The other hypothetical alignment shows the most direct routing to shore which passes between the Jones Islands.

4.7 SCENARIO NUMBER THREE

The third scenario to be evaluated corresponds to the U.S.G.S. high-level estimate of reserves (5% probability) in the eastern Beaufort Sea OCS area; an estimated 2.3 billion barrels of oil and 5.8 trillion cubic feet of gas are discovered offshore from Camden Bay.

The principal discovery is made by an oil producer with an effective domestic tax rate of 10% who is strongly betting on a substantial price increase (in real dollars) over the prevailing prices for oil and gas: $13/barrel for oil and $6/unit (2.5 mcf/unit) for gas delivered from the North Slope. With prices as they are, he calculates he can earn at least a 20% return on investment if development costs run high, and considerably greater than 25% if he can somehow keep development costs under strict control (see Table 3-14d). As he anticipates oil prices rising much faster than either general inflation or Arctic construction costs, he expects his return to be that much greater. With respect to gas development, he similarly calculates his rate of return under his present market conditions to be between 8% and 18%, and he thinks future prices will elevate his return considerably.

Overall, the investment appears promising given his financial objectives and his speculative outlook on future prices; and he decides to go forward.

4.7.1 Chronology of Major Events

In summary, the exploration and development phases involve two sequential five-year periods following the lease-sale. Oil begins to flow in the eleventh year, and reaches a peak of 256 million barrels per year over the next six years. Thereafter, it declines rapidly to a level of only 15 million barrels per year, at which time unit costs begin to exceed unit revenues,and the operations are discontinued. In contrast, gas production, which begins in the thirteenth year, remains stable over the 20-year production period at roughly 300 billion cubic feet per year. The production profiles for oil and gas are shown in Table 4-17.

The scenario begins with a mixture of optimism and caution surrounding the lease-sale event. The geophysical and geological findings appear conflicting, data interpretations are in great variance, and rumors float. The only point of agreement is that the principal exploratory focus lies in the waters offshore of Camden Bay. Some 40 tracts in that region are purchased, and exploration activites are immediately launched from the existing facilities at Prudhoe Bay.

In the first year, two platforms are built on the most promising tracts and two exploratory wells are completed. Oil is struck almost immediately and exploration activites are stepped up intensely. By the second year, construction of a production base camp is underway near the anticipated landfall in Camden Bay and 10 platform construction crews (40 men/crew) have been mobilized along with 10 drilling crews (30 men/crew). The activity continues into the third year with still another two platform crews being brought in. As knowledge of the geologic formation increases, many of the purchased tracts are eliminated from consideration and exploration activities begin to take on sharper focus. Altogether, in the third year, some 10 platforms (ice or gravel) are constructed (or mobile rigs employed) and 28 exploratory wells are drilled. As soon as the drilling is completed (1 to 5 wells per platform), the construction crews return to demobilize the platform, and the equipment is transferred to a new location. By the end of the fourth year, another eight tracts have been explored and another 14 wells drilled. Location of the oil-bearing formations is now relatively certain and efforts begin to wind down and shift toward delineating the extremes of the productive fields. No further tracts are explored in the fifth year, although six additional wells are completed from existing platforms.

The developmental phase gets underway rapidly in the sixth year with the opening of the production base camp and harbor, as well as a general resurgence in activity. With the start of production platform construction, production drilling, and the laying of pipeline, manpower levels nearly double over the previous year. Four onshore pipeline crews with 120 people per crew account for much of the sudden jump in employment, and they will be kept fully employed over the next four years.

By the end of the seventh year, offshore platform construction is nearing a peak; six of the eventual eight production structures have been finished, allowing drilling activities to intensify. Fourteen drill crews are now at work, and 72 wells have been sunk and capped to await production. Moreover an additional pipeline crew is nonworking off-shore in the open-water season.

Employment reaches a peak in the eighth year with two additional drilling crews and an offshore pipeline crew. All other activities continue unabated with the exception of the beginning of the phase-out in platform construction. The final two production platforms are completed by the end of the eighth year, along with 88 production wells, and 64 kilometers (40 miles) of pipeline, 48 kilometers (30 miles) of which are onshore oil and gas lines.

The next two years represent the completion of field development and the transition toward field operations. Employment levels remain only moderately below the peak as drilling activites and pipeline installations race to meet the scheduled start of operations. During the two-year period, 171 production wells are drilled, and 96 kilometers (60 miles) of onshore line and 32 kilometers (20 miles) of offshore line are finished. Platforms are now being readied for operations, and 7 of the 8 production structures are equipped with petroleum fluids processing equipment.

The operational phase begins in year 11 after the last 16 kilometers (lo miles) of offshore line and the gas plant are installed. Employment, subsequent to the intense period of construction-installation, and drilling activities, plumets to about 15% of the average level of the preceding four years. Oil production peaks for six years at 256 million barrels per year and then declines rapidly through the life of the field. Gas production remains stable at about 300 billion cubic feet per year. After 20 years, further recovery of the oil appears uneconomic. Operations are temporarily discontinued to await some improvement in the economic climate of oil recovery that would permit profitable stripper operations. Maintenance of the base camp and platforms requires a minimal crew.

Tables 4-16 and 4-17 provide tabularized summaries of the material upon which the descriptive scenario was based.

4.7.2 Facility Requirements

Total facility requirements for scenario three are shown in Table 4-15, and are detailed by phase of development in the construction and installation schedule of Table 4-16. Altogether, 343 production wells are required to be drilled from 8 platforms, representing an average of 44 wells per platform. The scenario also calls for the construction of a production base camp in the vicinity of Camden Bay, following the temporary use of Prudhoe Bay facilities during the exploration phase. Moreover, 209 kilometers (130 miles) of oil and gas pipeline (double lines) are required to transport the reserves from the platforms to the interconnections with the Alyeska line and one of the proposed gas lines.

The total capital requirements for the specific development envisioned in scenario number three are between $4.1 billion and $5.9 billion. The figures exclude all exploration costs (tracts, exploratory platforms and wells). The cost of pipelines represents nearly 50% of the total capital requirements, and wells account for another 25%.

TABLE 4-15

SCENARIO THREE
DEVELOPMENT SUMMARY

Activity/Facilities	Total Requirements	Peak Number of Construction/Drill Crews
Tracts Explored	20	4 Survey Teams
Tracts Held	8	NA
Exploration Platforms Constructed	22	12
Production Platforms Constructed	8	7
Exploratory Wells Drilled	50	10
Production Wells Drilled	343	16
Pipeline Kilometers (Miles) Layed	209 (130)	6
Offshore	64 (40)	
Onshore	145 (90)	
Base Camp/Harbor	1	1
Barges	60/30*	NA
Trucks and Tractors	1 00/12*	NA
Aircraft Complement	9/4*	NA
Rotary	6/4*	
Fixed Wing	3/2*	

* Split by Phase: Construction/Operation.

TABLE 4-16

SCENARIO THREE
CONSTRUCTION AND INSTALLATION SCHEDULE

		Number of Completions				
				Pipeline Kilometers (Miles)		Other
Phase	Year	Platforms	Wells	onshore	fshore	Installations
Exploration	1	------------	Lease Award Year	-------------		
	2	2	2			Exploratory Base Camp at Prudhoe Bay
	3	10	28			
	4	8	14			----
	5		6			----
	Subtotal	213	50	0	0	NA
Development	6	2	12			Production Bay Camp
	7	4	72			----
	8	2	88	48 (30)	16 (10)	----
	9	0	96	48 (30)	16 (10)	2 Platforms Equipped
	10		75	48 (30)	16 (10)	5 Platforms Equipped
	Subtotal	8	343	145 (90)	48 (30)	NA
Production	11				16 (10)	1 Platform Equipped
	12					Gas Plant
	13-30					----
	Subtotal	0	0	0	16 (10)	NA
	TOTAL	30	393	145 (90)	64 (40)	NA

TABLE 4-17

SCENARIO THREE
PRODUCTION SCHEDULE

Year		Annual Output Oil (MMB)	Gas (tcf)
11		130	----
12		256	----
13		256	.308
14		256	.306
15		256	.306
16		256	.306
17		256	.306
18		192	.306
19		141	.306
20		115	.306
21		84	.300
22		77	.300
23		64	.300
24		51	.300
25		38	.300
26		27	.300
27		27	.290
28		27	.290
29		20	.290
30		15	.290
	TOTAL	2300	5.750 tcf

4.7.3 Manpower Requirements

Manpower requirements in this scenario go through two distinct cycles, one for the exploratory phase and one for the development phase, with the latter being far more pronounced. In the exploratory cycle, the total job count peaks in the third year at 850 jobs and then declines to 550 jobs during the fifth year. At that time, primarily due to the sudden influx of pipeline workers, the job count begins to accelerate upward into the much steeper development cycle which crests three years later at 1,400 jobs. This level is generally maintained until construction and installation are completed three years later, just prior to production, at which time manpower falls precipitously to the average level required for operations, 184 jobs. The manpower schedule is shown in Table 4-18.

Total direct employment, which excludes all secondary or indirect employment, such as those suppliers who are not directly affiliated with the base camp operations, is roughly twice the number of jobs required. As stated previously, this factor provides adjustment for normal rotation and turnover of personnel. Thus for scenario three, the peak employment in the seventh through tenth years is approximately 2,800 employees. Over one-half of these workers are engaged in the preparation and laying of pipelines.

Table 4-19 provides a breakdown of peak jobs by skill level and occupational designation. Unskilled workers comprise about 50% of the labor force during the exploratory phase, but drop to less than 25% during the development phase. Just the opposite trend can be seen with the semi-skilled

TABLE 4-18

SCENAR10 THREE
MANPOWER SCHEDULE
(Peak Number of Jobs)/ (Total Man-Months Required)

Activity	Year 1	2	3	4	5	6	7	8	9	10	11	12-30 (Yr. Round Avg. Jobs)
Base Camp Construction		40/80	40/480	40/480	40/400							
Base Camp Operation* and Supply					20/120	30/360	30/360	30/360	30/360	30/360	30/360	46
Exploration Platform Construction	80/480	400/1600	480/2880	240/1440								
Exploration Platform Demobilization	**/40	**/360	**/400	**/400								
Exploration Drilling	60/240	300/1800	300/3600	240/2520	180/840							
Production Platform Construction						160/840	280/1320	80/400				
Production Drilling						240/2400	420/5040	480/5760	480/5760	480/4800		
Offshore Pipeline-Gas							60/240	120/1200	120/1200	120/1200	120/1200	
Offshore Pipeline-Oil							60/240	120/1200	120/1200	120/1200	120/1200	
Onshore Pipeline-Gas						240/1440	240/2880	240/2880	240/2880	240/2880		
Onshore Pipeline-Oil						240/1440	240/2880	240/2880	240/2880	240/2880		
Equipment Installation								60/130	75/250	75/250	30/120	
Local Transport	30/180	30/360	30/360	30/360	30/360	30/360	30/360	30/360	30/360	30/360	30/360	10
Survey 20/20	20/20				20/40							
Product ion Operation and Maintenance											128 jobs average	128
Total	190/920	770/3880	850/7680	550/5200	530/2160	940/6840	1360/13320	1400/15170	1335/14890	1335/1390	462/4776	184

* Prudhoe Bay for exploratory base comp
**Same men as in platform construction; therefore, they are not counted in job peak totals

Table 4-19

SCENARIO THREE
MANPOWER DISTRIBUTION BY SKILLS
(Peak Number of Jobs)

Skills Inventory	Year 1	2	3	4	5	6	7	8	9	10	11	12-30 (Yr. Round Average)
Skilled Jobs												
Supervisor, Engineer	15	20	22	15	25	28	33	41	43	43	15	8
Aircraft	4	4	4	4	4	4	4	4	4	4	3	2
Foremen	5	26	28	18	14	26	37	46	44	44	12	8
Mechanics (craft)	3	34	34	28	20	46	55	75	77	77	34	24
Welders (certified)	3	20	22	18	15	43	51	58	62	62	19	2
Technicians (senior)	15	18	20	9	25	39	49	90	85	85	49	45
Skilled Subtotal	45	122	130	92	103	186	229	314	315	315	132	89
Semi-Skilled Jobs												
Clerical and Adm.	10	28	32	24	20	58	92	90	84	84	24	16
Operators	20	102	110	52	49	112	177	151	139	139	31	14
Technicians	34	158	170	134	118	333	470	533	530	530	175	33
Semi-Skilled Subtotal	64	288	312	210	187	503	739	774	753	753	230	63
Unskilled	81	360	408	248	240	251	392	312	267	267	100	32
Total	190	770	850	550	530	940	1360	1400	1335	1445	462	184

technicians who comprise only slightly more than 20% of the labor force during the peak of the exploratory cycle, and nearly 40% during the peak of the development cycle. Again, much of this is due to the skills required for pipeline workers.

4.7.4 Locational Factors Analysis

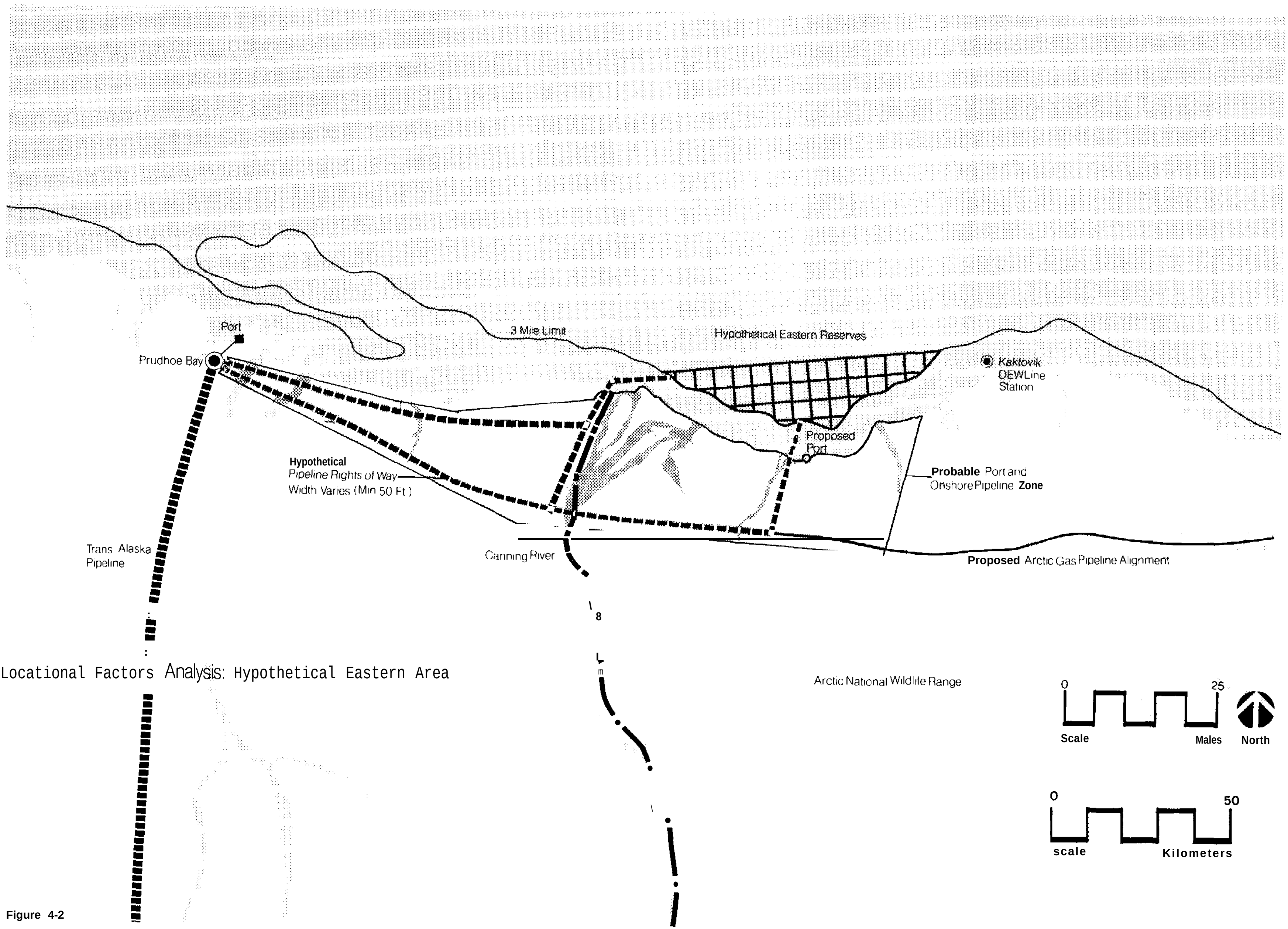
This section includes a discussion of factors which may be of importance in determining the location of offshore and onshore facilities at Camden Bay. The evaluation is structured to identify locational criteria associated with the principal functional requirements of the development and production phases. These requirements include:

- The production base camp
- Offshore and onshore pipelines

Figure 4-2 illustrates the hypothetical location of reserves at Camden Bay, and summarizes the key locational aspects of port and pipeline development which are discussed below.

4.7.4.1 Production Base Camp

It is assumed that development and production of a hypothetical reserve will necessitate construction of a completely new base camp, subsequent to the use of facilities at Prudhoe Bay or Kaktovik during the early years of exploration activity. The base camp would be located as close as possible to offshore production fields.



Locational Factors Analysis: Hypothetical Eastern Area

Figure 4-2

0 Proximity of Base Camp to Offshore Production Field

Efficient operations require minimum distance between the offshore field and the supply base camp. Although this requirement is also important for the exploration phase, it is particularly necessary during the development and production phases. Costs of daily supply boat, truck or helicopter operations, throughout the 20-year production period, require that travel time be minimized. On the basis of this criterion, a port site zone within the southern portion of Camden Bay would be preferred.

o Potential for Utilization of the Proposed Arctic Gas Supply Port in Camden Bay

Plans for construction of the proposed Arctic Gas pipeline include a supply port at Camden Bay. The plans indicate that the port would be used only during the construction phase of the pipeline, but could become available for potential OCS use thereafter (U.S. Department of Interior, 1976).

The limited dock and wharf area of the proposed port would probably better serve the OCS exploratory phase than the development and production phases. However, the Arctic Gas port and its facilities could be expanded to meet production needs.

0 <u>Minimization of Disruption to Subsistence Hunting and Fishing Areas</u>

The preservation of subsistence hunting and fishing areas of the residents of Kaktovik will be a consideration in section of a base camp site. Consequently, a base camp site in the western portion of the Camden Bay will be preferable to potential sites in the eastern portion, where subsistence hunting and fishing in most intensive. (See Figure 1-4, Resource Areas).

It has been speculated that poorly planned movement of construction vehicles and frequent air traffic could disturb the Porcupine caribou herd at their calving grounds, the fall staging area of snow geese, the musk oxen range and other habitats, all within the Arctic National Wildlife Range. In addition, if base camp construction were located in areas of known and suspected polar bear dens, it could cause a decrease in bear population (Department of the Interior, 1976).

There are also wildlife considerations associated with a port site west of the Canning River which lies within a narrow lagoon extending east across the river delta. Barge and supPly boat activity breaching in the lagoon could be disruptive to summer marine mammal migration patterns through the lagoon channel. The extent and significance of such disruption are unknown.

However, as intrinsically important as these potential impacts may be, it is important to note that they could occur at various locations along the coast within the "probable port and onshore pipeline zone" (see Figure 4-2). This concern constitutes a criterion for base camp location insofar as such disruptions may damage fish and wildlife resources required for subsistence by the people of Kaktovik. '

o Proximity to Water and Gravel Supply Sites

Base camp proximity to exploitable water and gravel resources may be a locational consideration. Gravel is required for the construction of building pads, roads and an airstrip; and water is required for personnel, construction and maintenance of ice roads, hydrostatic testing, mixing of drilling mud, and possible reinjection into wells as part of the production phase.

State environmental stipulations on removal of grave"l from coastal areas and removal of gravel and water from certain rivers are discussed in Section 1.5.2. More restrictive State legislation is pending which are designed to maintain stream flows to protect fish and wildlife.

These restrictions may require careful consideration of base camp locations in proximity to rivers from which sufficient quantities of water and gravel can be removed without disruption. However, the potential severity of such restrictions anywhere along the coast of Camden Bay could require alternative methods for water storage and restricted use of gravel for artificial islands, building pads, and the camp airstrip.

4.7.4.2 Offshore and Onshore Pipelines

This scenario assumes the construction of a number of offshore pipelines converging on a pipe union facility, normally located at the base camp. A single onshore pipeline of approximately 145 kilometers (90 miles) in length would be constructed from the camp to the trans-Alaska pipeline at Prudhoe Bay. Figure 4-2 indicates a broad zone within which a coastal base camp and any onshore pipelines would probably be required. Two of a number of hypothetical pipeline alignments from the offshore fields of the TAPS corridor are shown within this zone. Criteria which have been utilized to identify these and other possible pipeline alignments include:

- Minimization of the length of offshore and onshore pipelines;
- Minimization of disruption to fish and wildlife;
- Minimization of pipeline river crossings; and
- Utilization of proposed Arctic Gas pipeline corridors.

Minimization of the length of offshore and onshore pipelines requires close proximity of the production platforms, pipeline landfalls, and connection to the Alyeska pipeline at Prudhoe Bay.

The application of this criteria would favor a hypothetical landfall-base camp location at Camden Bay in preference to an alternative location to the west of the Canning River. The offshore pipeline distance between the approximate center of the hypothetical reserves and a base camp location in Camden Bay is approximately 16 kilometers (10 miles), while it is more than 40 kilometers (25 miles) to a location west of the Canning River. The investment cost differential between four separate offshore piplines to Camden Bay and four pipelines to a point west of the Canning River could approach $500 to $700 million.

Minimization of disruption to fish and wildlife may be in conflict with the least-cost, direct alignment of pipeline corridors. The potential for disruption could require pipeline realignment around sensitive areas, and careful control over the timing of construction and the maintenance of pipelines. Any of these modification could increase the cost, and hence, the overall viability of the scenario.

Nearshore, in areas of near-surface, ice-rich permafrost, earth or gravel causeways may be an alternative to conventional trenching and burial to carry offshore pipelines.

Subsea permafrost extends offshore to a distance of approximately 1.6 kilometers (1 mile) in Camden Bay and near the Canning River delta. An improperly designed 1.6 kilometer (1 mile) long causeway constructed in this zone could create a barrier to fish and marine mammal migration along the coast. This barrier would probably be more significant for a landfall west of the Canning River, because it would extend into the narrow end of the lagoon. Fish and marine mammals migrating east through the lagoon or into the Canning River delta could be diverted by the causeway.

Onshore pipeline impacts on the Porcupine caribou herd could affect the subsistence requirements of the Natives of Kaktovik, as well as those of northwestern Canada. Approximately 100 caribou are taken by Kaktovik residents annually (Department of Interior, 1976).

An onshore pipeline between Camden Bay and Prudhoe Bay would pass through the caribou calving grounds. Caribou migration and the location of calving areas could be modified by the barrier presented by a raised pipeline, and by vehicular movement along the parallel gravel or snow haul and maintenance road. The Alaska Department of Fish and Game indicates it is possible that even slight alterations of caribou movements can decrease herd size or prevent pregnant females from reaching the calving grounds in time to bear their calves (Department of Interior, 1976).

Possible mitigating measures include relocation of a pipeline to the west of the Canning River, burying the pipeline in non-permafrost areas of the wildlife range, and controlling the timing of construction and maintenance activities during periods of caribou migration.

Minimization of pipeline river crossings is important because it requires costly winter burial of pipelines beneath the riverbed. Pipeline alignments would be selected which minimize the number of crossings and which avoid crossings in wide, braided sections and deltas.

The application of this locational criteria would favor landfall location west of the Canning River. This would avoid crossing rivers within the Arctic National Wildife Range, which would otherwise be required for a pipeline landfall within Camden Bay.

Utilization of proposed Arctic Gas pipeline corridor would include the Alaska portion of the pipeline from Prudhoe Bay east, through the Arctic National Wildlife Range to a point on the Canadian border about 8 kilometers (5 miles) inland from the Beaufort Sea.

This locational criteria suggests consideration of the use of a portion of this alignment from Camden Bay to Prudhoe Bay for the oil pipeline (see Figure 4-2) . The establishment of a multiuse corridor would minimize disruptive impacts of separate corridors.

4.8 SCENARIO NUMBER FOUR

The fourth scenario under consideration corresponds to the 2% probability level on a distribution curve that was fitted to published U.S.G.S. estimates of oil and gas reservesin the Beaufort Sea OCS lease-sale area.

The so-called "bonanza" level scenario envisions the discovery of 3.5 billion barrels of oil and 8.8 trillion cubic feet offshore from Smith Bay in the western Beaufort region.

The principal discovery is made by a producer with an effective U.S. tax rate of 35% whose financial objective is to achieve at least a 15% return on his investment. At the time of discovery, the southern California market will support prices (constant 1975-76 dollars) of $14/barrel for oil and $7/unit (2.5 mcf/unit) for gas. Since he feels he can beat the quoted cost for laying pipeline in the Arctic, he anticipates no problem in meeting his financial objective with respect to oil development (see Table 3-14c). However, he calculates that an 8% return is the best he can possibly do on related gas development if he must tie into the existing gas line to the south from Prudhoe Bay. Counteracting this is mounting evidence of substantial gas reserves located in nearby Naval Petroleum Reserve No. 4, such that in conjunction with the offshore finds it would be sufficient to justify an entirely new trunk line to the south. He is willing to speculate on the possibility, and decides to proceed with development.

4.8.1 Chronology of Major Events

In summary, the exploration phase lasts for five years and is followed by an even more intensive five-year period of field development. By the twentieth year, over 500 production wells are delivering oil at an annual rate of around 350 million barrels. Gas production begins a year later at a steady annual rate of 450 billion cubic feet. By the eighteenth year, oil production starts to fall off and goes into a rapid decline until operations are terminated some thirty years after the lease sale.

The scenario begins with a general air of optimism surrounding the lease sale. Nearby discoveries in state waters are believed to belong to related formations in the OCS lease-sale area; the latter location is considered to be even more favorably situated. Intense bidding ensues and some 60 tracts are purchased at an average cost approaching $10 million per tract.

Exploration activities begin within the first year. Four survey teams complete their geophysical data gathering and the first three platform construction crews begin to work on the most favorable tracts. Twelve additional construction crews are brought in the second year, as well as drilling crews. However, by the end of the second year only two exploratory platforms have been completed and two wells drilled. Construction on a small exploratory base camp has also begun.

During the third year, exploration activity reaches a peak; 20 platform construction crews are now at work both building new platforms and demobilizing these from which drilling activities have been completed. Altogether, 24 platforms are finished in the third year, as well as 40 exploratory holes. Subsequently, the platforms on nine of the tracts which have been adequately explored are dismantled and the equipment (and possibly gravel) transferred to new tracts. Oil and gas have now been found in several tract locations, helping to clarify the nature of the geological formation; and thus narrowing the search among the remaining tracts.

Base camp operations are fully open by the fourth year, while construction activity continues in order to expand and prepare the camp for the field development and production phases. Fourteen exploratory platforms are also added which complete the full complement of 20 tracts to be ultimately explored. Exploratory drilling continues with 40 new wells being sunk in the fourth year and 16 in the fifth year, bringing the exploration program to a close.

Construction and drilling activities by the sixth year have turned toward permanent production platforms and wells designed to delineate the perimeters of the major fields. Two such platforms and four wells are finished by the end of the year. Also, the production base camp is now fully operational and the first four pipeline crews have been brought in to prepare the work pads for the installation of the onshore oil and gas pipelines.

Employment surges three-fold in the seventh year with the arrival of 16 additional drill crews (30 people per crew), 12 pipeline crews (120 people per crew), and 2 platform construction crews. By the end of the year, 8 production platforms have been added along with 40-wells; and the first 32 kilometers (20 miles) of onshore line and 24 kilometers (15 miles) of offshore line have been laid.

The level of manpower and intensive drilling and pipeline installation activity witnessed in the seventh year is maintained virtually throughout the next three years. The number of completions on production wells averages about 140 per year. During the eight and ninth years, 193 kilometers (120 miles) of onshore line is installed, and 129 kilometers (80 miles) of offshore line is laid into trenches from reel barges. In the tenth year, the remaining 48 kilometers (30 miles) is laid offshore, and the last 16 kilometers (10 miles) of onshore line is put into place; after the terminal completions are made, the lines are hydraulically tested. In preparation for oil production in the next year, the processing equipment is installed on the platforms.

Oil production begins in the eleventh year following the lease-sale award, and is at a maximum of 350 million barrels per year for six years. Subsequently, its flow diminishes rapidly until the unit costs become prohibitive, which is estimated to be sometime after year 30. Gas production begins in year 13 and flows at a relatively constant rate of around 450 billion cubic feet per year.

Operations are terminated and the decision is made to postpone abandonment for up to 10 years to await future market developments that could justify stripper operations or until the lines could be sold to other potential producers in the western Beaufort region. A minimal crew would be required to maintain the platforms and wells and operate the base camp. If outright abandonment is eventually called for by unattractive economics, the base camp could be sold as salvage. The platforms would be demobilized, and either abandoned outright or removed.

The latter might occur if required by regulation or stipulation to lease-sale award, or if their partial erosion would pose a subsurface navigational hazard. Buried offshore and onshore lines would normally be abandoned. Those sections that were on gravel causeways or elevated onshore might be dismantled.

The major requirements and events outlined in the above narrative of scenario four are shown in Tables 4-20, 4-21, and 4-22.

4.8.2 Facility Requirements

Table 4-20 summarizes the principal facilities required by the developmental assumptions of scenario four. The exploration phase requires 40 platforms and 100 wells. "Requirements for the developmental and production phases include 12 platforms with 516 wells, 443 kilometers (275 miles) of pipeline, a base camp and harbor in the vicinity of Smith Bay, and a large complement of barges, trucks, tractors, and aircraft. About two-thirds of the total pipeline requirements are for onshore lines between the landfall and the Prudhoe Bay interconnections.

Total capital requirements for the facilities outlined in scenario four, excluding all exploration costs, ranges from $7.8 billion to $10.7 billion. Pipelines account for nearly 60% of the total investment with production wells accounting for another 20%.

4.8.3 Manpower Requirements

The manpower requirements for scenario four, as shown in Table 4-23, can be seen to pass through two major cycles, one cycle corresponding

TABLE 4-20

SCENARIO FOUR
DEVELOPMENT SUMMARY

Activity/Facilities		Total Requirements	Peak Number of Construction/Drill Crews
Tracts Explored		40	(4 Survey Teams)
Tracts Held		12	NA
Exploration Platforms Constructed		40	20
Production Platforms Constructed		12	10
Exploratory Wells Drilled		100	20
Production Wells Drilled		516	24
Pipeline Kilometers (Miles) Layed		443 (275)	16
Offshore	169 (105)		
Onshore	274 (170)		
Base Camp/Harbor		1	2
Barges		72/36*	NA
Trucks and Tractors		148/48*	NA
Aircraft Complement		9/6*	NA
Rotary	6/3*		
Fixed Wing	3/3*		

* Split by Phase: Construction/Operation.

TABLE 4-21

SCENARIO FOUR
CONSTRUCTION AND INSTALLATION SCHEDULE

		Number of Completions				
				Pipeline Kilometers (Miles)		Other
Phase	Year	Platforms	Wells	Onshore	Offshore	Installations
Exploration	1	------------ Lease Award Year -------------				
	2	2	4	-		----
	3	24	40	-		----
	4	14	40	-		Exploratory Base Camp
	5		~	-		----
	Subtotal	40	100	0	0	NA
Development	6	2	4	-		Production Base Camp
	7	8	40	32 (20)	24 (15)	----
	8	2	130	96 (60)	64 (40)	----
	9		144	96 (60)	64 (40)	3 Platforms Equipped
	10		144	48 (30)	16 (10)	5 Platforms Equipped
	Subtotal	12	462	274 (170)	169 (105)	NA
Production	11		54	-		4 Platforms Equipped
	12					Gas Plant
	13-30					----
	Subtotal	0	54	0	0	NA
	TOTAL	52	616	274 (170)	169 (105)	NA

TABLE 4-22

SCENARIO FOUR
PRODUCTION SCHEDULE

Year		Annual Output Oil (MMB)	Gas (tcf)
11		200	----
12		357	----
13		351	0.47
14		351	.46
15		351	.45
16		351	.44
17		351	.44
18		256	.45
19		205	.45
20		167	.45
21		128	.45
22		111	.45
23		90	.48
24		73	.48
25		55	.48
26		38	.50
27		37	.50
28		36	.50
29		31	.40
30		22	.30
	TOTAL	3500	8.75 tcf

to the exploration phase and the second corresponding to the developmental phase, with the second having nearly twice the amplitude (peak number of jobs) as the first.

The exploration cycle climbs rapidly to a total count of 1,470 jobs in the third year, and then declines to a level of 960 jobs in the fifth year during the transitional stage into field development. The sixth year experiences only a very moderate increase in the peak number of jobs, but with the sudden influx of pipeline workers and drill crews in the seventh year, the job count soars by 300% to a total of 3,040 jobs. This crest in developmental activity endures for three years and then falls precipitously as construction, installation and drilling activities terminate just prior to production start-up in the eleventh year.

Total direct employment is estimated as roughly twice the required number of jobs. Therefore, during the peak of developmental activity, in years seven through nine, approximately 6,000 employees per year can be expected. This figure includes employees off the job due to rotation schedules, as well as allowances for turnovers.

Table 4-24 shows the distribution of manpower according to skilled, semi-skilled, and unskilled workers. During the peak in exploration activities (year 3), the unskilled workers account for nearly 50% of the labor force; whereas during the peak development activities (years 7 and 8), they represent only about 20% of the labor force. This shift is principally a result of the large number of pipeline workers entering the labor pool during field development.

TABLE 4-23

SCENARIO FOUR
MANPOWER SCHEDULE
(Peak Number of Jobs)/ (Total Man-Months Required)

Activity	1	2	3	4	5	6	7	8	9	10	11	12-30 (Yr. Round Average)
Base Camp Construction		10/160	40/480	40/480	80/960	80/960						
Base Camp Operation and Supply				30/360	30/360	60/720	60/720	60/720	60/720	60/720	60/720	24
Exploration Platform Construction	120/ 360	600/3600	800/4400	640/3840	320/600							
Exploration Platform Demobilization			*/600	*/1200	*/600							
Exploration Drilling		120/720	600/7200	600/7200	360/2880							
Production Platform Construction					120/240	320/1040	400/2000	280/560				
Production Drilling						120/1200	600/6000	720/8640	720/8640	720/8640	120/936	
Offshore Pipeline-Gas							480/3546	480/3600	480/3600	120/720		
Offshore Pipeline-Oil							480/3586	480/3600	480/3600	120/720		
Onshore Pipeline-Gas						240/1440	480/5760	480/5760	480/5760	480/2088		
Onshore Pipeline-Oil						240/1440	480/5160	480/5760	480/5760	480/2088		
Equipment Installation									150/1800	150/1800	150/900	
Local Transport	30/180	30/360	30/360	30/360	30/360	60/720	60/720	60/720	60/720	60/720	60/720	10
Survey	20/20			20/20	20/40							
Production Operation and Maintenance											192 jobs average	192
Total	170/560	760/4740	1470/13040	1360/13460	960/6040	1120/7520	3040/28052	3040/29360	2910/30680	2190/17496	582/9916	226

*Same men as in platform construction; therefore, they are not included in job peak totals

Table 4-24

SCENARIO FOUR
MANPOWER DISTRIBUTION BY SKILLS
(Peak Number of Jobs)

Skills Inventory	1	2	3	4	5	6	7	8	9	10	11	12-30 (Yr. Round Average)
Skilled Jobs												
Supervisor, Engineer	6	22	36	36	28	32	97	102	72	56	20	8
Aircraft	4	4	4	4	4	8	8	8	8	6	4	2
Foremen	6	28	40	40	18	32	58	62	72	64	18	9
Mechanics (craft)	3	16	54	60	47	60	145	152	150	124	72	26
Welders (certified)	3	12	28	42	34	56	110	120	130	110	30	2
Technicians (senior)	11	14	72	63	40	54	204	206	265	158	73	45
Skilled Subtotal	33	96	234	245	171	242	621	650	697	518	217	92
Semi-Skilled Jobs												
Clerical and Adm.	6	24	50	46	42	56	218	213	199	139	22	20
Operators	20	122	168	148	102	196	419	358	329	231	30	18
Technicians, Mechanics	21	103	340	332	114	278	1114	1174	1173	880	149	37
Semi-Skilled Subtotal	47	249	558	526	358	530	1751	1745	1701	1250	201	75
Unskilled Subtotal	90	415	678	589	431	348	668	645	512	422	164	59
Total Jobs at Peak	170	760	1470	1360	960	1120	3040	3040	2919	2190	582	226

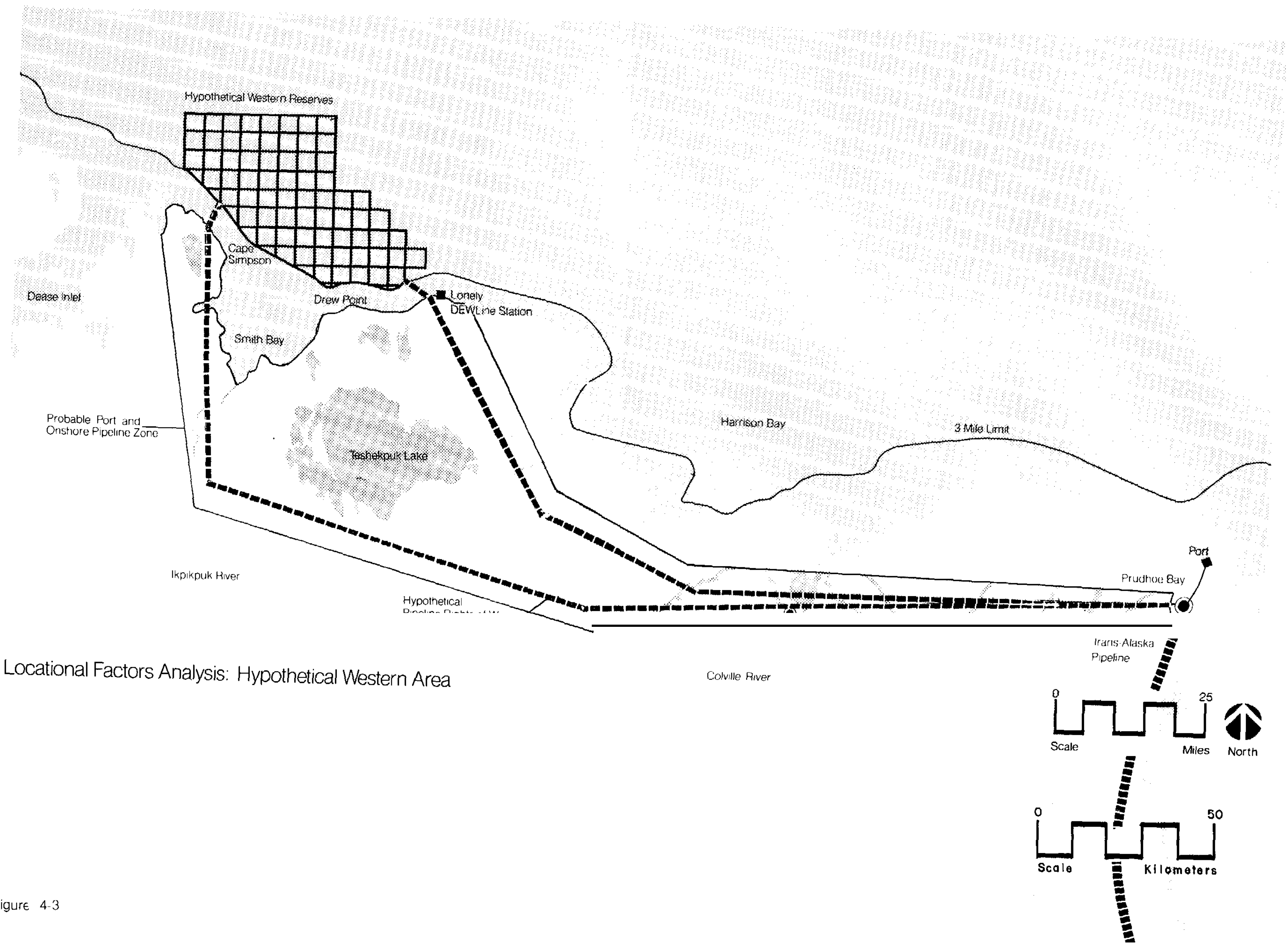
4.8.4 Locational Factors Analysis

This section discusses locational criteria for the siting of offshore and onshore facilities for the development and production phases. General locational criteria (developed in Section 4.4.4) are applied to the specific functional requirements and environmental considerations of the hypothetical western reserves area. The discussion is organized around the construction and operational requirements of two broad categories of facilities: the production base camp, and offshore and onshore pipelines. Figure 4-3 shows the locational factors of this scenario.

4.8.4.1 Production Base Camp

The production base camp created near the offshore reserves could either expand upon a suitably located exploration base camp, or could be built at a new location in close proximity to the designated production field. Locational criteria for the development base camp include:

- Proximity of development fields and potential port sites;
- Potential for utilization of the existing offshore DEW Line station at Lonely;
- Potential land-status limitations to the utilization of a port site inside Smith Bay; and
- Minimization of disruption of sensitive fish and wildlife habitats.



Locational Factors Analysis: Hypothetical Western Area

Figure 4-3

Proximity of development fields and potential port sites is considered important in order to minimize travel time to offshore production platforms. To accomplish this, port staging areas would normally be built somewhere along the coast adjacent to the hypothetical oil and gas fields. Figure 4-3 illustrates a "probable port and offshore pipeline zone" within which a coastal base camp would be constructed. On the basis of this locational criterion, a location at Cape Simpson or Drew Point would be preferred to sites within Smith Bay or Barrow.

Potential for utilization of the existing DEW Line station is important because the existing port, airport and storage facilities at the Lonely DEW Line station east of Drew Point could be expanded to serve the needs of OCS "development. OCS requirements would reinforce the planned utilization of the Lonely port for supply of petroleum exploration activities in Naval Petroleum Reserve No. 4.

Potential land status limitations include the area around Smith Bay. Smith Bay is directly south of the block of tracts respresenting the hypothetical western reserves. The Bay falls within a zone for possible port/camp development. Port development within Smith Bay, however, could be complicated by the Navy's 1972 claim to the submerged coastal tidelands of Smith Bay. In this action, the Navy redefined the original 1923 boundaries of NPR-4.

The coastal extent of NPR-4 was reestablished on the basis of the mean highwater mark of the Beaufort Sea, instead of the highest highwater mark. This action had the effect of adding potentially oil rich State near-shore tidelands. Resolution of any disagreements between the State and the Navy could either encourage or discourage the establishment of an OCS base camp within Smith Bay.

Avoidance of Smith Bay shallow water and spring breakup conditions would be economically advantageous. This is true because the Ikpikpuk River has an extensive shallow mud flat delta which extends well out into Smith Bay which is shallow with numerous shoals. A point-to-point transect across Smith Bay from Drew Point to Cape Simpson crosses a maximum depth of 4.5 m (15 feet; and inside the bay depths are only 2-3 m (7-9 feet) (Department of the Navy, 1975). Strong spring run-off creates the mud which causes this shallow depth in the southern half of the bay.

If barges were required for exploration activities, the shallow water conditions inside Smith Bay could restrict their movement. A port site outside the bay, such as the one at Lonely, may be preferred.

Potential for disruption to sensitive wildlife habitats may be minimized through application of the four preceding criteria for selection of suitable locations for an exploration base camp. Port site locations within Smith Bay are less preferable to locations such as Drew Point or Cape Simpson because of the potentially sensitive fish and marine mammal habitats within the Bay.

Potentially adverse impacts to other environmentally sensitive areas may be mitigated by properly timing operations and routing of ground and air transportation. Environmentally sensitive areas include the nesting habitats of large numbers of snow geese and other waterfowl; a resident caribou herd between Smith Bay and the Canning River; and the winter denning areas of polar bears.

Due to the fact that other criteria reinforce the concerns of protection of wildlife habitats, this criterion is deemed of secondary importance in locating suitable sites for a base camp for exploring the western reserves.

4.8.4.2 Offshore and Onshore Pipelines

This section discusses key locational criteria for pipeline routing. Small diameter offshore pipelines would carry oil to shore, probably near the supply base camp, where it would be transported in a single pipeline to Prudhoe Bay. Figure 4-3 indicates a "probable port and onshore pipeline zone" within which the pipeline would be built. Two of a number of possible pipeline alignments are illustrated, and discussed in terms of the locational criteria below:

- Minimization of the length of offshore and onshore pipelines.

- Minimization of construction requirements for gravel .

- Minimization of impacts to fish and wildlife.

Minimization of the length of offshore and onshore pipelines is considered because the cost of laying offshore pipelines is estimated to range between $8 and $12 mi 11 ion per mile, and onshore pipelines between $7 and $11 million per mile. Therefore, pipeline distances must be kept to a minimum. This is particularly true for offshore pipelines, since multiple alignments are anticipated.

Since offshore pipelines would normally converge at a pipe union facility at the base camp, this locational criteria applies to base camp locations as well.

The distance between the offshore field and the closest pipeline landfall within the port zone is approximately 5 kilometers (3 miles) at Cape Simpson or Drew Point, but nearly 24 kilometers (15 miles) for landfalls at the southern portion of Smith Bay.

Onshore pipeline distances between a base camp at Cape Simpson and Prudhoe Bay, however, would be nearly 80 kilometers (50 miles) longer than a pipeline between a base camp at Drew Point and Prudhoe Bay.

Additional costs are associated with the length of alternative offshore pipeline alignments. Because most of Smith Bay is underlain by permafrost, while subsea permafrost at Cape Simpson and Drew Point probably extends less than 3 kilometers (2 miles) offshore, any pipeline alignments directed into Smith Bay would be less favorable.

Minimization of construction requirements for gravel is closely tied to the length of pipelines because a significant increase in the length of onshore alignments includes increased demands for gravel for construction. The west Arctic has limited amounts of exploitable gravel, located mostly on coastal beaches. Environmental stipulations may prohibit extraction of much of these already limited resources.

The Navy has recognized that limited gravel resources in the Naval Petroleum Reserve No. 4, which extends over much of the west Arctic, could limit or influence development. Plans for continued petroleum exploration in NPR-4 discuss alternatives, such as transporting gravel by barge from areas outside the North Slope and the use of synthetic film materials, or prefabricated building pallets (Department of the Navy, 1975). Thus, the limited availability of gravel reinforces the concerns for the most direct pipeline alignment between the offshore pipeline landfalls and Prudhoe Bay.

Minimizing disruption of fish and wildlife habitats may require an alignment of corridors to avoid sensitive areas, control over the timing of construction and maintenance, or special provisions such as pipeline burial .

Since alternative pipeline alignments will encounter sensitive areas anywhere within the zone, no alignment is clearly preferred. Rather, this criteria serves to make localized adjustments to basic alignments established by the preceding criteria.

For example, the alternative onshore pipeline alignments illustrated in Figure 4-3 cross the migration route of the Arctic caribou herd and the range of a smaller resident herd which extends from the Colville River to Teshekpuk Lake. Both alignments could present a potential barrier to caribou migration between inland and coastal areas.

The alignment from Lonely also passes through major waterfowl areas, including a snow geese molting area. Although winter construction would avoid disruption to the waterfowl, maintenance of the pipeline from an adjacent gravel or ice road could be disruptive.

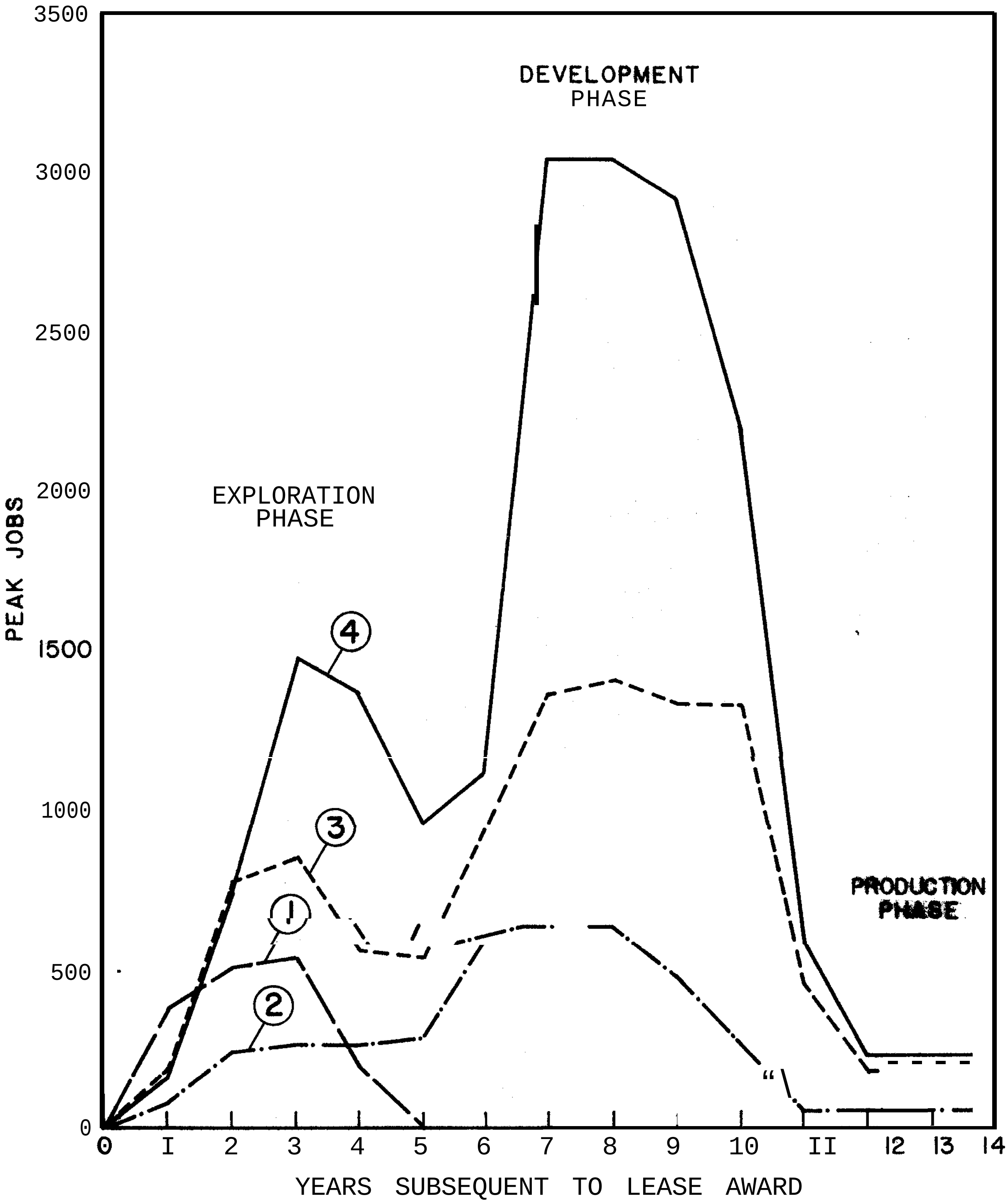
The most direct alignment of an onshore pipeline crosses rivers near their wide, downstream deltas. These crossings are costly because pipelines must be buried beneath the riverbed to avoid the channel scour. In addition, they are sensitive fish and water fowl areas.

4.9 MANPOWER IMPLICATIONS

This section draws together some of the principal conclusions regarding the manpower requirements of the four selected scenarios. It also discusses three issues critical to the recruitment of manpower in the Beaufort Sea region: Alaskan local hire, minority group hire, and North Slope hire.

4.9.1 Comparison of the Four Scenarios

A comparison of the respective manpower requirements for the selected scenarios is shown graphically in Figure 4-4. Manpower is expressed in terms of the peak number of jobs in any given year. Direct employment would be approximately twice the number of required jobs.



COMPARATIVE MANPOWER REQUIREMENTS

FOR FOUR SCENARIOS

(PEAK JOBS PER YEAR)

FIGURE 4-4

It can be seen from the graph that the four scenarios follow very similar patterns from the time of the lease award to the start of production, which represents a period of approximately 11 years. The level of manpower moves through two distinct cycles corresponding to the phases of exploration and field development. The exploratory cycle lasts for five years, reaching a peak in the third year; and the developmental cycle lasts for six years, reaching a peak in the seventh and eighth years after the lease award. Notably in scenario number one, no oil is discovered, and consequently, there is no developmental cycle.

The peak of the developmental cycle is significantly larger than that of the exploratory cycle, primarily the result of the large amounts of labor required for pipeline installation during field development. The peak-to-peak ratio (the manpower in year eight divided by that in year three) is: 2.6 in scenario number two, 1.6 in scenario number three, and 2.1 in scenario number four. Thus, in general, manpower levels will increase by roughly 200% during the transition from exploration to the installation of production facilities.

During the exploration phase, total manpower requirements are directly related to the number of tracts explored, which are in turn directly related to the level of discovered reserves. This can be seen from Table 4-25. The only exception is, again, scenario number one, in which exploration occurred in three separate locations. In contrast, in all other scenarios exploration was limited to a single location.

TABLE 4-25

SELECTED FACTS FOR FOUR SCENARIOS

I terns	Scenario No. 1	No. 2	No. 3	No. 4
Tracts Explored (total)	8	4	20	40
Reserves Discovered (Bbbl)	0	0.7	2.3	3.5
Pipeline Layed [total kilometers (miles)]	0	72 (45)	209 (130)	443 (275)
Production Wells Drilled (total)	0	103	343	516

During the development phase, the total manpower requirements are directly related to: (1) the number of production wells drilled, and (2) kilometers (miles) of pipeline layed. In turn, the number of wells drilled is a direct function of the amount oil discovered; and the length of pipeline a direct function of the distance to Prudhoe Bay for link-up with Alyeska. By placing the largest amount of oil at the greatest distance from Prudhoe Bay (scenario number four), the two significant relationships concerning manpower were compounded. As a result, although the amount of oil in scenario number four is 150% of that in scenario number three (3.5 Bbbl divided by 2.3 Bbbl = 1.5), the relative manpower required during peak development (year eight) is over 200% greater for scenario number four.

One of the significant conclusions to arise from the manpower analyses of the four scenarios is the large percentage of unskilled workers required during the exploration phase (about 45% of the total) contrasted with the large percentage of semi-skilled workers required during the development phase (about 55% of the total). This is principally due to the skills required for pipeline workers combined with the disproportionate share of the work force they comprise during the development phase. One of the major implications is that the employment opportunities for local, unskilled labor are greatest during the early years of OCS activity.

4.9.2 Issues of Hire

4.9.2.1 Local Hire

When the Alaska Legislature considered the thousands of jobs which were to be created by the Alyeska pipeline, it attempted to insure that as many of those jobs as possible went to existing Alaska residents. The Local Hire Act was passed by the State Legislature in 1972, and it states that Alaska residents must be given employment preference in projects relating to oil/gas leases. A "resident" is defined as one who: "(1) except for brief intervals of military serve has been physically in the state for a period of one year immediately prior to the time he enters into a contract or employment*; and (2) maintains a place of residence within the state; and (3) has established a residency for voting purposes within the state; and (4) has not, within the period of required residency, claimed residency in another state; and (5) shows by all attending circumstances that his intent is to make Alaska his permanent residence." (See. 38.40.090 of the Local Hire Act).

Despite the very specific definition of an Alaska "resident" in the local Hire Act, the enforcement of this Act remained a problem. Theoretically, the Fairbanks union hiring halls were obligated to give preference in hiring to all long-time "resident" Alaskans as defined by the Local Hire Act. However, in practice the union gave preference to persons who claimed Alaska residency but who did not strictly meet the specific qualifications of the Act. For example, traditionally the prime evidence of one's Alaska residency was simply the possession of an Alaska driver's license, and in order to obtain such a license all one had to do was give some basic personal information, such as one's name, address and birthdate, and then pay a nominal fee. This could be done on the day one arrived in Alaska. Moreover, for the purpose of

*The one year residency requirement was declared unconstitutional by the Alaska Supreme Court in 1977 and the case has been appealed to the U.S. Supreme Court.

voting in Alaska, a new immigrant needed only to live in Alaska for 30 days before he could claim his constitutional right to vote as an Alaska resident.

In order to remedy this situation of recent in-migrants claiming to be Alaska "residents," the State Department of Labor (Wages and Hours Division) in March, 1974, instituted a process called the Certification of Residency. A certificate was given only to those Alaskans who could satisfy the five criteria for residency set forth in the Local Hire Act (Sec. 38.40.090; see above). Of the five criteria, that one that the Department of Labor relied on most heavily was number five -- that the person "shows by all attending circumstances that his intent is to make Alaska his permanent residence." This criterion could be satisfied in a variety of ways, such as purchasing property in Alaska, moving one's family to Alaska, putting his or her children in Alaskan schools, etc. Of course, the state's reliance on this criterion only reinforced the historical patterns of in-migration.

Although the certification process was instituted in early 1974, the state did not initially design procedures which would ensure that only long-term, bona fide residents received job preference. However, today, in order to receive preferential treatment in the hiring of pipeline workers, a prospective worker must present his certification of residency card to the union. Moreover, on March 9, 1976, the State Commissioner of Labor ordered that all resident Alaskans (no matter how low their union seniority) who received a certification of residency had to be dispatched by the unions before any non-resident could be dispatched. As of January 30, 1976, 17,099 certification cards had been issued by the State Department of Labor.

The percentage of "resident" Alaskan working on the pipeline has been substantial. According to the Alaska Department of Labor, the percentage of resident Alaskans working on the pipeline increased from 28.4% in the third quarter of 1974 to 53.9% in the fourth quarter of 1974. Thereafter, the percentage of resident Alaskans rose very slowly, reaching 66.7% in the last quarter of 1975.

Local Hire on the Alyeska Pipeline

Date Quarter Ends	Percentage of Resident Alaska Workers
September 30, 1974	28.4%
December 31, 1974	53.9%
March 31, 1975	57.0%
June 30, 1975	59. 4%
September 30, 1975	60.1%
December 31, 1975	66. 7%

Source: Ken Dunker, Alaska Department of Labor
March 10, 1976.

These statistics may be somewhat inexact. As stated above, the definition of who exactly is an Alaska "resident" varies, depending on whether one relies on a certification of residency, on a worker driver's license, or on the fact that during the last election a worker voted in Alaska. In all likelihood, since initially in-migrants were able to avoid the requirements of the Local Hire Act and still claim to be residents of Alaska, the early figures overstate the percentage of Alyeska workers who actually were one-year residents of the state. Only recently have the enforcement provisions of the Local Hire Act and the certification of residency been strengthened so as to ensure that one-year residents in fact receive employment preference.

4.9.2.2 Minority Group Hire

While the Local Hire Act gave preference to resident Alaskan job applicants, it did not deal specifically with guidelines for the hiring of Native or minority group members. Such guidelines are to be found in the Alaska Plan to Provide Equal Opportunity in the Construction Industry (U.S. Department of Labor, March 1972). This voluntary plan seeks to increase minority group employment in all phases of the construction industry and defines minority group to include Black, Filipino, Spanish-surnamed, Oriental, American Indian, Eskimo and Aleut. Its goal for minority manpower utilization in all construction trades by 1978 is 26.1% to 28.1% of the total work force (Order of Bid Conditions, Alaska Plan, p. 10).

4.9.2.3 North Slope Local Hire

OCS construction hiring on the North Slope will have to adhere to both the conditions set for local Alaskan hire and the Alaska Plan for

for minority group employment. Projections for local hiring on the North Slope can be derived from census data on population and employment characteristics.

Barrow Census Division

1970	Males	Females
Population over 16	822	653
Number in Labor Force	547	166
Percentage Participation in Labor Force	66.5%	25.4%

Source: Employment Characteristics for Census Divisions: 1970, U.S. Census, Table 121.

To project the maximum labor force in Barrow in 1970, one can use 1970 Anchorage percentages of labor participation as a model and apply them to Barrow's over-16 population:

90.6% for males (822) = 745

50.7% for females (653) = 327

Then, to project the maximum manpower available for local hire, the actual number in the Barrow labor force is subtracted from the maximum labor force numbers cited above.

	Males	Females
1970 maximum number in labor force	745	327
1970 actual number in labor force	-547	-166
1970 projected available local manpower	198	161

Thus, the total number of people additionally available for local hire in the Barrow census district, according to these calculations, is 359 for the year 1970.

To make similar projections for 1975 (the year for which most recent statistics are available) one must first understand the population changes in the Barrow-North Slope area since 1970. Table 4-26 shows the relevant figures. According to the table, almost all of the migration increase was due to non-native pipeline workers. It is assumed that most of these in-migrants will leave the area when their work is completed. Hence, the baseline 1975 population of 3,566 consists of the 1970 population (3,343), plus the natural increase figure (223).

Based on 1970 data, only 44 percent of the population was over 16 years of age, and of this group, 56 percent were males and 44 percent females. Therefore, in 1975, the over-16 population was 1,569 people (3,566 x 44% = 1,569), of which 879 were male and 690 female.

Projections of the labor force for 1975 can be calculated by applying the 1970 labor force participation figures for Barrow and Anchorage to the 1975 estimated population of males and females over 16:

	Males	Females
1975 total population over 16	879	690
Percentage participation in labor force (Barrow)	66. 5%	25.4%
1975 projected actual labor force	585	175
Percentage participation in labor force (Anchorage)	90. 6%	50.7%
1975 projected maximum labor force	796	350

TABLE 4-26

Estimates of Civilian Population in Barrow-North Slope Census Division as of July 1, 1975 and Components of Population Change Since April 1, 1970*

1970 Population (April			3,343
Natural Increase:			
	Births	337	
	Deaths	(114)	
			223
Net In-Migration			2,783
1975 Population (July)			6,349
Net Change 1970-1975:			3,006
Percentage Increase 1970-1975:			89.9%

*The creation of the North Slope Borough in 1973 brought about changes in the geographic borders of the Barrow, Upper Yukon, and Kobuk census divisions. The 1975 population estimates reflect the change in census division borders as do the 1970 census figures given. Thus, the population for Barrow in 1970 was adjusted upwards by 788 by the Census Bureau. The Barrow census division's population is 80% to 90% Native.

Source: Current Population Estimates by Census Division, Alaska Dept. of Labor, July 1, 1976

TABLE 4-26

Estimates of Civilian Population in Barrow-North Slope Census Division as of July 1, 1975 and Components of Population Change Since April 1, 1970*

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		223
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Percentage Increase 1970-1975:		89. 9%

*The creation of the North Slope Borough in 1973 brought about changes in the geographic borders of the Barrow, Upper Yukon, and Kobuk census divisions. The 1975 population estimates reflect the change in census division borders as do the 1970 census figures given. Thus, the population for Barrow in 1970 was adjusted upwards by 788 by the Census Bureau. The Barrow census division's population is 80% to 90% Native.

Source: Current Population Estimates by Census Division, Alaska Dept. of Labor, July 1, 1976

The maximum additional manpower available for local hire in 1975 in the area can be derived by subtracting the projected actual labor force from the projected maximum labor force:

	Males	Females
1975 projected maximum labor force	796	350
1975 projected actual labor force	-585	-175
1975 maximum manpower available for local hire	211	175

Thus, according to these calculations, the total number of people additionally available for local hire in the Barrow/North Slope census district, is 386 for the year 1975.

It should be noted that those most likely to get OCS jobs as a result of Beaufort Sea petroleum development activities would probably be drawn from the ranks of the already employed, since their skill levels are quite high. New recruits to the labor force, namely the projected additional local hires, would probably fill the old jobs left by experienced and skilled workers moving into OCS opportunities.

As far as source of origin of other manpower for OCS operations in the Beaufort Sea are concerned, some general observations can be made. Based on the Alyeska pattern of hiring resident Alaskans as of December 1975, one may assume that 66 percent of the annual average OCS employment (as estimated in any given scenario) would be resident Alaskans. This 66 percent figure would be made up of two components: Alaskan minority group members as 27 percent of the total manpower (if the Alaska Plan guidelines are followed) and non-minority Alaska residents as 39 percent of total manpower. With these Alaskans assumed to comprise 66 percent of the scenario manpower estimate, the remaining 34 percent could be assumed to be in-migrants from out of state.

Using 1,000 as a theoretical scenario manpower figure, here is how the percentages on local, minority, and in-migrant hires would look:

Minority Group Alaskans (27%)	270
Non-Minority Group Alaskans (39%)	+390
Alaska Local Hire Residents (66%)	660
Alaska In-migrants (34%)	+340
Total Manpower	1,000

It can clearly be seen from this example (1,000 OCS employees), that the demand for local hire exceeds the number available in the North Slope local labor force. Beyond the 386 projected additional hires available in the Barrow census division (1975), all other Alaskans (Native and non-native) would have to come from other parts of the state. Such a situation is most likely to occur during the labor-intensive phases of exploration and development; however, by the production phase, when manpower needs decrease, the local North Slope labor supply might be able to meet OCS manpower requirements.

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GLOSSARY

(Important economic, technical and environmental terms are defined in the text)

caisson - load-bearing enclosures sunk into the ground to protect excavation for a foundation, or serve as part of a permanent structure, or enclose subsurface space for machinery, constructed of steel or concrete.

gabions - wire-mesh enclosures of rock or aggregate used for slope protection, erosion control.

ice rafting - pressure process by which one ice floe overrides another forming a ridge.

ice scours or gouges - linear scars in sea bottom sediments caused by plowing of grounded ice masses.

isobath - submarine contour or line joining points of equal depth of a horizon below the surface.

lead - a navigable passage through floating ice.

permafrost - perennially frozen ground in which a temperature below 0°C (32°F) has existed for a long time (from two years to tens of thousands of years).

piles - slender, underground columns, generally placed in groups, supporting loads, constructed of wood, steel or concrete.

pingo - large ice-cored mound, ranging from a few feet to over 60 m (200 feet) in height, term derived from an Eskimo name for hill.

polynya - any water area in pack ice or fast ice other than a lead, not large enough to be called open water; some are found in the same location every year, e.g. off the mouth of a large river.

pressure ridge - ridge or wall of broken floating ice forced up by pressure [can be up to 45 m (150 feet) thick].

pressure ridge keel - underside of pressure ridge projecting toward sea floor.

Quaternary - the latest period of geologic time encompassing the past 2 million years including the glacial epochs and post-glacial (Holocene) time.

sheet piles - vertical, interlocking sections driven into ground to form a wall or enclosure, commonly made of wood, steel or concrete.

stamukhi zone - boundary betwen landfast ice and (westward) drifting polar pack ice characterized by linear pressure and shear ridges, and ice gouging of the bottom sediments.

strudel - from the German meaning whirlpool, irregularly-shaped drain holes in fast ice through which fresh water drainage gushes downward during breakup, commonly where rivers temporarily overflow fast ice during spring between shore and barrier islands.

thermokarst - collapse of topographic features produced by melting of ground-ice and subsequent settling or caving of the ground; degradation of permafrost caused by disturbance of thermal regime.

APPENDIX A

A CRITICAL REVIEW OF THE SCENARIO ASSUMPTIONS

The assumptions used in this interim report to construct petroleum development scenarios have been reviewed by several federal and state government agencies and petroleum operators. A broad spectrum of critiques and suggestions for alternative frameworks was received. Since the intentions of this interim report include exploration of the variables which will eventually determine petroleum development, it is appropriate to review these critiques and alternatives implied in them.

Number of Exploratory Wells. The assumption that up to 2.5 wells per tract explored might be drilled in exploratory actitivites has been viewed skeptically by some reviewers. The Gulf of Alaska provided an example of a region in which the negative prospects of many tracts were determined by a very few exploratory wells. There are a few counter examples, notably the Dustin Dome structure offshore Florida, in which several exploratory holes are being drilled in spite of lack of success to date.

The basis for projecting a higher number of wells per exploratory tract lies in the expectation that encouraging and favorable indication will be found in holes which do not yield economic reserve discoveries. The "oiliness", i.e., original marine organic content and subsequent temperature regime, of the Cretaceus sands underlying the Arctic Slope is generally expected to be favorable. The chances for resource deposits depend upon whether reservoir formation conditions are also favorable.

The assumption of 2.5 wells per exploratory hole could overstate exploratory impacts if clearly negative results were indicated on the geologic structures drilled. It could also overstate exploratory drilling where a large reserve is located, fortunately requiring little exploration. On the other hand, the exploratory impact period could be understated for a well program limited to one well per annual ice platform.

One question raised by this critique is whether a single average number of wells per exploratory prospective tract can adequately cover potential impacts due to the period of activity and employment in exploration.

Investment Schedule

Some reviewers commented that the assumed development schedule, i.e., drilling most of the producing wells first, and then beginning production all at once, could be inappropriate or misleading. First, the development period prior to first production may be too long, so that the capitalized interest charges may be higher than typical field practice. This could, in turn, decrease the apparent return on investment, or increase the minimum economic field size. The alternative approach is to stage the drilling so that for a while, new wells are filling in the decline in production of the first drilled. Volume utilization of trunk pipelines and processing stations is more efficient, the facilities needs are sized somewhat smaller, and the cash flow of the early wells reduces the necessary "up-front" capital outlay.

However, with respect to the simplified economic analysis of return and field sizes, there is a trade-off. The absolute present worth at start of production is greater for the unit block approach than that achieved from staged drilling. This offsets much of the overstatement in capitalized interest.

In the sensitivity analysis, it was noted that small perturbations in costs and efficiencies had less effect upon rate of return when the nominal rate was low ($\sim$5%), compared to cases where the rate is higher, say above 12%. For this reason, it was concluded that the minimum field size could be adequately determined for this interim report with the block approach.

Field Parameters

Some reviewers felt that the use of Salderochit reservoir characteristics for offshore finds could be inappropriate, pointing out that the size of the Prudhoe Bay field is unique, and that potential offshore objectives could lie at deeper or shallower depths. Some of the wells produced 10,000 bpd.

It should be pointed out that for the descriptive qualities of the offshore reservoirs, with respect to oil gravity, water, impurities, etc., the use of Prudhoe Bay values is likely to be as close as any other projection.

The reservoir parameters adapted, 50,000 barrels reserve per surface acre, the production curve, and the well spacing, lead to an average nominal maximum production of 2,500 bpd per well. The surface fill factor is representative of the average of all U.S. oilfields, as well as Prudhoe Bay. The production curve is typical of a combination depletiondrive/waterflood for oil of this gravity. The nominal maximum well production projected is well within reasonable expectations, (i.e., does not reflect a projection of a supergiant field).

The assumption of well spacing has a strong effect on the projected economics of the field. Conditions which could reduce the well spacing are reservoir sands of low horizontal permeability, or reservoirs with complex, closely spaced structure. The latter condition, thus has been projected not to occur within the study area. The well spacing of about 140-160 acres may be adequate if at least 300 millidarcy permeability is discovered.

The final assumption of reservoir property is that gas reserves would be closely associated with the oil reserves, geographically if not as a gas cap. The alternative assumption - geographic separation of the resources - has not been considered in this interim report.

It is recognized, however, that the possibility exists that commercial oil and gas resources may be encountered in non-Sadlerochit reservoirs such as the Pennsyl vanian-Missi ssippian Lisburne Group and Cretaceus Kuparuk formation or younger Tertiary strata which may have different reservoir characteristics and hydrocarbon properties. However, the scope of this study did not include a detailed geologic evaluation of Beaufort Sea oil and gas resources nor was warranted since it is anticipated that a significant portion of offshore petroleum resources will probably be encountered in Permo-Triassic (Sadlerochit) reservoirs. Further, without a detailed geologic assessment a non-Sadlerochit reservoir model cannot be confidently formulated.

Future Beaufort Sea petroleum development studies, which will consider a State-Federal lease sale, NRP-A and other onshore North Slope developments, will include a detailed geologic assessment in order that several reservoir models can be evaluated and a degree of geographic reality be introduced in the location of possible discovery areas.