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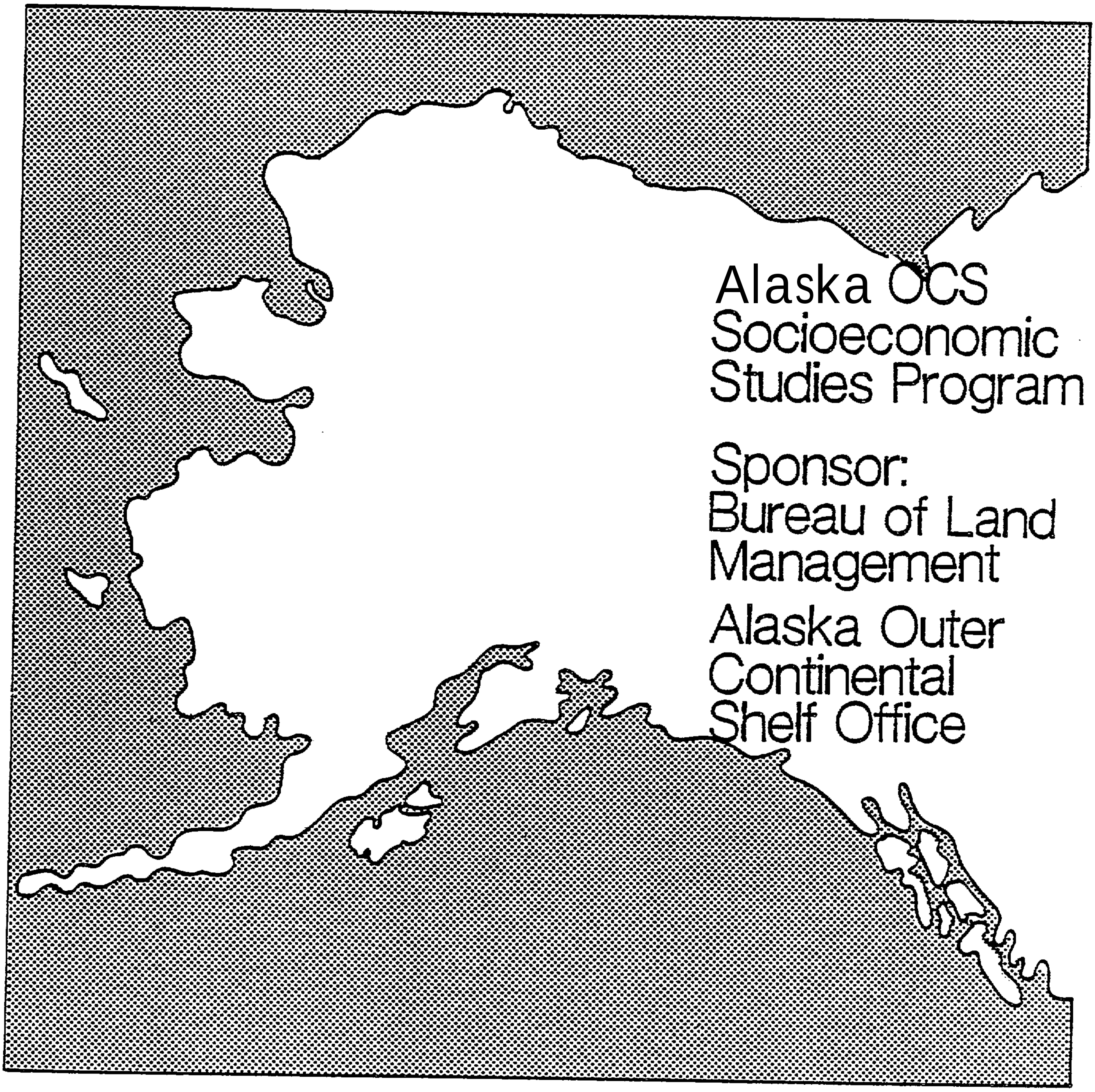
Technical Report Number 80



Alaska OCS Socioeconomic Studies Program

Sponsor: Bureau of Land Management Alaska Outer Continental Shelf Office

Bering Sea Cumulative Economic OCS Petroleum Development

The United States Department of the Interior was designated by-the Outer Continental Shelf (OCS) Lands Act of 1953 to carry out the majority of the Act's provisions for administering the mineral leasing and development of offshore areas of the United States under federal jurisdiction. Within the Department, the Bureau of Land Management (BLM) has the responsibility to meet requirements of the National Environmental Policy Act of 1969 (NEPA) as well as other legislation and regulations dealing with the effects of offshore development. In Alaska, unique cultural differences and climatic conditions create a need for developing additional socioeconomic and environmental information to improve OCS decision making at all governmental levels. In fulfillment of its federal responsibilities and with an awareness of these additional information needs, the BLM has initiated several investigative programs, one of which is the Alaska OCS Socioeconomic Studies Program (SESP).

The Alaska OCS Socioeconomic Studies Program is a multi-year research effort which attempts to predict and evaluate the effects of Alaska OCS Petroleum Development upon the physical, social, and economic environments within the state. The overall methodology is divided into three broad research components. The first component identifies an alternative set of assumptions regarding the location, the nature, and the timing of future petroleum events and related activities. In this component, the program takes into account the particular needs of the petroleum industry and projects the human, technological, economic, and environmental offshore and onshore development requirements of the regional petroleum industry.

The second component focuses on data gathering that identifies those quantifiable and qualifiable facts by which OCS-induced changes can be assessed. The critical community and regional components are identified and evaluated. Current endogenous and exogenous sources of change and functional organization among different sectors of community and regional life are analyzed. Susceptible community relationships, values, activities, and processes also are included.

The third research component focuses on an evaluation of the changes that could occur due to the potential oil and gas development. Impact evaluation concentrates on an analysis of the impacts at the statewide, regional, and local level.

In general, program products are sequentially arranged in accordance with BLM's proposed OCS lease sale schedule, so that information is timely to decisionmaking. Reports are available through the National Technical Information Service, and the BLM has a limited number of copies available through the Alaska OCS Office. Inquiries for information should be directed to: Program Coordinator (COAR), Socioeconomic Studies Program, Alaska OCS Office, P. O. Box 1159, Anchorage, Alaska 99510.

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Technical Report No. 80

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM

AN ECONOMIC ANALYSIS OF CONCURRENT DEVELOPMENT OF OUTER CONTINENTAL SHELF OIL AND GAS LEASES IN THE BERING SEA

Prepared For

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ABSTRACT

Bering Sea oil and gas resources represent an important potential energy source for the United States. The resources of the four Bering Sea sales represent nearly 10 percent of the estimated undiscovered offshore oil resources of the U.S. Exploration and development of this potential resource will entail considerable concurrent activity in the Bering Sea.

Dames & Moore has recently completed Petroleum Technology Assessments for each of the four federal Bering Sea lease sale areas: Norton Sound--Sale 57 (D&M, 1979), St. George Basin--Sale 70 (D&M, 1980), Navarin Basin--Sale 83 (D&M, 1982) and the North Aleutians Shelf--Sale 92 (D&M, 1980). In these studies, we assessed the most suitable technologies for developing petroleum resources under the harsh conditions of the Bering Sea. Each of the technologies identified were analyzed from an economic and financial standpoint, and equivalent amortized costs per unit of production were developed. Manpower needs for each phase of development of each lease sale were also estimated. These prior analyses assumed that each lease sale was developed in isolation.

The primary purpose of this study is to determine the impacts of concurrent development on the economic and labor requirements of the four Bering Sea lease sales, compared with the stand-alone sales. An additional major purpose of this study is to calibrate, update, and compare the economics of the Bering Sea lease sales. This study updates the earlier Bering Sea reports to reflect our current thinking and to present a consistent basis for comparison.

Based on the analysis conducted for this study, we conclude that oil discovered in any of the Bering Sea lease sales will be economic to develop, assuming favorable reservoir conditions and regulatory climate. Gas development appears to be uneconomic, even under very favorable assumptions. Concurrent development enhances the economic attractiveness of oil development but does not significantly improve the bleak economic picture for gas development.

Concurrent development will stimulate considerable growth in one or more Aleutian Island ports; but will probably not create any serious labor shortages. Labor requirements under concurrent development will not significantly differ from the labor required for development of individual lease sale are as.

Under these assumptions, the equivalent amortized costs (EAC) per barrel of oil range from $22.50 to $24.90, compared with an assumed value of $27.50/BBL (F.O.B. a convential tanker at an Aleutian Islands port). At these costs of production, real after tax discounted cash flow rates of return on investment range from 15.0 to 21.2 percent. Concurrent development would reduce these costs by a maximum of $1.49 per barrel which increases the rate of return 1.2 percentage points.

In general, the two Southern Bering Sea sales (St. George and N. Aleutian) are more economically attractive than the two Northern sales (Norton and Navarin). The latter sales must support a dedicated fleet of shuttle tankers which transport the crude from a Northern Bering Sea terminal to a VLCC transshipment terminal in the Aleutians. Opportunities for pooling the shuttle tanker fleet requirements offer only modest economies. All concurrent scenarios benefit from opportunities of sharing the Aleutian Islands oil terminal which is assumed to be operated as a joint venture between lease sale developments.

If Navarin and St. George both prove commercial, the opportunity may exist for these sales to share a common oil pipeline to an Aleutian Islands terminal. This scenario would obviate the need for both the Navarin to Aleutians shuttle tanker fleet and a terminal on St. Matthew Island.

Gas development is very costly in the Bering Sea because of the high costs of liquefaction and transportation to market. Each sale would require liquefaction facilities and a dedicated fleet of ice-reinforced LNG tankers to transport the product to a presumed market in California. The gas scenarios show decidedly unfavorable economics, given the assumed value for LNG (4.80/MCF, C.I.F. in California). Real after-tax rates of return in the 4 to 6 percent range. The savings due to concurrent development (mainly from pooling the LNG tanker fleet) make very little improvement in gas development economics. Barring a dramatic reduction in liquefaction costs and a large increase in the price of gas, Bering Sea gas will not be economic to develop.

With the exception of a possible advance base on St. Matthew Island, exploration activity will be focused in the existing communities of Unalaska, Cold Bay, Nome, and possibly Port Heiden. Since the exploration labor force will be largely non-Alaskan, exploration will not significantly affect the local labor market. Commercial hydrocarbon development anywhere in the Bering Sea could have significant implications for Aleutian Island development, especially if two or more areas prove commercial. A terminal facility for transshipping crude onto large conventional tankers would be required. In this study, we assume that this facility will be built at Cold Bay/Morzhovoi Bay for illustrative purposes.

Commercial development of Bering Sea oil resources will have important long-term employment impacts in the region. Concurrent development would only minimally reduce the direct employment requirements compared with the sum of the separate sale requirements. Indirect employment due to creation or expansion of a commercial center in the Aleutians would more than offset the direct labor savings from concurrent development.

1.0 INTRODUCTION AND EXECUTIVE SUMMARY

1.1 PROJECT PURPOSE

Bering Sea oil and gas resources represent an important potential energy source for the United States. The combined resources of the four Bering Sea sales represent 9.9 percent of the estimated undiscovered offshore oil resources of the U.S. (Dolton et al, 1981 and BLM, personal communication, 4/82). Exploration and development of this potential resource will entail considerable concurrent activity in the Bering Sea.

Dames & Moore has recently completed Petroleum Technology Assessments for each of the four federal Bering Sea lease sale areas: Norton Sound--Sale 57 (D&M, 1979), St. George Basin--Sale 70 (D&M, 1980), Navarin Basin--Sale 83 (D&M, 1982) and the North Aleutians Shelf--Sale 92 (D&M, 1980). In these studies, we assessed the most suitable technologies for developing petroleum resources under the harsh conditions of the Bering Sea. Each of the technologies identified were analyzed from an economic and financial standpoint, and equivalent amortized costs per unit of production were developed. Manpower needs for each phase of development of each lease sale were estimated within these technology assessments.

These prior analyses concluded that producing oil in the Bering Sea is both technically feasible and economically attractive. Gas production was found to be technically feasible, but marginal to uneconomic. Although Bering Sea hydrocarbon development is technically feasible, it may be an even more difficult task than developing Prudhoe Bay.

The prior analyses assumed that each lease sale was developed in isolation. None of the infrastructure, supply bases, or petroleum development facilities were assumed to be available from prior or concurrent development for other Bering Sea leases. While this was a reasonable (and necessary) first assumption, a read-through of prior technology assessments leaves the impression that there are no opportunities to share facilities and infrastructure among the lease sale areas.

The primary purpose of this study is, therefore to determine the impacts of concurrent development on the economic and labor requirements of the four Bering Sea lease sales, compared to the stand-alone sales.

An additional major purpose of this study is to calibrate, update, and compare the economics of the Bering Sea lease sales. Since 1979, when the Norton Basin Technology Assessment was completed, petroleum product prices have risen and fallen, and USGS mean resources estimates have changed at least twice. At the same time a great deal of new research has been completed. Furthermore, in assessing field development economics, Dames & Moore has used different assumptions concerning sizes of fields, development and investment schedules, as well as altering its equipment and facilities cost estimates over the course of the four projects. As a result, it is difficult to compare the economic and financial attractiveness of the four sales. This study updates the earlier Bering Sea reports to reflect our current thinking and to present a consistent basis for comparison.

In the course of this study, we have postulated eight scenarios. The first four consist of the stand-alone sales and the last four consist of selected pairs of sales. In evaluating the scenarios, we have used identical product prices. Technologies and equipment cost assumptions, and development and investment schedules are comparable, differing only with respect to specific individual characteristics of each area. As a result the four scenarios accomplish the purpose of creating a comparable set of economic and financial results.

The last four scenarios accomplish the primary purpose of this study in revealing the impacts of concurrent development on petroleum production economics. By comparing the development costs in the stand-alone context with those in the combined-sale scenarios, the differences become apparent.

1.2 SIGNIFICANT FINDINGS AND CONCLUSIONS

Based on the analysis conducted for this study, we conclude that oil from any of the Bering Sea lease sales will be economic to develop, assuming favorable reservoir conditions and regulatory climate. Gas development appears to be uneconomic, even under very favorable assumptions. Concurrent development enhances the economic attractiveness of oil development but does not significantly improve the bleak economic picture for gas development. Concurrent development also will stimulate considerable growth in one or more Aleutian Island ports, but will probably not create any serious labor shortages. Labor requirements under concurrent development will not significantly differ from the labor required for development of individual lease sale areas.

Economic analyses of both oil and gas were conducted using optimistic assumptions regarding reservoir size, optimal sharing of facilities between reservoirs and early discovery and productions of hydrocarbons. No permitting delays were assumed. The entire USGS estimated mean resources are assumed to be concentrated in a single reservoir or in adjacent reservoirs. A single operator (or consortium) was assumed to operate all oil or gas development facilities in each lease sale area. Figures 2-1 and Tables 2-1 summarize the development scenarios.

Capital expenditures required for development of each lease sale area are shown in Tables 2-3 (oil) and 2-4 (gas). Annual operating expenses are summarized in Table 2-12.

Under these assumptions, the equivalent amortized costs (EAC) per barrel of oil range from $22.49 to $24.91, compared with an assumed value of $27.50/BBL (F.O.B. a convential tanker at an Aleutian Islands port). At these costs of production, after tax discounted cash flow rates of return on investment, range from 15.0 to 21.2 percent in real terms. Concurrent development would reduce these costs by a maximum of $1.49 per barrel which increases the rate of return 1.2 percentages points. Results of the economic model of Bering Sea oil development are summarized in Table 3-1.

In general, the two Southern Bering Sea sales (St. George and N. Aleutian) are more economically attractive than the two Northern sales (Norton and Navarin). The latter sales must support a dedicated fleet of shuttle tankers which transport the crude from a Northern Bering Sea terminal to a VLCC transsshipment terminal in the Aleutian. Opportunities for pooling the shuttle tanker fleet requirements (in the scenario of concurrent Norton/ Navarin development) offer modest economies. All concurrent scenarios benefit from opportunities for sharing the Aleutian Islands oil terminal which is assumed to be operated as a joint venture between lease sale developments.

If Navarin and St. George both prove commercial, the opportunity may exist for these sales to share a common pipeline to an Aleutian Islands terminal. This scenario would obviate the need for both the Navarin to Aleutians shuttle tanker fleet and the terminal on St. Matthew Island. Although the very high cost of the 856-km long pipeline appears to slightly outweigh the savings, this option has the advantages of avoiding most of the development on St. Matthew and reducing transportation risks and difficulties inherent in operating tankers in ice-prone waters.

As shown in Table 3-3, increasing capital expenditures for oil development facilities by one third reduces profitability of the operation by 3 to 4 percentage points, but does not cause any of the scenarios to fall below the presumed 12 percent real after-tax hurdle rate.

Gas development is very costly in the Bering Sea because of the high costs of liquefaction and transportation to market. Each sale would require liquefaction facilities and a dedicated fleet of ice-reinforced LNG tankers to transport the product to a presumed market in California.

Given the assumed value for LNG ($4.80/MCF, C.I.F., California), the gas scenarios show decidedly unfavorable economics, with real after-tax rates of return in the 4 to 6 percent range (see Table 3-4). The savings due to concurrent development (mainly from pooling the LNG tanker fleet) make very little improvement in gas development economics. Barring a dramatic reduction in liquefaction costs and a large increase in the price of gas, Bering Sea gas will not be economic to develop.

With the exception of an advance base on St. Matthew Island, exploration activity will be focused in the existing communities of Unalaska, Cold Bay, Nome , and possibly Port Heiden. Since the exploration labor force will be largely non-Alaskan, exploration will not significantly affect the local labor market.

Commercial hydrocarbon development anywhere in the Bering Sea could have significant implications for Aleutian Island development, especially if two or more areas prove commercial. A terminal facility for transshipping crude onto large conventional tankers would be required. Ideally, the logistical support base for the area(s) served by this terminal would also be located nearby. The two sites with potential for the requisite port, harbor, airport and infrastructure requirements for such development are Unalaska Bay and Cold Bay/Morzhovoi Bay. Because of poor airport facilities and congestion, Unalaska appears to be somewhat less favorable than Cold Bay/ Morzhovoi Bay. Implementation of the proposed Unalaska runway extension project could tip the balance in favor of that site, however. In this study, we assume development of Cold Bay/Morzhovoi Bay for illustrative purposes.

Commercial development of Bering Sea oil resources will have important long-term employment impacts in the region. Concurrent development would only minimally reduce the direct employment requirements compared with the sum of the separate sale requirements. Indirect employment due to creation or expansion of a commercial center in the Aleutians would more than offset the direct labor savings from concurrent development.

2.0 ANALYTIC APPROACH

This chapter describes the assumptions and analytic approaches used to model individual and concurrent development of the four Bering Sea lease sales. In Section 2.1 the scenarios are described. Section 2.2 discusses consideration for facilities siting. Technology and cost assumptions for offshore production systems and transportation and processing facilities are presented in Sections 2.3 and 2.4, respectively. Finally, in Section 2.5 the economic modeling procedures are described.

2.1 SCENARIO DESCRIPTION

Eight scenarios have been selected from among the 15 possible combinations of the four lease sale areas in the Bering Sea. The selected scenarios are:

1. Norton Sound (Sale 57) alone
2. St. George Basin (Sale 70) alone
3. Navarin Basin (Sale 83) alone
4. North Aleutian Shelf (Sale 92) alone
5. St. George plus North Aleutian
6. St. George plus Norton
7. St. George plus Navarin
8. Navarin plus Norton

The resource estimates and peak production for each of the four sale areas are as follows:

Sale Area:	Norton	St. George	Navarin	North Aleutian
Oil Resources (MMBBL)	480	1120	1740	370
Peak Oil Production (MB/D)	135	300	460	100
Non-Associated Gas Resources (BCF)	1500	2200	5500	1800
Peak Gas Production (MMCF/D)	245	360	907	302

The oil and gas resources equal the USGS mean resource estimates (BLM, Personal Comm., 1982). Dames & Moore assumes that of the total estimated gas resources, 75 percent is non-associated. The remaining 25 percent occurs as gas caps to oil reservoirs. This gas is reinfected. The peak production rates shown are estimated by Dames & Moore based on indicated petroleum geology, standard reservoir engineering practices, platform capabilities determined within our prior technology assessments, and analytical assumptions. These represent lease sale peak production rates associated with discoveries of the mean resource estimates and other analytic assumptions.

The individual sale scenarios allow the individual sale areas to be compared and provide a basis for comparing stand-alone sales to the same areas in a concurrent sale context. The scenarios were selected to illustrate the opportunities for shared faciliites assuming:

1. Concurrent Northern Bering Sea development.
2. Concurrent Southern Bering Sea development.
3. A mix of both.

The essential difference between the Northern Bering Sea sale areas (Norton and Navarin) and the Southern Bering Sea areas (St. George and North Aleutian Shelf) is that the northern sales require ice reinforced shuttle tankers to move oil to an Aleutian Very Large Crude Carrier (VLCC) terminal. By contrast, our research indicates that the southern sales will be produced by pipeline directly to an Aleutian VLCC terminal.

Scenario 5 represents the impact of Southern Bering Sea development only. Scenario 8 serves the same purpose for Northern Bering Sea development. St. George plus Navarin (Scenario 7) combines the two areas with the greatest estimated mean resources, and shows the effects of combining development in the Northern and Southern Bering Sea areas. Finally, Scenario 6 shows the effects of combining the relatively small resources of the Norton Sale with the larger resources of the Southern Bering Sea St. George sale.

Possible pairings not included in scenarios are those combining the North Aleutian Shelf sale with the two northern areas. Those results can be inferred from the St. George combinations. Development of three or even all four areas concurrently was not included in scenarios due to the very low probability of the existence of commercially developable hydrocarbons in three or more of the areas. However, the combined effects of exploration of three or more areas, a virtual certainty, is treated in relation to labor requirements in Section 4.0.

Tables 2-1 and 2-2, and Figure 2-1 together present an overview of the development scenarios. Figure 2-1 shows the locations of the four lease sale areas and the hypothetical discoveries, storage terminals, pipelines, shipping routes, and transshipment terminals for Bering Sea petroleum development. (Note that while facilities for all eight scenario areas are shown on Figure 2-1, no one scenario requires all facilities illustrated.) Table 2-1 presents the development schedules assumptions used in economic modelling of oil and gas development. These are based on the Department of Interior's July, 1982 lease schedule and our own research developed over the course of the technology assessments of the Bering Sea lease sales. Table 2-2 summarizes the logistics and facilities locations illustrated in Figure 2-1.

Figure 2-1 illustrates several important characteristics about transportation alternatives in the Bering Sea that determine opportunities for sharing facilities if joint development of discoveries in separate lease sales occur.

Development of Northern Bering Sea oil reserves will necessitate use of a fleet of dedicated ice-reinforced shuttle tankers to transport the crude to an ice-free Aleutians transshipment terminal. If both Norton and Navarin Basins are developed concurrently, the opportunity will exist for pooling tanker fleet requirements. Under a pooling arrangement, the combined fleet could be smaller than the sum of the fleet size needed for the two individual sales. This is possible because peak production in the Navarin occurs after the onset of production decline in the Norton. Additional savings are also possible closer matching of fleet capacity to required throughput and the higher reliability of a larger fleet.

TABLE 2-1

OEVEIOPMEIITSC HEDUIJNGAS GUMPTIONS
GOVERNING BERING SEA OIL & GAS PRODUCTION

YEAR	SCENARIO 1 NORTON BASIN	SCENARIO 2 ST GEORGE BASIN	SCENARIO 3 NAVARIN BASIN	SCENARIO 4 Il. ALEUTIAN
1982	SALE (11/82)			
1983	EXPLORATION	SALE (2/83)		
1984	DISCOVERY DELINEATION	EXPLORATION	SALE (3/84)	
1985		DISCOVERY DELINEATION	EXPLORATION	SALE (4/85)
1906	DECISION TO DEVELOP		DISCOVERY DELINEATION	EXPLORATION
1981		DECISION TO DEVELOP		DISCOVERY DELINEATION
1988				
1989	BEGIN GRAVEL ISLAND CONSTR. (OIL-1, GAS-1)		DECISION TO DEVELOP	
1990	BEGIN GRAVEL ISLAND CONSTR. (OIL-2)	INSTALL PLATFORMS (OIL-1, GAS-1)		DECISION TO DEVELOP
1991	BEGIN DRILLING (OIL-1, GAS-1)	V INSTALL PLATFORMS (OIL-2, GAS-2)		
1992	BEGIN DRILLING (OIL-2) START PRODUCTION {OIL-1, 64S-1)	V INSTALL PLATFORMS (OIL-2, GAS-2) + BEGIN DRILLING {OIL-1. GAS-1)	INSTALL PLATFORMS (OIL-1, GAS-1)	
1993	START PRODUCTION (OIL-2)	INSTALL PLATFORM (OIL-3) BEGIN DRILLING (OIL-2, GAS-2) START PRODUCTION (011-1, GAS-1)	INSTALL PLATFORMS (OIL-2, GAS-2)	INSTALL PLATFORMS (OIL-1, GAS-1)
1994		INSTALL PLATFORM [011.41 BEGIN DRILLING (OIL-3) START PRODUCTION [OIL-2, GAS-21	INSTALL PLATFORMS (OIL-3, GAS-3) BEGIN DRILLING (OIL-1, GAS-1)	
199s		BEGIN DRILLING (OIL-4) START PRODUCTION (OIL-3)	INSTALL PLATFORMS (OIL-4, GAS-4) BEGIN DRILLING (OIL-2, GAS-2) START PRODUCTION [OIL-1. GAS-1)	BEGIN DRILLING (OIL-1, GAS-1)
1998		START PRODUCTION (OIL-4)	INSTALL PLATFORMS (011-4, 64s-4) BEGIN DRILLING [OIL-3, GAS-3) 0 START PRODUCTION {OIL-2. 64S-2)	START PRODUCTION [011-1, GAS-1)
1997			V INSTALL PLATFORM (OIL-51 BEGIN DRILLING (OIL-4, GAS-4) START PRODUCTION (OIL-3, GAS-3)	
1998			BEGIN DRILLING (OIL-5) START PRODUCTION (OIL-4, GAS-4)	
1999			START PRODUCTION (OIL-5)	

SOURCE: DAMES & MOORE , For Scheduling Assumption Rationale See Section 2.1.1.

TABLE 2-2

ASSUMED LOGISTICS FOR BERING SEA OIL AND GAS DEVELOPMENT SCENARIOS[1]

Scenario	Shuttle Tanker Terminal Location	Shuttle Tanker Terminal Pipeline Distance[2]	VLCC Terminal Location[4]	Support & Supply Base	Air Transport
1. Norton alone	Offshore Norton Sound	144 Km	Morzhovoi Bay	Nome	Nome
2. St. George only	None	320 Km	Morzhovoi Bay	Unalaska/ Morzhovoi Bay	Cold Bay/Unalaska
3. Navarin only	St. Matthew Is.	240 Km	Morzhovoi Bay	St. Matthew Ia.[3] and Unalaska	St. Matthew Is.[3] and Cold Bay
4. North Aleutians only	None	128 Km	Mohzhovoi Bay	Cold Bay/ Morzhovoi Bay	Cold Bay
5. St. George and North Aleutians	None	320/128 Km	Morzhovoi Bay	Cold Bay/ Morzhovoi Bay	Cold Bay/Unalaska
6. St. George and Norton	None/ Norton Sound	320/144 Km	Morzhovoi Bay	Unalaska/ Morzhovoi Bay/ Nome	Cold Bay/Nome
7. St. George and Navarin	St. Matthew Is.	320/240 Km	Morzhovoi Bay	Unalaska/ Morzhovoi Bay/ St. Matthew Is.	Cold Bay/ St. Matthew Is.
7a. St. George and Navarin {Pipeline)	None	320/856 Km	Morzhovoi Bay	Unalaska/ Morzhovoi Bay	Morzhovoi Bay
8. Norton and Navarin	Offshore Sound St. Matthew Is.	144/240 Km	Morzhovoi Bay	Nome/ St. Matthew Is.	Nome/ St. Matthew 1s.

Notes:

1 Facilities shown represent permanent facilities to support development of proved reserves. Exploration activities. to the maximum extent. will impinge on existing western Alaska infrastructure. Hence, Unalaska doubtless will be the staging-area for-much of the exploration effort.

2 Pipeline distances shown are either to the shuttle tanker termnal or the VLCC terminal at Morzhovoi Bay in the St. George and N. Aleutian scenarios. Distances are approximate.

3 References to St. Matthew Island as a supply baae or air transport beae necessarily imply a secondary staging area elsewhere in western Alaska. Supplies arriving by ship will either be staged from Unalaska or Morzhovoi Bay. Air traffic will be routed either through Cold Bay or Bethel.

4 The selection of Morzhovo Bay as the VLCC terminal location is "for illustrative purposes only. For a discussion of siting considerations aee Sections 2.2 and 4.0.

Source: BLN, Technical Paper #1 1981 and Dames & Moore.

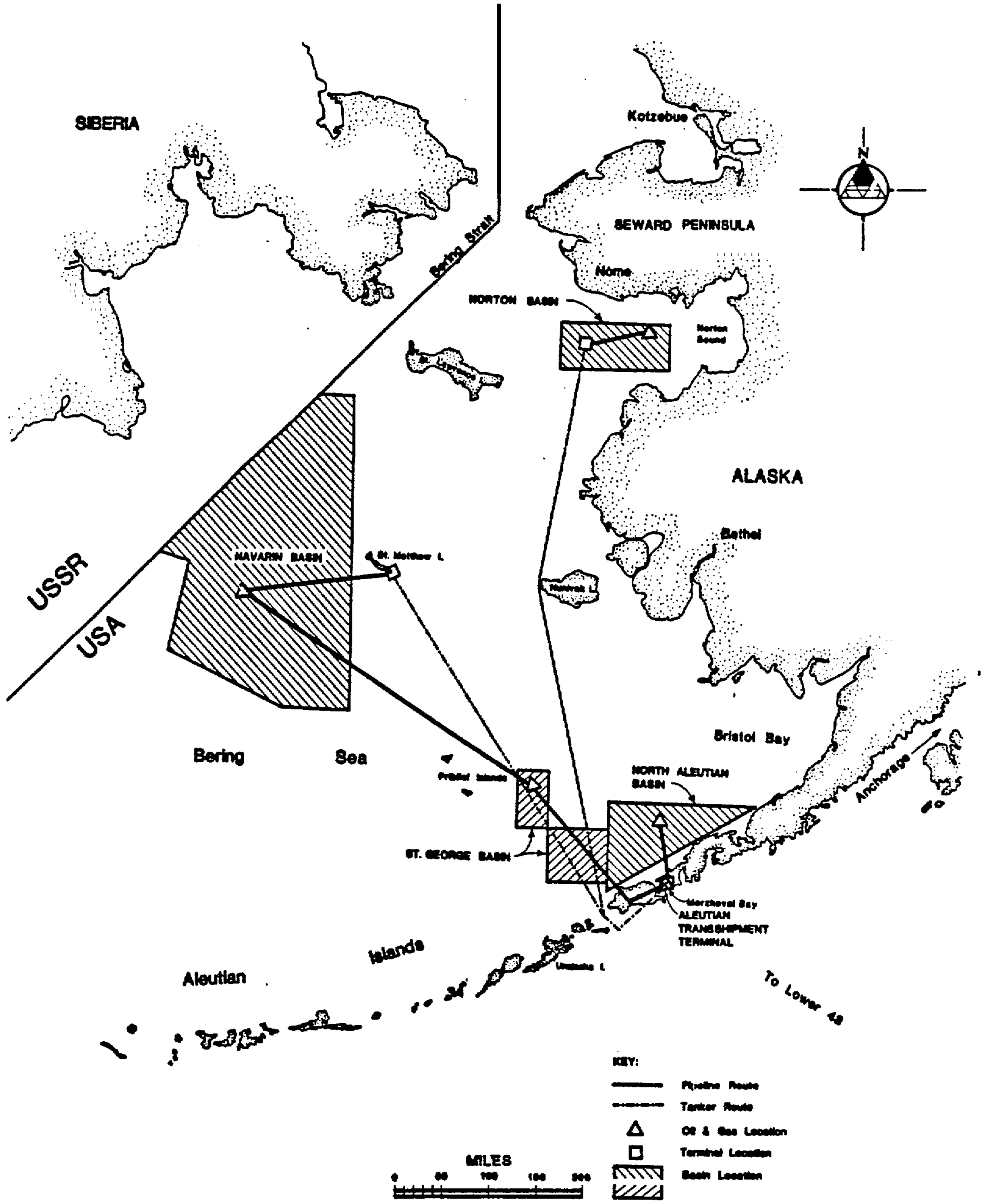

FIGURE 2-1

BERING SEA OIL AND GAS DEVELOPMENT

Development of gas resources in many of the combined sale scenarios also presents the opportunity for pooling dedicated fleet requirements. The benefits of pooling are limited, however, because peak gas production periods in all areas are largely overlapping.

Concurrent Southern Bering Sea development would require separate pipelines from the sale areas directly to the Aleutian VLCC terminal, unless discoveries in each lease sale area are close to their adjoining edges so that a joint trunk line could be shared.

Concurrent development of the Navarin and St. George sales (both of which have high resource potential) could facilitate a major pipeline running from the Navarin Basin to a booster platform in the St. George Basin and a combined trunkline from there to the Aleutian terminal (a variation of Scenario 7). If this option were not chosen, the shuttle tanker trade from the Navarin would only interact with St. George production at the Aleutian terminal.

2.1.1 Development Scheduling Assumptions

In order to provide a sound basis for economic comparison among the four Bering Sea sale areas, the following uniform set of development scheduling assumptions are adopted:

Lease sale to start of exploration	- 1 year
Exploration to discovery	- 1 year
Delineation to decision to develop	- 2 years (3 years for Navarin)
Decision to develop to platform placement	- 3 years
Platform placement to start of drilling	- 2 years
Drilling to production	- 1 year

Table 2-1 shows the schedule of petroleum development which results from the above assumptions for the four stand-alone scenarios. The rationale for these assumptions is given in the following paragraphs.

Except for Norton, lease sales are scheduled in spring as shown below:

Norton Basin (Sale 57)	November, 1982
St. George Basin (Sale 70)	February, 1983
Navarin Basin (Sale 83)	March, 1984
North Aleutian Basin (Sale 92)	April, 1985

The successful bidders would not have sufficient time to complete permit requirements and plan the exploration activities until the following spring. The Norton sale is scheduled for November; it would be just possible to begin exploration in the following summer. To miss this open water season would mean another year delay. We assume lease operators will begin exploring Norton by Summer, 1983. In each case then, exploration could begin the year after the sale.

When the exploration effort results in the discovery of what will ultimately become a commercial field is, of course, unknown. We assume that this will occur in the second season of exploration. Two years of delineation drilling is assumed to confirm the extent and commercial feasibility of the discovery. Thus the decision to develop is assumed to be made after the third year of exploration and delineation, except in the case of the Navarin. Since Navarin Basin is so large, so remote from supply bases, and contains such large potential resources, it is assumed that the decision to develop will not be reached until the end of the fourth drilling season.[1]

Following the decision to develop, platforms must be designed, built and towed out. We assume that this will take place in the summer of the third year following a decisior to develop. In scenarios requiring more than one platform, only one oil and one gas platform is emplaced in the third year after decision to develop. Additional platforms required are assumed to be emplaced in subsequent years at a rate of one oil and/or one gas platform per year. (See Section 2.3, for more detail.)

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[1] These time periods are somewhat optimistic.

well drilling is assumed to begin on each platform in the second year following emplacement. Two platform mounted rigs complete 12 wells per year. Ten of those wells begin production the year after they are drilled. The remaining two wells are service wells.

Although the above-described development scenarios and Table 2-1 discuss the stand-alone scenarios (Scenarios 1 through 4), the same schedules apply to the combined scenarios (Scenarios 5 through 8).

Table 2-1 shows that these development scheduling assumptions would create exploration, physical construction activity and employment in the Bering Sea from mid 1983 to mid-to late in 1990's discoveries were made in two lease sale areas. The facilities events described for the sales in stand-alone scenarios follow the same schedule in the combined scenarios except for transport facilities (tankers and terminals). Those are discussed below and in more detail in Section 2-4.

The foregoing schedule assumptions are optimistic in that they assume a fairly compressed progression of development activities. Exploration, discoveries, and facilities construction take place as soon as technically possible. No delays are considered within the planning, coordination and permitting of development. While such delays can be expected in any frontier petroleum development project, they are unpredictable. Rather than arbitrarily injecting such delays, we prefer to adhere to our technically determined but admittedly compressed schedule. Remember, however, that given the billions of dollars potentially at risk in Bering Sea development, the time cost of delays is extremely high with the current high cost of capital.

2.1.2 Production and Transportation Scenarios

The following paragraphs provide a brief overview of the production and transportation facilities assumed in the analysis. For a more complete discussion of production and transportation facilities assumed in the analysis. For a more complete discussion of production facilities see Section 2.3. For a detailed discussion of transportation facilities required, see Section 2.4.

For analytical simplicity, we assume that the entire mean resources estimated by the USGS for each lease sale area are contained in two nearby fields, one containing the oil and a second containing the non-associated gas. The triangular symbols on Figure 2-1 show the hypothetical locations of the commercial discoveries for the four basins. Those locations were identified on very limited geological bases or entirely arbitrarily; their only purpose is to illustrate the basis for transportation distances.

All fields (oil and gas) are assumed to produce into pipelines which carry the petroleum to shore-based storage terminals. In the case of oil production the terminals stabilize and store crude. In the case of gas production, the terminals liquify and store the gas. These terminals are presumed to be located at Morzhovoi Bay (just west of Cold Bay) for the St. George and North Aleutian sales. For the Navarin, the terminal is assumed located on St. Matthew Island. The Norton pipeline extends to an offshore (artificial) concrete terminal in western Norton Sound where sufficient draft for tankers is available.

Morzhovoi Bay was selected to illustrate a major Aleutian Islands terminal, supply and transshipment point for Bering Sea development for several reasons which are discussed more fully in Sections 2.2 and 4.0.

For oil production, the Norton and Navarin terminals load the crude into ice-reinforced shuttle tankers. These tankers offload at a VLCC transshipment terminal in the Aleutians. Here the crude is stored and loaded on conventional VLCC tankers bound for Lower 48 markets.

A tanker fleet to shuttle within the Bering Sea was selected for delivering Northern Bering Sea oil because of the need for ice-reinforcement. A fleet of dedicated tankers will be required for this service. To lower capital and operating expenses, this fleet shuttles to the Aleutians where the oil can be transshipped to conventional tankers. Conventional tankers are more economic to operate over the long haul to market. The size and scheduling of the required shuttle tanker fleet is discussed in Section 2.4.

LNG terminals are assumed to be located adjacent to the oil terminals in Western Norton Sound (Norton), Morzhovoi Bay (St. George, N. Aleutian) and St. Matthew Island (Navarin). A fleet of dedicated ice-reinforced tankers, each with capacity of 140 million cubic feet (NPC, 1981, pp. 5-15), is used to transport LNG to the assumed California market. Unlike crude from the Norton and Navarin Basins, LNG is shipped direct to market rather than being trans-shipped due to safety considerations. The size and configuration of the LNG fleet required under each scenario are discussed in Section 2.4.

In Scenario 7a (St. George to Navarin via pipeline) the terminal at St. Matthew Island is eliminated by piping the crude to the St. George Basin where pressure is boosted by a pumping station. The Navarin crude then shares with St. George production an enlarged common pipeline to the Aleutians.

The combined lease sale scenarios (Scenarios 5 through 8) rely on the same individual sale development, offshore facilities schedules, and production streams stand-alone sales. The shipping and terminal requirements (and, in the case of Scenario 7a, the pipeline) are modified, however. The modification due to combined sales are described in Sections 2.2 and 2.3.

2.2 FACILITIES SITING ASSUMPTIONS

This section describes the considerations used to select assumed sites for shore facilities for exploration support, production support, pipeline terminals, and the transshipment terminal. A more in-depth analysis of siting considerations and implications appears in Chapter 4.0.

Exploration efforts prior to discovery are ideally based at the nearest onshore location with a pre-existing protected deepwater harbor, airport, and housing, storage and communications infrastructure. Nome is the obvious site for Norton Basin exploration support. For St. George and North Aleutian Shelf exploration, the existing infrastructure and port facilities at Dutch Harbor offer some advantages; but limitations of land availability and airport facilities may necessitate some support from Cold Bay. The closest port, Port Heiden, is a possible site for servicing N. Aleutian exploration. Navarin exploration will probably use the same combination of facilities. However, due to the remoteness of the Navarin, a support base on St. Matthew may be required during exploration. This uninhabited island is the only land area reachable by helicopter from the sale area. Safety considerations as well as practical requirement favor the use of St. Matthew Island in Navarin petroleum development.

Production phase requirements essentially parallel those of the exploration phase. However, existence of production revenues and the longer duration of the production phase permit development of new facilities where existing facilities are not adequate. There is a strong tendency to locate support and terminal facilities at the same site.

For Norton Basin, production support facilities would be located at Nome. Studies by Brain Watt Associates (personal communication, 1982) indicate that a concrete island offshore of Nome would be the most practical terminal location. Siting for St. George and North Aleutian Shelf support and terminal facilites presents a problem. Although Unalaska is the primary marine center and has the largest community infrastructure, its inadequate airport and onshore congestion present serious constraints to development. Cold Bay offers a good airport, but only limited community infrastructure. A road link could be built to Morzhovoi Bay which offers potential for a good protected deepwater port and adequate space for onshore terminal construction. Major development expenditure would be necessary to realize this potential, however.

For analytical purposes, we assume tnat support and terminal facilities for St. George and North Aleutian Shelf development will be located at Morzhovoi Bay utilizing Cold Bay airport community infrastructure. Under concurrent development of Navarin with St. George Basin, a supply base for Navarin would also be located there, with a secondary advance base on St. Matthew Island.

2.3 OFFSHORE PRODUCTION SYSTEMS FOR BERING SEA OIL AND GAS - TECHNOLOGY AND COST ASSUMPTIONS

This section describes the offshore production facilities required for development of the estimated mean petroleum resources in each of the stand alone scenarios. The costs associated with these facilities are also presented here. Facilities and costs are summarized in Table 2-3 for oil development and Table 2-4 for gas development.

2.3.1 PLATFORM PRODUCTION UNITS

The number of platform production units in each of the four stand-alone scenarios is shown in Table 2-3 (oil) and Table 2-4 (gas). Combined sale scenarios contain the sum of the platform production units in their constituent lease sales. There is no reason to alter the offshore facilities requirements when more than one area is developed concurrently. Only the terminal and transportation facilities are affected.

Where the estimated resources for the area indicate a fraction of a standardized production system, the cost of the components of the standardized system were simply multiplied by the indicated fraction. This implies a neutral economy of scale in offshore facilities. This assumption might appear to minimize costs, because in fact, installing a smaller "fractional" platform in the Bering Sea would be nearly as costly as our assumed 48-well capacity platform. However, by adjusting equipment capacity, well numbers and capacities, an operator could engineer around our analytic assumptious to even out apparent lumpiness of costs. In any case, the simplification of using standardized production units helps to focus on the inherent economic differences among the scenarios rather than on the spurious influences of lumpiness.

As indicated on Tables 2–3 and 2-4, the water depth of the platform production units vary by lease sale. The water depths in the most promising tracts . The water depths in the most promising tracts are: 'Norton, 18

TABLE 2-3

FACILITIES AND INVESTMENTS REQUIRED TO PRODUCE BERING SEA SALES MEAN RESOURCES - OIL[1]
(Million 1981 Dollars)

Scenario	1 Norton Basin		2 St. George Basin		3 Navarin Basin		4 North Aleutian Basin	
Sale Date	November 1982		February 1983		March 1984		April 1985	
Mean Resource Estimate	480		1120		1740		370	
OFFSHORE FACILITIES	Capital Equipment	$MM 1981	Capital Equipment	$MM 1981	Capital Equipment	$MM 1981	Capital Equipment	$MM 1981
Platform Production Unita (Water Depth)	1.7 gravel islands (18m)	140	3.9 steel jacket, ice-reinforced platforms (107m)	600	4.8 steel jacket, ice-reinforced platforms (125m)	845	1.3 steel jacket, ice-reinforced platform (45m)	136
Wells Per Platform	48	449	48	1236	48	1837	48	412
Total Producing Wells	68	incl	156	incl	192	incl	52	incl
Deck Equipment Processing Capacity (per Platform)	80,000 B/D	281	80,000 B/D	664	100,000 B/D	872	80,000 B/D	215
Pipelines	90 miles of 22-inch trunkline	196	200 miles of 36-inch trunkline	550	150 miles of 36-inch trunkline	578	80 miles of 20-inch trunkline	158
SUBTOTAL - Offshore Facilities		1066		3030		4132		921

[1] Required equipment is baaed on Table 2-1 and the resource estimates. Unit prices for equipment are shown in Table 2-9 On this Table, unit prices from Table 2-5 were increased by a 10 percent contingency factor.

Source: Dames & Moore.

TABLE 2-4

FACILITIES AND INVESTMENTS REQUIRED TO PRODUCE BERING SEA SALES NEAN RESOURCES - GAS[1]

Scenario	1 Norton Basin		2 St. George Basin		3 Navarin Basin		4 North Aleutian Basin	
Sale Date	November 1982		February 1983		March 1984		April 1985	
Mean Resource Estimate Non Associates Gas (BCF)	1500		2200		5500		1800	
OFFSHORE FACILITIES	capital Equipment	$MM 1981	capital Equipment	$NN 1981	capital Equipment	$MM 1981	capital Equipment	$MM 1981
Platform Production Units (Water Depth)	1.0 gravel island (18m)	82	1.5 ateel jacket plat-forma (107m)	231	3.? steel jacket plat-forma (125)	651	1.2 ateel jacket plat-forma (45m)	125
Wells Per Platform (Target Depth)	17 (3050m)		17 (3050m)		17 (3050m)		17 (3050m)	
Total Producing Wells	17	94	25	165	63	457	21	139
Deck Equipment Processing Capacity (per Platform)	245 MMCFD	94	245 MMCFD	94	245 MMCFD	94	145 MMCFD	94
Pipelines	90 miles 20-inch diem.	158	200 miles 22-inch diam.	396	150 miles 36-inch diem.	578	80 miles 20-inch diem.	141
SUBTOTAL - Offshore Facilities		428		886		1780		499
SHIPS								
Shuttle Tankera (0.6 MM BBL, 75 MDWT)	1.7 tankera	527	2.2 tankera	682	6.3 tankera	1952	1.8 tankera	558
Workboat a	1 workboat	44	1 workboat	44	1 workboat	44	1 workboat	44
TERMINALS								
Storage & Loading	250 MMCFD	750	370 MMCFD	1100	900 MMCFD	2090	300 MMCFD	900
SUBTOTAL - Transportation and Onshore		1321		1826		4088		1502
TOTAL CAPITAL COSTS		1749		2712		5866		2001

[1] Required equipment is baaed on Table 2-1 and the resource estimates. Unit prices for equipment are shown in Table 2-9 On this table, unit prices from Table 2-5 were increased by a 10 percent contingency factor.

Source: Dames & Moore

meters; St. George, 107 meters; Navarin, 125 meters; and North Aleutian Basin, 45 meters. The same water depths meters, are assumed for both oil and gas platforms. Target depths for hydrocarbons in the Bering Sea range from about 2,000 to 3,500 meters. For comparability among leases (in the absence of firm data to the contrary), depth for oil and gas is assumed to be 3,050 meters (10,000 feet) for all lease sale areas.

The oil reserves producible from each 48 well platform production unit is a function of the following reservoir engineer factors and their assumed values:

- Initial productivity '- 2000 B/D for Norton, St. George, North Aleutian, and 2500 B/D for Navarin.

- Ratio of producing wells to service (gas injection) wells -- 5 to 1.
- Production efficiency -- 96 percent.
- Ratio of peak year production to reserves -- 1 to 10.

Except for Navarin, the initial productivity is 2000 B/D per well "or 730,000 B/year. At 96 percent production efficiency, peak production per well is 701,000 barrels per well or 40 times that amount (28 million barrels) per year. Assuming that 10 percent of reserves are produced in a peak year (a common industry practice), 280 million barrels can be produced from each platform production unit. For Navarin Basin, initial productivity is assumed to be 25 percent higher (2500 B/D) for a peak annual production of 35 million barrels per platform production unit. At peak year production of 10 percent of reserves, 350 million barrels of reserves are assumed to be produced by each Navarin platform production unit.

The above consideration, together with assumptions that 45 percent of oil reserves are produced on peak, a ten wells per year step-up, and exponential decline rates of 14.5 to 16.6 percent result in an assumed productive life of about 20 years. This life is consistent with normal oil industry practice.

For gas development, each platform production unit is presumed to contain 17 wells, each with an initial productivity of 15 million cubic feet per day (MMCF/D), for an annual production of 89.3 BCF per year. Assuming peak year production is six percent of reserves, each production unit produces about 15 trillion cubic feet (TCF) of reserves. This applies to all four lease sale areas and all combinations of sales.

The above gas reservoir engineering considerations, together with the assumption that 75 percent of reserves are produced on peak, a five well per year step-up, and exponential decline rates of 10 to 14 percent, result in a productive life of about 20 years.

Deck equipment is needed to extract the oil and gas, to stabilize the product for pipeline transport, and to support the crew. The specifications and cost of platform equipment is largely a function of peak throughput. Each of the platform production systems for gas is designed to accommodate a peak throughput of 245 MMCFD. Deck equipment for oil production in Norton, St. George, and North Aleutian are designed for a peak throughput of 80,000 B/D. Navarin deck equipment is designed for 100,000 B/D to allow for the greater initial productivity of Navarin oil wells.

2.3.2 Production Flows

As noted in Section 2.1.1, the first oil and gas platforms are installed in the third year following the decision to develop. In scenarios requiring multiple platforms, subsequent platforms are assumed to be installed at the rate of one oil (and, if needed, one gas platform per year. This is an analytical simplification that follows from our assumption that the mean resource estimate is discovered in one utilized field with one operator.

Well drilling is done from the platform (or gravel island). Two rigs are assumed for each oil platform and a single rig for each gas platform. Each rig is capable of drilling a 3,050-meter (10,000-foot) hole in 60 days.

Thus , in each year 12 oil wells (10 producers and two gas reinjectors) can be completed in a year. On each gas production unit, six wells per year can be completed. This establishes the production step-up rates.

Tables 2-5 and 2-6 indicate the annual production of oil and gas (respectively) from Bering Sea leases. These tables reflect the step-up to peak production due to the staggered emplacement of platforms and the necessary time for completing the 48 wells per oil production unit and 17 wells per gas production unit. Oil fields produce at peak until 45 percent of their recoverable reserves are depleted, at which time production declines exponentially at the rates indicated on Table 2-5. Gas fields produce at peak until 65 percent of their reserves are depleted, at which time production declines at the rate indicated in Table 2-6. Production ceases when the economic limit is reached (when produced revenues fall below operating cost) and/or when the assumed mean recoverable reserves are exhausted.

For reference purpose, a second set of Tables (2-7 and 2-8) show the average daily throughput by year for each scenario. For the four stand-alone scenarios, those tables result from dividing the entries in Tables 2-5 and 2-6 by 365 days. The combined scenarios' average daily throughputs are the sum of the throughputs of the scenarios constituent lease sales. The daily throughputs are the essential determining of the capacity of the deck equipment, the size of required pipelines, terminal capacity, and requirements.

2..3.3 <u>Cost of Offshore production Facilities</u>

At present no petroleum development has occured in the four lease sale areas included in this report. As a result, cost estimates for required facilities are subject to a high degree of uncertainty. The costs described in this section and used throughout the analysis are based on updated costs from early Dames & Moore technology assessments and on the advice of Sante Fe Engineering (now known as S.F. Braun, Inc.). Every effort has been made to use costs which are internally consistent (i.e. costs that reflect relative difference among the sale areas and correct economies of scale). As we shall

TABLE 2-5
PRODUCTION SCHEDULE FOR BERING SEA OIL DEVELOPMENT

Scenario:		1	2	3	4
	Units	Norton	St. George	**Navarin**	N. Aleutia
Mean Reserves	(MMBBLS)	480	1120	1740	370
Economic Limit	(B/D)	13,150	17,933	26,699	9265
Decline Percent		14.47	16.62	15.0	15.23
Peak Production	(MB/D)	130.5	299.5	460.8	99.8

Year	Annual Production Million Barrels Per Year (MMB/Yr)			
1992	7.0			
1993	21.0	7.0		
1994	35.0	21.0		
1995	47.6*	42.0	8.8	7.0
1996	47 .6*	70.0	26.3	21.0
1997	47 .6*	91.1	52.6	29.4
1998	44*3	105	87.6	36 .4*
1999	38.2	109.3*	122.6	36 .4*
2000	33.0	109.3*	143.9	36.4"
2001	28.5	100.0	166.4	33.6
2002	24.6	83.3	168.1*	28.6
2003	21.2	69.5	155 [illegible]0	24.3
2004	18.3	51.9	13,1.4	20.6
2005	15.7	48.3	111.4	17.5
2006	13.6	40.2	94.4	14.9
2007	11.8	33.6	80.0	12.7
2008	10.2	28.0	67.9	10.8
2009	8.8	23.5	57.5	9.1
2010	7.6	1905	48.8	7.8
2011	6.0	16.2	41.3	6.6
2012		13.5	35.0	5.6
2013		11.3	29.7	4.8
2014		9.4	25.1	4.1
2015		7.8	21.3	
			18.1	
			15.3	
			13.0	
			11.0	
TOTAL	480	1,117	1,738	370

*Indicates Peak Year(s) of Production.

Source: Dames & Moore calculations.
Footnote 1: For assumptions concerning production schedules see Text Section 2.1

TABLE 2-6
PRODUCTION SCHEDULE FOR BERING SEA
GAS DEVELOPMENT

Scenario:	Units	1	2	3	4
		Norton	St. George	Navarin	N. Aleutian
Mean Reserves	(MMCFD))	1500	1100	5500	1800
Economic Limit	(MMCFD)	69.0	91.9	192.9	79.3
Decline Pet.		14.1	14.1	15.7	15.9
Peak Production	(MMCFD)	245	360	907	302

Year	Annual Production Billion Cubic Feet Per Year (BCF/YR)			
1992	31.5			
1993	63.1	31.5		
1994	89.4	78.8		
1995	89.4	120.1	31.5	31.5
1996	89.4	131.4	94.6	84.1
1997	89.4	131.4	184.0	110.4
1998	89.4	131.4	273.3	110.4
1999	89.4	131.4	131.1	110.4
2000	89.4	131.4	131.1	110.4
2001	89.4	131.4	331.1	110.4
2002	89.4	131.4	331.1	110.4
2003	89.4	131.4	331.1	110.4
2004	89.4	131.4	331.1	110.4
2005	83.0	31.4	331.1	110.4
2006	71.2	131.4	331.1	110.4
2007	61.2	121.9	331.1	110.4
2008	52.5	104.7	331.1	101.2
2009	45.1	90.0	331.1	85.1
2010	38.7	77.3	331.1	71.6
2011	33.3	66.4	304.3	60.2
2012	33.3	66.4	304.3	60.2
2013		49.0	216.3	42.6
2014		42.1	182.4	35.9
2015		36.1	153.8	
			129.3	
			109.3	
			92.1	
			76.8	
TOTAL	1,492	2,200	5,495	1,1770

Source: Dames & Moore calculations.
Footnote 1: For assumptions concerning production schedules see Text Section 2.1

TABLE 2-7

PRODUCTION SCHEDULE FOR BERING SEA OIL DEVELOPMENT
AVERAGE DAILY PRODUCTION
(Thousand Barrels Per Day (MB/D))

Scenario:	1	2	3	4	5	6	7	8
	Norton	St. George	Navarin No.	Aleutian No.	St. George Plus Aleutian	St. George Plus Norton	St. George Plus Navarin	Norto Plus Navar
1992	19.2					19.2		19.
1993	57.6	19.2			19.2	76.8	19.2	57.
1994	96.0	57.6			57.6	153.6	57.6	96
1995	130.5*	115.2	24.0		115.2	245.7	139.2	154
1996	130.5*	192.0	72.0	19.2	211.2	322.5	264.0	202
1997	130.5*	249.6	144.0	57.6	307.2	380.1	393.6	174.
1998	112.6	288.0	240.0	80.6	368.6	400.6*	528.0	352
1999	97.2	299.5*	336.0	99.8	399.3*	396.7	635.5	433
2000	83.9	299.5*	408.0	99.8*	399.3*	383.4	707.5	491
2001	72.4	274.0	456.0	99.8*	373.8	346.4	730.0*	528
2002	62.5	228.2	460.8*	92.1	320.3	290.7	689.0	523.
2003	53.9	190.4	424.7	78.4	268.8	244.3	615.1	478.
2004	46.5	158.6	360.0	66.6	225.2	205.1	518.6	406.
2005	40.2	132.3	305.2	56.4	188.7	172.5	437.5	345.
2006	34.7	110.1	258.6	47.9	158.0	144.8	368.7	293.
2007	29.9	98.6	219.2	40.8	139.4	128.5	317.8	249.
2008	25.8	76.7	186.0	34.8	111.5	102.5	262.7	211.
2009	22.3	53.4	133.7	24.9	78.3	76.6	187.1	152.
2010	19.2	53*4	133.7	24.9	78.3	76.6	187.1	152.
2011		44.4	113.2	21.4	65.8	44.4	157.6	113.
2012		37.0	95.9	18.1	55.1	37.0	132.9	95.
2013		31.0	81.4	15.3	46.3	31.0	112.4	81.
2014		25.8	68.8	13.2	39.0	25.8	94.6	68.
2015		21.3	58.4	11.2	32.5	21.3	79.7	58.
2016			49.6					[illegible]
2017			41.9					41.
2018			35.6					35.
2019			30.1					30.

***Indicates** Peak Year(s) of production.

Source: Dames & Moore calculations.

Footnote 1: For assumptions concerning production schedules see Text Section 2.1
In Scenarios 5 to 8 asterisk indicates coincident peak production.

TABLE 2-8

PRODUCTION SCHEDULE FOR BERING SEA GAS DEVELOPMENT-
AVERAGE DAILY PRODUCTION
(Million Cubic Feet Per Day (MMCF/D))

Scenario:	1	2	3	4	5	6	7
Year	Norton	St. George	Navarin	N. Aleutians	St. George plus N. Aleutians	St. George plus Norton	St. Geor plus Navari
1992	86.3					86.3	
1993	172.9	86.3			86.3	259.2	86.3
1994	244.9	215.9	86.3	86.3	215.9	460.8	215.9
995	244.9	329.0	259.2	230.4	415.3	604.9	415.3
1996	244.9	360.0	504.0	302.5	590.4	604.9	619.2
1997	244.9	360.0	748.8	302.5	662.5	604.9	864.0
1998	244.9	360.0	907.1	302.5	662.5	604.9	1108.8
1999	244.9	360.0	907.1	302.5	662.5	604.9	1267.1
2000	244.9	360.0	907.1	302.5	662.5	604.9	1267.1
2001	244.9	360.0	907.1	302.5	662.5	604.9	1267.1
2002	244.9	360.0	907.1	302.5	662.5	604.9	1267.1
2003	244.9	360.0	907.1	302.5	662.5	604.9	1267.1
2004	244.9	360.0	907.1	302.5	662.5	604.9	1267.1
2005	227.4	360.0	907.1	302.5	662.5	587.4	1267.1
2006	195.1	360.0	907.1	302.5	662.5	551.1	1267.1
2007	167.7	334.0	907.1	302.5	636.5	501.7	1241.1
2008	143.8	286.9	907.1	277.3	564.2	430.7	1194.0
2009	123.6	246.6	907.1	233.2	449.8	370.2	1153.7
2010	106.0	211.8	907.1	196.2	408.0	317.8	1118.9
2011	91.2	181.9	833.7	164.9	346.8	273.1	1015.6
2012	78.4	156.2	702.7	138.9	295.1	234.6	858.9
2013		134.3	592.6	116.7	251.1	134.3	726.9
2014		115.3	499.7	98.4	213.7	115.3	615.0
2015		98.9	421.4	98.4	213.7	115.3	615.0
2016			355.0				
2017			299.5				
2018			252.3				
2019			210.4				
2020							
2021							
TOTAL							

Source: Dames & Moore calculations.

[1]For assumptions concerning production schedules see Text Section 2.1

show in Section 3.1.3, raising the cost of equipment by as much as 33 percent does not qualitatively alter the economic results.

The costs for offshore production components is given in Table 2-9. To develop the scenario-wide cost shown previously in Table 2-3 and 2-4 those unit costs are multiplied by the number of units required under the scenario, then the total cost is increased 10 percent as a contingency factor. costs appearing in Table 2-9 are derived from the costs developed by Sante Fe Engineering and Dames & Moore in earlier Technology Assessments (Dames & Moore, 1979, 1980a, 1980b, 1982). Costs from these earlier studies were inflated to 1981 levels at a rate of 15 percent per year. Where inconsistencies arose due to changes in assumptions, these were rectified. In general, the costs follow those used in Dames & Moore's Navarin Basin Technology Assessment, but are adapted to the specific lease sale characteristics.

The gravel island production unit selected for Norton Basin is ideally suited for the shallow conditions in the Norton Sound and the availability of gravel in that area. These islands, at $75 million each, are less costly than a steel jacket platform suitable for use in Norton Sound.

In the remaining areas, ice-reinforced steel jacket platforms are assumed. These platforms can be designed for ice infested waters by omitting all cross-bracing at the water line. Costs of $140MM, $160MM, and $95MM for St. George, Navarin and North Aleutian platforms are principally a function of water depth. In addition, a 10 percent premium was added to the Navarin platform to reflect the higher cost of emplacing a platform in a very remote and inaccessible location. Although gas platforms require fewer conductors than oil platforms, the cost difference is not very significant, therefore the same costs are used for oil and gas platforms.

The deck equipment costs vary as a function of throughput. Since this equipment is typically prefabricated in modules, the remoteness of the location in which it is installed is a minor factor and is ignored.

TABLE 2-9

UNIT COSTS FOR BERING SEA OIL AND GAS DEVELOPMENT FACILITIES*
($ Millions, 1981)

Facility	Units	Norton		St. George		Navarin		North Aleutian	
		Specification	Coat	Specification	Coat	Specification	Coat	Specification	Cost
Platform Production Units (Oil or Gas)	Meters of water	18m Gravel Island	$ 75	197m Steel Jacket	$140	125m Steel Jacket	$160	45m Steel Jacket	$95
Deck Equipment									
oil	MS/D Throughput	80 MB/D	$150	80 MB/D	$150	100 MB/D	$165	80 US/D	$150
Gaa	MMCF/D Throughput	250 MMCF/D	$ 85	250 MMCF/D	$ 85	250 MMCF/D	$ 85	250 MMCF/D	$85
Production Wells									
Oil or Gaa	Depth in Meters	3, 050m	$ 6 (each)	3,050m	$ 6 (each)	3,050m	$ 8.7	3,050m	$ 6
Pipelines									
Oil	Diameter (inches)/ Length (Kilometers)	20"/90km	$1.00/ km	30"/320km	$1.56/ km	36"/240km	$2.19/ km	20"/128km	$1.00/ km
Gaa	Above	20"/90km	$1.00/ km	22"/320km	$1. 13/ km	36"/240km	$2.19/ km	20"/128km	$1.00/ km
Terminals									
Oil-Storage or Transportation	MB/D Throughput	125 MB/D	$290	290 MB/D	$470	450 MB/D	$630	100 MB/D	$250
Gas-Storage and Liquification	MMCF/D Throughput								

Source: Dames & Moore and Sante Fe Engineering.

[1] In using these coat data to develop the scenario costs on Tables 2-3 and 2-4, a 10 percent contingency factor was added.

Well completion costs include the purchase cost of platform-mounted drill rigs, in addition to consumables and labor. On oil platforms where two rigs are used initially, the second rig is assumed to be salvaged when the drilling is completed. The cost to remove the rig is assumed to equal its salvaged value so no net salvage value is assumed. The second rig is kept on the platform for use in workovers. The cost of eventual workovers is included in the initial purchase cost of the wells. The cost of wells in all areas except the Navarin are $6.0 million per 3,050 meter hole. Navarin wells are assumed to cost 30 percent more because of the added costs of equipment and supplies in that remote location.

Operating costs and general and administrative (corporate overhead for administration) costs for platform production units are assumed to be as listed in Table 2-10.

TABLE 2-10

PLATFORM OPERATING AND GENERAL & ADMINISTRATIVE COSTS

System	Operating Cost Per Platform ($MM)	General and Administrative Cost per Platform During: Construction ($MM)	Production ($MM)
1 Platform Field	$50	$20	$10
2 Platform Field	40	18	8
3 Platform Field	35	17	7
4 Platform Field	30	16	6
5 Platform Field	30	15	5

For fractions of production units, the above table is linearly interpolated.

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

2.4 TRANSPORTATION AND PROCESSING FACILITIES: TECHNOLOGY AND COST ASSUMPTIONS

In this section, the technology and cost assumptions for pipelines, terminals and ships are treated in subsections 2.4.1, 2.4.2, and 2.4.3, respectively. The reader is again directed to Tables 2-3 and 2-4 for a summary of scenario-wide costs, and to Table 2-5 for unit costs of transportation and processing facilities.

2.4.1 Pipelines

In all scenarios produced in the Bering Sea, oil and gas is delivered to terminal via pipelines as opposed to offshore load. All early technology assessments conducted by Dames & Moore have considered the option of off-shore loading; but in no case has this technology appeared to be generally more economic than pipelines. It may be necessary in the Navarin; but the pipeline alternatives would be more economic if they prove feasible.

Peak annual throughput, crude properties, and pipeline length affect the required pipe diameter. These factors were all considered in selecting the pipe diameters shown in Tables 2-3, 2-4 and 2-5. Favorable crude properties (similar to North Slope crude) are assumed, permitting long pipelines such as the 320-km St. George pipeline to operate without need for the booster pump and compressor stations. Third generation lay barges and specialized pipe supply vessels are assumed to be available to facilitate pipe laying operations in the Bering Sea. Conventional equipment would result in lower productivity and higher costs in these remote areas.

With one exception, combined development scenarios require the identical pipelines at the same cost as their constituent stand-alone scenarios. The exception involves scenario 7a, a variation of the St. George/Navarin Basin scenario. In this variation, the oil from Navarin Basin is piped not to a terminal on St. Matthew island but rather through a 535-km 36-inch pipeline to a booster station in the St. George Basin. From there, a common 42-inch pipeline carries the production of both sale areas another 320 km to a terminal in Morzhovoi Bay. This alternative has the advantage of avoiding the cost and regulatory difficulties attendant upon building a terminal on St. Matthew Island, a National Wildlife Refuge. On the other hand, it poses formidable difficulties in feasibility of a combined 855-km pipeline and of laying the 42-inch diameter pipeline in the Bering Sea. The cost of the 42-inch pipeline is estimated by Sante Fe Engineering to be $2.40MM per kilometer. In addition, the booster station and a platform on which it would be mounted adds $225MM to the cost of Navarin's development. However, the added costs for additional pipelines and a booster station are largely offset by obviating the need for shuttle tankers and the St. Matthew storage terminal.

2.4.2 Storage and Transshipment Terminals

Figure 2-1 shows the locations of terminals required under each scenario. Stand-alone scenarios for Norton and for Navarin each require two terminals-- a storage terminal near the field and a crude oil transshipment terminal, presumed to be located at Morzhovoi Bay. St. George (Scenario 2) and North Aleutian (Scenario 4) would use a single terminal for storage and for loading conventional tankers. This terminal is also assumed to be located at Morzhovoi Bay.

Storage terminals perform the following functions: pipeline controls, final stabilization of crude, LPG recovery, tanker ballast treatment, and tanker offloading of crude. Terminals are sized to store 15 days of throughput; thus a 500 MB/D terminal provides 7.5 million barrels of storage. This storage permits continuous production even if weather delays tanker docking or uneven shuttle tanker arrivals cause oil flows to stack up or draw down.

The terminal at Morzhovoi Bay will provide deep water docking and loading for VLCC class (or smaller) tankers, and treatment of ballast water. In scenarios including St. George or North Aleutian, (Scenarios 2, 4, 5, 6, 7 and 7a), the Morzhovoi terminal will also serve the additional function of a storage terminal--i.e., final stabilization and LPG recovery.

Table 2-11 displays the capital expenditures and operating cost for oil terminals of various sizes. The cost for terminals in Scenarios 1 through 4 shown on Table 2-3 are derived from Table 2-11. Costs for intermediate size terminal capacities are obtained by linear interpolation. Terminal costs exhibit moderate economics of scale in capital investment and marked economics in operation. The largest capital expense for terminal facilities is associated with providing storage. Since the cost of storage tanks is roughly proportional to their capacity, no economies of scale are expected from the storage function. The other functions do offer opportunities for economics of scale. For example docking and loading facilities can be more fully utilized in larger capacity terminals, as can utilization of treatment, separation, maintenance and stabilization facilities. Since the crew needed to operate larger terminals is proportionally smaller than that need in small facilities, crew support facilities also offer economics of scale. The disproportionately small increase in crew requirements in larger terminals accounts for the marked decrease in operating cost per unit of throughput.

The cost of terminals for combined oil production scenarios is determined by the average daily throughput of the scenario during its peak year. Since the dates of the lease sales are staggered, the peak production years for the combined scenarios is not necessarily the simple sum of the peak productions of the lease sale areas. As seen in Table 2-7 in all but Scenario 5, the earlier Lease sale's production has begun to decline by the time the later sale reaches its peak. This permits the combined scenario transshipment terminal to be sized smaller than would be the case if peak throughput were coincidence. This consequent cost savings is in addition to the cost savings resulting from the realization of economies of scale in combined scenario terminal facilities.

To determine capital expenditures for combined terminals, the peak throughput for the combined sale is taken from Table 2-7. The cost for a terminal of this throughput is then taken (or interpolated) from Table 2-11. This total cost must then be allocated between the sales constituting the scenarios. Since the terminal must be designed for the peak year's

TABLE 2-11

ESTIMATES OF OIL TERMINAL COSTS[1]

Peak Throughput (Thousand Barrels per Day)	Capital Cost ($ Millions 1981)	Operating Cost ($ Millions 1981)
100	250	23
200	380	25
300	470	27
400	560	29
500	650	31
800	960	33

(1) The shore terminals costed here are assumed to perform the following functions: pipeline terminal (for offshore lines), crude stabilization, LPG recovery, tanker ballast treatment, crude storage (sufficient for about 15 days' production), and tanker loading of crude.

Source: Dames & Moore[t] estimates compiled from National Petroleum Council, 1981; and Sante Fe Engineering Services Company.

daily throughput, capital expenditures are apportioned on the basis of each sale's contribution to the peak throughput. Table 2-12 displays this apportionment procedure for the combined scenarios.

In estimating operating costs a different procedure is used. Operating costs are less influenced by peak throughput than by total throughput. Thus, the operating costs for combined scenario terminals are based on the proportion of the combined scenario reserves contained in each constituent lease sale. Terminal operating cost allocations are shown on Table 2-13. Table 2-13 also summarizes all operating and general and administrative costs.

For gas production scenarios, transshipment was ruled out because of safety considerations. Thus, each lease sale area has its own LNG terminal which receives gas via pipelines, completes its stabilization, stores it, liquifies it, and loads it into ice-reinforced LNG shuttle tankers for transport to (presumably) California. As with oil terminals, 15 days of storage capacity provides a cushion for supply irregularities.

The cost for LNG terminals could only be very roughly approximated, since few such facilities have been built in the world, and none have been built in remote northern climates. The best source of costs are cost estimates for a proposed LNG facility at Nikiski on the Kenai Peninsula (Pacific Alaska, 1976). Costs for this project were updated to 1981 dollars, then increased by 20 percent to reflect the greater costs of construction in colder and more remote areas. On this basis, a 500 million cubic-foot per day terminal is expected to cost roughly $1,530 million. Although some economies of scale probably exist, there were no data available on which to estimate these economies. Rather than make any purely arbitrary assumptions, no economies of scale are included. Thus, LNG terminal costs vary in direct proportion to throughput. Since no combined LNG facilities are envisioned, the cost of LNG terminal facilities for combined scenarios is simply the sum of the terminal costs in the constituent scenarios.

TABLE 2-12

ALLOCATION OF CAPITAL EQUIPMENT INVESTMENT IN SNARED TRANSHIPMENT TERMINALS FOR COMBINED OIL PRODUCTION SCENARIOS

Scenario	Combined Peak Throughput[1] (MB/D)	Peak Year(s)[1]	Combined Terminal Investment[2] ($MM 1981)	COINCIDENT PEAK: PERCENT OF COMBINED THROUGHPUT DUE TO:				ALLOCATED TERMINAL INVESTMENT			
				Norton	St. George	Navarin	N. Aleutians	Norton	St. George	Navarin	N. Aleutians
Scenario 5: St. George Plus N. Aleutians	339.3	1998,1999	560		75.		25		420		140
Scenario 6: St. George Plus Norton	400.6	1996	560	28.	72.			157	403		
Scenario 7: St. George Plus Navarin	730.0	2000	890		37.5	62.5			334	556	
Scenario 8: Norton Plus Navarin	528.4	2000	680	13.7		86.3		93		587	

SOURCE: Dames & Moore

Footnotes:

1. See Table 2-7
2. See Table 2-11. Cost for intermediate throughputs are interpolated.
3. coat allocated based on each lease sale areas proportional contribution to the coincident (combined) peak throughput.

TABLE 2-13

ANNUAL OPERATING COSTS FOR BERING SEA OIL AND GAS DEVELOPMENT
(Million 1981 Dollars)

Scenario[2]	Units	1 Norton	2 St. George	3 Navarin	4 N. Aleutian
OIL					
Peak Production	MBD	135	300	290	100
Operating Costs					
Fields	$MM	73	105	144	55
Ships	$MM	16	None	42	None
Terminals	$MM	52	27	58	23
Total Operating Cost	$MM	157	132	244	78
General & Administrative Costs					
During Construction		32	56	72	23
During Production		15	21	24	11
GAS					
Peak Production	MMCFD	245	360	907	302
Operating Costs					
Fields	$MM	50	61	118	52
Ships	$MM	47	68	164	56
Terminals	$MM	14	21	41	18
Total Operating Cost	$MM	111	150	323	126
General & Administrative Costs					
During Construction		20	26	60	21
During Production		10	12	23	10

Source: Dames & Moore and Santa Fe Engineering, 1982.

[1] Operating costs are for all the indicated facilities and are lease sale-wide, assuming resource estimates as indicated in Section 2.1.

[2] For combined sale scenarios (5 through 8), operating lists for all facilities except for terminals and ships are the simple sum of the single sale scenarios. For terminals and ship operating costs see Tables 2-11.

2.4.3 Shipping

Production of Norton and/or Navarin Basin crude requires a fleet of ice-reinforced shuttle tankers ferrying between the lease sale areas and our hypothetical Morzhovoi Bay terminal. These tankers load at storage terminals at the offshore terminal in eastern Norton Sound (Scenarios 1, 5, and 8) and/or at a terminal located on St. Matthew Island (Scenarios 3, 7, and 8).

The fleet is composed of 75,000 DWT (0.6 MMBBL) tankers. This size was selected as a compromise between the greater economy available with larger tankers (e.g., the 150,000 DWT tankers selected in Dames & Moore, 1982) and the greater flexibility of smaller vessels. This flexibility allows fuller utilization of vessels since they can be brought into service and salvaged in smaller increments to closely follow the production step-up, peak and decline. In addition, the smaller tankers offer greater system resilience--production flow is less seriously disturbed by unplanned break-downs or delays of smaller vessels than would be the case with fewer larger ships. The tankers are assumed to experience a 25 percent down-time due to weather, docking delays, or scheduled maintenance breakdowns. The vessels are assumed to travel at 14 knots, or 26 kilometers per hour (KPH). A 30-hour turnaround time is assumed at each terminal call. A round trip from St. Matthew to Morzhovoi is 1,760 Km (1,100 miles). A round trip from Norton to Morzhovoi is 2,432 Km (1,520 miles).

Applying the above assumption, the average daily throughput is computed to be 85,000 B/D per tanker for Navarin and 69,000 B/D per tanker for Norton.

By dividing the average annual throughput in each scenario (see Table 2-7) by the throughputs per vessel calculated above, the purchase and salvage schedule for oil tankers can be derived. Ships are purchased at the beginning of years when average daily throughput exceeds fleet capacity. When fleet capacity exceeds throughput by one vessel, the newest vessel is salvaged.

Table 2-14 shows the purchase and salvage schedule for scenarios 1 (or 5), 3, and 8. Note that tankers requirements for Scenario 5 (Norton plus St. George) is identical to the requirements for Norton alone (Scenario 1).

Each vessel is estimated to cost $119 million except for the "marginal" vessel. Where a scenario requires a fraction of a standard size tanker, the number of vessels is rounded to the nearest integer. We assume that the marginal vessel will be either larger (if number of vessels was rounded down) or smaller (if number of vessels was rounded up) than the standard 0.6 MMBBL tanker. Costs are assumed to be in linear proportion to the $119 million per standard vessel (a simplifying analytical fiction).

When a scenario[s] production passes its peak, vessels are salvaged on a last-purchased/first-salvaged basis. To maximize salvage value the assumed salvage value is as follows:

40% - for ships in service 6 years or less.
30% - for ships in service 8 years or less.
20% - for ships in service 12 years or less.
10% - for ships in service 16 years or less.
0% - for ships in service more than 16 years.

Oil tankers are assumed to cost $8 million per year to operate as shown on Table 2-14. (Sante Fe Engineering, 1981).

In Scenario 8 (Norton-Navarin) the shuttle fleet is sized to meet the combined requirements of the two sales. Thus , the same peak-shaving effect described in terms of terminals occurs for tankers. As a result, the combined scenario require 0.5 fewer tanker equivalents than the sum of the stand-alone requirements . The timing of the purchase and salvage of tankers offers some additional savings since the combined scenario provides an opportunity to match the fleet to the annual requirements of two producing areas.

TABLE 2-14

TANKER PURCHASE AND SALVAGE [1] SCHEDULE
BY SCENARIO FOR BERING SEA OIL DEVELOPMENT
(Million 1981 Dollars)

Year	Scenario 1: Norton	Scenario 3: Navarin	Scenario 8: Navarin & Norton	
1991	119[2]		119	
1992	107'		119	
1993				
1994		119	119	
1995		119	119	
1996		119	119	
1997		119	119	
1998		166[2]		
1999				
2000	-32 (30%)[3]			
2001				
2002				
2003		-66[3](40%)[4]	-48(40%)	=48 11/37
2004			-36(30%)	36 8/28
2005		-36(30%)		
2006			-24(20%)	24 5/19
2007				
2008		24(20%)	-12(10%)	12 3/9
2009				
2010		12(10%)		
2011				

Source: Dames & Moore and Santa Fe Engineering, 1982.

1 Salvage value is assumed to be the following percentage of new cost:
40% - for ships in service 6 years or less
30% - for ships in services 8 years of less
20% - for ships in service 12 years or less
10% - for ships in service 16 years or less
0% = for ships in service more than 16 years

2 Each $119MM represents one 0.6 MMBBL (75,000 DWT) tanker. Where larger or smaller dollar amounts are indicated, the size of the marginal tanker *'non-standard" was varied to match requirements. Costs of these ships are assumed to be in proportion to cost of 75,000 DWT tankers.

3 Negative valves indicate salvage.

4 Percentages are of the purchase loss of the newest tanker remaining in service

In apportioning the purchase costs (and salvage revenues) between the Norton and Navarin the total combined fleet costs are divided in proportion to each sales share of the combined resources. Thus Norton, with 22 percent of the combined (estimated mean) resources, bears 22 percent of the cost while Navarin bears the remaining 78 percent.

LNG tankers are needed in each scenario, since all sale areas are assumed to pipeline their product to their sale-specific LNG terminal from where it is shipped direct to market in dedicated LNG tankers. According to the National Petroleum council (NPC, 1981, pp. 5-15 and E-27), 140,000 cubic meter (3 BCF) ice-reinforced tankers could be used to transport LNG from Navarin to California. These ships are reported to cost $310 million each. Seven ships are sufficient for a one BCF/D throughput.

On the basis of these data and the average daily LNG production shown in Table 2-8, Table 2-15 was developed. The required number of ships is also shown graphically in Figure 2-2.

For LNG tankers the same assumptions and procedure described for oil tankers 'are applied.

Economies due to peak shaving are much less pronounced for LNG tankers than they are for oil tankers. This is due to the typical production profile of gas reservoirs. While we assume that our typical oil reservoir produces only 45 percent of its recoverable reserves on peak, gas reservoirs typically (and by our assumption) produce 75 percent of reserves at peak. This is reflected in the flat tops of the curves in Figure 2-2. As a result, individual lease sale peaks largely coincide with scenario-wide peaks. Combined scenarios do experience some savings due to greater utilization rates, however.

FIGURE 2-2

REQUIRED LNG FLEET SIZE BY YEAR AND SCENARIO

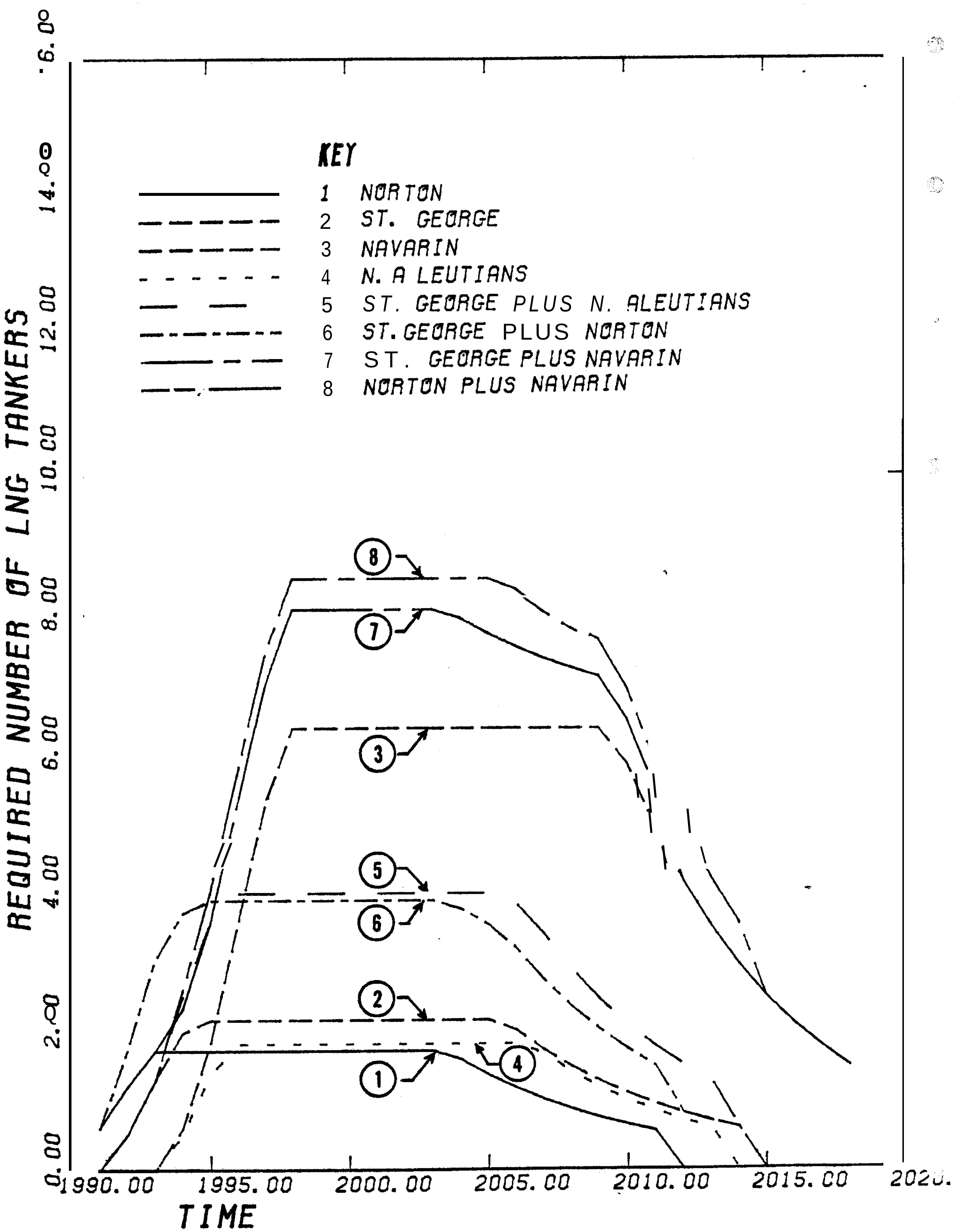

TABLE 2-15

LNG TANKER PURCHASE AND SALVAGE[1] SCHEDULE
BY SCENARIO ($MM 1981)[2]

Year[1]	Scenario 1	2	3	4	5	6	7	8
991	310					310		310
992	310	3103			310	310	310	310
'93		372			310	310	310	
994			310	310	310	310	310	310
?95			310	310	310		310	310
996			620[5]				620[5]	620[5]
997			434[3]				465[5]	310
998			310				310	310
'99								
)00								
)01								
)02								
)03								
)04								
'05								
)06								
)07	-31[3](10%)[4]					-31		
)08					-31(10%)			
309							-64	-64
310			-43(10%)	-31(10%)				
'11							-47	-31
)12			-31(10%)					

Salvage value is assumed to be the following percentage of new cost:
- 40% - for ships in service 6 years or less
- 30% - for ships in services 8 years of less
- 20% - for ships in service 12 years or less
- 10% - for ships in service 16 years or less
- 0% = for ships in service more than 16 years

Each $310MM represents one 140,000 cubic meter tanker. Where larger or smaller dollar amounts are indicated, the size of the marginal tanker "non-standard"' was varied to match requirements. Costs of these ships are assumed to be in proportion to cost of 140,000 cubic meter tankers.

Negative valves indicate salvage.

Percentages are of the pure'~+.<e loss of the newest tanker remaining in service.

Represents two ships.

ource: Dames & Moore, 1982

2.5 ECONOMIC ASSUMPTIONS AND MODELING APPROACH

To maintain consistency with economic and financial assumptions from earlier studies, the assumptions used in this study closely follow those used in earlier Dames & Moorets technology assessments. Those are discussed in detail in Appendix A-IV of the St. George Study (Dames & Moore, 1980b).

2.5.1 The Time Value of Money

The EAC Model (see Section 2.5.4) is a discounted cash flow model. This model uses discount rate to calculate the present value of future income streams. Discounting is necessary to reflect three independent factors.

1. Inflation
2. Real cost of borrowed capital or opportunity cost of owner capital
3. Increasing risk of future revenue streams

The first factor is eliminated in this analysis by assuming "inflation is a wash": that is, that all costs, prices, and revenue streams escalate at an identical rate over time. This permits all costs and revenues to be computed in constant dollar terms. For consistency with earlier work, all financial calculations are in terms of constant 1981 dollars.

The second and third factors (cost of capital and risk) are combined in a 12 percent hurdle rate for real after-tax return on investment. This rate is in the range of other competing opportunities for private investments in OCS development.

2.5.2 Oil and Gas Prices

The constant 1981 dollar value of Bering Sea crude FOB Aleutian terminal is assumed to be $27.50. This equates to about $30 laid-into Los Angeles. The value of natural gas C.I.F. an LNG tanker in Southern California is assumed to be $4.80 per MCF. This value is based on the value of the heat equivalent of $32.00 per barrel of diesel ($5.50/MMBTU) less the assumed $0.70/MCF cost of regassification.

2.5.3 Income Taxes, Royalties, Tax Credits, Tangible and Intangible Expenses

Federal taxes on corporate income now stand at 46 percent of taxable income. Dames & Moore assumes revenues from Bering Sea development would be incremental and taxable at 46 percent after the usual industry deductions indicated below. Tracts are in Federal OCS. No state or local tax applies. The Federal Petroleum Excise Tax (windfall profits tax) does not apply to new Alaska production.

Royalty is assumed to be 16-2/3 percent of the value of production. In consultation with BLM economists, their judgment was adopted that future royalty schemes would not change the outcome of this analysis substantially.

Investment tax credits of 10 percent apply to tangible investments. Depreciations of tangible investments are calculated by the units-of-production method. No depletion is allowed over the production life of the field. Bonus and lease expenses are treated as sunk costs for development decision analysis.

Expenses are written off as intangible drilling costs to the maximum extent permissible by law. Expenses incurred before production are assumed to be expenses against other cash flows of the producer.

The allocation of tangible and intangible investments costs varies with the component parts of offshore development. In consultation with Santa Fe Engineering, Dames & Moore has determined that approximately 50 percent of the offshore investment costs are tangible. Thus a 50/50 split between tangible and intangible offshore development is used in this analysis.

2.5.4 The Equivalent Amortized Cost Model

The equivalent amortized cost (EAC) model uses a discounted cash flow model to compute before and after tax rates of returns, discounted cash flows and costs per unit of production. The EAC model used in this study is identical to that used in the prior studies. For further information regarding its structure and solution algorithm, see the St. George study (Dames & Moore 1980A) Appendix A IV.2.

2.5.5 Scheduling of Capital Expenditures

Investments are scheduled to permit development facilities to be in place at the times specified in Table 2-1. Obviously, in order for capital equipment to be in place in a given year, expenditures must be made in advance of installation. Table 2-16 shows the timing of expenditures for specified facilities and equipment. The year of the expenditure is indicated in reference to the decision to develop. The numbers in the body of the table indicate the percentage of the total expenditure occurring in a particular year.

Small differences in the timing of expenditures are assumed for the different lease sales, to reflect differences in equipment or conditions. For example, expenditures for gravel islands (for Norton Basin) are more heavily weighted toward early development years than are steel-jacketed platforms.

For platforms, deck equipment, wells and ships, more than one unit is needed for most scenarios. In these cases, the expenditures are lagged in relation to the initial unit. An example will be helpful here.

Norton oil transportation requires approximately two tankers. They go into service in the sixth and seventh year following decision to develop (Table 2-14). Table 2-16 indicates that expenditures for the first tanker will occur during years two through five following the development decision at a rate of 25 percent (0.25 x $119MM = $30MM). Since the second tanker

TABLE 2-16

SCHEDULE OF CAPITAL EXPENDITURE FOR PETROLEUM DEVELOPMENT FACILITIES
(Percent of Expenditure)

Years[1]	1	2	3	4	5	6	7	8	9	10	11	12
St. George & North Aleutian												
Platform[3]	10	40	40[2]	10								
Equipment[3]			30	30	30	10						
Wells[3]					40	20	20	20				
Terminal	10	20	30	30	10							
Pipelines		10	40	40	10							
Navarin												
Platform[3]	10	30	30	30[2]								
Equipment[3]			30	30	30	10						
Wells[3]					40	20	20	20				
Terminal	10	20	30	30	10							
Pipelines		10	40	40	10							
Ships		25	25	25	25							
Norton												
Gravel Island[3]	40	50	10									
Equipment[3]			30	30	30	10						
Wells[3]					40	20	20	20				
Terminal	10	20	30	30	10							
Pipelines		10	40	40	10							
ships		25	25	25	25							

Source: Dames & Moore estimates

[1] Years are measured from decision to develop.

[2] Indicates year when platform is emplaced.

[3] Those percentages are based on single offshore platform. Where a scenario requires more than one Platform, these percentages are staggered on the basis of installation of one platform per year see Section 2.5 for more details.

goes into service a year later, its expenditures lag by one year. Expenditures for both are thus:

Year	$ Million 1981 Dollars					
	1	2	3	4	5	6
ship 1		30	30	30	30	
Ship 2			30	30	30	30
Total	0	30	60	60	60	30

In combined scenarios expenditures for common facilities follow the timetable specified for each of the constituent sales. Thus, expenditures for Norton's share of the tanker fleet is timed similarly to the Norton alone scenario while Navarin's share is timed similarly to the Navarin alone scenario.

3.0 RESULTS OF THE ECONOMIC MODEL OF CUMULATIVE BERING SEA PETROLEUM DEVELOPMENT

3.1 COMPARISON OF OIL PRODUCTION ECONOMIES WITH AND WITHOUT CONCURRENT DEVELOPMENT

The economic modelling results comparing Bering Sea oil production with and without concurrent development are summarized in Table 3-1. As indicated by the after-tax rate of return, all scenarios exceed the 12 percent (real) hurdle rate. The cumulative development scenarios, in all cases, make development more attractive but only to a limited extent.

3.1.1 Stand-Alone Scenarios (1 through 4)

A comparison among the stand-alone cases indicates that while all cases exceed the 12 percent hurdle rate. The southern two lease sales -- St. George and North Aleutian Shelf--are considerably more economic than the Northern Leases -- Norton and Navarin. This result is quite marked, despite the disparity in resources among the four areas. St. George and N. Aleutian can be produced through pipelines directly to a shore terminal, while Norton and Navarin must bear the additional cost of a Bering Sea transshipment terminal and a shuttle tanker fleet. Thus, while St. George and N. Aleutian return 18.9 and 18.7 percent on invested capital respectively, Navarin and Norton return 16.9 and 15.0 percent, respectively.

Table 3-2 shows the equivalent amortized cost (EAC) breakdown for selected scenarios. It is apparent that most of the EAC cost of oil production is due to the capital charge (interest and amortization) on investment in capital equipment. At the bottom of Table 3-2, the capital charge is shown allocated among the major facilities groups: offshore production, pipelines, terminals and ships. Offshore facilities (platforms, wells, deck equipment) account for about half of the capital charge. Terminals is the next most significant category, especially for the northern sales which have to support two terminals. Ships are a minor cost for the southern sales "which only require workboats. In the northern sales, the cost of shuttle tanker accounts for about one dollar per barrel of capital charges.

TABLE 3-1

RESULTS OF ECONOMIC ANALYSIS OF BERING SEA OIL DEVELOPMENT

SCENARIO	Recoverable Reserves(1) (MMBBL)	Net Present Value @ 12% ($MM)	After Tax Rate of Return(2) (percent)	Equivalent Amortized Total Cost ($/BBL)	Equivalent Amortized Investment Cost(3) ($ /BBL)	Equivalent Amortized Operating cost ($/BBL)	Total Capital Investment ($MM)
Norton							
Alone	480	974	15.0	24.91	10.01	4.82	1974
With St. George	480	1124	16.5	24.02	9.09	4.30	1810
With Navarin	480	999	15.2	24.77	10.53	4.08	2156
St. George							
Alone	1120	2794	18.9	22.49	8.61	2.88	3635
With N. Aleutian	1120	2875	19.6	22.22	8.27	2.80	3522
With Norton	1120	2884	19.6	22.00	8.27	2.77	3520
With Narvarin	1120	2952	20.1	21.00	8.07	2.64	3452
With Navarin (Pipeline)	1120	3048	21.0	22.66	7.57	2.64	3274
Navarin							
Alone	1740	4260	16.9	23.11	9.17	2.75	6030
With St. George	1740	4332	17.2	22.95	8.97	2.72	5920
With St. George (Pipeline)	1740	4070	15.8	23.65	9.93	2.72	6020
With Norton	1740	4222	17.6	22.76	8.73	2.66	5820
N. Aleutians							
Alone	370	842	18.7	23.31	8.51	5.70	1240
With St. George	370	977	21.2	22.23	7.50	2.94	1108

Source: Dames & Moore calculations.

(1) See Table 2-6.
(2) Discounted cash flow rate of return in real terms.
(3) For Model assumptions, see Section 2.5.4.

Royalties, based on a fixed 16.67 percent of value of gross revenues account for $4.58 /BBL in all scenarios. This royalty payment is tied to $27.50 per barrel of oil.

Operating *costs* and general and administrative (G&A) costs together account for $5 to $6 per barrel in the smaller resource leases (Norton and North Aleutian) versus only $2.50 to $3.00 per barrel for the larger *two* sales (St. *George* and Navarin). This is due to the economies of scale inherent in operating and administering larger fields. The added cost of shuttle tanker operation, together with its smaller scale, makes Nortonts operating costs (G&A) the highest at $6.18 per barrel.

Federal tax per barrel (Table 3-2) generally increases as a function of increasing rate of return and therefore higher profits. Federal taxes thus act as a buffer, tending to reduce differences between the higher cost and lower cost scenarios.

3.1.2 Concurrent Development Scenarios (5 through 8)

Concurrent development of pairs of lease sales enhances profitability and lowers cost. The savings are due to sharing the VLCC terminal and (in the case of Norton/Navarin) pooling of the shuttle tanker fleet.

The most significant effects due to concurrent development impact the two smaller resource leases (Norton and North Aleutians). Concurrent development allows these leases to benefit from greatly reduced terminal costs. Not only do they benefit from the economies of scale available to large terminals, they also benefit from the peak-shaving effect of non-concurrent peak production. The effect of the terminal cost savings are evident on Table 3-2. Comparing Norton Scenarios 1 and 8 for example, the capital charge due to termi-nals falls from $3.24 to $1.79 per barrel--a savings of $1.45 per barrel. On the other hand, the effect of concurrent development on the two larger resource scenarios (Navarin and St. George) is less pronounced. Those areas enjoy the economies of scale due to large terminals, even without concurrent development. The benefits due to concurrent development are largely a

TABLE 3-2

EQUIVALENT AMORTIZED COST OF OIL PRODUCTION
IN THE BERING SEA ($/BARREL)

SCENARIO:	1	8	2	5	6	7	3	7a	4	5
LEASE SALE:	Norton	Norton	St. George	St. George	St. George	St. George	Navarin	Navarin	N. Aleutian	N. Aleutian
Capital Charge	10.01	7.92	8.61	8.27	8.27	8.07	9.17	8.97	8.51	7.50
(of which capital cost @ 12%)	(6.30)	(4.87)	(5.69)	(5.72)	(5.72)	(5.58)	(6.14)	(5.99)	(5.69)	(4.99)
General and Administration	1.36	1.36	0.48	0.48	2.77	0.48	0.96	0.96	1.44	1.44
Operating Coat	4.82	4.08	2.88	2.80	4.58	2.64	2.75	2.72	3.70	2.94
Royalties @ 16.67%]	.4.58	4.58	4.58	4.58	6.10	4.58	4.58	4.58	4.58	4.58
Federal Taxes (net of tax credits)	4.13	5.16	5.94	6.08		6.22	5.64	5.72	5.07	5.77
Subtotal - Development	24.90	23.10	22.49	22.22	22.20	22.00	23.11	22.95	23.31	22.23
Transport to California	2.65	4.65	2.65	2,65	2.65	2.65	2.65	2.65	2.65	2.65
TOTAL - Laid-In	27.55	25.75	25.14	24.87	24.85	24.65	25.76	25.60	25.96	24.88
Allocation of Capital Charge										
Offshore Production	4.41	4.41	5.87	5.87	5.87	5.87	5.16	5.16	5.24	5.24
Pipelines	0.99	0.85	1.25	1.25	1.25	1.24	0.88	0.87	1.08	1.04
Terminal(a)	3.24	1.79	1.28	0.95	0.95	0.76	2.03	1.84	1.89	0.92
Ships	1.37	0.87	0.20	0.20	0.20	0.20	1.11	1.10	0.30	0.29
TOTAL	10.01	7.92	8.61	8.27	8.27	8.07	9.17	8.97	8.51	7.50

Source: Dames & Moore.

TABLE 3-2

EQUIVALENT AMORTIZED COST OF OIL PRODUCTION
IN THE BERING SEA ($/BARREL)

RIO:	1	8	2	S	b	7	3	7a	4	5
SALE:	Norton	Norton	St. George	St. George	St. George	St. George	Navarin	Navarin	N. Aleutian	N. Aleutian
al Charge	10.0I	7.92	8.61	8.27	8.27	a.07	9.17	8.97	8.51	7.50
which capital ost @ 12%)	(6.30)	(6.87)	(5.69)	(5.72)	(5.72)	(5.58)	(6.14)	(5.99)	(5.69)	(4.99)
al and nistration	1.36	1.36	0.48	0.48	0.48	0.48	0.96	0.96	1.44	1.44
ting Cost	4.82	4.08	2.88	2.80	2.77	2.64	2.75	2.72	3.76	2.94
ties @ 16.67%)	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.56	4.5S
Taxes (net of credits)	4.13	5.16	5.94	6.0S	6.10	6.22	5.64	5.72	5.07	5.77
tal - Development	24.90	23.10	22.49	22.22	22.20	22.00	23.11	22.95	23.31	22.23
port to California	2.6S	4.65	2.65	2.65	2.65	2.65	2.65	2.65	2.05	2.65
L - Laid-In	27.SS	25.75	25.14	24.87	24.85	24.65	25.76	25.60	25.96	24.68
cation of al Charge										
hore Production	4.41	4.41	5.67	5.87	5.87	5.87	5.16	5.16	5.2-	5.24
lines	0.99	0.85	1.25	1.25	1.25	1.24	0.88	0.87	1.(E	1.04
inal(s)	3.26	1.79	1.28	0.95	0.95	0.76	2.03	1.84	1.S9	0.92
•	1.37	0.87	0.20	0.20	0.20	0.20	1.11	1.10	0.30	0.29
L	10.01	7.92	8.61	8.27	8.27	8.0?	9.17	8.97	8.51	7.50

ce: Dames • Moore.

result of peak-shaving alone. For example, comparing the Navarin alone (scenario 3) versus Navarin plus Norton (Scenario 8), savings on terminal capital charges for Navarin amount to only $0.18/BBL. Savings from pooling shuttle tankers account for an additional $0.24/BBL. Together these two factors account for $0.42 of the $0.44/BBL savings due to concurrent development.

The only exception to the general economic benefits of concurrent development is Scenario 7A - the Navarin/St. George pipeline. Here the extremely high cost ($1.3 billion) of building a 535-km pipeline direct from the Navarin to St. George Basin, plus the cost of a compressor station, more than offsets the savings from obviating the need for shuttle tankers and a terminal on St. Matthew Island. Under Scenarios 7A versus 7, Navarin's EAC rises $0.70/BBL while the rate of return falls 1.4 percentage points to 15.8 percent. However, even in this scenario a case can be made for the beneficial economic effects of concurrent development. The model explicitly ignores the costs due to permitting delays, since this is largely an unpredictable factor. In the case of St. Matthew Island terminal, permitting delays become almost a certainty, since the island is a major wildlife refuge. Furthermore, the high costs of creating an enclave and development support infrastructure probably have been inadequately reflected in the economic model. Those effects might easily overcome the apparent inferiority of the pipeline scenario.

3.1.3 Sensitivity Analysis of Capital Equipment Purchase Costs

As noted in Section 2.3., estimating the costs of petroleum development equipment and facilities in remote sub-Arctic frontier areas is very difficult. It is of interest, therefore, to compare the sensitivity of the economic results reported to potentially higher capital expenditures. A *series* of model runs were made to address this issue. Specifically, each annual investment total for each oil development scenario was arbitrarily increased 33 percent.

TABLE 3-3

SENSITIVITY ANALYSIS: EFFECT OF INCREASING CAPITAL INVESTMENT IN OIL DEVELOPMENT FACILITIES BY 33 PERCENT

Scenario	Investment ($MM)	Before Tax Rate of Return (Percent)	After Tax Rate of Return (Percent)	Equivalent Amortized Investment cost ($/BBL)	Equivalent Amortized Operating cost ($ /BBL)	Equivalent Amortized Total Cost ($/BBL)
Norton						
Alone	2590	14.1	11.8	13.32	4.82	27.04
With St. George	2374	15.7	13.2	12.11	4.30	25.97
With Navarin	2175	15.2	18.0	10.53	4.08	24.77
St. George						
Alone	4836	18.4	15.4	11.45	2.88	24.34
With N. Aleutians	4686	19.1	16.0	11.01	2.80	24.00
With Norton	4684	19.1	16.0	11.01	2.77	23.98
With Narvarin	4594	19.6	16.4	10.74	2.64	23.73
Navarin						
Alone	7926	16.5	13.9	12.21	2.75	25.10
With St. George	7774	16.8	14.2	11.93	2.72	24.89
With Norton	7649	17.2	14.6	11.62	2.66	24.65
N. Aleutians						
Alone	1640	17.9	14.9	11.31	3.70	25.09
With St. George	1472	20.6	17.3	9.97	2.94	23.79

Source: Dames & Moore calculations.

The results of this analysis are summarized in Table 3-3. Comparing the rates of return on this table to those on Table 3-1, shows that the after-tax rate of return is depressed between 3 and 4 percentage points while EAC's rise about $2 per barrel as a result of a one-third increase in capital expenditures. It is interesting to note that in only the least economic of the oil scenarios (Norton alone) does the increased expenditure cause the return on investment to fall below the 12 percent (real) hurdle rate. Even in this case, the 11.8 percent rate of return is very close to the hurdle rate. Thus, even if all capital costs are one-third higher, the proposed production systems and development scenarios remain economically viable.

3.2 COMPARISON OF GAS PRODUCTION ECONOMICS WITH AND WITHOUT CONCURRENT DEVELOPMENT

The economic outlook for Bering Sea gas development is in marked contrast with the favorable outlook for oil development. As seen in Table 3-4, which summarizes the model results, none of the scenarios modelled even approaches the presumed 12 percent (real) hurdle rate for attracting investment. Despite the relatively large gas resources estimated to occur in the Bering Sea, and despite our optimistic assumptions regarding the occurrence of the resource in a single large field, gas development does not appear to be economic. The benefits of concurrent development appear to have fairly minimal influence in improving the economic viability of the resource.

The stand-alone scenarios result in after-tax rates of return in the 4 to 6 percent range. At those rates of return, it is of little interest to compare the differences between scenarios. It is more interesting to examine the factors common to all scenarios which result in their uneconomic status.

In general, it is not the wellhead cost of producing gas which renders it uneconomic, but rather the downstream costs of bringing it to market. This is apparent from the equivalent amortized cost (EAC) results reported in Table 3-5. Roughly 60 percent of the total development costs are due to

TABLE 3-4

RESULTS OF ECONOMIC ANALYSIS OF BERING SEA GAS DEVELOPMENT

Scenario	Recoverable Reserves(1) (BCF)	Net Present Value @ 12° ($MM)	After Tax Rate of Return(2)(4) (Pecent)	Equivalent Amortized Total Cost ($ /MCF)	Equivalent Amortized Investment cost(3) ($ /MCF)	Equivalent Amortized Operating cost ($/MCF)	Total Capital Investment ($MM)
Norton							
Alone	1,500	- 325	4.1	6.21	3.84	1.51	1,749
With St. George	1,500	- 283	4.4	6.08	3.65	1.51	1,712
With Navarin	1,500	- 257	4.4	5.97	3.51	1.51	1,754
St. George							
Alone	2,200	- 502	4.5	6.40	4.14	1.49	2,712
With N. Aleutians	2,200	- 475	4.6	6.33	4.04	1.49	2,712
With Norton	2,200	- 443	4.8	6.28	3.97	1.49	2,620
With Navarin	2,200	- 459	4.6	6.27	3.97	1.49	2,782
Navarin							
Alone	5,500	-1547	5.8	6.10	3.74	1.41	5,866
With St. George	5,500	- 622	5.9	6.01	3.62	1.41	5,976
With Norton	5,500	- 462	6.3	5.89	3.544	1.41	5,655
N. Aleutians							
Alone	1,800	- 226	5.6	5.89	3.55	1.40	2,001
With St. George	1,800	- 161	6.1	5.73	3.30	1.40	1,914

Source: Dames & Moore.

[1] See Table 2-8

[2] Discounted cash flow rate of return in real terms.

[3] For Model assumptions, see Section 2.0.

[4] LNG is based on a value of $4.80 per MCF C.I.F. an LNG tanker in southern California.

TABLE 3-5

EQUIVALENT AMORTIZED COST OF GAS PRODUCTION
IN THE BERING SEA ($/PER MCF)

SCENARIO: (1)	1	8	3	8	2	7	4	5
LEASE SALE:	Norton	Norton	Navarin	Navarin	St. George	St. George	N. Aleutian	N. Aleutian
Capital Charge	3.84	3.51	3.74	3.44	4.14	3.97	3.53	3.30
(of which capital cost @ 12%)	(2.65)	(2.39)	(2.71)	2.48	(2.97)	(2.82)	(2.42)	(2.26)
General and Administration	0.34	0.39	0.31	0.31	0.33	0.33	0.31	0.31
Operating Cost	1.51	1.51	1.40	1.41	1.49	1.40	1.40	1.40
Royalties @ 16.67%)	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Federal Taxes (net of tax credits)(2)	(0.28)	(0.54)	(0.15)	(0.07)	(0.36)	(0.23)	(0.15)	(0.02)
TOTAL Development Costs (including Transportation	6.21	5.97	6.10	5.89	6.40	6.27	5.89	5.83
Allocation of Capital Charge								
Offshore Production	0.59	0.59	0.77	0.77	0.75	0.75	0.63	0.63
Pipelines	0.35	0.35	0.31	1.37	0.60	0.60	0.25	0.25
Terminal(s)	1.65	1.65	1.33	1.33	1.68	1.68	1.59	1.59
Shipa	1.25	0.91	1.27	0.97	1.11	0.94	1.06	1.83
TOTAL	3.84	3.51	3.74	3.44	4.14	3.97	3.53	3.30

Source: Dames & Moore.

Notes;

(1) Columns are ordered by lease area rather than by scenario.

(2) Federal taxes are negative due to the unprofitability of the investments. The negative value represents the discounts EAC value of the tax ahelter when written off against other investments.

capital charges (interest plus amortization on investment). Offshore production facilities represent only about one-fourth of those costs. Terminals, which convert the gas to LNG and load it on tankers, account for a third to a half of the capital charge. The tanker fleets account for almost as much of the capital charge as do terminals. Together, tankers and terminals account for two-thirds to three-fourths of the capital charges.

Aside from capital charges, operating costs are the next most significant component of the EAC per MCF. Again the costs for terminals and ships outweigh the offshore costs. For Scenario 2 (St. George) for example, field operating *costs* are assumed to be $61MM versus a total $79MM for terminal and ship operations ($21MM and $68MM) respectively.

Concurrent development offers few opportunities for reducing costs of stand-alone sales. This is evident from the results on Table 3-4 which show a maximum spread of 0.5 percentage points between the stand-alone and concurrent development scenarios. Exploration costs are specifically excluded from our analysis. Even assuming that concurrent exploration would produce economies, the total cost of exploration is *too* small a fraction of total development costs to have a significant impact. Offshore production facility costs are assumed unaffected by concurrent developments. No opportunities exist for sharing pipelines or terminals, assuming as we have, that LNG cannot be feasibly transshipped.

Therefore, the only remaining opportunity for economies due to concurrent development is related to the tanker fleet. Even here, however, opportunities for economies are united. As noted in Section 2.3, gas fields typically produce 75 percent of their reserves on peak. Thus the opportunity for economizing on the site of the tanker fleet as a result of peak-sharing is limited, since the field will produce on peak for about 10 years, while there is only a four-year difference in the onset of peak production. What economies are available due to concurrent development are the result of better utilization of the fleet and earlier salvage opportunities. As seen on Table 3-5, the savings on capital charges on ships due to concurrent development ranges between $0.16 and $0.34 per MCF.

4.0 EMPLOYMENT AND SOCIOECONOMIC IMPLICATIONS OF CUMULATIVE DEVELOPMENT SCENARIOS

In this section we assess the implications of concurrent petroleum development in the Bering Sea for employment and socioeconomic impact of shore facility siting. Earlier technology assessments have assessed employment requirements for individual Bering Sea lease sales. The question raised in this study is whether concurrent development would have effects that are significantly different from those estimated in the prior employment assessments. In particular, it is important to determine whether concurrent development has unforeseen impacts on prior manpower forecasts and on facility siting assumptions.

These specific questions were posed for analysis:

1. Would some combination of concurrent development in two lease sale areas have the potential for changing the location and/or size of support bases from what would be expected if only one area were developed, and if so, what are the secondary employment implications of this eventuality?

2. Would overlapping petroleum development activities create manpower peaks that could conceivably strain the Alaska labor market or overburden the logistical network in the Bering Sea?

3. Would concurrent development decrease overall manpower demand by creating the opportunities for efficiencies that would not otherwise exist, as through shared infrastructure?

The following subsections address these three questions in the above order.

4.1 IMPLICATIONS OF CONCURRENT DEVELOPMENT ON SIZE AND LOCATION OF TERMINALS AND SERVICE BASES

4.1.1 General Siting and Logistical Considerations

Concurrent development of more than one discovery would significantly effect the pattern of logistical support for Bering Sea oil production. There would be strong incentive to consolidate supply and service operations in the vicinity of the Aleutian Island oil terminal site. A new community could emerge from this industrial enclave, and the site could become a new regional center of the Aleutian Islands.

During exploration, industry would prefer to use existing infrastructure for service bases if at all possible to keep capital costs to minimum during this temporary stage of petroleum activity. These service bases till most likely be located as follows:

Sale Area	Exploration Service Base
Norton Basin	Nome
St. George Basin	Unalaska
Navarin	Unalaska/St. Matthew Island
North Aleutian Shelf	Port Heiden/Unalaska

Concurrent exploration activity, which is almost certain to occur, will not materially affect selection of these sites, as they are primarily determined by the proximity of existing marine and air transport centers to the lease sale areas.

If, however, a commercial discovery is made, a service base in the existing infrastructure may be only marginally adequate and not optimal for accommodating the necessary increases in traffic, docking facilities, and land use that will accompany field development and production. Furthermore, industry will have the economic incentive to invest in a larger more permanent service base separate from the existing infrastructure. Such a permanent service base would likely be incorporated as part of a tanker terminal depending on its location in relation to the field offshore. LNG plants could also be developed for support functions.

There are several incentives to locate the supply base close to the terminal. One incentive is to lower development costs. Presumably, it will cost less to build the necessary docks, warehouses, shops, and storage yards at the terminal site than elsewhere because of the shared infrastructure and other economies that will exist such as mobilized construction equipment, a construction dock, water and electric power supplies, and a communication network.

An ideal site for a combined terminal and production support base would have the following characteristics:

- o Natural protected deepwater harbor
- o Existing port facilities
- o Adequate level land for development of terminal facilities and supply warehouses and yards
- o A runway capable of handling large aircraft under IFR conditions
- o Existing communications and housing infrastructure.

No Aleutian Islands site has all of these characteristics.

While our St. George Basin Technology Assessment (Dames & Moore, 1980) surveyed several other sites for potential terminal locations, we believe that industry planners could be attracted to the vicinity of Cold Bay or Unalaska for locating a crude oil transshipment terminal because of the existence of the airports there. The existing infrastructure for possible service base sites around Cold Bay and Unalaska appear to be the only communities capable of acting as service bases to the southern Bering Sea sales without major capital improvement by industry.

The potential use of these sites may depend largely on future land conveyances under the Alaska Native Claims Settlement Act. Recent 20-year Federal land withdrawals included all Federal land on Unalaska, which is not selected under the Alaska Native Claims Settlement Act for transfer to the State or natives.

Permanent Federal land withdrawals include Unimak Island (part of the Aleutian Islands National Wildlife Refuge) and the northwestern half of the lower 80 kilometers (50 miles) of the Alaska Peninsula (Izembek National Wildlife Range). In addition, the entire southeastern half of the Alaska Peninsula is part of a temporary emergency land withdrawal under Section 204e of the Federal Land Policy and Management Act of 1976 (Alaska Peninsula National Wildlife Range). Although this withdrawal expired in November 1981, its status is very much in doubt. Although these withdrawals as part of the National Wildlife System do not completely preclude use of the lands by industry, the justification for such usage would have to be extremely strong and should be considered a last resort.

There are trade-offs in considering either of these locations. Although no site selection evaluation ‘is implied, the physical characteristics of the alternatives are described below.

<u>**UNALASKA:**</u> The city of Unalaska is the regional commerce center for the Aleutians. Unalaska is slightly closer to the sale areas than Cold Bay, particularly for sea transportation, but has generally poorer facilities and more potential for conflicts in demand for those facilities from the local fishermen and community. Its airport is only 1,311 meters (4,300 feet) long, unlighted and not equipped for instrument approaches. Although Coast Guard C-130 Hercules have been noted to occasionally use the strip, they do not consider it adequate for regular supply activities in such large cargo aircraft. Docking facilities, although smaller than Cold Bay, are adequate to serve a couple of supply boats. Harbor characteristics are also adequate. Problems with this site are the marginal airfield and potential conflict with fishermen over use of the facilities. State airfield improvement feasibility

studies are currently under way and may result in elimination of the airfield problem prior to major exploration activities.

Several bays within Unalaska Bay could serve as terminal sites. The entrance to Dutch Harbor is too shallow (26.8 meters [42 feet]) to accommodate tankers. Captains Bay is deep enough but is otherwise marginal. Its entrance is very narrow (130 to 1S2 meters [400 to 500 feet]), the turning basin is small (only 914 to 1,524 meters [3,000 to 5,000 feet] wide), and there is a shortage of suitable land for facilities. The best land availability within Unalaska Bay occurs adjacent to Broad Bay where water depths are sufficient within 610 to 914 meters (2,000 to 3,000 feet) of this shore, but the shelter here is poor and not easily remedied by artificial means. Wide Bay has probably the best harbor characteristics, being well sheltered with sufficiently deeper water less than 305 meters (1,000 feet) offshore, but its steep topography limits the available land suitable for facilities. Perhaps a combination of these sites is the most likely, such as locating the terminal at Wide Bay, and the shore facilities at Broad Bay located 3.2 to 6.2 kilometers (2 to 4 miles) away.

COLD BAY/MORZHOVOI BAY: Cold Bay, although more distant from the sale area than Unalaska, has several advantages. Its airport has two paved runways 3,174 and 1,562 meters (10,415 and 5,126 feet) long, is lighted, and is equipped for instrument approaches (IFR). Several major air carriers currently *use* the site for refueling international jet traffic. A dock exists with an 290-meter (850 foot) pier front in 9 to 10 meters (30 to 33 feet) of water and habor size. Depths are well in excess of those required for supply boats.

Morzhovoi Bay (see Figure 4-1) has several favorable characteristics; a good harbor with adequate shelter, an excess of suitable land for shore facilities, and an airstrip. However, adequately deep water lies 914 to 1,829 meters (3,000 to 6,000 feet) offshore in those areas of the bay that are well protected, and it is farther from the central portion of the sale areas than other sites considered. Furthermore, it lies within Federal land withdrawals -- part permanent (The Alaska Peninsula National Wildlife Range), and part temporary (The Alaska Peninsula National Wildlife Range). No regional commerce center exists at Cold Bay. The only development in the area is associated with the airstrip.

Morzhovoi Bay is close enough to Cold Bay to be connected by a road. We further believe that industry planners would seek to consolidate supply and service operations at the terminal site. If the oil terminal were built at Morzhovoi Bay and linked to Cold Bay by road, it reasonably could become a major supply and service base for Bering Sea oil and gas fields, even though alternative sites might be closer to the fields.

Because of the congestion and poor runway facilities at Unalaska and the good existing and potential harbor and airport facilities at Cold Bay/ Morzhovoi Bay, we have used the latter site as our hypothetical Aleutians support base and oil/LNG Terminal.

4.1.2 Siting and Logistical Considerations Under Concurrent Development

Given the general efficiencies that can be achieved by combining the VLCC terminal, air link and service base, there are some specific differences associated with the stand alone and combined scenarios.

In the case of the Norton Basin (Scenario 1), Nome would be used as a supply base. Bulk commodities would be brought by barge for stockpiling and warehousing at the Nome base. Air traffic would be routed to Nome through Anchorage. There would be little or no need for a transshipment point of arriving supplies in the Aleutian Islands.

In the case of the St. George and North Aleutian Basins (Scenarios 2 and 4), a service and supply base for the production phases would be built in the Aleutian Islands, preferably at the terminal site. In the case of development in the Navarin Basin (Scenario 3), the point of supply would be St. Matthew Island, which is the assumed site of an oil transshipment terminal. Heavy

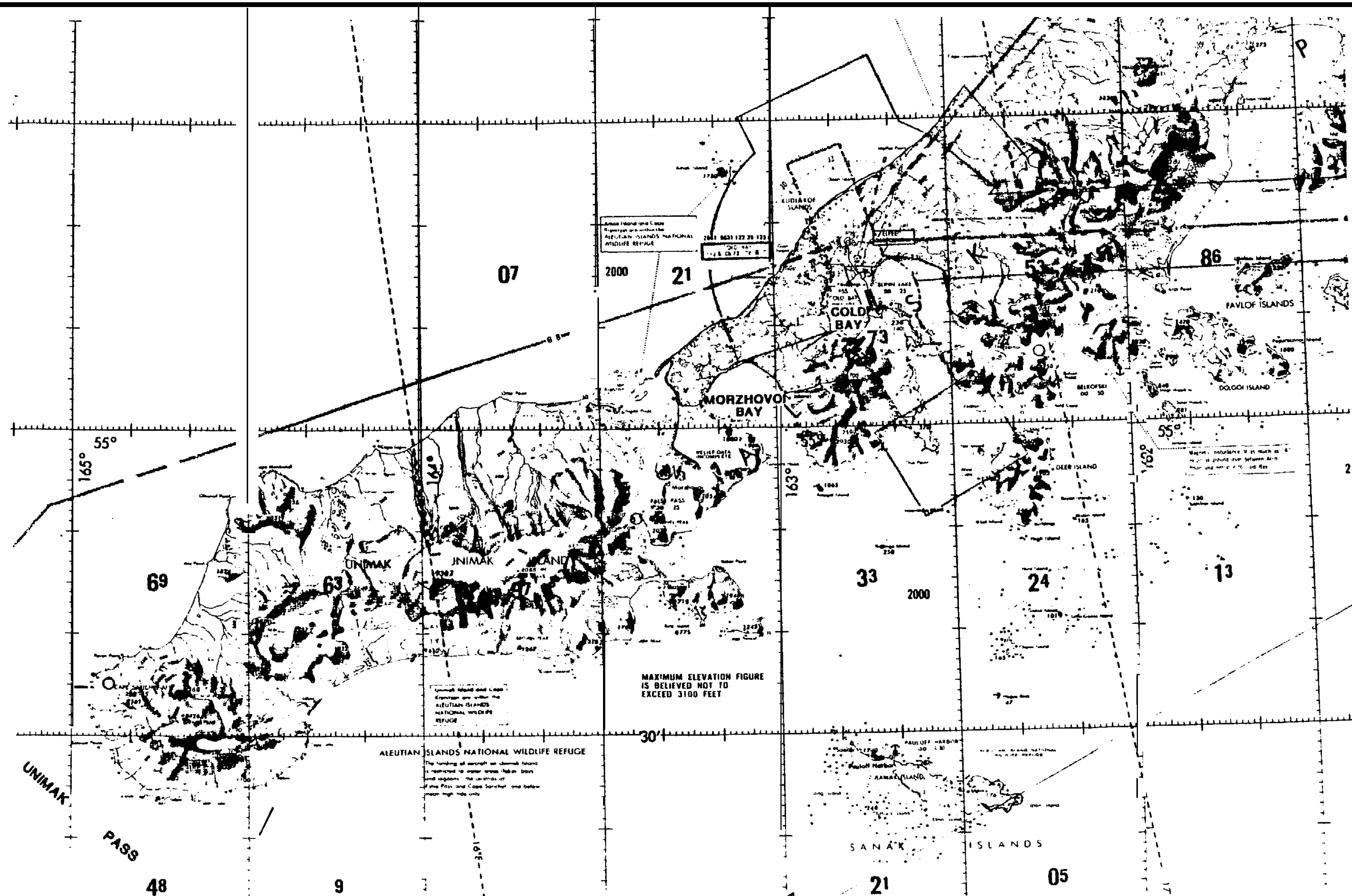

FIGURE 2-2
COLD BAY / MORZHOVOI BAY SUPPORT AND VLCC FACILITY

materials would be shipped directly to St. Matthew from outside Alaska. (Winter barge shipments directly to St. Matthew Island and Norton Sound would be possible because the fleet of shuttle tankers would keep the lanes open.) Air traffic would be routed and staged from a secondary location in western Alaska, perhaps Bethel or Dillingham.

In the case of Scenario 5 (St. George and North Aleutian), we hypothesize that Morzhovoi Bay will be the site of all onshore facilities, just as it will be if only one of those two basins were developed. In the case of Scenario 6 (St. George and Norton), we expect the role of Nome as a service base to be reduced significantly. Some supplies still would be barged, stockpiled and warehoused at Nome; but Marzhovoi Bay would become the primary repair, maintenance and service center. Nome would be used as a supply center for relatively lightweight freight, much of which would arrive by air via Anchorage. Anchorage would remain the primary air link.

In the case of Scenario 7 (St. George and Navarin), we envision that Morzhovoi Bay would be the primary marine staging and transshipment supply base rather than St. Matthew Island. A runway and passenger transit station would be required on St. Matthew island for helicopter shuttle flights to the platforms. Also, a port for supply vessels would be necessary. *Crew* rotations and air freight could be routed either through Bethel from Anchorage, or through Cold Bay from Seattle.

In the case of Scenario 8 (Navarin and Norton) , we would expect a similar impact on Nome as Scenario 6 (St. George and Navarin). Morzhovoi Bay would become the major repair, maintenance and service center for both areas. However, most air freight for Norton would go straight to Nome via Anchorage.

If concurrent development of lease sale areas in the Bering Sea resulted in a major industrial settlement at the site of the oil transshipment terminal, it could have significant regional socioeconomic consequences. This is especially true if the terminal site is close *to* the existing settlement at Cold Bay. There would be a long-term tendency for private housing to be built and a secondary economy to emerge. This trend could estabish Cold Bay as the regional center of the area. As a regional center, it would be the focus of transportation, communication, and commercial activity in the Aleutian Islands.

4.2 EFFECTS OF OVERLAPPING SCHEDULES DURING CONCURRENT DEVELOPMENT

Although the total level of manpower utilization in the Bering Sea region and the demands placed on shore bases will be higher than expected without concurrent development, we see no significant consequences of these overlapping schedules.

Lease sales occur in 1982, 1983, 1984, and 1985. Since exploration programs (including delineation of discoveries) will last an average of three or four years, simultaneous activity is inevitable. Table 2-1 shows that exploration programs will be underway at the same time in at least two lease sales areas during most of the exploration period (1983-1990) and in three sale areas for several years in the middle of the period.

Shore support functions for the four exploratory programs will be dispersed throughout the Bering Sea region. Unalaska is likely to be an important service and transshipment center during the entire exploration period, but it is likely to be the primary shore base for only the St. George Lease Sale area. Nome will be the primary shore base for exploration in the Norton Sound; St. Matthew Island will be an important forward base for the Navarin Basin; and a site on the north side of the Alaska peninsula such as Port Heiden will serve as a forward base for activity in the North Aleutian Sale area. Also, operators throughout the Bering Sea region are likely to utilize freighters and barges for offshore support and supply functions, in order to reduce reliance on shore facilities. Thus, we foresee very little potential for logistical bottleneck at Unalaska to constrain exploration activities, even though Unalaska is not ideally suited to oil support activity (as discussed below in Section 4.2.

Field development activity will occur concurrently in three of the four joint development scenarios (Scenarios 5, 6, and 7). Production will occur concurrently in each joint development scenario. Table 2.1 shows the development and production schedules assumed in this report. Providing incremental capacity at Morzhovoi Bay for supply and service activities for a second field should not present significant difficulties. Jet aircraft and ocean-going ships and barges will be able to operate directly to the Cold Bay Airport and the supply base at Morzhovoi Bay. Neither the airport at Cold Bay nor the supply base should be a bottleneck in the flow of goods and people to the oil fields during the development and operational phases.

The size and capability of the Alaska labor market will not be an impediment to offshore oil development in the Bering Sea, because exploration and development activities will draw heavily on the national labor market. Direct flights from Seattle operate to the Aleutians. Crew changes by this route may be attractive to operators if non-Alaskan employees can be recruited at lower wages than Alaskans. By analogy, most cannery workers in Unalaska are currently recruited in Seattle and flown directly to Unalaska via Cold Bay.

4.3 EFFECTS ON EMPLOYMENT

Concurrent development in two lease sale areas potentially could reduce construction and operational employment, but labor savings would be so small that they would not have any significance for OCS planning purposes in the Bering Sea.

The total employment needed to install platforms, lay pipeline, and operate all offshore production equipment in each field will not be affected by concurrent development. The only opportunity for reduction in manpower utilization is associated with the construction and operation of on-shore facilities, primarily the oil terminal. The question, then, is the potential significance of labor efficiencies that could be realized by building one large terminal rather than two smaller ones.

Historically, the evidence is that large terminals are disproportionately more labor intensive than small ones. One explanation of the disproportionately higher labor requirements may be that the technological complexity of terminals increases as thoughput rises. Another explanation is that large terminals have involved extraordinary circumstances. There are indeed, too few relevant examples to establish clear patterns; both the Alyeska terminal at Valdez and the Sullom Voe terminal in the North Sea involved unusual construction problems (site preparation at Valdez and design changes and labor relations at Sullom Voe).

It seems reasonable to assume, however, that some labor efficiencies would be realized from the construction and operation of one large terminal to serve both producing lease sale areas rather than two smaller terminals designed to serve the respective producing areas, all else being equal (remoteness, site conditions, water depth at tidewater, etc.). We estimate that a labor savings of 15 percent might be expected during construction and operation of a single terminal facility. Our computer-assisted OCS employment modelling in previous technology assessments suggests that during the peak year of terminal construction a 15 percent labor savings would result in a project-wide reduction in labor demand by approximately 5 to 10 percent for that year. During the operational period a 15 percent reduction in terminal employees would amount to an annual project-wide labor savings in the neighborhood of one percent.

Somewhat greater labor savings might be expected in the case of Scenario 7 (St. George and Navarin pipeline) because construction and operation of an oil -terminal on St. Matthew Island could be unusually labor intensive (it is more remote than Morzhovoi Bay, the environment is more severe, and an airfield would have to be built). The need for this terminal is eliminated if fields in the Navarin Basin are produced through a pipeline that is partially shared with fields in the St. George Basin. Nonetheless, we do not consider the potential manpower savings to be of significance in the overall scheme of Bering Sea petroleum development. Of far more significance in this case is the avoidance of potential adverse environmental impacts by eliminating a terminal on St. Matthew Island (which is a U.S. Fish and Wildlife Service Refuge).

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ADDENDUM TO TECHNICAL REPORT NO. 80: BERING SEA

CUMULATIVE ECONOMIC OCS PETROLEUM DEVELOPMENT

Subsequent to the analysis performed in connection with this study, Dames & Moore received new information on the cost of oil terminal facilities which modifies the conclusions regarding the economic effects of concurrent development of Bering Sea Oil and Gas Leases. This information indicates that the savings from concurrent development may be greater than those stated in this report.

The updated information indicates that:

1. Terminal costs in the report might be understated by as much as 40 percent on an average.

2. An Aleutian Islands transshipment terminal would perform more functions and thus be more costly than the shore terminals located in each lease sale area.

3. The economies of scale for larger terminals are positive rather than essentially neutral as we assumed in the report.

Taken together, these three considerations imply that rates of return-have been slightly overstated and that cost savings for concurrent development have been understated relative to single sale development.

The first item above indicates that since terminal cost estimates are low, the rates of return reported in all scenarios are too high, and equivalent amortized costs proposed are too low. However, since Section 3.1.2 indicates that raising all facilities investments by one third would have only slight economic impacts, the effects of this item is probably negligible.

The new information indicates that the ballast treatment, ship maintenance, and tanker fuel storage facilities would be located at the transshipment terminal facility site but not at the receiving terminal site. Thus, transshipment terminals are about 45 percent more costly than shore terminals. The two are shown in the report to have the same cost . In scenarios involving Navarin and Norton leases (in which the transshipment terminal is separate from the shore terminal), the positive (rather than the reported neutral) economies of scale tend to compound this effect. The net result is that combined scenarios should show greater economies compared with stand-alone sales, especially in the case of Navarin and Norton leases.

Without entirely recalculating all oil development scenarios, it is not possible to precisely determine how those new data would alter the results. However, rough estimates based on equivalent amortized costs indicate that concurrent development could result in rates of return up to 2.5 percent higher and equivalent amortized costs up to $2.50 per barrel lower than those for stand-alone lease sale development. This is in contrast to the 1.2 percent higher rate of return and $1.49 per barrel reduction in costs reported in the study. Hence, the reported difference in rate of return between concurrent development and stand-alone development is up to 1.3 percent too low, while the reported cost difference is up to $1.00 per barrel too low.