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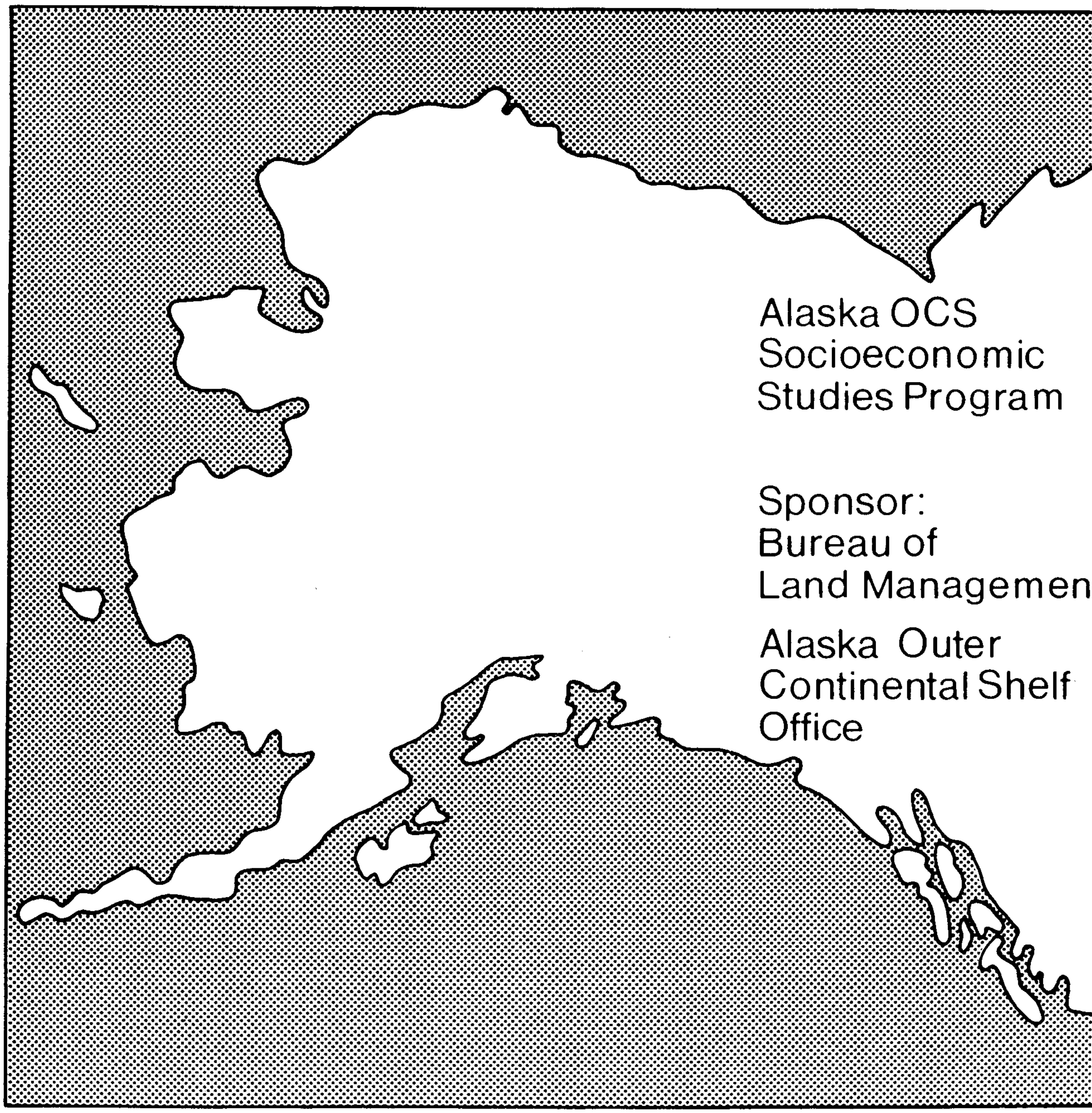

Alaska OCS
Socioeconomic
Studies Program

Sponsor:
Bureau of
Land Management

Alaska Outer
Continental Shelf
Office

"The Marketing and Equivalent Amortized Costs of Bering - Norton Oil and Gas"

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.

SPECIAL REPORT NO. 3

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Alaska OCS Socioeconomic Studies Program

THE MARKETING AND EQUIVALENT AMORTIZED COSTS OF BERING-NORTON OIL AND GAS

Prepared For

Bureau of Land Management

Alaska Outer Continental Shelf Office

Prepared By

DAMES & MOORE

June 1980

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APPENDIX F

REVIEW OF SUPPLY-DEMAND AND MARKETING PROBLEMS OF OCS OIL AND GAS FROM THE BERING-NORTON LEASE SALE

I. Introduction

Potential oil and gas resources from the Norton Basin lease sale could be developed and supplied to the United States energy market as early as 1989. The Dames & Moore final report dated January, 1980, entitled "Norton Basin Petroleum Development Scenarios OCS Lease Sale No. 57" described the critical technology, environmental and economic issues governing the development and production of Bering - Norton oil and gas. This appendix to that report describes how the potential supplies of Norton Basin oil and gas relate to the United States energy balance after 1990. These potential supplies are based upon the petroleum scenarios described in Chapters 6.0, 7.0 and 8.0 of the Bering-Norton report.

Supply and demand forecasts are developed for U.S. oil and gas with particular reference to the West Coast--Petroleum Administration District V. Potential Norton Basin oil and gas supplies are shown to supplement supply shortages expected in the U.S. within the next decade. California--PAD V--is the natural domestic market for the Norton sale's oil and gas. The critical issues that will determine the marketability of Norton Sound oil and gas in California are developed in detail.

In view of the overriding significance of OPEC's oil, the U.S. supply and demand situation is presented in context with the world oil supply and demand balance. The United States is critically dependent on OPEC supplies and must adopt a rational energy policy to maximize development of domestic oil and gas supplies and hasten the shift to alternate energy forms.

Section II presents the market potential for Norton Basin oil. Section II discusses first the world picture; then it narrows to the U.S. and focuses on California and the Northern Tier pipeline to show how Norton's oil resources could be marketed either to Washington state or California. World oil prices are then explored to complete Section II.

Section III describes the potential relationship of Norton Basin natural gas to the U.S. natural gas market. "Conventional"--less costly--natural gas is declining and Section III describes, first, expected U.S. conventional gas supply deficits and then the need for expensive supplemental gas supplies--including Norton Basin gas delivered to Point Conception, California, as LNG.

The California gas markets is linked to the rest of the United States gas market via the tradition Southwest U.S. gas supplies. This link is emphasized to show that California could take all of Norton's potential LNG supplies. Expected costs of Norton Basin LNG are then developed and compared to expected costs for other alternate gas supplies. Strictly speaking, Norton Basin gas looks marginally uneconomic right now. But it won't be here for ten years. By then oil prices will have risen and Norton LNG will become economic.

Unit costs are developed in detail with the Equivalent Amortized Cost Model in Appendix A. These are considered but not included within Appendix F.

II. Oil

II.1 Background: World Oil Supply and Demand[1]

II.1.1 OPEC'S Continued Importance

Political considerations within the Middle-East oil producing countries at the beginning of the 1980's suggest that even though proved reserves would allow higher production, OPEC oil during the 1980s probably will not be produced at maximum rates just because consuming countries want the oil. The world of the last two decades of the twentieth century will be oil-supply limited--but limited more by political instability than by physical resource limitations. Table F-1 reveals that OPEC's share of the non-communist world oil production was over 61 percent in 1978. Consequently, the world is dependent on OPEC's oil.

Yet "oil will continue to account for nearly one-half of all energy supplies through 1990." (OGJ, November 12, 1979, p. 165.) Both Walter J. Levy and Exxon project oil's share of the non-communist world's 1990 energy consumption at 48 percent. To the extent, therefore, that oil supplies are politically curtailed, either other conventional sources or new technologies will have to

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[1]This section draws on the following references:

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

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

"Oil in the Eighties: Tight Supply, Soaring Capital Outlays," OGJ, November 12, 1979, 163-169.

"EIA Optimistic on Crude Supply, Outlook," OGJ, September 10, 1979, 102-103.

"CIA: Global Oil Supply Outlook Poor," OGJ, September 3, 1979, 50-51.

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

TABLE F-1

NON-COMMUNIST WORLD OIL PRODUCTION: 1978

	(Million B/D)		%
Total OECD		14.2	28.6
of which, U.S.	10.3		
Total OPEC		30.3	61.1
of which, Saudi Arabia	8.5		
of which, Iran	5.2		
Total other countries		5.1	10.3
of which, Mexico	1.3		
Total non-communist		47.0	100.0

Source: U.S. Energy Information Agency

be substituted faster than projected in many forecasts, or energy consumers will have to substitute more energy efficiency (i.e., conservation) or do without. The last alternative--do without--is the least palatable to the typical U.S. energy consumer.

The top half of Table F-2 shows a consensus non-communist world demand forecast put together by Michael F. Thiel in the October 1979 issue of World Oil. According to him, most informed estimates put western world oil demand near 66 million B/D by 1990. This represents a 2.0 percent annual growth in consumption. Thiel's consensus forecast shows considerably more upside risk--80 million B/D--than downside sensitivity--60 million B/D. According to him, "Failure to develop alternate fuels, such as nuclear energy and coal could push 1990 requirements as high as 80 million B/D." (World Oil, October 1979, p. 124.)

The bottom half of Table F-2 shows that Thiel estimates OPEC's upper limit of production in 1990 at 40.7 million B/D. This results in a western world supply of oil of nearly 70 million B/D. The lower limit is under 60 million B/D. In the next decade strong measures must be taken to assure that western world demand trends are not heading to a consumption rate approaching 70 million B/D. In fact, Thiel--as well as other observers--predict serious world oil price instability and supply disruption in the late 1980s if non-OPEC demand for OPEC oil approaches 40 million B/D. Some argue OPEC production will never exceed 35 million B/D.

II.1.2 World Oil Production Forecasts

Table F-3 shows several crude oil production forecasts that recently appeared in the Oil & Gas Journal and World Oil. The range in these forecasts after 1985 is generally explained by the various company and agency assumptions about OPEC production. "Most industry analysts expect OPEC production to remain about 30 million B/D at least through 1985." (OGJ, November 12, 1979, P. 165.) Thereafter, British Petroleum believes the economic incentives to

TABLE F-2

NON-COMMUNIST WORLD OIL DEMAND
(Million B/D)

	Actual 1978	Forecast 1980	Forecast 1985	Forecast 1990
Low	51.9	52	57	60
Probable	51.9	54	60	66
High	51.9	58	69	80

NON-COMMUNIST WORLD OIL SUPPLY
(Million B/D)

		1978	1980	1985	1990
Non-OPEC LDC		5.1	6.8	9.3	11.2
OECD, Excl U.S.		3.9	5.5	6.3	7.5
U.S.		10.3	9.1	10.0	9.8
Subtotal, Production		19.3	21.4	25.6	28.5
Sino-Soviet Imports		1.8	1.0	0.5	--
Process Gain		0.5	.5	.6	.6
Free World Supply, Excl OPEC		21.6	22.9	26.7	29.1
OPEC Production:	Lower Limit	30.3	26.4 -	29.8 -	29.7 -
	Upper Limit		35.2	39.4	40.7
Total Supply	Lower Limit	51.9	49.3 -	56.5 -	58.8 -
	Upper Limit		58.1	66.1	69.8

NOTE: Upper and lower limits of OPEC production are defined by conservative physical production limitations on the top side and estimated foreign exchange requirements on the bottom side.

Source: Michael F. Thiel, "World Oil and OPEC: The Razor's Edge," World Oil, October, 1979, 123-133.

TABLE F-3

NON-COMMUNIST WORLD CRUDE PRODUCTION FORECASTS[1]

(Million B/D)

	FORECAST DESCRIPTION	1980	1985	1990	1995	2000
British Petroleum	-OPEC At Max	--	64	62	--	52
	-OPEC No Inc.	--	55	52	--	43
Standard of Indiana	-Base Case	53.8	59.1	--	--	--
	-Pessimistic	52.5	55.1	--	--	--
Standard of California	-1990 Plateau	53.0	58	60.5	60	60
Shell	-Optimistic	--	--	66.5	--	70.3
	-Pessimistic	--	--	57	--	63.0
Exxon	-1978-Year-End	54	--	68	--	--
Energy Information Administration (EIA)	-Optimistic	--	59	76	85	--
	-Pessimistic	--	55	67	69	--
Michael F. Thiel	-Upper OPEC Political Limit	56.6	65.0	69.8	--	--
	-95% OPEC Limit	54.8	63.0	67.2	--	--
	-Lowest OPEC Production	47.8	55.4	58.8	--	--

[1] For consistency between forecasts NGL is excluded. NGL equals about an additional 5 percent.

SOURCES:

[1] "Oil in the Eighties: Tight Supply, Soaring Capital Outlays," OGJ, November 12, 1979, 163-169.

[2] "EIA Optimistic on Crude Supply Outlook," OGJ, September 10, 1979, 102-130.

[3] C.C. Pocock, Chairman, Shell transport and Trading Co., "Prospects for Oil & Gas: A Look Ahead to year 2000," World Oil, October, 1979, 107-111.

[4] Michael F. Thiel, "World Oil & OPEC: The Razor's Edge," World Oil, October, 1979.

exporting countries will be reduced. Incremental production would only increase the OPEC nations' financial assets held in foreign banks and would not benefit their domestic economic growth. Furthermore, if inflation continues, oil would earn more in the ground than as a financial asset in foreign banks.

The British Petroleum forecast not only sees the possibility that OPEC may limit production to 30 million B/D beyond the mid-1980s, it is also very pessimistic about the remaining world production capacity. BP assumes significant new supplies in areas other than OPEC will not be brought into production and believes non-communist world production capacity will peak by 1985 at the latest.

A CIA forecast (CIA, "The World Oil Market in the Years Ahead," August, 1979.) not shown on Table F-3 contends that the potential oil shortage in the western world will be compounded by Soviet Bloc production capacity limitations. The CIA predicts that the Sino-Soviets will change from a net exporter to the western world of 1.8 million B/D in 1978 to a net importer of 700,000 B/D by 1982. In view of the very tenuous western world oil supply/demand balance existant in 1979 and forecasted to continue, a 2.5 million B/D change in Sino-Soviet supply patterns to the non-communist world could be very disruptive both to the real price of oil and to political conditions already very uncertain. (OGJ, September 3, 1979, p. 50)

If the Carter policy to limit exports of American technology to Russia announced in January, 1980, in retaliation for the Soviet invasion of Afganistan continues for very long, Russia certainly will not meet its 1980s production goals. Russia's oil production industry is heavily dependent on U.S. oil field tools and technology. Without a continuing supply of this American technology, the CIA's forecast that Russia will become a net importer by 1982 seems assured. The Soviet production problem is regarded by analysts as a technological constraint rather than a geologic limitation on potential recoverable oil resources.

Regardless of their technical problems, the Soviets could destabilize the world oil market by simply withholding their crude from the export market. In view of the Afganistan situation this is a likely possibility. Continued instability in the spot market in late January, 1980 indicates that the oil traders have not yet assumed supply patterns are settled. Even though OPEC price increases have been known for a month, the Middle-East instability overhangs the world oil market.

This instability is not expected to go away soon. Senior Vice-President of Conoco, Samuel Schwartz, was recently quoted: "The world will remain highly vulnerable to disruptions in oil supplies throughout the next decade." (OGJ, November 12, 1979, p. 181.)

The EIA's forecast (shown on Table F-3) is the most optimistic. Its high case calls for OPEC production to be 39 million B/D by 1990. EIA's pessimistic case calls for OPEC production of 32 million B/D in 1990. Exxon's forecast, the second highest, was made before the current Middle-East turmoil. It called for OPEC production of 38 million B/D by 1990. Their forecast probably has changed by now. Standard Oil of California forecasts a production peak by 1990 and plateau to the end of the century. Their forecast calls for OPEC to produce 37 million B/D by 1990.

C.C. Pocock, Chairman of the Shell Transport & Trading Company, captured the essence of all of these forecasts, in a discussion of Shell's forecast. "Previous high hopes for OPEC production, which suggested figures rising from 30 million B/D last year to 45 million in 1990 and 50 million in 2000, are no longer realistic." (World Oil, October 1979, p. 107.) Shell, like Chevron, believes that world oil production "will probably reach a plateau well before the year 2000." Shell predicts a plateau of "around 65 million B/D." (World Oil, p. 108.)

II.2 United States Oil Situation[1]

II.2.1 Demand: A Radical Change In Consumption Patterns

Oil will remain the predominant fuel in the U.S. at least through 1990 although its share of total energy consumed will decline. U.S. energy demand during the 1980s and the 1990s will be crude oil supply limited. These two decades will be a transition period to alternate energy sources. Methods will be sought to produce new energy resources on a large scale and integrate their use into the existing distribution network in an economic and environmentally compatible way.

Shell, Exxon and Chevron forecast 1990 U.S. energy demand to range from 47.6 million B/D oil equivalent (B/D O.E.) to 49.9 million B/D O.E., a narrow range of estimates. They further agree that crude oil will account for 20-21 million B/D of this total. 1978 U.S. crude oil demand was 19.2 million B/D of a total of 38 million B/D O.E. for U.S. energy consumption. Underlying Shell, Exxon, and Chevron's forecasts to 1990 are real GNP growth rates between 3 and 3.5 percent. The 1978-1990 U.S. oil consumption growth rate is forecast to range between 0.35 percent (to 20 million B/D) and 0.75 percent (to 21 million B/D). Total U.S. energy use growth is expected to fall within 2.0-2.25 percent between 1978 and 1990. Consequently, the ratio of total energy use to real GNP, shown on Figure F-1 to be declining since the early 1970s, is projected to continue its decline, as the U.S. replaces energy inefficient technology created during the era of cheap energy with energy efficient technology. Energy conservation will be an important aspect of U.S. consumption patterns throughout the remainder of this century.

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[1] This section is largely drawn from four sources:

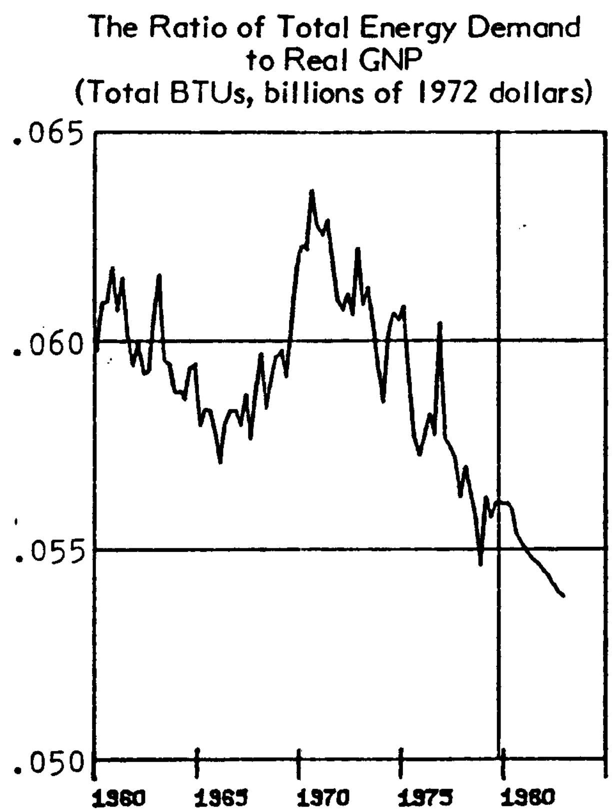
"U.S. Petroleum Industry Will Face Monumental Task in Next Decade," OGJ, November 12, 1979, 170-184;

Exxon, Energy Outlook, 1979-1990, December, 1978;

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

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

FIGURE F-1



Source: Data Resources, Inc., Forecast November, 1979.

U.S. oil consumption grew from 10 million B/D in 1960 to 17.6 million B/D in 1973 when OPEC quadrupled the price of world oil and ended the period of cheap energy. This represented an annual growth rate of 4.4 percent for oil use compared to 4.1 percent for total energy use. Both oil and energy growth rates slightly exceeded the average growth in real GNP during this period.

While absolute oil requirements are forecast to grow slightly to 1990, oil's relative share is expected to decline from 50 percent in 1978 to about 42 percent in 1990. The growth rate in oil use compared either to: (1) forecasted growth rate in GNP during this period, or (2) historical U.S. oil consumption growth rates from 1960 to 1973, reflects a radical change in U.S. oil consuming patterns.

II.2.2 Domestic Production

While the expected change in U.S. oil consumption growth rates evidences a significant drop, the fact remains that the domestically produced oil consumed in the 1990s must all be developed during the 1980s. The U.S. is currently producing flat-out at the rate of approximately 3.75 billion barrels/year. January 1, 1979 proved reserves amounted to 27.8 billion barrels--a sufficient inventory to last only 7.5 years, through mid-year 1986 at current production rates. Thus, to hold domestic production at current levels for another 7.5 years beyond mid-year 1986, the industry will have to find and develop reserves during this period at least equal to total current proved reserves. According to an article in the Oil & Gas Journal, "Assuming a constant for reserves added per well drilled, U.S. operators would have to drill about twice as many wells as they are now drilling to add reserves of this magnitude. That would be nearly 100,000 wells annually." (November 12, 1979, p. 170). The industry drilled 48.5 thousand wells in 1978.

The requirement for a sharp increase in domestic drilling implies the need for places to drill all these wells--hopefully places with the best potential for large additions to reserves. The offshore frontiers particularly in Alaksa remain among the best wildcat prospects even though recent Alaskan experience has been disheartening. (Wall Street Journal, "After 200 dry holes oil companies turn cool toward Alaska," November 26, 1979). In spite of the monumental exploration task facing the U.S. oil industry in the 1980s, most forecasts of domestic oil production for the coming decade predict domestic production at about present levels. 1978 production of crude and NGL was 10.3 million B/D. A number of informed forecasts (Shell, Arco, Chevron) peg a production range of 8.5 to 10 million B/D in 1990. Gulf estimates 8, 10 and 12 million B/D as the minimum, probable, and maximum domestic levels. Exxon estimates 1990 domestic minimum production as low as 7.0 million B/D, maximum as high as 9.0 million B/D and most likely as 7.5 million B/D.

Table F-4 illustrates the range in industry estimates for additional discoveries onshore and offshore Alaska by 1990. Domestic oil production from lower 48 and Cook Inlet proved reserves are declining. Neither Shell nor Chevron expect new discoveries to off-set this decline. While Shell and

TABLE F-4

DOMESTIC OIL PRODUCTION
(Million B/D)

	Lower 48 and South Alaska	Arctic Alaska	Syn Crude	Total
Shell				
1978 Actual	9.2	1.1	0	10.3
1980	7.9	1.6	0	9.5
1990	5.8	3.0	0.5	9.3
Chevron				
1978 Actual	9.2	1.1	0	10.3
1980	8.4	1.6	0	10.0
1990	7.0	1.8	0.5	9.3

Sources: OGJ, "U.S. Petroleum Industry Will Face Monumental Task in Next Decade," November 12, 1979.

California Energy Commission, "Fuel Price and Supply Projections: 1980-2000," November , 1979.

Chevron differ in their view of the relative shares of 1990 Lower 48 and Alaskan production, they agree that they expect 1990 production to be 1.0 million B/D lower than 1978--including 500 MB/D of syncrude. By 1990 production from the giant Prudhoe Bay field will be in decline, producing just under 1.5 million B/D. Shell's forecast assumes incremental production from new discoveries in Arctic Alaska will double the Alaskan production rate by 1990. Chevron, however, is more conservative and assumes production only sufficient to maintain the Alaska pipeline near its maximum designed rate. (Shell does not specify an assumption about transportation of crude from Arctic Alaska in excess of pipeline capacity.)

No matter how they get there, both Shell's and Chevron's estimates of 1990 domestic production are far short of the forecast 20-21 million B/D 1990 demand requirement. It appears that a maximum effort must be made to develop potential new resources, such as those from the Norton Basin, just to maintain domestic production near existing levels over the next decade.

II.2.3 Imports

In view of the expected U.S. demand for oil in the 20-21 million B/D range and domestic production--including production from yet undiscovered reserves on the north slope of Alaska--in the 8.5-10 million B/D range, imports to make up the difference will have to amount to 10-12.5 million B/D by 1990. Exxon's forecast calls for 13 million B/D imports by 1990. "Despite President Carter's vow last summer to hold net imports to 8.5 million B/D, industry analysts insist that imports must top that level if the country is to maintain its economic growth. . . . Despite a slower rate of growth in total energy demand, these large oil imports [will be needed]. . . because nuclear and the direct use of coal have encountered environmental delays and costs, and the cost of new energy technology [development] has been higher than the short-term cost of oil imports." (OGJ, November 19, 1979, p. 181).

Industry executives remain very worried about the impact of import supply disruptions on the U.S. economy and quality of life. The U.S. as well as much of the rest of the world will remain critically dependent on oil from the politically unstable Middle East until sometime in the next century when alternative technologies and sources of energy are developed. Minor import supply disruptions will continue to have major economic disruptions. When these will occur cannot be forecast. To the extent that U.S. energy policies can stimulate domestic production above the 8.5 - 10 million B/D expected 1990 level or reduce expected 1990 demand for oil below the forecasted 20-21 million B/D, the U.S. will become less vulnerable to unpredictable disruptions.

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

II.3 Petroleum Administration V With Special Reference To California[1]

II.3.1 PAD V Supply/Demand Balance

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

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[1]This section is based mostly on recent publications from the California Energy Commission.

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

__________, "California's Energy Challenge: The Next 20 years," November 1979.

__________, "Fuel Price & Supply Projections, 1980-2000", November, 1979.

__________, "Energy Futures for California, Two Scenarios, 1978-2000," November 1979.

__________, "California Energy Demand, 1978-2000: A Preliminary Assessment," August, 1979.

Oil & Gas Journal, "California Ponders Ways to Match Crude, Refining," April 16, 1979, 27-30.

TABLE F-5

U.S. DISTRICT V SUPPLY/DEMAND
(Thousand B/D)

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

Source: Oil Company Confidential, "World Energy Outlook: 1979-1990," July, 1979.

Table F-5 shows the District V 1978 and estimated 1979 supply/demand balance for crude oil and petroleum products. The table illustrates several situations about PAD V petroleum flows that will be discussed in detail in subsequent sections.

Table F-5 shows that:

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

- California crude production provides about 35 percent of PAD V product demand. (This is true for California in isolation, also.)

- PAD V imports approximately 700 MB/D of foreign crude and products at the same time it transships to Districts I-IV 400-500 MB/D of Alaskan crude.

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

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

These are all interrelated problems driven by the refiners' task of economically matching potential crude supplies with their required demand slate.

II.3.2 California's Refinery Balance Problem With Special Reference To Alaskan Crude

The natural domestic market for Alaskan oil is the West Coast, and since the bulk of the West Coast refining capacity is located in California, California refineries are the logical destination. In the fourth quarter, 1979, the Alaska pipeline was running about 1.5 million B/D. PAD V refiners were processing between 0.9-1.0 million B/D and the rest of the north slope crude was going either to the Hess Refinery in the Virgin Islands or to the U.S. Gulf Coast. At the same time California refiners were importing about 400 MB/D of sweet Indonesian crudes.

Table F-6 shows that Indonesian crudes are vastly different from North Slope and California crudes. The Indonesia crudes are high in gravity (API) and low in sulfur. In contrast, California crudes shown on Table F-6 have a weighted average of 18^{0} API. Besides these, there are vast reserves of heavy crude oil in the southern San Joaquin Valley, perhaps as much as 12 billion barrels that range between 8^{0}-10^{0} API and are very high in sulfur.

Existing California refineries are not capable of processing all the available California and Alaskan crude without producing a surplus of heavy products (fuel oils) and a deficit of light products (gasoline). This situation is further complicated by the Southern California environmental requirement that fuel oils must contain less than 0.25 percent sulfur. Indonesian crude is the perfect feed stock to make both low sulfur fuel oil and California's demand for light products. Refining North Slope crude results in too little gasoline and too high sulfur content residual oil.

The product shipments shown as demand on Table F-5 are high sulfur fuel oils and coke. (Coke is the absolute "bottom of the barrel" and is shipped to Japan for use in the steel industry.) The product shipments shown as supply are light product imports--nearly all finished or unfinished gasoline. (Unfinished gasoline is Naptha which is a direct product of atmospheric distillation. Naptha is hydrotreated and reformed to upgrade its octane and anti-knock characteristics for unleaded and premium gasolines.)

Without discussing the technical nuances of refinery modifications, it is possible to retrofit the existing refineries with expanded hydro-cracking and

TABLE F-6

API GRAVITY AND SULFUR CONTENT OF REPRESENTATIVE CRUDES RUN IN CALIFORNIA REFINERIES.

California	°API Gravity	Percent Sulfur
Dos Cuardras Offshore	24.0	1.14
Ventura Group	30.5	1.02
San Ardo	11.5	2.25
Cat Canyon	12.1	4.69
Santa Maria	13.3	4.56
Huntington Beach	20.8	1.44
Wilmington	18.4	1.51
Elk Hills, Stevens	36.0	.41
Yowlume	32.8	.44
Elk Hills, Shallow	21.4	.51
Kern River	13.8	1.19
Belridge South	17.8	.23
Midway Sunset	16.3	.28
Alaska		
Cook Inlet	35.0	.20
North Slope	27.2	1.05
Indonesian		
Ataka	40.4	.06
Sumatran Light	35.8	.08
Seria[1]	38.8	.05

[1]Seria crude is from Brunei, which while close, strictly speaking is not part of Indonesia.

Source: California Energy Commission, "Fuel Price and Supply Projections," 1978-2000," November, 1979.

residuum de-sulfurization (RDS) capacity to process additional quantities of either north slope or heavy California crudes. Whether these refinery "de-bottlenecking" modifications will occur entails two factors: 1) economics--comparing the expected profitability of making products from domestic crude sources including new "debottlenecking" investments to the expected profitability of running Indonesian crude through the existing refinery equipment; and 2) state and national energy policy issues.

The economics of the technical considerations of refining more California and Alaskan crude are currently under study by a joint committee of California state agencies and California oil companies, the "California Oil Scenario Study Subgroup." Their study, due in draft form in early 1980, will address the production-refining mix problem in the context of refinery modifications that will have to be made over the next five years to be on-stream by 1985.

Unless these refinery modifications are made, no more than 1.0 million B/D North Slope quality crude can be processed in PAD V and incremental supplies of domestic low gravity, higher sulfur crude will move to PADS I-IV.

National and state energy policies are interrelated with technical refinery issues but can be isolated within this discussion to emphasize the two major considerations:

1. Security of supply;
2. Natural gas policy.

II.3.2.1 Security of Supply

So long as the United States is heavily dependent on OPEC oil we are vulnerable to supply disruptions and periodic unpredictable exogenous price increases. California Energy Commission staff argue that since California's imports are Indonesian, and have been supplied reliably for the past decade, "cutting off Indonesian imports may not contribute at all to improved security of supply [and will] instead antagonize a friendly nation. . . .It may make more sense to continue importing their crude to California and send the Alaskan oil on east to displace Arab crude there." ("Fuel Price and Supply Projections, 1980-2000," p. 31.) According to this point-of-view, incremental supplies of Alaskan oil will, therefore, move to the U.S. Gulf Coast to displace Middle East crude and California will remain up to 20 percent dependant on Indonesian crude--unless incremental discoveries of new Alaskan crudes are high in gravity, low in sulfur and can displace Indonesian imports.

II.3.2.2 Natural Gas Policy Issues: The Effects On Oil Supply/Demand

If sufficient gas supplies were available, the environmental problems of using fuel oil in California power plants could be avoided by substituting clean natural gas. Every oil-fired power plant in the state is capable of burning gas. According to the introductory document to the California Energy Commission biennial energy report, "refiners looking at the possibility of retrofitting thus have to consider the possibility that the low sulfur residual oil market, which is dominated by power plant use, may shift into gas." ("Energy Choices for California. . . Looking Ahead," March, 1979 p. 53.)

Table F-7 shows a preliminary result from the "California Oil Scenario Study Subgroup" to illustrate the magnitude of the potential 1985 range in the demand for fuel oils as a function of potential natural gas availability. The resultant 1985 refinery demand slate could be as low as 1940 MB/D or as high as 2313 MB/D--a range of 373 MB/D associated with upper and lower limit low sulfur fuel oil and distillate fuel requirements due to natural gas availability. This implies a range in crude oil requirements to the refineries of about the same magnitude.

Natural gas availability is a national policy issue as well as a state issue. If high gas supplies are available nationally, whether they are allocated to California or to the rest of the nation is still an undecided issue. (Natural gas considerations are discussed in Section III.) Investment decisions need to be made in early 1980 if refinery "debottlenecking" equipment to handle additional high sulfur, low gravity domestic crudes is to be on-line by 1985.

TABLE F-7

CALIFORNIA REFINERY PRODUCT DEMAND 1985 FORECAST AS A FUNCTION NATURAL GAS SUPPLY.
(Thousand B/D)

	1978 Actual	1985 Forecast[1] Expected Gas Supply	High Gas Supply	Low Gas Supply
Gasoline	841.5	880.0	880.0	880.0
Jet Fuel	188.0	243.0	243.0	243.0
Subtotal: Light Products	1029.5	1123.0	1123.0	1123.0
Distillate Fuel Oil	242.2	299	298	370
Residual Low Sulfur Fuel Oil	208.4	364	107	408
High Sulfur Fuel Oil	199.9	186	186	186
Misc. Other Products	225.8	226	226	226
Total Refinery Products	1905.8	2198.0	1940.0	2313.0
High/Low as a Percent of Expected 1985 Demand		--	88%	105%
Difference in Fuel Oil Demand		--	(258)	115
NATURAL GAS SUPPLY (MMCF/D)	4153	4012	5582	3343

Source: Preliminary table for discussion purposes only, "California Oil Scenario Study Subgroup," November, 1979.

[1] Forecast product demands and gas supplies are for illustrative purposes only and are not necessarily the same as those shown in Section III.3.2. Table F-22 shows the California energy commission 1985 mid-range gas supply to be 4302 MMCF/D.

Industry management is in a difficult position. Even if state policy is decided based on the study group report, national gas policies appear that they will not be resolved with certainty by 1981. Certainly the likely price of OPEC Indonesian crude in 1985--the presumed industry alternative to running more domestic crude will remain unknown. Consequently, depending on the interrelated considerations of natural gas availability and refinery debottlenecking investments, the low gravity, high sulfur North Slope crude may or may not continue to move to PADs I-IV in the mid-1980's. Too many policy and economic variables remain unknown at this time.

II.3.3 FORECAST OF PAD V SUPPLY & DEMAND

Table F-8 shows two forecasts of California's energy consumption by the year 2000. Scenario II is the California Energy Commission (CEC) conventional outlook and represents what the CEC expects to happen without additional actions to redirect established trends. Scenario III emphasizes alternate resources and reflects the CEC's idea of a plausible future energy use pattern.

Under Scenario II petroleum use grows at 1.4 percent annually from 62 percent of total consumption to 64 percent by 2000. Scenario III assumes a 0.2 percent annual growth rate with petroleum use declining to 56 percent by 2000. From 1960 to 1973, petroleum use in PAD V grew at 4.5 percent annually. After a momentary pause in 1974 as West Coast consumers adjusted to the new price structure imposed by OPEC after the embargo, west coast petroleum consumption resumed its rapid growth--at 4.6 percent annually. Districts I-IV, which also saw petroleum use grow at 4.5 percent from 1960 to 1973, had a drop to 2.9 percent from 1974 to 1978.

In this context, even though the growth rate of economic activity is assumed to be somewhat lower for the last two decades of the twentieth century than during the 1960s, a reduction in energy use growth to 1.4 percent in the CEC's conventional case will require a radical change for Californians. The alternate growth path may not be attainable.

TABLE F-8

CALIFORNIA NET ENERGY CONSUMPTION BY FUEL TYPE
(Thousand B/D Oil Equivalent)

	1978	2000 Scenario II	2000 Scenario III
Gasoline	1014	1037	748
Aviation Fuels	278	470	447
Distillates	274	354	305
Other Petroleum Products	491	927	629
Subtotal: Petroleum Products	2057	2786	2129
Natural Gas	838	809	692
Electricity	346	531	445
Bio Mass	45	105	208
Coal	38	69	69
Geothermal	8	22	107
Solar	0	9	76
Methanol	0	32	63
Net Total Consumption	3332	4363	3789

SOURCE: California Energy Commission, "Energy Futures For California: Two Scenarios, 1978-2000," Staff Draft, November, 1979, Table IV-2.(TBTU converted to B/D O.E.).

NOTES:
1. Scenario II is the conventional outlook and represents what the CEC expects to happen without additional actions to redirect established trends in California energy use.
2. Scenario III emphasized alternative resources and reflects CEC thinking about an achievable future use pattern which minimizes reliance on conventional resources and reduces oil use drastically from the conventional forecast.
3. The underlying state economy growth rate appears to be between 3.25-3.5 annually over this period based on Table 3 of "California Energy Demand: 1978-2000," California Energy Commission, August, 1979.

TABLE F-9

U.S. DISTRICT V DEMAND/SUPPLY BALANCE
(Thousands B/D)

DEMAND	Actual 1978	Forecast 1980	1985	1990	1995	2000
Direct V Consumption[1]	2624	2699	2959	3018	3155	3298
Interdistrict Product Exports[5]	136	140	116	126	126	126
Total Demand	2760	2839	3075	3144	3281	3424
SUPPLY						
Alaskan Production[2]						
Cook Inlet	137	112	53	25	--	--
Prudhoe Bay	1065	1500	1600	1490	700	370
Subtotal: Alaskan	1202	1612	1653	1515	700	370
California Production[3]						
Most Likely	918.6	1000	1100	1100	1000	950
Maximum	918.6	1000	1400	1400	1300	1200
Minimum	918.6	1000	980	930	850	800
Foreign Imports (Crude & Products)[4]	690	637	540	330	330	330
Interdistrict Product Receipts[5]	167	175	75	50	50	50
Process Gain	112	115	130	130	130	135
Total Supply (Most Likely)[6]	3089.6	3539	3498	3125	2210	1835
Upper and Lower Limit	--	--	3378-3798	2955-3425	2060-2510	1685-2085
Supply Surplus/(Deficit)[7]	329.6	700	423	(19)	(1017)	(1589)
Upper and Lower Limit	--	--	233-723	(189)-281	(1221)-(771)	(1739)-(1339)
Forecast of Potential New Alaskan Production[8]						
Most Likely	--	--	--	285	1000	2130
Maximum	--	--	350	1385	1750	2630
Minimum	--	--	--	--	800	1430

NOTES TO TABLE F-9

[1]District V consumption was shown on Table F-7 to be sensitive to supplies of natural gas to District V. This forecast assumes most likely gas supplies. Upper and lower limit demand cases are not shown. Directionally, a single demand case is sufficient to show how potential new Alaskan production might supplement expected California and projected Alaskan production.

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

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

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

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

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

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

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

SOURCES:

[1]Oil Company (confidential), "World Energy Outlook, 1979-1990," July, 1979.

[2]California Energy Commission, "Fuel Price & Supply Projections, 1980-2000," November, 1979.

[3]Alaska Department of Revenue, Petroleum Revenue Division, "Petroleum Production Revenue Forecast," Quarterly Report, September, 1979.

[4]DOE, "Petroleum Supply Alternatives For The Northern Tier And Inland States Through 2000," Vol. 1, October 31, 1979, Tables 3-6, 3-7.

Table F-9 shows a base case confidential demand forecast done in July, 1979 by a west coast oil company. Their forecast calls for petroleum use to grow at 1.7 percent annually to 1985, but average 1.0 percent over the entire 22 year period from 1978 to 2000. This forecast assumes more conservation and shifting to alternate fuels than the CEC conventional forecast -- but less than the CEC Scenario III forecast. PAD V consumption of petroleum products was shown on Table F-7 to be sensitive to natural gas supplies. The demand forecast shown on Table F-9 assumes most likely gas supples. Alternate demand cases are not shown because Table F-9's focus is to show how new production from yet undiscovered Alaskan resources may fit together with projected production of proved Alaskan reserves and the consensus range of forecasts of California crude production. The demand forecast is a reasonably moderate forecast with an implicit envelope of about plus or minus 10 percent by 2000.

Table F-9 shows that production from the proved reserves of Cook Inlet are rapidly declining and will be exhausted soon after 1990. The Alaska Department of Revenue, Petroleum Revenue Division, expects that production from Prudhoe will start declining in 1989. By the year 2000, Prudhoe Bay will be producing less than 400 MB/D. Together with the expected range in California production and a reasonable, but conservative mix of Indonesian imports, PAD V will be short between 1.3 and 1.7 million B/D of crude by 2000.

In 1995 Prudhoe Bay production is forecast at 700 MB/D. As a result of this decline from historic levels, Table F-9 shows that PAD V will most likely require 1.1 million B/D of new crude production by 1995. The deficit ranges from 770 MB/D to 1.2 million B/D.

Crude is potentially short as much as 189 MB/D in PAD V as early as 1990. That means either new Alaskan crude must be found and produced or additional foreign imports will be required by 1990 in District V--assuming a demand of 3.144 million B/D and California production in range of 930 MB/D.

Hence, after 1990, new production from the Norton Basin or other Alaskan OCS regions could replace declining Alaskan North Slope crude production. However, if Beaufort reserves are found and developed in the mean time to keep the pipeline running full and they are similar to Prudhoe crude, then Norton Basin crude could only be processed in PAD V to the extent that the California refineries are debottlenecked--unless the Norton crude is high gravity and low sulfur.

II.3.4 Effect of Northern Tier Pipeline On Alaskan Resource Development

President Carter in January, 1980, endorsed the Northern Tier pipeline project designed to move crude oil from Port Angeles, Washington, to Clearbrook, Minnesota. The initial design capacity of the 1,557 mile pipeline is rated at 709,000 B/D; ultimate design capacity is 933,000.

The Northern Tier pipeline was conceived in the mid-1970s to move surplus Alaskan North Slope crude on the west coast to the crude short northern tier and upper midwest states. These states are crude short due to curtailments of crude exports to the United States by Canada and the decline of U.S. production.

A study by The Pace Co. published in September 1978 and updated in January 1980 suggests, however, there is some constraint on the amount of low gravity, high sulfur Alaskan North Slope crude that the refineries along the pipeline can process. These refineries were designed to process a mix of crudes including high gravity, low sulfur Canadian and domestic crudes. Table F-10 shows the ability to replace these crudes with North Slope crude.

Line number (1) shows the Pace forecast of lost low sulfur, high gravity Canadian crude along the northern tier route. These refineries are expected to be short approximately 180 MB/D of high quality Canadian crude.

TABLE F-10

POTENTIAL NORTHERN TIER PIPELINE DELIVERIES TO PRIMARY SERVICE AREA

	1985	1990	2000
	(Thousand B/D)		
1) Replace Lo S./hi gravity Canadian	180	180	180
Demand Growth[1]	85	120	130
Replace hi S. imports	320	320	320
Refinery modification[2]	100	120	150
2) Subtotal: sour crude	505	560	600
3) Total: supplemental crude	685	740	780
Required domestic production			
Decline to fill pipeline:			
- capacity: 709,000 B/D	24	--	--
- capacity: 933,000 B/D	248	193	153

Source: OGJ, "Preliminary Design of Proposed Northern Tier Pipeline Complete," November 20, 1978, 73-88.

The Pace Co., "Potential for Northern Tier Pipeline: An Update," January, 1980.

Telcon with Pace February, 1980.

NOTES:

1. Pace's lowest demand growth forecast for products in excess of those moving into the service area by product pipeline.
2. Pace's highest refinery modification forecast.

Line number (2) shows the subtotal of sour crude from the pipeline that could be accommodated by the refineries along the route. By 1990 The Pace Co. anticipates that these refineries could consume approximately 560 MB/D of crude equivalent to Alaskan North Slope. Line number (3) shows that these two requirements for supplemental crude are nearly sufficient to fill the pipeline in 1985 when it will probably be in operation at its initial design capacity.

Pace also forecasted that Alaskan crude could be moved through the pipeline to supplement declining domestic production. This could require nearly 200 MB/D of new crude delivered to Port Angeles by 1990 if the pipeline is boosted to maximum capacity. Whether this would have to be high quality crude would depend on which former lower 48 crude source it was replacing. There would probably be some flexibility, however, to rebalance upper midwest refineries and replace some amount of high quality lower 48 crude with Alaskan North Slope type crude. Thus, the worst case 1990 requirement for low gravity, high sulfur Alaskan crude is probably above the 560 MB/D shown on line number (2).

These Northern Tier crude requirements can be usefully compared with the PAD V crude supply surplus shown just under the line on Table F-9. The 700 MB/D surplus existing in 1980 is expected to decline to 423 MB/D by 1985 and disappear before 1990--assuming no new production from newly discovered reserves. Thereafter, the projected decline of the Prudhoe Bay field will leave a large gap in PAD V that will require a new crude source to meet West Coast requirements.

Hopefully, by the beginning of the last decade of the twentieth century some of the anticipated vast Alaskan resources will have been discovered and developed to fill both the gap in PAD V and leave a surplus to move east in the Northern Tier pipeline. Otherwise, both PAD V and the northern tier refineries will be increasingly dependent on foreign imports.

The "most likely" forecast of potential new Alaskan production shown on Table F-9 for 1990 does not, however, indicate a supply of new oil of sufficient size to both cover PAD V requirements and meet the 740 MB/D requirement shown on Table F-10 for 1990 for the Northern Tier pipeline.

The maximum forecast of new Alaskan production shown on Table F-9 as 1385 MB/D implies very optimistic OCS field development schedules and high finds in the early 1980s lease sales including the Norton lease sale. New oil production in the range of 1385 MB/D shown on Table F-9 could not fit through the Alaska pipeline from a new field in the Beaufort. Hence, the 1385 MB/D estimate of new Alaskan production by 1990 from any of the other Alaskan OCS regions is unrealistic.

Only by 2000 does the difference between the "most likely" forecast of new Alaskan production--2130 MB/D--and PAD V crude deficit from proved reserves--(1589) MB/D--show a surplus of sufficient size to approach the Northern Tier's capacity.

The maximum forecast of new Alaskan production implies a speed-up of lease sales as suggested by Shell. Without an acceleration in the lease schedule, the West Coast surplus of Alaskan crude may not materialize. The critical crude shortage forecast for the upper midwest may not be covered by West Coast surpluses unless the lease schedule is accelerated.

II.4 Relationship of Norton Basin Oil Resources to PAD V Supply

Tables F-11, F-12 and F-13 show likely production scenarios for potential Norton Basin oil resources estimated by Dames & Moore to coincide with USGS low find, medium find and high find resource estimates (Fisher et al., 1979). These production scenarios were developed for the Norton Basin petroleum development study Draft Report completed in October, 1979, for BLM. In the low find Case (Table F-11) production starts in 1990 at 38.4 MB/D and peaks at 154 MB/D in 1993. In both the medium find and high find cases, (Tables F-12 and F-13) production starts at 19.2 MB/D in 1989 and peaks for the medium find at 436 MB/D in 1994 and for the high find at 764.4 MB/D in 1995.

TABLE F-11 NORTON BASIN

LOW FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL) Central Sound 200	180	Totals MmBbl/Year
1983	1			
1984	2			
1985	3			
1986	4			
1987	5			
1988	6			
1989	7			
1990	8	7.008	7.008	14.016
1991	9	14.016	14.016	28.032
1992	10	21.024	21.024	42.048
1993	11	28.032	28.032	56.064
1994	12	27.050	26.962	54.012
1995	13	22.401	20.788	43.189
1996	14	17.432	16.028	33.460
1997	15	13.897	12.357	26.254
1998	16	11.000	9.527	20.527
1999	17	8.886	7.346	16.232
2000	18	6.835	5.663	12.498
2001	19	5.250	4.366	9.616
2002	20	4.154	3.366	7.520
2003	21	3.286	2.595	6.881
2004	22	2.600		2.600
2005	23	2.057		2.057
2006	24			
2007	25			
2008	26			
2009	27			
2010	28			
2011	29			
2012	30			
2013	31			
2014	32			
2015	33			
2016	34			

Peak Oil Production = 153,600 b/d

Source: Dames & Moore
"Norton Basin Petroleum Development
Scenarios OCS Lease Sale No. 57,"
Final Report, January, 1980, p. 177.

TABLE F-12 NORTON BASIN

MEDIUM FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL) Inner Sound 200	Inner Sound 200	Central Sound 500	Central Sound 250	Outer Sound 250	Totals MmBbl/Year
1983	1						
1984	2						
1985	3						
1986	4						
1987	5						
1988	6						
1989	7			7.008			7.008
1990	8			24.528	7.008	7.008	31.536
1991	9	7.008		45.552	17.520	7.008	77.088
1992	10	14.016	7.008	56.064	28.032	17.520	122.640
1993	11	21.024	14.016	56.064	28.032	28.032	147.168
1994	12	28.024	21.024	54.005	28.032	28.032	159.125
1995	13	27.050	28.032	46.354	27.982	28.032	157.450
1996	14	22.401	27.050	38.598	24.906	27.982	140.937
1997	15	17.432	22.401	32.168	20.647	24.906	117.554
1998	16	13.897	17.432	26.840	17.116	20.647	95.932
1999	17	11.000	13.897	21.420	14.187	17.116	77.620
2000	18	8.886	11.000	18.757	11.763	14.187	64.593
2001	19	6.835	8.886	15.221	9.751	11.763	52.456
2002	20	5.250	6.835	12.703	8.084	9.751	42.623
2003	21	4.154	5.250	10.616	6.701	8.084	34.805
2004	22	3.286	4.154	8.886		6.701	23.027
2005	23	2.600	3.286	7.452			13.338
2006	24	2.057	2.600	6.263			10.920
2007	25	1.628	2.057	5.328			9.013
2008	26			4.417			4.417
2009	27						
2010	28						
2011	29						
2012	30						
2013	31						
2014	32						
2015	33						
2016	34						

Peak Oil Production = 436,000 b/d.

Source: Dames & Moore
"Norton Basin Petroleum Development
Scenarios OCS Lease Sale No. 57,"
Final Report, January, 1980, p. 152.

TABLE F-13 NORTON BASIN

HIGH FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - OIL

Calendar Year	Year After Lease Sale	PRODUCTION IN MMBBL YEAR BY FIELD SIZE (MMBBL)							Totals MmBbl/Year
		Inner Sound			Central Sound		Outer Sound		
		500	200	200	500	200	750	250	
1983	1								
1984	2								
1985	3								
1986	4								
1987	5								
1988	6								
1989	7				7.008				7.008
1990	8				24.528	7.008	7.008		38.544
1991	9	7.008			45.552	14.016	24.528	7.008	98.088
1992	10	24.528	7.008		56.064	21.024	52.560	17.520	178.704
1993	11	45.552	14.016		56.064	28.032	73.584	28.032	245.280
1994	12	56.064	21.024	7.008	54.005	27.050	84.096	28.032	277.279
1995	13	56.064	28.032	14.016	46.354	22.401	84.096	28.032	278.995
1996	14	54.005	27.050	21.024	38.598	17.432	76.708	27.982	262.799
1997	15	46.354	22.401	28.032	32.168	13.897	62.453	24.906	230.211
1998	16	38.598	17.432	27.050	26.840	11.000	51.293	20.647	192.860
1999	17	32.168	13.897	22.401	22.420	8.886	40.869	17.116	157.757
2000	18	26.840	11.000	17.432	18.757	6.835	33.885	14.187	128.936
2001	19	22.420	8.886	13.897	15.221	5.250	28.094	11.763	105.531
2002	20	18.757	6.835	11.000	12.703	4.154	23.293	9.751	86.493
2003	21	15.221	5.250	8.886	10.616	3.286	19.312	8.084	70.655
2004	22	12.703	4.154	6.835	8.886	2.600	16.012	6.701	57.891
2005	23	10.616	3.286	5.260	7.452	2.057	13.274		41.935
2006	24	8.886	2.600	4.154	6.263		11.007		32.910
2007	25	7.452	2.057	3.286	5.328		9.126		27.249
2008	26	6.263		2.600	4.417		7.566		20.840
2009	27	5.328		2.057			7.088		14.473
2010	28	4.417					5.876		10.293
2011	29						4.872		4.872
2012	30						4.040		4.040
2013	31						3.349		3.349
2014	32						2.776		2.776
2015	33						2.302		2.302
2016	34								

Peak Oil Production = 764,400 b/d.

Source: Dames & Moore
"Norton Basin Petroleum Development
Scenarios OCS Lease Sale No. 57,"
Final Report, January, 1980, p. 125.

PAD V could consume all of the estimated 1995 Norton Basin production even under the high find production schedule. The high find schedule shows the Norton Basin producing 764.4 MB/D in 1995 and this is just slightly less than the low end estimated supply deficit of 770 MB/D shown on Table F-9. Declining production in the Norton Basin after 1995 in conjunction with an increasing supply deficit in PAD V implies that additional supply sources from other OCS regions will be required before the end of the twentieth century to satisfy PAD V demand--not-to-mention that of the rest of the nation. When Northern Tier pipeline requirements are added to PAD V requirements clearly larger reserves than the high USGS estimates for Norton Basin will be required to satisfy the demand.

II.5 World Oil Price Projection[1]

II.5.1 OPEC Politics, Not Economics, Will Determine Price Movements

A tenuous balance exists between world oil supply and demand in 1980 due to the instability of the Middle East. This tenuous balance is projected to continue. The link between the "invisible hand" of supply and demand in the market place and prices appears to be broken. Instead, visible but unpredictable political forces are driving the price of middle eastern oil. Short of some theories that act to suggest upper and lower limit OPEC prices, the

[1] Two 1979 publications elaborate the material briefly presented in this section.

> Energy Future: Report of the Energy Project at the Harvard Business School, Robert Stobaugh and Daniel Yergin, editors. New York: Random House, 1979.
>
> Energy: The Next Twenty Years, A report of a study group administered by RFF, Hans H. Landsberg, Chairman. Cambridge, Mass.: Ballinger Publishing, 1979.

(The ideas developed in Energy Future appear to be reflected in several of the references quoted previously.)

Current information is drawn largely from two year-end 1979 articles and newspaper and PIW accounts:

> "Action By OPEC Further Disarrays Crude Prices." OGJ, December 24, 1979, 19-23.
>
> "OPEC Fails To Make A Fix," Time, December 31, 1979, 22-23.

consensus among interested observers of world oil markets is that since "there is no theory for predicting the decisions of OPEC, there is no theory that relates foreseeable forces of supply and demand into a forecast of orderly market behavior and the orderly progression of prices." (Energy: The Next Twenty Years, p. 208). "It is obvious," according to Thiel, "that for the next 10 years, barring some drastic development, the western world will be unable to put any significant pressure on OPEC through curtailed demand for oil or expanded supply." (World Oil, October, 1979, p. 130.)

Only the cost of alternate sources appears to limit the top side risk of OPEC price increases. Data Resources, Inc. (DRI) did a November 24, 1979 forecast of world oil supply and demand for 1980 that showed 51.5 million B/D as the balancing point between supply and demand. Their forecast indicated that a 2 million B/D cutback in OPEC crude from an expected level of 29.4 million B/D would result in a 50 percent increase in the price of incremental quantities of imported oil in 1980.(Their forecast shows Iran producing 3.6 million B/D and Saudi Arabia 8.7 million B/D in 1980.)

DRI's forecast appears to confirm that short of going without there is no alternative to dampen the price impacts of small changes in supply. In terms of economic jargon, both supply and demand remain extremely inelastic in the near term and--short of drastic actions--probably will remain so through the end of this century.

OPEC oil ministers gathered in Caracas, Venezuela, December 17, 1979, to adjust oil prices. Arab Light was boosted from $18.00 to $24.00--33 percent. In late January, the Saudis raised the price to $26.00. And four other Arab nations followed.

Over year-end 1978, Table F-14 shows that at $26.00 Arab Light was up 105 percent--and the Saudis were called the "price moderates" in the world press. The African members, Algeria, Nigeria and Libya--the price hawks of OPEC--have increased their prices between 134 and 150 percent since year-end 1978. The

TABLE F-14

OPEC PRICE INCREASES

Country	Crude	Gravity	Price Dec 31, 1978	Price Aug 1, 1979	Price Jan, 1980	Percent Increase
Saudi Arabia	Arabian Light	34^{0}	12.70	18.00	26.00	105
Iraq	Basrah Light	34^{0}	12.66	19.96	30.15	138
Kuwait	Burgan	31^{0}	12.22	19.49	27.50	125
Qater	Dukhan	40^{0}	13.19	21.42	29.40	122
U.A.E.	Murban	39^{0}	13.26	21.56	29.60	123
Venezuela	Centrolago	36.5^{0}	12.90	19.25	28.75	122
Iran	Iranian Light	34^{0}	12.81	22.00	30.00	135
Indonesia	Minas	35^{0}	13.55	21.12	30.75	127
Mexico*	Isthmus	34^{0}	13.10	22.60	32.00	144
Algeria	Saharian	49^{0}	14.10	23.50	33.00	134
Nigeria	Bonny Light	37^{0}	14.10	23.47	34.48	145
Libya	Zuetina	40.5^{0}	13.90	23.50	34.72	150

*Not a member of OPEC

Source: OGJ, "Action by OPEC Further Disarrays Crude Prices," Dec 24, 1979, p. 22.
___, "OPEC Members Settling on Crude Prices," Jan 7, 1980, p. 39.

average price of imported oil has increased form $13.33 in December 1978 to $30.86 in January 1980--a rise of 132 percent.

The world oil market shows no sign of entering the 1980s on a stable basis. The underlying supply/demand balance forecasted for the 1980s does not suggest a stable basis for predicting price movements.

II.5.2 Price Projections

Since United States oil price regulations expire in late 1981, development of Alaskan OCS resources is hinged to world oil prices. In spite of the difficulty of predicting world oil prices, policy makers require price forecasts and economists oblige. Table F-15 shows two late 1979 price forecasts and a contrasting 1978 forecast by A.D. Little, Inc. When A.D. Little, Inc. made its forecast, Arab Light was officially priced at $12.70 FOB RAS Tanura. Now it is $26.00 and already exceeds not only the A.D. Little forecast but also the two low government forecasts for 1990 shown on Table F-15. The only forecasts on Table F-15 that look plausible just two months after they were made are the high forecasts. Both the CEC's and EIA's upper limit forecast for 1985 call for oil in the $34.00 range in 1979 dollars. If inflation averages 8.5 percent for the next five years then in 1985 dollars we can expect to be paying $50.00 per barrel.

There are three generalizable assumptions that can be drawn from these world oil price forecasts -- and some people would argue with the first.

Assumption Number 1: Forecasters have stopped arguing that OPEC will fall apart and prices will drop back into a relationship with costs.

Assumption Number 2: The real price of oil will increase throughout the remainder of this century; that is, oil prices will rise faster than general inflation.

TABLE F-15

WORLD OIL PRICE FORECASTS FOR ARAB LIGHT
1979 Dollars

	Date of Forecast	January 1979 Official Price Arab Light	1980	1985	1990	1995	2000	Annual Real Rate of Growth %
A.D. Little, Inc.- Median	April, 1978	26.00	--	--	24.40	--	29.80	2.4
Cal. Energy Comm.	Nov., 1979							
Low		26.00	20	21.00	22.0	--	24.00	1.4
Most Likely		26.00	20	27.50	31.80	--	37.70	3.6
High		26.00	20	33.80	42.60	--	56.30	5.6
Energy Information Agency	Nov., 1979							
Low		26.00	--	18.40	22.75	28.10	--	2.8
High		26.00	--	34.60	45.00	56.25	--	7.4

Source: California Energy Commission, "Fuel Price and Supply Projections, 1980-2000, November 1979.

Assumption Number 3: The relationship of the price of oil to the cost of finding and developing oil is the essential element in the economics of OCS development--and oil costs will probably rise faster than general inflation also.

The world oil market is dominated by OPEC and likely will remain so throughout the remainder of this century. To predict an overall reduction in the price of crude oil, the power of OPEC to set prices will have to be broken. This can occur only if large oil deposits are discovered in non-OPEC areas and those nations sell the oil at a price related to cost rather than OPEC's price level. This possibility is not very likely. North Sea oil, for example, is generally indexed to the world prices dictated by OPEC. The physical problems involved in finding a giant oil reserve somewhere in the world and bringing it into production at sufficient speed to replace OPEC's dominance before the end of the century are staggering.

The basic question, therefore, is how much will the inflation in oil prices exceed the general inflation rate? A prevalent myth for several years has been that real oil prices will increase between 2-3 percent annually. Dr. Walter Hoadley, Chief Economist of Bank of America, predicted in the December 10, 1979 OGJ that "world crude price will increase at about 2-3%/year plus the world inflation rate . . . throughout the 1980's." (p.46). While real oil prices declined for three years 1975-1978, economists predicted 2-3 percent/year inflation in 1978 and since then average OPEC crude postings moved up more than 100 percent. It appears that western dependence on Middle Eastern oil will continue to allow unpredictable price increases well above 2-3 percent real price inflation. "Real prices will continue to rise until consumers are willing to do without or develop substitutes," according to John Swearinger, Chairman of Standard Oil of Indiana.

While oil prices will increase faster than general U.S. inflation that does not necessarily imply that the economics of finding and developing expensive OCS oil resources will improve. The change in the price of oil relative to the change in the cost of developing oil is the important determinant of the economics of finding and developing oil reserves[1]. Oil prices may not

[1]James M. Jondrow and David Chate, "An Evaluation of the GNP Deflator as a Basis for Adjusting the Allowable Price of Crude Oil," Center for Naval Analysis, January 7, 1977.

inflate faster than the cost of those items and those activities required to find, develop and produce new reserves in the environmentally inhospitable areas of the world such as Alaska. Since 1974, the cost of petroleum development has risen about 5 percent faster than general U.S. inflation. Whatever happens in the future, the ratio of oil prices to oil costs is the critical element in the economics of OCS development.

Equivalent amortized cost (EAC) calculations based on a 15 percent discount rate show that development costs for potential large oil fields in the Norton Basin are less than the oil prices assumed in the analysis. The analysis assumed a well-head crude price of $18.00. The EAC of specific development options shown on Table A-13 fall in the mid-$16.00 range for multiple-platform development scenarios for "Giant" discoveries of 500 and 750 million barrels of recoverable reserves. Fields of 250 million barrels show EAC ranging from $16.60 to $17.50 per barrel depending on length of off-shore pipeline. Smaller fields -- 180-200 million barrels -- even with short pipelines show EAC in excess of $18.00. Thus, with a discount rate of 15 percent, these smaller fields are uneconomic if well-head prices are no higher than $18.00.

III. Natural Gas

III.1 Introduction

The marketability of Norton Basin natural gas is an exceedingly complex problem that can be best understood in context with the U.S. natural gas situation, and the U.S. West Coast supply/demand balance, particularly in the State of California. Norton Basin gas has a role within the non-conventional or supplemental gas supplies such as Alaska pipeline gas to meet future U.S. energy needs. The problem is further complicated by evolving national energy policy, particularly as it pertains to gas pricing, LNG imports, and LNG facility siting and safety. The first part of this section aims to identify the key U.S. and California gas supply/demand problems and the projected role of Alaskan supplemental gas, including Norton Sound, in the supply/demand picture.

The second part of this section focuses on LNG from Alaska, and the most likely mode for delivery of Norton Sound gas to market. This discussion is placed in the context of both national LNG projects (existing and planned). Transportation options for Norton Sound gas are then reviewed. To complete the discussion, the possible costs of Alaskan LNG are compared with estimates for other supplemental gas sources.

III.2 U.S. Natural Gas Situation[1]

The common perception is that the United States, although currently experiencing a momentary surplus, is running out of natural gas. The real situation is

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[1] This section is based mostly on the following references:

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

______________, "The Future for Gas Energy in the United States," 1979.

______________, "Comparison of Conventional Natural Gas Supply Forecasts," September, 1979.

______________, "New Technologies for Gas Energy Supply and Efficient Use," April 1979.

Business Week, "The Gloom Behind the Natural-Gas 'Bubble,''' April 23, 1979, p. 63 and following.

that the nation may be running out of cheap so-called "conventional" natural gas but vast quantities of more costly so-called "supplemental" gas are potentially available. The "conventional" supplies refer to gas relatively easy to produce from oil fields or nonassociated gas fields in the lower 48. "Supplemental" gas sources considered to be the major alternates include:

1) Synthetic methane from coal (SNG);

2) Liquefied natural gas from Alaska or foreign sources (LNG); and

3) Pipeline gas from Alaska.

Canadian and Mexican imports essentially complete twentieth century U.S. gas supply alternatives.

The marketability of these high-cost "supplemental" sources depends, first, on the gap between expected gas demand and "conventional" less-costly supplies and, second, on the cost competitiveness of "supplemental" gas compared to alternate fuels, notably coal burned as coal, no. 2 and no. 6 fuel oils, and Canadian and Mexican gas imports.

III.2.1 Conventional Supplies

The American Gas Association in late 1979 surveyed forecasts by major U.S. natural gas producers, gas transmission companies and government agencies of conventional natural gas reserve additions and production. Table F-16 shows the group's estimate of lower 48 reserve additions through 1990.

The range of average annual reserve additions in the lower 48 over 1980-1990 is between 7.0 and 15.2 TCF/year with the average estimate of 12.2 TCF/year.

TABLE F-16 LOWER 48 FORECAST RESERVE ADDITIONS
Tcf/Year

	Average		Annual		
	1980-1985	1980-1990	1980	1985	1990
I. Oil and Gas Co.'s					
AMOCO	14.1	14.4	14.1	14.0	14.8
ARCO	12.5*	12.2*	12.5*	12.5*	11.3*
Exxon	10.9	11.0	10.8	11.0	11.3
Gulf	18.3	18.8	17.0	19.5	20.0
Mobil	12.0	12.0	12.0	12.0	12.0
Shell	12.0	12.0	12.0	12.0	11.0
Medium Size Producer	--	--	--	--	--
II. Gas Transmission Co.					
Michigan-Wisconsin	10.7	10.4	10.8	10.5	9.6
Tenn. Gas. Trans.	7.9	7.0	8.6	7.2	4.6
Texas Eastern	9.2	8.7	9.6	8.7	7.7E
Pipeline A	14.5	14.6	14.0	15.0	15.0
Pipeline B	8.1	8.2	8.3	7.8	8.0
III. Government Agencies					
DOE/EIA (Series C Med./Med.)	13.8*	13.5*	12.5*	15.1*	11.9*
GAO	--	--	--	--	--
IV. A.G.A. - TERA	14.9	15.2	13.9	15.9	15.9
Total Average	12.2	12.2	12.0	12.4	11.8

E = Extrapolated based on data through 1987
*Includes Alaska

Source: American Gas Association, "Comparison of Conventional Natural Gas Supply Forecasts," September, 1979, Table F-2.

Nine of the fourteen estimates on Table F-16 fall between 10 and 15 TCF/year.

Table F-17 shows the group's estimate of lower 48 gas production through 1990. The average of the estimates shows that production drops from 18.5 TCF/year in 1980 to 15.1 TCF/year in 1990. (These forecasts compare to 19.1 TCF in 1978.) These forecasts also are coincident with results reported by Professor James L. Sweeney of Stanford who examined eleven leading gas supply models on a standardized input basis. Sweeney discovered that, "A generally steady decline in the production of conventional lower 48 natural gas was . . . relatively common" among the gas supply models. (AGA, "Comparison of Conventional Natural Gas Supply Forecasts," September, 1979, p.2.)

Proved reserves in 1978 were 200.3 TCF. The ratio of proved reserves to 1978 annual production was 10.5 years. Table F-18 shows four authoritative estimates of remaining recoverable conventional gas resources in the U.S. including Alaska. These show a range of 563 to 1283 TCF as of December 31, 1978. If conventional reserve additions average 12.2 TCF/year as shown on Table F-16, by 1990 134.2 TCF additional reserves will have been discovered. Cumulative production through year-end 1990 (estimated from Table F-17) subtracted from cumulative discoveries gives an idea that remaining proved U.S. reserves will approximate 150 TCF at year-end 1990.[1] At that time the estimated ratio of proved reserves to 1990 production estimated at 15.1 TCF on Table F-17 will be 9.9 years--down from 10.5 years for 1978 production of 19.1 TCF.

There is little question but that conventional U.S. natural gas supplies are, indeed, running out. By the year 2000 the AGA forecasts conventional gas production to fall between 12-14 TCF/year.

---

[1] 200 TCF + 11(12.2 TCF) - [6((18.5 + 16.6)/2) + 5 ((16.6 + 15.1))/2] = 149.65 TCF

1978 (Year-End Proved Reserves) + (Estimated Reserve Additions) - [Estimated Production] = Estimated 1990 Proved Reserves

TABLE F-17 LOWER 48 GAS PRODUCTION FORECASTS
TCF/Year

Source	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
I. Oil and Gas Co.'s											
AMOCO	19.1	18.5	17.6	17.1	16.6	16.3					15.2
ARCO	18.3	17.8	16.4	17.0	16.7	16.4	16.2	16.0	15.6	15.5	15.2
Exxon	18.2					14.4					13.4
Gulf	19.0	19.0	19.2	19.4	19.5	19.2	19.2	19.2	19.2	19.2	19.2
Mobil	19.5					18.1					16.3
Shell	17.9	17.4	16.9	16.5	16.1	15.7	15.2	14.7	14.4	13.8	13.2
Medium Size Producer	19.1	18.6	17.7	16.8	15.9	15.2	15.2	15.2	15.2	15.2	15.1
II. Gas Transmission Co.											
Michigan-Wisconsin	18.1	17.4	16.9	16.4	16.0	15.5	15.1	14.7	14.4	14.0	13.6
Tenn. Gas. Trans.	18.9	18.7	18.2	17.7	17.0	15.9	14.9	13.9	12.8	11.9	10.9
Texas Eastern	19.2	18.9	18.5	18.1	17.6	17.1	16.6	16.1	15.6E	15.1E	14.6E
Pipeline A	18.0	17.5	17.3	16.9	16.8	16.7	16.4	16.2	16.1	16.0	15.9
Pipeline B	18.8					16.6					14.6
III. Government Agencies											
DOE/EIA (Series C Med./Med.)	18.5					16.8					15.7
GAO	18.1					17.6					17.1
IV. A.G.A. - TERA	17.3					16.9					18.0
Total Average	18.5					16.6					15.1

E = Extrapolated based on data through 1987

Source: American Gas Association, "Comparison of Conventional Natural Gas Supply Forecasts," September, 1979, Table F-3.

TABLE F-18

(TCF)	Year of Est.	POTENTIAL RESOURCES[1] New Fields	Old Fields	Total Potential	1978 PROVED RESERVES	TOTAL[2] REMAINING RESOURCES
USGS[3]	1974	322-655	162	524-857	200	624-957
National Academy of Sciences	1974	530	118	648	200	788
Exxon Base	1974	342-942	56-321	423-1143	200	563-1283
Potential Gas Committee	1978	820	199	1019	200	1219

[1]Does not include possible resources from unconventional sources such as Coal-Bed Degasification, Devonian Shale, Rocky Mountain Tight Gas Formation, Geopressured Resources, Biomass and Coal Gasification

[3]U.S. Geological Survey.

[2]As of December 31, 1978. Estimates are corrected for gas consumed since the date of resource estimate.

Source: American Gas Association, "The Future for Gas Energy in The United States," 1979.

III.2.2 Demand For Gas

The 1978 gas demand was 20.4 TCF. Figure F-2 shows the AGA estimated potential and economic demand forecast to 1990. Economic demand refers to the "demand for gas energy based on price and technology alone--not constrained by government regulation, misperceptions of short supply and other restraints." (AGA, "The Future for Gas Energy in the United States," 1979, p. 22). Their economic demand is estimated to range between the 25.2 TCF shown on Figure F-2 and 27.7 TCF/year by 1990.

The difference--2.6 TCF/year--reflects the change in demand in the industrial use category if prices are allowed to rise sufficiently to justify significant development of supplemental natural gas supplies. AGA calls this their "High Supply Scenario."

Table F-19 shows the AGA's two economic demand cases that reflect higher or lower prices and consequently lower or higher demands. Only industrial users show price sensitivity within the price ranges assumed in AGA's analysis.

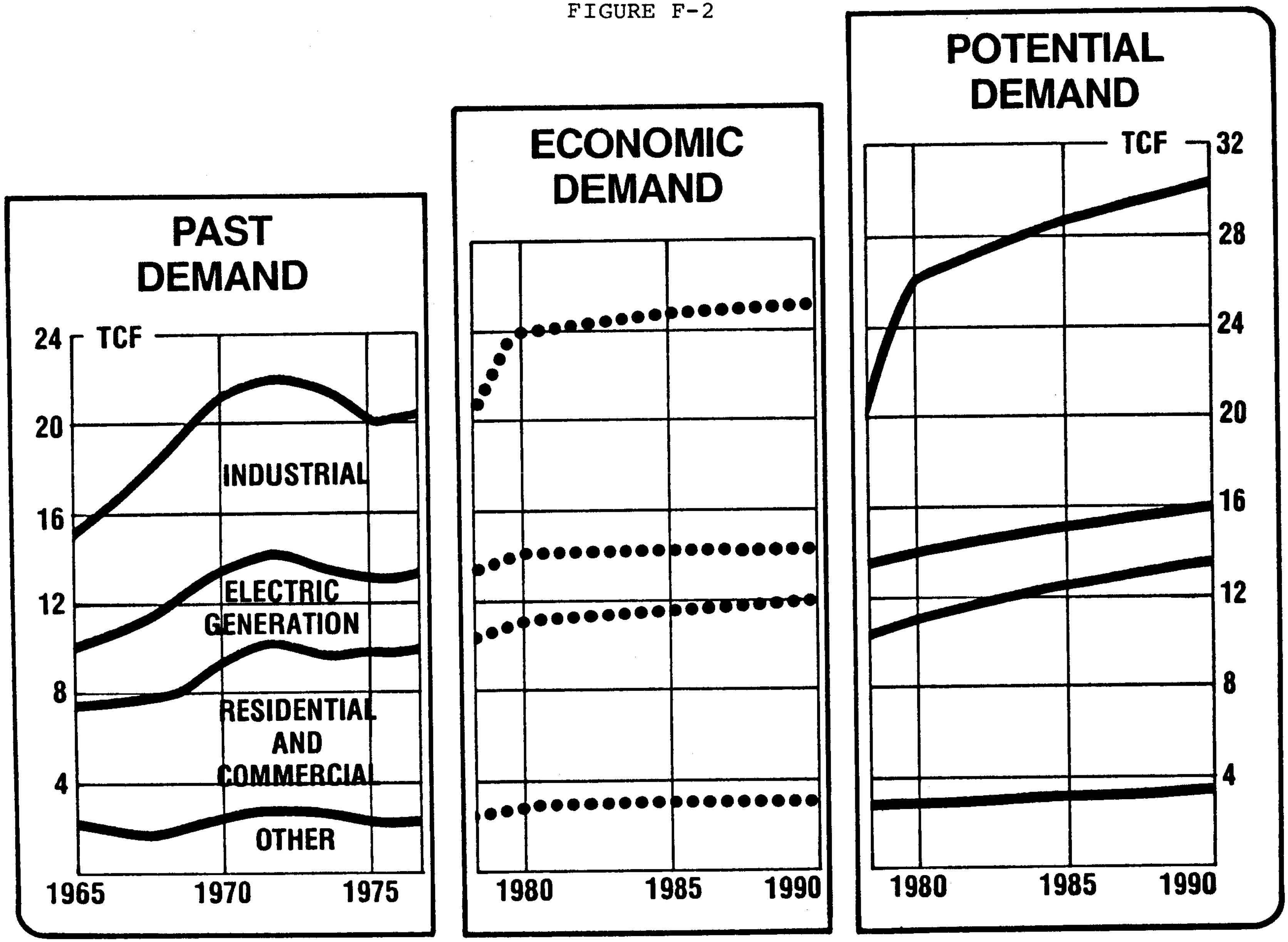
The AGA's potential demand forecast as shown on Figure F-2 is their upper limit case "if environmental and other restrictions continue to impede coal use, and if federal policy discourages oil imports." Potential demand could exceed 30 TCF/year by 1990. (AGA, "The Future for Gas . . ., p. 22.)

The AGA's economic demand forecast implies a natural gas demand growth rate of 2.3 percent to 25.2 TCF/year and 3.2 percent to 27.7 TCF/year by 1990. This growth in demand is associated with a real GNP growth rate of 3.2 percent. This is about the same GNP growth rate associated with oil use growth in Section II.2.

III.2.3 U.S. Supply/Demand Balance

Table F-20 combines the AGA conventional supply and demand forecasts to identify the supply gap that must be met by supplemental gas plus imports from

FIGURE F-2



Source: American Gas Association, "The Future for Gas Energy in The United States," 1979.

TABLE F-19 RESULTS OF ECONOMIC GAS DEMAND FORECASTS
(Tcf)

Case 1 - Low Supply Scenario

	Actual	Forecast			Average Annual Growth
	1977	1980	1985	1990	Rate (1977-1990)%/yr.
Residential	4.8	5.2	5.5	5.8	1.4
Commercial	2.7	2.9	3.1	3.2	1.3
Industrial	6.8	10.3	11.8	13.5	5.4
Power Plant	3.3	3.0	2.6	2.2	-3.0
Other[1]	2.8	2.9	3.0	3.0	0.5
Total	20.4	24.3	26.0	27.7	2.3

Case 2 - High Supply Scenario

	Actual	Forecast			Average Annual Growth
	1977	1980	1985	1990	Rate (1977-1990)%/yr.
Residential	4.8	5.2	5.5	5.8	1.4
Commercial	2.7	2.9	3.1	3.2	1.3
Industrial	6.8	9.9	10.6	10.9	3.7
Power Plant	3.3	3.0	2.6	2.2	-3.0
Other[1]	2.8	2.9	3.1	3.1	0.8
Total	20.4	23.9	24.9	25.2	1.6

[1]"Other" category includes (1) lease and plant fuel, (2) net change in underground storage, (3) pipeline fuel and (4) gas unaccounted for (see Appendix C for further details).

Source: American Gas Association, "A Forecast of the Economic Demand for Gas Energy in the U. S. through 1990," February, 1979, p. 12.

Mexico and Canada. The low gas demand shown on Table F-20 is taken from a confidential oil company forecast. Their forecast reflects a pessimistic view of supplemental gas alternatives in the next decade. It is, therefore, a supply-limited demand forecast.

The supply gap ranges between 7.6 and 15.3 TCF/year by 1990. The moderate case gap is 9.2 TCF/year. The moderate case supply gap is the difference between the lower limit economic demand forecast and the average of conventional supply forecasts.

The last line of Table F-20 shows AGA's estimate of potential supplemental gas sources. In each of the three time periods shown through 1990 the AGA supplemental gas estimate is less than the moderate case gap and much less than the worst case gap. In 1980, the supplemental gas estimate is less than even the smallest estimate of the supply gap. This forecast indicates that 1980 will be the year that the momentary U.S. gas surplus disappears.

Table F-21 shows the component parts of the potential supplemental gas sources and shows how all these fit together to comprise the AGA U.S. gas supply forecast to 2000. In 1978, supplementals amounted to 1.3 TCF including 0.9 TCF imported Canadian gas (which is really a "conventional" gas source). By 1990, this forecast calls for the U.S. to increase the use of supplemental gas sources to 8.6 TCF. This is an increase from 6 percent of total gas to 34 percent. This implies imports of Alaskan and foreign gas as LNG and Alaskan gas by pipeline of 3.6 TCF/year or 9.86 BCF/day. The LNG portion of this is 5.48 BCF/day.

This appears to be a very optimstic supplemental gas development forecast. For instance, a recent OGJ article ("Mexico Aims For 3 Million B/D by 1985," June 25, 1979, p.52) estimated 1985 Mexican gas exports at 0.6 TCF. Canadian exports must increase to 1.5 TCF annually from their 1978 0.9 TCF level for total 1985 imports to equal 2.1 TCF as estimated by AGA. There is a current recognized gas surplus in Canada, and a consortium of companies have filed to the Canadian National Energy Board to receive 5.5 TCF over a period of 12

TABLE F-20

SUPPLY GAP BETWEEN FORECAST U.S. DEMAND & CONVENTIONAL SUPPLIES
TCF/YEAR

	1980	1985	1990	2000
DEMAND FORECASTS				
Potential Gas Demand[1]	26.1	28.7	30.3	--
Economic Gas Demand[2]-Upper Limit	24.3	26.0	27.7	--
Lower Limit	23.9	24.9	25.2	--
Low Gas Demand[3]	22.2	22.5	22.6	--
CONVENTIONAL SUPPLY FORECASTS[4]				
High	19.0	18.0	17.0	14.0
Low	18.0	16.0	15.0	12.0
SUPPLY GAP[5]				
Best Case	3.2	4.5	7.6	--
Moderate Case	5.4	7.9	9.2	--
Worst Case	8.1	12.7	15.3	--
AGA SUPPLEMENTAL GAS FORECAST[6]	2.5	5.8	8.6	17.2

Sources: AGA, "A Forecast of the Economic Demand for Gas Energy in the U.S. through 1990," February 1979.

AGA, "Comparison of Conventional Natural Gas Suply Forecasts," September 1979.

AGA, "The Future for Gas Energy in the United States," 1979.

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

NOTES TO TABLE F-20

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

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

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

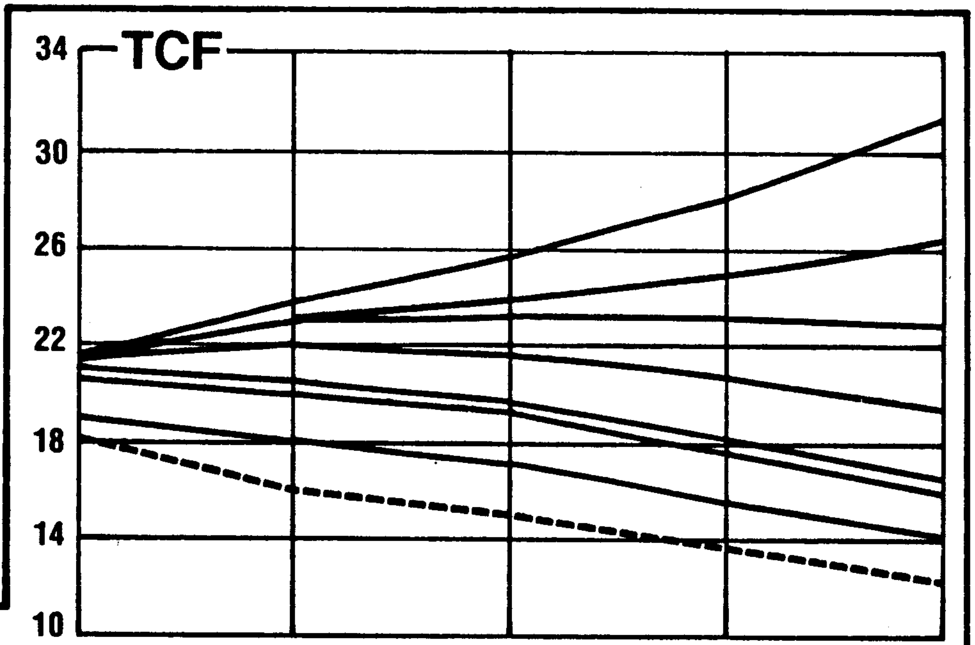
[4]Conventional gas supplies from the lower 48 are declining.

[5]The supply gap represents a range of demand estimates to be met from supplemental gas supplies.

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

TABLE F-21 POTENTIAL SUPPLEMENTAL GAS SOURCES

ACTUAL 1978	
LNG IMPORTS	0.1
SNG	0.3
CANADA & MEXICO	0.9
SUPPLEMENTALS	1.3
CONVENTIONAL LOWER - 48	19.1
TOTAL	20.4



POTENTIAL SUPPLEMENTALS	1980	1985	1990	1995	2000
NEW TECHNOLOGIES	—	0.9	1.8	3.2	5.0
HIGH-BTU COAL GAS	—	0.1	0.6	1.8	3.3
ALASKA	—	0.8	1.6	2.5	3.6
LNG IMPORTS	0.4	1.6	2.0	2.5	3.0
SNG	0.5	0.5	0.5	0.5	0.5
CANADA & MEXICO	1.6	1.9	2.1	2.0	1.8
SUPPLEMENTALS	2.5	5.8	8.6	12.5	17.2
CONVENTIONAL LOWER-48	18-19	16-18	15-17	13.5-15.5	12-14
TOTAL	20.5-21.5	21.8-23.8	23.6-25.6	26-28	29.2-31.2

Source: American Gas Association, "The Future For Gas Energy in the United States," 1979.

years to justify construction of the southern portion of the Alcan pipeline. (CEC, "Fuel Price and Supply Projections," p. 53.) While both of these imports may rise to equal the 1990 2.1 TCF level, it remains only conjecture that LNG imports may rise to equal 2.0 TCF annually by 1990 or that new technologies including such things as peat gasification, gas from tight sands or biomass or municipal wastes, coal seam methane, etc., will equal another 1.8 TCF/year by 1990. There is reason to believe that some share of the estimated supply gap shown on Table F-21 will remain unmatched by supplemental gas supplies.

III.3 California[1]

III.3.1 Supply

California's gas supply historically has been supplied by pipeline from the Southwest (65 percent), from Canada (23 percent) and from California and federal offshore (12 percent). California consumed 1.5 TCF in 1978. Beyond the mid-1980s California's historical supplies - Canada and Southwestern U.S. - will begin to decline. The new sources--Rocky Mountain gas, Mexican gas, LNG and SNG and Alaskan North Slope pipeline gas--must rise to match forecasts demands or consumers will have to switch to alternate fuels.

Table F-22 shows the CEC mid-range gas supply forecast for California. By 2000, California, Southwest and Canada traditional supplies are expected to be less than 45 percent of their estimated 1980 levels. By 2000, California which is currently dependent on two major and dependable suppliers--Canada and the southwestern U.S.--will become dependent on a variety of supplemental sources. Conventional gas supplies will be less than 50 percent by 2000.

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[1]This section is based on California Energy Commission documents, mostly:
CEC, "Fuel Price and Supply Projections, 1980-2000," November 1979.
CEC, "Natural Gas Supply and Demand For California, 1978-1995," March 1978.
Oil & Gas Journal, "Mexico Aims for 3 million B/D by 1985," June 25, 1979, 52-53.

TABLE F-22

CALIFORNIA
NATURAL GAS SUPPLY BY SOURCE
MID-SUPPLY CASE
(MMCFD)

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

Source: CEC, "Fuel Price & Supply Projections: 1980-2000," November 1979, p.49.

Figure F-3 displays the CEC high case forecast which rises to 3340 MMCFD by 2000. The high supply case assumes 1700 MMCFD of LNG from a variety of sources instead of 900 MMCFD from Indonesia and Cook Inlet shown on Table F-22 in the mid-supply case. Figure F-3 emphasizes how much LNG and coal gasification may figure in California's energy future.

III.3.2 California Supply And Demand Balance

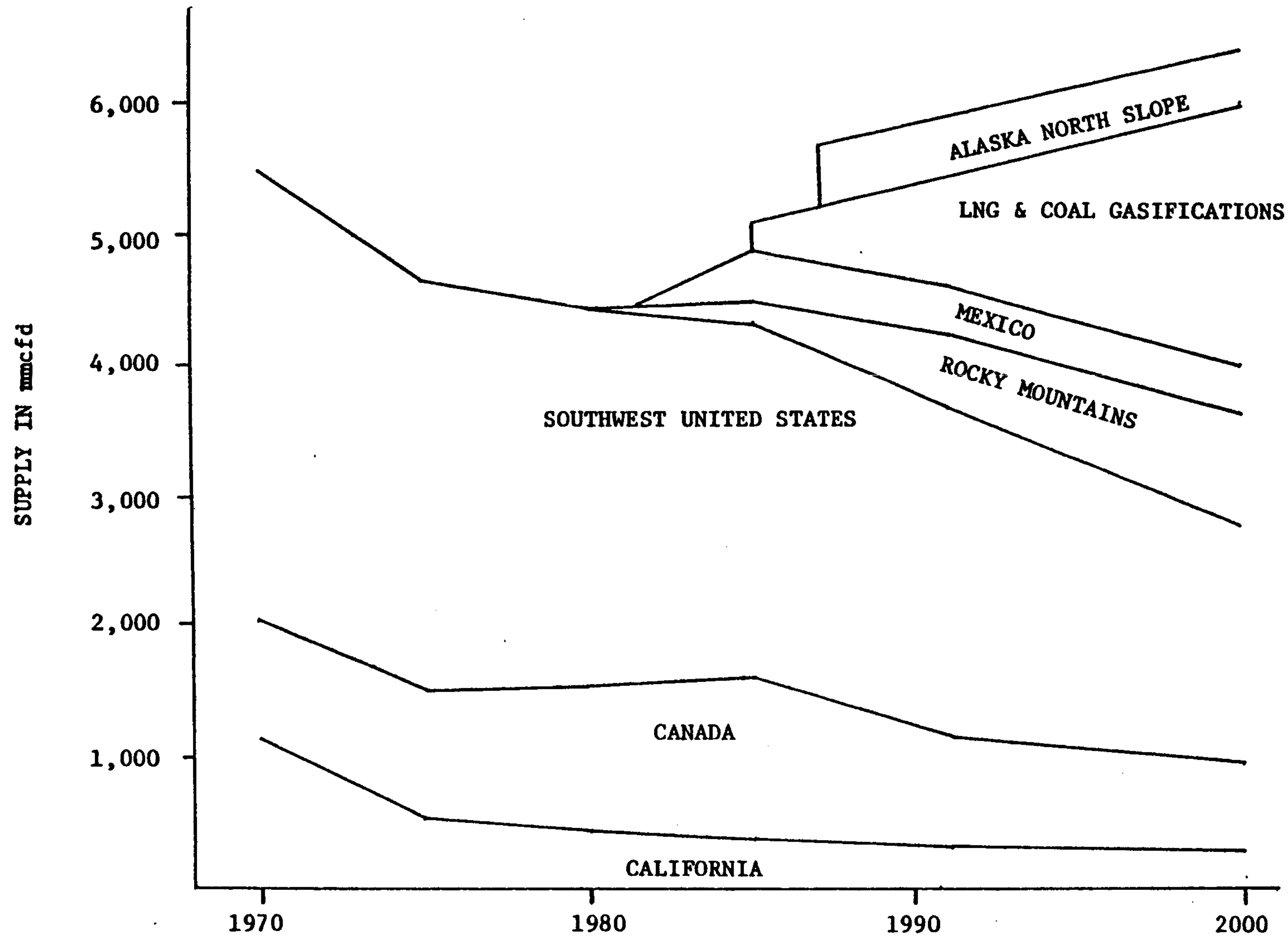
Demand is forecast by priority. P1-P4 priorities are considered firm demand. P5, gas burned in combined cycle gas turbines to make electricity, is considered lower priority and is supplied only after the P1-P4 demand is satisfied. Table F-23 shows the P1-P4 demand together with the CEC's low, mid and high supply cases. The low supply case is pessimistic about supplemental gas projects coming to fruition. If so, not all of the P1-P4 demand will be met. In the mid-case, P1-P4 demand is covered and decreasing amounts of gas are available to cover P5, electric power generation. Under PIFUA regulations (The Fuels Use Act) power plants are limited to the quantity of gas they can use between now and 1989. Because of the current surplus in natural gas, exceptions currently are being granted by the Federal government. Whether this policy will continue is uncertain. By 1990 power plants are not supposed to burn gas.

The supply and demand balance for the U.S. shown previously on Table F-20 indicated the surplus is about to disappear for the nation as a whole. The CEC assumed that in California gas would continue to be available for P5 demand and would be burned in California power plants until 1989. Then the Federal government may take the gas and reallocate it for distribution and sale outside of California ("Fuel Price . . .," p. 75).

If large supplies of supplemental LNG imports materialize in California the LNG may cause less conventional U.S. gas to move to California from the Southwest. This conventional gas will be reallocated for P1-P4 demand in the rest of the lower 48. In view of declining conventional gas production, there is almost an unlimited requirement for supplemental gas supplies--LNG from Norton Basin--at prices competitive with other alternatives.

FIGURE F-3

HISTORIC AND ESTIMATED FUTURE
NATURAL GAS SUPPLY TO CALIFORNIA, HIGH SUPPLY CASE



Source: CEC, "Fuel Price and Supply Projections: 1980-2000," November, 1979, p. 63.

TABLE F-23

CALIFORNIA NATURAL GAS

SUPPLY & DEMAND BALANCE
(MMCFD)

	P1-P4 Demand	Supply			Balance[1]		
		Low	Mid	High	Low	Mid	High
1980	3673	4051	4221	4483	378	548	810
1985	3814	3702	4302	5037	(112)	488	1223
1991	4071	3203	4485	5876	(841)	414	1799
2000	4502	2130	4630	6340	(2372)	128	1838

[1]Available to satisfy P5 demand for generating electricity.

Source: CEC, "Fuel Price and Supply Projections: 1980-2000," November 1979, p.74.

III.3.3 Relationship of Norton Basin Gas Resources to California Supply

Tables F-24, F-25 and F-26 show likely production scenarios for potential Norton Basin gas resources. These were estimated by Dames & Moore to coincide with USGS low find, medium find and high find resource estimates (Fisher et al., 1979). These production scenarios were developed for the Norton Basin petroleum development study Draft Report completed in October 1979, for BLM.

In the low case (Table F-24) production starts in 1990 at 21.0 BCF/year and peaks at 84.1 BCF/year 1993. In the medium find and high find cases, (Tables F-25 and F-26) production starts in 1989 at 21.0 or 26.3 BCF/year and peaks between 1992 and 1993 at 168.2 or 336.4 BCF/year.

If this Norton Basin gas is converted to LNG and shipped to California as incremental supply above the 328.5 BCF/year of Indonesian and Cook Inlet forecast by the CEC for 1991-2000 mid-supply case, then the Norton Basin LNG would cause less conventional U.S. gas to move to California from the Southwest. This conventional gas would then be available to off-set the U.S. supply gap shown on Table F-20 to range between 7.6 and 15.3 TCF/year by 1990.

While the amount of LNG from Norton Sound that could be expected to arrive in California is not large in comparison to the total U.S. gas supply deficit expected within the next ten years, it is large in comparison with other LNG projects under development in conjunction with the Point Conception LNG terminal. Norton Sound's medium find daily peak production rate - 460.8 MMCFD -- is about equal to the planned Pacific Alaska Cook Inlet project capacity of 400 MMCFD.

The low find peak production rate - 230.4 MMCFD - is about equal to the first phase of the Cook Inlet plant. The high find case would allow an LNG plant of nearly double the Cook Inlet plant capacity - nearly 691.2 MMCFD.

TABLE F-24 NORTON BASIN

LOW FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL NON-ASSOCIATED GAS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound 1200	Totals
1983	1		
1984	2		
1985	3		
1986	4		
1987	5		
1988	6		
1989	7		
1990	8	21.024	21.024
1991	9	42.048	42.048
1992	10	63.072	63.072
1993	11	84.096	84.096
1994	12	84.096	84.096
1995	13	84.096	84.096
1996	14	84.096	84.096
1997	15	84.096	84.096
1998	16	84.096	84.096
1999	17	84.096	84.096
2000	18	84.096	84.096
2001	19	84.096	84.096
2002	20	69.600	69.600
2003	21	54.680	54.680
2004	22	42.933	42.933
2005	23	33.710	33.710
2006	24	26.468	26.468
2007	25	20.782	20.782
2008	26	16.317	16.317
2009	27	12.812	12.812
2010	28	10.059	10.059
2011	29		
2012	30		
2013	31		
2014	32		
2015	33		
2016	34		

Peak Gas Production = 230.4 MMCFD.

Source: Dames & Moore
"Norton Basin Petroleum Development Scenarios OCS Lease Sale No. 57,"
Final Report, January, 1980, p. 178.

TABLE F-25 NORTON BASIN

MEDIUM FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL NON-ASSOCIATED GAS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound 1300	1000	Totals
1983	1			
1984	2			
1985	3			
1986	4			
1987	5			
1988	6			
1989	7	26.280		26.280
1990	8	63.072		63.072
1991	9	84.096	21.024	105.120
1992	10	84.096	42.048	126.144
1993	11	84.096	63.072	147.168
1994	12	84.096	84.096	168.192
1995	13	84.096	84.096	168.192
1996	14	84.096	84.096	168.192
1997	15	84.096	84.096	168.192
1998	16	84.096	84.096	168.192
1999	17	84.096	84.096	168.192
2000	18	84.096	84.096	168.192
2001	19	76.846	72.423	149.269
2002	20	61.980	54.122	116.102
2003	21	49.936	40.521	90.477
2004	22	40.265	30.710	70.575
2005	23	32.454	22.672	55.126
2006	24	26.157	16.958	43.115
2007	25	21.002	12.685	33.772
2008	26	16.992		16.992
2009	27	13.696		13.696
2010	28			
2011	29			
2012	30			
2013	31			
2014	32			
2015	33			
2016	34			

Peak Gas Production = 460.8 MMCFD.

Source: Dames & Moore
"Norton Basin Petroleum Development
Scenarios OCS Lease Sale No. 57,"
Final Report, January, 1980, p. 153.

TABLE F-26

HIGH FIND SCENARIO PRODUCTION BY YEAR FOR INDIVIDUAL FIELDS AND TOTAL - NON-ASSOCIATED GAS

Calendar Year	Year After Lease Sale	PRODUCTION IN BCF YEAR BY FIELD SIZE (BCF) Central Sound 1000	1000	1200	Totals
1983	1				-
1984	2				
1985	3				
1986	4				
1987	5				
1988	6				
1989	7	21.024			21.024
1990	8	42.048	21.024		63.072
1991	9	63.072	42.048		105.120
1992	10	84.096	63.072	21.024	168.192
1993	11	84.096	84.096	42.048	210.240
1994	12	84.096	84.096	63.072	231.264
1995	13	84.096	84.096	84.096	252.288
1996	14	84.096	84.096	84.096	252.288
1997	15	84.096	84.096	84.096	252.288
1998	16	84.096	84.096	84.096	252.288
1999	17	72.423	84.096	84.096	240.615
2000	18	54.122	72.423	84.096	210.641
2001	19	40.521	54.122	84.096	178,739
2002	20	30.310	40.521	84.096	154.927
2003	21	22.672	30.310	84.096	137.078
2004	22	16.958	22.672	69.600	109.23
2005	23	12.685	16.958	54.680	84.323
2006	24	9.788	12.685	42.933	65.106
2007	25	7.097	9.488	33.710	50.295
2008	26	5.309	7.097	26.468	38.874
2009	27		5.309	20.782	26.091
2010	28			16.317	16.317
2011	29			12.812	12.812
2012	30			10.059	10.059
2013	31			7.888	7.888
2014	32			6.193	6.193
2015	33			4.862	4.862
2016	34			3.817	3.817
2017	35				

Peak Gas Production = 691,200 mmcfd.

Source: Dames & Moore
"Norton Basin Petroleum Development
Scenarios OCS Lease Sale No. 57,"
Final Report, January, 1980, p. 126.

Some clarifications are required with respect to the American Gas Association's projections of potential supplemental gas supplies shown on Table F-21 for Alaska and LNG import categories. The LNG category relates exclusively to foreign LNG and does not include potential Alaskan LNG. The Alaska gas category can be disaggregated as follows:

TABLE F-27
Supplemental Alaskan Gas Supply Forecast

	Supply (TCF)			
Source	1985	1990	1995	2000
North Slope (Pipeline)	0.7	1.4	2.2	3.0
South Alaska (LNG)	0.1	0.2	0.3	0.6
Total	0.8	1.6	2.5	3.6

Source: American Gas Association, Telcon, January 1980.

The North Slope gas is assumed to be transported through the Alaska Highway Gas Pipeline. The 1985 production of 0.7 TCF represents about 2.0 BCFD average daily throughput of the gas pipeline. By the 1990s, however, new discoveries on the North Slope (e.g. NPR-A) and in the Beaufort Sea are assumed to have come on line and to augment Prudhoe Bay gas production. At this time twinning of the Alaska Highway gas pipeline or construction of a second pipeline would be required to move the quantities greater than those shown in Table F-27.

The AGA's South Alaska projections include some new onshore and offshore (OCS) discoveries (south of the Arctic Circle) coming into production in the 1990s in addition to existing Upper Cook Inlet production. Implicit in this projection is the assumption that the gas will be marketed to California as LNG. The South Alaska 1990 production of 0.2 TCF represents a daily average production of about 550 MMCFD of which 400 MMCFD can be accounted for by the Pacific Alaska Project. By the mid-1990s additional onshore and offshore discoveries will have boosted average daily production to about 820

MMCFD according to the AGA projections. For comparison with the AGA estimates, the production from our Norton Sound scenarios are summarized in Table F-28.

TABLE F-28

Norton Sound Production

	Production Year (TCF)			
Scenario	1985	1990	1995	2000
Low Find	-	0.02	0.08	0.08
Medium Find	-	0.06	0.17	0.17
High Find	-	0.06	0.25	0.21

Source: Dames & Moore

By comparing the AGA's annual production figures for South Alaska with our scenarios, it can be seen that even the Norton Sound low find scenario in 1995 is supplying a substantial portion of the additional gas production from South Alaska that is brought on line from 1990 to 1995. (The Pacific Alaska project's daily throughput of 400 MMCFD represents 0.14 TCF production annually).

There are two significant conclusions from this comparison:

1. The AGA's estimates of aggregrate South Alaska gas production in the 1990s are very conservative relative to our production scenarios derived from USGS estimates for a single Bering Sea Basin.

2. Assuming gas production from several Alaska OCS lease sale basins will come on line in the mid 1990s, then Alaska's contribution to the nation's supplemental gas supplies, notably LNG, landed on the U.S. West Coast could far exceed the AGA's projections.

III.4 Liquefied Natural Gas (LNG) From Alaska

III.4.1 Introduction

Natural gas from Alaska supplied to the lower 48 states will be high cost "supplemental" gas due both to its high cost of production and transportation. The development of Bering Sea gas from areas such as Norton Sound will present special and expensive engineering problems due to the harsh Arctic environment and remoteness from existing and planned transportation infrastructure including the Alaska Highway natural gas pipeline.

A brief review of U.S. base-load LNG projects followed by a description of Arctic LNG projects will lead-off this discussion about Alaskan LNG. These sections will provide the necessary technical and economic context to understand the problems of development of Bering Sea natural gas resources, in general, and Norton Sound in particular.

The production and transportation options for the disposition of Bering-Norton natural gas are then described. Using projections for other Arctic, sub-Arctic and lower 48 LNG projects, Section III.4.5 brackets the delivered costs of Bering-Norton LNG to the U.S. West Coast and the individual component costs, such as liquefication, transportation and regasification.

III.4.2 National LNG Projects

Recent articles in the _Oil and Gas Journal_ (December 18, 1978), _Pipeline and Gas Journal_ (June 1979) and the American Gas Association's "Gas Energy Review" (September 1979) have reviewed the status of LNG base-load projects in the U.S. These and other reviews point to the increasing importance of LNG base-load projects in U.S. natural gas supply and the significant increase of LNG in international trade in the 1970s. As shown in Table F-29 twelve base-load LNG projects are currently operational accounting for an international LNG trade of 4.382 billion CFD (124.1 million m^3 day).

TABLE F-29

INTERNATIONAL BASE-LOAD LNG PROJECTS CURRENTLY OPERATIONAL

Trade	Contract initial delivery	Contract term yr	Companies involved	Daily gas volume, million cf	Number of ships and country of construction	Capacity of ships, cu m	Estimated investment $ million Facilities	Tankers	Total
Algeria-United Kingdom (Arzew-Canvey Island)	1964	15	Camel, British Gas Corp., Conch Int'l	100	2, United Kingdom	27,400		28	
Algeria-France (Arzew-Le Havre)	1964	25	Camel, Gaz de France	50	1, France	25,500		15	
Total cost							205	43	248
Alaska-Japan (Kenai-Negishi)	1969	15	Phillips Petroleum Co., Marathon Oil Co., Tokyo Electric, Tokyo Gas	*135	2, Sweden	71,500	125	85	210
Lybia-Italy (Marsa el Brega-La Spezia)	1969	20	Esso Standard Libya, SNAM	235	3, Italy	40,000		78	
Lybia-Spain (Marsa el Brega-	1969	15	Esso Standard Lybia, Gas Natural	110	1, Spain	40,000		26	
Total cost							229	104	333
Brunei-Japan (Lumut-Sodegura) (Negishi, Semboku)	1972	20	Brunei LNG Coldgas Trading Osaka Gas, Tokyo Gas, Tokyo Electric Power	737	7, France	75,000	445	325	770
Algeria-France (Skikda-Fos s/Mer)	1972	25	Sonatrach, Gaz de France	350	2, France	40,000	190	60	250
Algeria-U.S. (Skikda-Everett)	1971	20	Sonatrach, Aloclean, Distrigas	115	1, France	1-129,500	†49	105	73
Algeria-Spain (Arzew-Barcelona)	1974	15	Sonatrach, Empresa Nacional de Gas	50	1, NA**	30,000	†30	NA**	NA**
Abu Dhabi-Japan (Das Island-Tokyo)	1977	20	Abu Dhabi Liquefaction Co., Tokyo Electric Power	450	3, Norway 1, Norway	125,000 87,600	¶450	650	1,100
Indonesia-Japan (North Sumatra, East Kalimantan-Japan)	1977	20	Pertamina, Osaka Gas, Kunsai Electric Power, Chibu Electric Power, Kyushu Electric Power, Nippon Steel	1,050	7, U.S.	125,000	‖1,365	735	2,100
Algeria-U.S. (Arzew-Cove Point, Savannah)	1978	20	Sonatrach, El Paso LNG Co. (Algerian subsidiary), Columbia LNG Corp., Consolidated System LNG Co., Southern Energy Co.	1,000	3, France 6, U.S.	125,000 125,000	1,320	765	2,085

*Plant capacity 186 MMcfd †Receiving only ‡Full delivery 1979. §Full delivery 150 MMcfd. ¶Liquefaction only. ‖Costs include export facilities for Pacific Lighting Intl. S.A., Table 2. **NA-not available.

Source: The Oil and Gas Journal, December 18, 1978.

Of this 1.115 BCFD are contracted for the United States. One of the projects involves the export of LNG from the United States to Japan (Kenai, Alaska to Negishi); this project is described below. Another five projects which are firm or under construction, will account for a further 2.406 BCFD (68.17 million m^3 day) of which 970 million will be delivered to the United States. A further twenty-five projects, which are in the planning stage or under consideration, would increase international LNG trade by about 20 BCFD (566 million m^3 day). Projections of supplemental LNG imports into the U.S. are estimated by AGA at 1.6 BCF/year in 1985 and 2.0 TCF/year in 1990 as previously shown on Table F-21.

At the beginning of 1980 there are three U.S. LNG import terminals in operation: Everett, Mass., Cove Point, Md., and Elba Island, Ga. In 1978, actual imports totalled about 84.4 BCF--significantly less than the 400 BCF/year anticipated when these three terminals are fully operational.

III.4.3 Arctic LNG Projects

Within North America, LNG base-load projects represent an alternative to lengthy pipeline systems to transport natural gas from remote areas of northern Canada and Alaska to lower 48 markets. No such projects to date have come on-line. The first Arctic sub-Arctic LNG project in North America involved export of Cook Inlet gas to Japan commencing in 1969 from Phillips' Nikiski liquification plant. Considerable research and planning was conducted for a LNG system to transport Prudhoe gas to the lower 48. This project, sponsored by El Paso, was one of the three contending projects, along with the Arctic gas consortium and Northwest Pipeline Company, to transport Prudhoe Bay gas to market. The El Paso project was abandoned after selection by the Federal Government of the Northwest Pipeline's Alaska Highway route. The last regulatory and judicial hurdle recently has been passed for the Pacific Alaska LNG project that will transport Cook Inlet gas to California. The Federal Energy Regulatory Commissin approved the project in September 1979 following the recommendation of Judge Gordon's August 1979 decision (Alaska Industry, October 1979). Construction on this project in Alaska and California is anticipated to commence in 1980 or early 1981.

Another project with relevance to the problems of producing Norton basin natural gas is the Arctic Pilot Project. Sponsored by Alberta Gas and Petro-Canada, this proposal involves shipping LNG from the Arctic Island to eastern Canada.

These projects are described in greater detail below and their relevance to the problems of producing Norton basin gas are discussed.

III.4.3.1 Phillips Nikiski LNG Project

Sponsored by Phillips Petroleum Co. and Marathon Oil Co. this project involves export of Cook Inlet gas to two Japanese utilities, Tokyo Gas Co. Ltd., and Tokyo Electric Power Co., under a 15 year sales contract signed in March 1967 (OGJ,December 18, 1978). The contract specified delivery of about 139 MMCFD or 50.74 BCF/year. Gas for the 186 MMCFD (peak) capacity liquefication at Nikiski is supplied from Phillips North Cook Inlet gas field (70%) and Marathon Kenai gas field (30%). Construction on the project commenced in late 1967 and was complete by the end of 1969; the first cargo of LNG was shipped from Nikiski on October 26, 1969. Two 71,500 cubicmeter capacity tankers, constructed in Sweden, transport the LNG to Tokyo; loading frequency at Nikiski averages 8 to 9 days. Total estimated investment in the project was $210 million of which $125 million was for facilities and $85 million for the two tankers. The project, which was constructed on schedule, has been highly successful; the liquefication plant has only required minor modifications to overcome operational problems and its on-stream factor is higher than originally estimated. The cost of the gas delivered (excluding regasification) at the Yokohama Terminal is currently $4.97/MMBTU (well head price is $0.794/MMBTU.)

The Phillips LNG project was constructed at a time when the market for Cook Inlet gas was limited even though proved reserves were estimated at 7 TCF as of December 31, 1975. (In 1975 ten of Cook Inlet area's fourteen gas fields were shut-in.) Small scale compared to existing international projects supplying LNG to the United States, the Phillips project has nevertheless demonstrated that the sub-Arctic gas resources in Alaska are technically feasible and economically viable under favorable conditions. Seventy percent of the gas for the LNG is supplied by the offshore North Cook Inlet gas field which has been developed with a single four-leg steel platform.

III.4.3.2 Pacific Alaska LNG Project

The Pacific Alaska LNG project is a two phase enterprise involving liquefication of Cook Inlet gas at Nikiski, Alaska, and transportation to southern California for regasification and distribution from a terminal located at Point Conception (Pacific Alaska LNG Co., et al. Docket No. CP75-140, October 12, 1979). Phase I calls for an average of 200 MMCFD while Phase II involves an additional 200 MMCFD. Phase I facilities will include one liquefaction train at the Nikiski plant and a 130,000 cubic meter capacity LNG tanker while Phase II will involve addition of a second liquefaction train and a second 130,000 cubic meter tanker. Construction in Cook Inlet would involve pipeline gathering networks on both sides of the Inlet and a submarine pipeline across the Inlet to transport gas from currently producing, shut-in and new discoveries to the plant at Nikiski.

In late 1979 the project participants (Pacific Gas and Electric Co., Pacific Alaska LNG Co., and Western LNG Terminal Co.) did not have under contract sufficient gas reserves in the Cook Inlet area to support Phase I of the project, much less Phase II. Recoverable reserves to Pacific Alaska totalled 777,433 MMCF from the Beluga River, Ivan River and Lewis River fields while an additional 198,789 MMCF recoverable reserves from the Beaver Creek and McArthur River fields are hoped to be obtained from renegotiated contracts. Only about half of the gas supply required to support Phase I of the project has been secured.

Pacific Alaska is a participant in on-going exploratory drilling program in the Cook Inlet area.) On-going exploration and the high potential for discovery of significant additional reserves, combined with the project participants favoured bargaining position with Cook Inlet independent producers, and the substantial volume of presently uncommitted proved reserves, makes the participants confident that sufficient gas supplies will be obtained to support both phases of the project.

Currently, construction of the Nikiski LNG plant, Cook Inlet pipeline network and field development is scheduled to start in 1981 with completion of Phase I anticipated by 1984/5.

In California, Pacific Alaska will share terminaling facilities with the Pacific Indonesia LNG project which involves import of gas from Indonesia into southern California. Preliminary site engineering is underway.

The Pacific Alaska project will provide important lessons and experience for development of discoveries on the Alaska OCS. However, in comparison with potential Bering-Norton gas resources, several important contrasts should be noted:

- The Pacific Alaska project is located in an area currently producing oil and gas and will draw a significant portion of its supply from currently producing fields. Much of the gas will be purchased from onshore fields which have significantly lower development costs than offshore fields.

- Considerable petroleum-related infrastructure (port facilities, oil-field supply services, etc.) already exists in the Cook Inlet area.

- Sea ice, though present in Upper Cook Inlet, is not a significant constraint on LNG transportation.

- Sea transportation distance from Upper Cook Inlet to southern California is somewhat shorter than that from Norton Sound and the tankers will not have to be designed with ice-breaking capabilities.

The projected costs of the Pacific Alaska project should therefore be somewhat less than an equivalent project located in the more remote and more severe environment of Norton Sound. However, the Pacific Alaska experience should provide a threshold for comparative cost estimates for Alaskan LNG projects.

III.4.3.3 Arctic Pilot Project

In June, 1979, Alberta Gas Trunk Line Company Limited (AGTL) and Petro-Canada presented a preliminary filing to the National Energy Board (NEB) of Canada as a first step in the regulatory process to obtain approval for their proposed Arctic Pilot Project. The Arctic Pilot Project is a small-scale pilot project intended to deliver High Arctic gas to markets on the east coast of Canada via LNG tankers.

With probable gas reserves of about 13 TCF proved to date in the High Canadian Arctic, the economic threshold to justify a pipeline to eastern Canada and the United States has not yet been reached although ultimate potential recoverable, reserves estimated at over 150 TCF in the High Canadian Arctic, indicate that such a pipeline will eventually be built. In the interim, to demonstrate the economic, technical and environmental feasibility of developing, producing and transporting Arctic natural gas, the Arctic Pilot Project will deliver 250 MMCFD of gas to eastern Canadian markets. The principal components of the project are (Gas Energy Review, March,1979; Milne, 1979).:

- Eight onshore directionally-drilled wells and related flowlines will provide 270 MMCFD/of gas to the LNG plant from the Drake Point gas field located on the Sabine Peninsula of Melville Island.

- A 160 kilometer (100 mile), 22 inch-diameter pipeline will take gas from the Drake Point field to the LNG plant located in Bridport Inlet.

- The LNG plant and terminal will be located on the shore of Bridport Inlet and will consist of a barge-mounted liquefaction plant and storage facility surrounded by rock-filled circular sheet metal cells about 20 meters (66 feet) in diameter. These circular sheet metal cells filled with crushed rock or gravel will also form the 450 meter (1,476 feet) long loading pier. Hot water effluent from the LNG plant will be utilized as an ice management system to minimize problems of berthing large vessels in thick ice. The liquifaction plant will be mounted on one barge while 200,000 cubic meters of storage will be provided on two additional barges mounted side by side. The rated output of the plant will be 275 MMCFD with a shrinkage factor of 9 percent and it will be designed to operate 345 days per year.

- The LNG will be transported to the eastern coast of Canada by two 170,000 cubic meter capacity ice breaking LNG tankers (Artcic Class 7 vessels). These vessels will have to contend with two meters of level ice, rubble ice fields, up to five ice ridges per mile, high winds and low temperatures. (Published descriptions of this project have not mentioned ice-breaker support requirements, if any.)

- Three sites have been identified as potential locations for the regasification terminal in eastern Canada: the St. Lawrence River downstream from Quebec City; the Strait of Canso, N.S., or Lorneville, N.B. This facility would include a terminal and unloading dock for the tankers, two 100,000 cubic meter (3.5 million cubic feet) storage tanks, and gas fired vaporizers to convert the LNG to gas for delivery at line pressure to a pipeline system.

No detailed cost of project and cost of service data is publically available for the Arctic Pilot Project. The June, 1979, filing with NEB did not include cost of service data although a second filing scheduled for January 1980 should include such information. Preliminary cost estimates for the Arcic Pilot Project facilities are presented in Section III.4.5.

The Arctic Pilot Project may well represent the prototype or model to develop remote Bering Sea gas resources that could not justify a major pipeline or pipeline interconnect. The use of barge mounted modular liquifaction facilities has been proposed for less harsh operating environments and barge-mounted process facilities (LPG) have been utilized successfully to develop fields in such areas as Indonesia. In the Arctic such facilities minimize on-site construction labor and reduce related costs, and reduce the logistical constraints of a narrow summer weather window for shipment of construction materials.

III.4.3.4 <u>El Paso Alaska LNG Project</u>

One of the three contending projects to transport Prudhoe Bay gas to the lower 48 states, the El Paso Alaska LNG project was abandoned by its promoters shortly after the president, on the recommendation of the FPC, selected the alaska Highway (Alcan) project in 1978. The project would have involved construction of a 42-inch diameter pipeline running 1,302 kilometers (809 miles) from Prudhoe Bay to Gravina Point on the ice-free coast of Prince William Sound near Cordova (Mead, Rogers and Smith, 1977). There the gas would be liquefied and shipped to southern California by a fleet of nine 165,000 cubic meter capacity LNG tankers. The LNG plant would have had a capacity of about 2.4 BCFD. The southern California terminal and regasification plant was tentatively planned to be located at Point Conception, a distance of about 3,540 kilometers (2,200 statute miles or 1,900 nautical miles) from Point Gravina.

The gas would then have been transported via pipeline to markets primarily in the western half of the United States, displacing gas from other fields in the southern tier of states which would be redirected to markets further east.

The advantages of the El Paso proposal over its competing projects were cited to be:

- The location would be totally within the United States thus would avoid any potential problems arising from Canadian national sovereignty, provincial conflicts, and native land claims;

- For about half the route the pipeline would parallel the trans-Alaska oil pipeline, utilizing the existing haul road and Alyeska access routes.

- Gas could be delivered to Fairbanks and other areas of eastern and central Alaska.

- The benefits from the employment generated would derive mainly to the U.S. labor market.

- The capital investments would for the most part be made within the United States.

The major disadvantages included:

- Expensive and potentially hazardous liquefaction, marine transportation and regasification of LNG.

- Location of the southern portion of the pipeline route and LNG plant in an area of high seismic activity;

- Delivery of gas in the southwest portion of the United states where it was least needed.

Estimated costs in 1975 of the El Paso Project were \$6.1 billion. (In 1980 dollars its cost can only be said to exceed \$12.0 billion.)

The El Paso proposal, which would have involved significant "scaling up" of existing technology, would have represented, if constructed, the largest LNG project in the World. In terms of the gas supply-demand picture in the western United States, the Californian supply situation described in Section III.3 would have been significantly different from those now projected with North Slope gas to be delivered primarily to mid-western markets via the Alcan pipeline. In turn, the marketability (and related transportation options) for Bering Sea gas would have been significantly different from that projected in this report.

III.4.4. Transportation Options for Bering Sea Natural Gas

This section will identify the key considerations and issues involved in selecting of the transportation system for moving Bering Sea gas to market.

The most viable alternatives to transport natural gas or its derivatives to lower 48 markets, ignoring more esoteric concepts such as LNG pipelines and 747 LNG airfreighters (!), are:

1. Overland pipeline, either new pipeline or shared use of an existing pipeline;

2. Marine mode, either;

(a) conversion to LNG and shipment in cryogenic tankers, or
(b) conversion of natural gas by chemical change to another product such as methanol (CH_3OH), Ammonia (NH_3) or Urea (NH_2CONH_3).

For Norton Sound natural gas, there are several marine mode options that relate to alternative strategies to overcome the constraints of sea ice.

III.4.4.1. Overland Pipeline

The first alternative for transportation of Norton Sound gas to lower 48 markets that would appear feasible in a superficial consideration of the problem would be construction of a spur pipeline to Fairbanks to link with the Alaska Highway (Alcan) gas pipeline.

While the final design capacity (and maximum potential capacity) of the Alcan pipeline have not been finalized, it is apparent that there will be significant limitations on the Alcan pipeline's capacity to transport non-North Slope gas. In the discussion of the "Tok Alternative" for the Pacific Alaska LNG project (i.e. to tranport Cook Inlet gas via pipeline to the Alcan line near Tok, Alaska) contained in Judge Gordon's decision finding in favor of the Pacific Alaska project, the Judge noted," "Further the general design and cost-sharing agreement in principle reached by the U.S. and Canadian governments with respect to the ANGTS does not contemplate substantial inputs to the system from South Alaska over and above those from Prudhoe Bay. [That] agreement is based on joint facilities in Canada having a base capacity of 2,400 MMCFD for Alaska gas and 1,200 MMCFD for Canadian gas with provision for increases in capacity. But in the event the total volume offered for shipment in Alaska exceeds the efficient capacity of the line, the method of assesing cost against Alaska shipments in excess of 2,400 MMCFD will be subject to review and further agreement by both governments." (Pacific Alaska LNG et al. Docket CP75-140, October 12, 1979 p. 97-98).

Overland transportation of Norton Sound gas to tie into the Alcan line is thus constrained by the agreement as well as by basic engineering economics. Investment in a spur line to the Alcan pipeline coupled with the allocation of costs for shipment in the Alcan line make it uncertain that there would be any cost savings compared with a LNG system. Any overland pipeline to Fairbanks from Norton Sound would involve expensive engineering through permafrost terrain ($5 to $10 million/mile?). Investment costs of a large diameter 483 kilometer (300 mile) long pipeline could easily equal or possibly exceed investment costs of a liquefication plant and LNG tanker fleet. It is unlikely that the Alcan line would have the surplus capacity, other problems aside, to accommodate the peak gas production of 691,200 MMCFD postulated in the high find scenario for Norton Sound. Even new North Slope and Beaufort Sea gas discoveries, which presumably would have first call on surplus Alcan capacity, may be delayed in their development since the gas production from Prudhoe will be "flat" for much of the project life (unlike the declining oil production) thereby postponing the availability of surplus capacity.

A gas pipeline from Norton Sound to an ice-free port on lower Cook Inlet, the Alaska Peninsula or Aleutian Islands, would not be an economic alternative to construction of ice breaking tankers and a LNG plant constructed even under more rigorous climatic and logistical constraints of Norton Sound.

III.4.4.2 Marine Transportation

Conversion to LNG and shipment in cryogenic tankers to the U.S. west cost is the most likely option for the delivery of Norton Sound gas. The principal constraints on this alternative are essentially the same as those on oil development -- sea ice constraints on tanker transportation, and sea ice and climatic constraints on the logistics and construction of onshore and offshore facilities. Since cryogenic tankers are generally constructed on a project specific or project dedicated basis, it is probable that Norton Sound tankers would be designed with ice breaking capabilities for the northern Bering Sea rather than as ice-reinforced ships necessitating ice breaker support. (There are more marine transportation options for Norton Sound crude oil due to the less rigorous requirements of transport and storage and the availability of a "pool" of tankers.)

Conversion of natural gas to methanol (CH_3OH)--a liquid at ordinary temperature and pressure which could be shipped in conventional tankers--has been considered as an option in several Arctic transportation studies (Global Marine Engineering Co., 1977; Acres Consulting, 1975). Although less hazardous and less expensive to transport than LNG, methanol has several significant disadvantages:(1) it takes a significant amount of energy to convert natural gas to methanol; (2) methanol is already partially oxidized and has less colorific value than natural gas; and (3) there are no present markets in the U.S. for additional methanol supplies.

Conversion of natural gas to petrochemical products or feedstocks such as ammonia (NH_3) or urea (NH_2CONH_2) has one readily apparent disadvantage: initial plant investment costs and subsequent operating and transportation costs would make Arctic Alaska products less competitive than other supplies on the national or world markets. Although an Ammonia/Urea plant has successfully operated in Cook Inlet since 1970 (and recently has been expanded to double capacity), the cost of Norton Sound petrochemical products would be higher because: (1) the costs of a Norton Sound plant would probably be significantly higher; and (2) the price of natural gas feedstock would be higher; (3) ice breaking capabilities or ice breaking support would be required by freighters.

III.4.5 Estimated Costs And Marketability of Alaskan LNG

This section briefly describes the principal capital cost components of a base-load LNG system and the components of the delivered cost of LNG. Using

Pacific Alaska LNG and other base load project cost estimates as a basis, possible costs of Norton Sound LNG are indicated. The delivered cost of Norton Sound LNG is also compared to conventional and other supplemental gas costs in order to place Alaskan costs in the overall context of the national natural gas price picture.

III.4.5.1 Pacific Alaska LNG Cost estimates

The projected costs of the Pacific Alaska LNG project, shown in Table F-30, provide a basis or threshold upon which costs for future LNG projects elsewhere in the state can be evaluated. In comparison with other base-load LNG projects, the Pacific Alaska project can be considered as small (Phase I) to medium (Phase II) with respect to delivery capacity. In the Alaskan context, the Pacific Alaska project is in the most favorable location with respect to both capital investment and operating costs. The liquefaction plant is located adjacent to the producing and shut-in gas fields and anticipated new discoveries which will supply the plant. Proven reserves (existing and shut-in fields) will supply between 25 and 50% of the project's gas requirements. Sea ice conditions are not severe enough to interfere with tanker shipments and impose a cost premium on facilities investment. Consequently, the cost experience of Pacific Alaska should reflect the lower end of anticipated investment costs for an LNG project elsewhere in Alaska of similar size.

Preliminary cost estimates for the Arctic Pilot Project, which would deliver about 250 MMCFD compared with Pacific Alaska's Phase I, 200 MMMCFD, indicate a total project cost of about $1.7 billion (1980). This figure includes $115 million for a delivery pipeline crossing Melville Island from the Drake Point gas field to the Bridport shipping terminal, 45 million for the terminal, $160 million for the 250 MMCFD capacity barge-mounted modular liquefaction plant, $115 million for 200,000 cubic meter floating storage facility and $70 million site preparation costs. The remainder of the costs comprise two ice-breaking LNG tankers and the eastern Canada regasification plant and terminal. The Arctic Pilot Project participants (Petro-Canada and AGTL) note

TABLE F-30

PACIFIC ALASKA LNG PROJECT

ESTIMATED FACILITIES AND TANKER COST

(Dollars in Millions, 1980)

Liquefaction Plant (Phase I 200 MMCFD)	709.1	
Liquefaction Plant (Phase II 200 MMCFD)	213.1	
Subtotal	922.2	
Cook Inlet Pipeline (Initial 200 MMCFD)	255.0	
(Next 200 MMCFD)	49.2	
Subtotal	304.2	
LNG Ships (2)	598.7	
Total Alaska Costs		1825.1
Point Conception Terminal and Regasification Plant* (900 MMCFD)		940.0

*Terminal and Regasification facilities to be shared with Pacific Indonesia Project.

Source: Pacific Alaska LNG Co., 1978. The original cost estimates are inflated from 1977 dollars to 1980 dollars with a 15 percent inflation rate. The original estimates are being revised and new figures are scheduled to be released in mid-1980.)

that total investment cost of $460 million for the installed LNG Plant is only $70 million more than a comparable plant in southern Canada due to the use of barge-mounted facilities.

The project costs of the Arctic Pilot Project appear lower than the Pacific Alaska LNG project although the former is located in the high Arctic. The costs of these two projects, however, may not be strictly comparable because the projects are not in comparable stages of planning and development.

The delivered cost of Pacific Alaska gas ($/MMBTU) and its sister project, Pacific Indonesia, and their components are shown in Table F-31. According to southern California Gas Co., Cook Inlet LNG will lay into California at $4.60 MMBTU ($4.46 MCF). These Pacific Alaska cost estimates probably can be regarded as the threshold in an assessment of the possible costs of LNG from the more remote locations and harsher environments of the Bering Sea OCS.

III.4.5.2 Estimated Cost of Norton Sound LNG Delivered To California

To estimate the costs of LNG facilities, transportation and operating costs and the delivered cost of gas from a Norton Sound LNG project is extremely difficult since so many cost factors are site specific or project specific. Our economic analyses of Norton Sound gas fields have been concerned with field development economics and the relationships among price allowed for new gas under NGPA, development costs, and geologic and location specific attributes. Our analyses have, therefore, identified the estimated cost of gas per MCF under a variety of reservoir conditions and engineering options. These costs would be the minimum cost of feedstock gas to a LNG plant.[1]

Without doing an analysis of LNG economics for hypothetical Norton Sound projects, it is possible to indicate contrasts between possible facilities

[1]Appendix A discusses the equivalent amortized costs of gas development in the Norton Sound.

TABLE F-31

ESTIMATES OF COST OF GAS DELIVERED PER MMBTU
PACIFIC ALASKA AND PACIFIC INDONESIA LNG PROJECTS

	1980 Dollars		
	Pacific Indonesia	Pacific Alaska	Combined
Purchased LNG or Feedstock	$1.84	$1.74	$1.81
Pac Indo Capital Tax	.02		
Liquefaction	-	1.88	.78
Transportation	1.59	.89	1.30
Landed Cost	3.95	4.51	3.89
Terminalling	.90	.09	.55
Landed and Regasified Cost of Gas	.35	4.60	4.44
Pipeline Transportation to Gosford	.09	-	.05
Delivered Cost	$4.44	$4.60	$4.49

Source: Southern California Gas Company

$1978 dollar estimates inflated to 1980 dollars at 15 percent annually.

and transportation costs of hypothetical Norton Basin project and the estimated Cook Inlet project costs shown on Tables F-30 and F-31 assuming similar quality of gas and throughputs. (For comparative purposes, it can be noted that the Norton Basin low find gas scenario with 1.2 TCF gas reserves supporting gas production of 230.4 MMCFD is roughly comparable with Pacific Alaska Phase I while the medium find scenario, 2.3 TCF reserves and 460.8 MMCFD, is roughly comparable to Pacific Alaska Phase II.) Our estimates of Norton Basin gas costs are indicated on Table F-32.

In constant 1980 dollars, our economic analysis bracketed \$2.40-\$2.90 for MMBTU[1] as the development cost of a medium sized gas field in the Norton Sound. This compares with the (\$1.74/MMBTU) price of Pacific Alaska's feedstock. If the Norton gas fields were located far from shore and/or reservoir characteristics were less favorable than assumed or a greater return on investment were require, the estimated minimum costs would be higher. Clearly, OCS gas feedstock for a Norton Sound LNG plant will cost more than Cook Inlet gas. We have indicated a midrange cost for feed stock gas of \$2.65/ MMBTU on Table F-32.

The remoteness and climatic constraints on construction in Norton Sound would undoubtedly place a cost premium on the LNG plant and terminal over the cost of the same facility in Cook Inlet. Barged-in, modular facilities, which would minimize on-site construction, could probably reduce the cost differential. Preliminary cost figures for the Arctic Pilot Project suggest that an Arctic LNG terminal may cost only 25% more than a comparable plant in a "southern" location. We have assumed that the higher LNG plant investment would translate to an additional \$0.50 MMBTU in liquification costs in a Norton Sound LNG plant over the projected Pacific Alaska plant (Table F-32).

Three principal factors will make transportation costs (expressed in dollar/ million BTU delivered) more expensive from Norton Sound than Cook Inlet: (1)

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[1]1979 costs in Appendix A inflated 15 percent to 1980 dollars and converted to MMBTU.

TABLE F-32

ESTIMATED COST OF NORTON BASIN GAS PER
MMBTU DELIVERED TO SOUTHERN CALIFORNIA TERMINAL

	1980 Dollars
Feedstock	2.65
Liquification	2.38
Transportation	1.39
Landed Cost	6.42
Terminalling	0.9
Land and Regasified Cost of Gas	6.51
Delivered Cost	6.51

Note: See Table F-31 for comparison with Pacific Alaska LNG Project costs.

Source: Dames & Moore estimate (see text) specially constructed, ice-breaking tankers will be required; (2) the shipping distance from Norton Sound to southern California is somewhat longer from Norton Sound, and (3) the roundtrip from Norton Sound will be further lengthened in winter because of speed reductions in areas of sea ice. We have assumed that shipping costs add only $0.50 MMBTU to the cost of Norton Sound LNG for a total transportation cost of $1.39 (Table F-32).

Revaporization and terminalling costs in the lower 48 should be comparable with Pacific Alaska's estimates. However, it should be noted that Pacific Alaska will be sharing terminalling and regasification facilities with the Pacific Indonesia project which will reduce the cost to both projects to some extent. To be conservative, however, we assume a no change to Pacific Alaska's cost in Table F-32.

Summing these changes to Pacific Alaska's cost estimates (shown on Table F-31), it would not be unreasonable to speculate that the delivered cost of Norton Sound gas to southern California in 1980 constant dollars could be in the range of $6.25 to $6.75 per MMBTU ($6.45-$7.00 MCF) with a midrange cost of $6.51 as shown on Table F-32.

III.4.5.3 Cost Of Foreign Gas And Other Supplemental Gas Supplies

The marketability of Bering Sea natural gas delivered to the West Coast as LNG has to be considered in context with the price of competing Mexican and Canadian gas, imported LNG and other "supplemental" sources.

In comparison to Norton Basin gas, estimates of the unit cost of Prudhoe Bay natural gas delivered range from $7.00 to $8.00/MCF according to knowledgable banking sources. The current export price of Canadian gas is $4.47/MCF, recently increased from $3.45/MCF. Mexican gas, as a result of recent negotiations, will be sold at the border for $3.625/MCF, while the highest price delivered under current contracts for imported LNG is $3.64/MMBTU for delivery in 1984 (Oil and Gas Journal, December 3, 1979). Under the

Natural Gas Policy Act of 1978 (NGPA) the price of "new" gas in 1980 will be $2.358/MMBTU, rising to $3.67/MMBTU in 1984, the year before this category is deregulated.

Norton costs LNG also can be compared with estimated costs of other supplemental supplies that have recently been presented in a preliminary report by the National Petroleum Council. As cited in the Oil and Gas Journal (December 24, 1979), potential additions as a function of cost to the nation's gas reserves to the year 2000, assuming a 10% rate of return and current technology, are estimated as follows:

- Devonian shale - 7 TCF at $2.50/MCF, 20 TCF at $5 MCF, and 27 TCF at $9/MCF. The projections do not include cost of compression estimated to add 50-70 cent/MCF.

- Coal seams - 5 TCF at $2.50/MCF, 25 TCF at $5/MCF, and 45 TCF at $9/MCF. Cost of compression, scrubbing, or connection to a gas transmission line is estimated to add between 60 cents and $2/MCF.

- Geopressured brines - Zero at $2.50/MCF, 100 BCF at $5/MCF, and 570 BCF at $9/MCF. These projections include cost of compression to 800 psi, which adds 5% to total capital and consumes 1% of produced gas.

- Tight Gas reservoirs - Estimates have been calculated for seven of 10 potential basins with only 25% of potential reserves expected to be developed by 2000. Result is 15 TCF at $2.50/MCF, 20 TCF at $5/MCF, and 25 TCF at $9/MCF. These include the fuel cost of compression but not gathering systems costs, investment costs of compressor stations or other operating costs.

These are potential total reserves and not annual supply additions. They can be compared to the 150 TCF estimate of 1990 conventional gas reserves. The total of all these potential supplemental additions to the nation's gas reserves at $5.00/MCF equals 65.1 TCF. This could yield production in the range of 5 TCF/year.

III.4.5.4 Marketability Of Norton Sound LNG

According to the supply gap indicated by the supply and demand forecasts discussed in Section III.2.3, the U.S. will need all of the natural gas it can find or buy. There has been great reluctance by decision makers to endorse projects or sales agreements that speed expensive gas to the U.S. market. The Alaska gas pipeline project is a prime example. The most recent authorization of the Alaska-California LNG project apparently represents the most expensive gas now destined to the U.S. market. At $4.60 MMBTU this LNG is priced below parity with No. 2 diesel fuel oil which costs approximately $6.00 MMBTU.

Strictly speaking Norton Sound LNG laying into California between $6.45-7.00 MCF does not appear economic-today. As oil prices continue to go up and conventional gas supplies continue to go down, however, Norton Basin LNG appears to be a good candidate to become economic very soon.

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EQUIVALENT AMORTIZED COST
MODEL DESCRIPTION

AND

NORTON SOUND
EAC CALCULATIONS

EAC MODEL DESCRIPTION

1.0 THE BASIS FOR CALCULATION OF EQUIVALENT AMORTIZED COSTS

1.1 Analytical Asumptions Within GUESS Determine Cost Flows To The EAC Model

The Equivalent Amortized cost model has been designed to calculate the cost per barrel or MCF of developing a petroleum field. The model has been used in conjunction with studies commissioned by the Alaskan OCS office of BLM under the socioeconomic studies program. As such the model has been used to estimate the per barrel (MCF) costs of developing oil or gas fields in the Alaskan OCS.

The inputs to the EAC Model are output cash flows developed within the Dames & Moore economic evaluation model run on the General Uncertainty Simulation System (GUESS) softwear package of Scientific Softwear Corporation. This model is used to evaluate the economics of developing an oil or gas field in a given Alaskan OCS lease sale area.

The evaluation process identifies likely production technologies suitable for a given lease sale area and the likely geologic characteristics that will influence oil or gas production characteristics. These determinants of production cost flows and revenue flows are estimated by Dames & Moore and become inputs to the economic model on GUESS. GUESS then calculates cash flows that realistically reflect the engineering, environmental, geologic and locational characteristics of developing oil or gas in the Alaskan OCS.

The cost flows over the production life of the field become the inputs of the EAC Model. Hence, the calculated equivalent amortized costs per barrel (MCF) reflect not only estimated costs of technology; they also reflect geologic assumptions that determine production flows and price assumptions upon which taxes are based. Since the EAC Model calculates amortized costs over time, locational and other considerations which determine the timing of production and cash flows are equally important determinants of the calculated equivalent amortized costs.

Clearly, per barrel (MCF) amortized development costs are sensitive to all of the estimated and assumed values that govern the cash flows generated by GUESS.

1.2 The Calculation Of Equivalent Amortized Costs Per Barrel (MCF) Of Production

Cost flows from GUESS are converted within the EAC Model to generate costs according to these categories:

1) Capital Investment Cost
2) Development Operating Costs
3) General and Administrative Expenses
4) Royalty
5) Federal Taxes Net of All Tax Credits
6) Total Costs: The Sum of The Above

As a separate step, the model calculates the capital earnings, which is a component part of capital investment and represents the opportunity cost of capital.

The EAC calculation involves three steps. For simplicity, inflation is ignored in this example.

1. The present value of cost are calculated as:

$$\text{PV Cost} = \sum_{t=1}^{T} \sum_{i=1}^{5} (C_{it}) e^{-rt} \qquad (1)$$

Where:

C_{it} = The cost streams for the five cost items shown above and taxes are net of depreciation tax credits and other tax credits.

e^{-rt} = Continuous discounting factor at value of money, r.

2. The present barrel equivalent of the production of oil is calculated as the present value of the oil discounted at r, the same rate employed to calculate the present value of costs.

$$P\,B\,E = \sum_{t=1}^{T} (Q_t) e^{-rt} \tag{2}$$

Where:

$P\,B\,E$ = Present barrel equivalent

Q_t = annual oil production in year t

e^{-rt} = continuous discounting factor at

The present barrel equivalent of production is clearly different from either average annual production or peak annual production and reflects the timing of the production flows.

3. The equivalent amortized cost (E A C) per barrel is equal to the present value of annual costs divided by present barrel equivalent.

$$E\,A\,C = \sum_{i=t}^{5} \frac{\sum_{t=1}^{T} (C_{it}) e^{-rt}}{\sum_{t=1}^{T} (Q_t) e^{-rt}} \tag{3}$$

Capital earnings, or the opportunity cost of capital, is calculated as a separate step. The capital earnings calculation assumes that returns can be re-invested to earn the opportunity cost of capital and is calculated as:

$$\sum_{t=1}^{T} [r\ [TANG_t(1\text{-}ITC(tax)) + INTANG_t(1\text{-}tax)] - D_t(tax)]\ e^{-rt} \tag{4}$$

Where: $Tang_t$ = Tangible Investments in year t

ITC = Investment tax credits

tax = Federal tax rate

$INTANG_t$ = Intangible investments in year t.

D_t = Depreciation in year t

e^{-rt} = Continuous discounting factor at value of money, r

T = Production life of project.

2.0 How The EAC Computer Model Works

2.1 Link To Guess

The analytical approach described above has been programmed into a computer model. This model is driven by a higher level economic evaluation model run on the General Uncertainty Economic Simulation System (GUESS). The GUESS program has been developed by Scientific Software Corporation of Denver, Colorado to serve as a flexible economic evaluation system. GUESS is a Fortran program which executes individual models from among its library of component models through a mini-compiler approach. Each time the Dames and Moore version of GUESS is run, the EAC model executes and prints out the EAC results along with other results of the economic evaluation model.

The various input parameters to the EAC model are described in detail in the input section which follows. Most of these inputs relate to the generation of a standard cash flow analysis which is generated within the economic evaluation model of GUESS. Outputs of this model become inputs to the EAC model. The accompanying manual explains the GUESS system and all the variables within the basic economic model.

2.2 Inputs From GUESS To EAC Model

The Equivalent Amortized Cost variables are calculated directly from the annual cash flow output of the GUESS model. The standard cash flow input variables to the EAC Model are shown below:

VARIABLE NAME	DESCRIPTION
INVTAN	Tangible Investment
ITXCR	Tax Credit Rate
FITRAT	Federal Income Tax Rate
INVINT	Intangible Investment
DEPR	Depreciation
DISC2	Discount Rate Including Real Value of Money and Inflation, If Assumed
DISC3	Real Value of Money
OPCOST	Operating Cost
ROYALT	Royalty Cost
FIT	Federal Income Tax Net of Tax Credits
GANDA	General and Administrative Expense
PRO	Oil or Gas Production
CAPITB	Total Investment

NOTE: DISC2 = DISC3 with inflation assumed away.

2.3 Model Solution

The following is a mathematical discussion of the EAC model. The model listing is shown at the end of this section. The model is set-up to allow for inflation although the example is an uniflated case.

The first step in the model involves calculating the undiscounted, incremental after tax captial investments as shown in equation (5).

$$KRET1_t = [(INVTAN_t)\ (1-(ITXCR)\ (FITRAT))] + INVINT_t (1-FITRAT) \tag{5}$$

where $KRET1_t$ = Undiscounted, Incremental capital investment net of tax credit; other variables as defined above.

The cumulative after tax capital investment is then equal to:

$$KRET2_t = \sum_{t=1}^{t_n} (KRET1_t) \qquad (6)$$

where: $KRET2_t$ = Running total of after tax investment; other variables as defined above.

The cumulative total of KRET2 is printed on The Single Valued Results Table.

The next step is to calculate the incremental, discounted capital cost. The effective capital cost at time = t must first be discounted back to the middle of time period t, since the discount rate is entered as a nominal rate. Equation (7) adjusts the value of the after tax capital investment so that its cost calculated in equation (8) is the correct value.

$$KRET_t = (KRET1_t) \quad [(e^{1/2\ DISC2_t} - 1)/(1/2\ DISC2_t\ (e^{1/2\ DISC2_t}))] \qquad (7)$$

Then, the present value of the "t^{th}" incremental, discounted capital earnings on $KRET_t$ net of depreciation tax credits is calculated in one step:

$$CIT1_t = [((DISC3_t\ )\ (KRET2_t)) - DEPR_t(FITRAT)]\ (e^{-DISC2_t})^{t-1/2} \qquad (8)$$

The first composite term within the brackets of equation (8) is the annual captial charge in year t. The second term is the depreciation tax credit in year t. The third term discounts the "t^{th}" incremental charge back to the base time period.

The cumulative, discounted, after tax capital earnings is:

$$COST1 = \sum_{t=1}^{T} CIT1_t \qquad (9)$$

Finally, the capital earnings per barrel or MCF is:

$$CIT1 = \frac{COST1}{PBE} \qquad (10)$$

CIT1 is equal to the capital earnings per barrel (MCF) on net after tax capital investment exclusive of capital recovery. This is contained within the total capital charge on total invested capital calculated in the following section. CIT1 is calculated and printd in the Table of Single Valued Results.

Next, the present value of the following component cost flows are calculated to give the equivalent amortized component costs associated with the project:

COST2	=	Operating Cost	(OPCOST)
COST3	=	Royalty	(ROYALT)
COST4	=	Federal Income Tax	(FIT)
COST5	=	General and Administrative Expenses	(GANDA)
COST6	=	Capital Investment	(CAPITB)

This is done in a manner almost identical to the calculations performed in equations (7), (8) and (9) for the cumulative, discounted, after tax capital investment cost.

The present value of oil production is carried in the model as PBE. PBE is calculated in the same manner as the cost flows, except it is discounted with DISC3, the real value of money since physical production has no inflation.

The following equations, illustrated for operating costs, are calculated by the EAC Model to arrive at the component and total EAC per barrel (MCF) for each cost item.

Equation (11) adjusts the nominal discount rate to the effective discount rate for mid-period discounting.

$$OPCOST_t = (OPCOST2_t) \ [((e^{1/2\ DISC2_t} - 1)/(1/2\ DISC2_t\ (e^{1/2\ DISC2_t}))] \qquad (11)$$

Equation (12) calculates the present value of each annual cash flow, using the effective discount rate.

$$CIT2_t = (OPCOST_t) \quad (e^{-DISC2_t})^{t-1/2} \qquad (12)$$

Equation (13) sums the discounted value of annual cash flows to arrive at the present value of the cost stream, operating costs in this example.

$$COST2 = \sum_{t=1}^{T} CIT2_t \qquad (13)$$

Equation (14) divides the present value of the cost stream by the present barrel equivalent of oil yields the component EAC of the cost stream.

$$CIT2 = \frac{COST2}{PBE} \qquad (14)$$

This is printed in a table of Single Valued Results. The total equivalent Amortized Cost per barrel is equal to the sum of the component EAC costs.

$$\sum_{i=2}^{5,7} (CIT_i) \tag{15}$$

(CIT6 is used in conjunction with PBE.)

The following computer printout is a complete listing of the EAC Model. The model statements are executed sequentially, and one pass is made through the entire model for each time step. Since the calculated costs are running totals, the model seeks out the values associated with the final production year or the end of the project, whichever comes first. Only these final values are the correct results. The final values are printed in a table of

Single Valued Results in the GUESS format.

Following the listing is an example printout showing the inputs to GUESS, the cash flows generated and the Single Valued Results Table.

A major strength of the GUESS softwear is its capabilities with sensitivity testing and Monte Carlo. Neither of these options was executed in this example. EAC is programmed to calculate only mid-point values and does not have the capability to generate explicit sensitivities or Monte Carlo values. Additional programming could provide this capability.

The example shown is the two platform case shown on Table A-13 of Appendix A.

The run description is a listing of inputs to GUESS. This is a two platform case. Production (GROIL) starts in year 5 (PRODYR) at 19.2 MB/D; steps up to 153.6 MB/D and produces flat until 45 percent (DCLSW) of recoverable reserves

(OILRSV) of 500 million barrels are produced. Then the production stream starts to decline exponentially (DCLINE) at 17.1 percent annually (DCLNPCT) until economic limit (QTO) of 12,176 B/D is reached. Oil is priced at $18.00 BBL (OILP). Tangible (INVTAN) and intangible (INBVINT) investments begin in year 1 (BASEYR) at $37.45 million and step up over seven years. General and administrative expenses (GANDA) begin in year 1 at $10.0 million annually; operating costs begin in year 5 at $70.0 million annually. Royalty rate (ROYRAT) is specified at 16.67 percent and taxes (FITRAT) at 46 percent. Investment tax credit (ITXCR) on tangible investments is specified at 10 percent. Other variables such as discount rates are assumed at certain values by GUESS unless changed and are automatically entered.

The next six tables shown are production and cash flows calculated by GUESS. The box on the last table contains the solution values of both the EAC model in the top eight lines and the basic economic model.

```
CMNT
CMNT ************************************************************************
CMNT *                                                                      *
CMNT *     THIS SECTION CALCULATES 'EQUIVALENT AMORTIZED COST'              *
CMNT *                                                                      *
CMNT *    NOTE:  EAC MODEL REQUIRES THREE TYPES OF DISCOUNT FACTORS         *
CMNT *           THESE ARE :   (1) REAL VAULE OF MONEY (DISC3)              *
CMNT *                         (2) INFLATION RATE (DISC4)                   *
CMNT *                         (3) COMPOSIT RATE (DISC2)                    *
CMNT ************************************************************************
CMNT
MODL              IF (GUNITS.GT.0) PRD = GRGAS                              ;
MODL              IF (OUNITS.GT.0) PRD = GROIL                              ;
MODL              KRET1      =          (INVTAN*(1-(ITXCR*FITRAT))+
MODL                         INVINT*(1-FITRAT))                             ;
MODL              CALL RUNTOT (KRET2,KRET1)                                 ;
MODL              KRET       =  (DISC3*KRET2)  -  (DEPR*FITRAT)             ;
MODL              CALL PRWRTH (DIATX,DISC2,KRET,MIDYR)                      ;
MODL              CIT1       = DIATX                                        ;
MODL              CALL PRWRTH (CIT2,DISC2,OPCOST,MIDYR)                     ;
MODL              CALL PRWRTH (CIT3,DISC2,ROYALT,MIDYR)                     ;
MODL              CALL PRWRTH (CIT4,DISC2,FIT    ,MIDYR)                    ;
MODL              CALL PRWRTH (CIT5,DISC2,GANDA  ,MIDYR)                    ;
MODL              CALL PRWRTH (CIT6,DISC3,PRD    ,MIDYR)                    ;
MODL              CALL PRWRTH (CIT7,DISC2,CAPITB,MIDYR)                     ;
MODL              CALL RUNTOT (COST1,CIT1)                                  ;
MODL              CALL RUNTOT (COST2,CIT2)                                  ;
MODL              CALL RUNTOT (COST3,CIT3)                                  ;
MODL              CALL RUNTOT (COST4,CIT4)                                  ;
MODL              CALL RUNTOT (COST5,CIT5)                                  ;
MODL              CALL RUNTOT (COST6,CIT7)                                  ;
MODL              CALL RUNTOT (PBE,CIT6)                                    ;
MODL              IF (PBE.EQ.0) GO TO 88                                    ;
MODL              CIT1       = COST1/PBE                                    ;
MODL              CIT2       = COST2/PBE                                    ;
MODL              CIT3       = COST3/PBE                                    ;
MODL              CIT4       = COST4/PBE                                    ;
MODL              CIT5       = COST5/PBE                                    ;
MODL              CIT7       = COST6/PBE                                    ;
MODL  L(88)       IF (PBE.EQ.0) CIT1 = 0                                    ;
MODL              IF (PBE.EQ.0) CIT2 = 0                                    ;
MODL              IF (PBE.EQ.0) CIT3 = 0                                    ;
MODL              IF (PBE.EQ.0) CIT4 = 0                                    ;
MODL              IF (PBE.EQ.0) CIT5 = 0                                    ;
MODL              IF (PBE.EQ.0) CIT7 = 0                                    ;
MODL              EAC        = CIT2 + CIT3 + CIT4 + CIT5 + CIT7             ;
MODL              CALL GETVAL (GROIL,IROW+1,TEST,0)                         ;
MODL              IF (YR.GT.9.AND.TEST.EQ.0) A1 = EAC                       ;
MODL              IF (YR.GT.9.AND.TEST.EQ.0) A2 = CIT1                      ;
MODL              IF (YR.GT.9.AND.TEST.EQ.0) A3 = CIT2                      ;
MODL              IF (YR.GT.9.AND.TEST.EQ.0) A4 = CIT3                      ;
MODL              IF (YR.GT.9.AND.TEST.EQ.0) A5 = CIT4                      ;
MODL              IF (YR.GT.9.AND.TEST.EQ.0) A6 = CIT5                      ;
MODL              IF (YR.GT.9.AND.TEST.EQ.0) A7 = CIT7                      ;
MODL              IF (YR+1.EQ.MAXYR.AND.A1.EQ.0) EAC1 = EAC                 ;
MODL              IF (YR+1.EQ.MAXYR.AND.A2.EQ.0) EAC2 = CIT1                ;
MODL              IF (YR+1.EQ.MAXYR.AND.A3.EQ.0) EAC3 = CIT2                ;
MODL              IF (YR+1.EQ.MAXYR.AND.A4.EQ.0) EAC4 = CIT3                ;
MODL              IF (YR+1.EQ.MAXYR.AND.A5.EQ.0) EAC5 = CIT4                ;
MODL              IF (YR+1.EQ.MAXYR.AND.A6.EQ.0) EAC6 = CIT5                ;
MODL              IF (YR+1.EQ.MAXYR.AND.A7.EQ.0) EAC7 = CIT7                ;
MODL              IF (YR+1.EQ.MAXYR.AND.A1.GT.0) EAC1 = A1                  ;
MODL              IF (YR+1.EQ.MAXYR.AND.A2.GT.0) EAC2 = A2                  ;
MODL              IF (YR+1.EQ.MAXYR.AND.A3.GT.0) EAC3 = A3                  ;
MODL              IF (YR+1.EQ.MAXYR.AND.A4.GT.0) EAC4 = A4                  ;
MODL              IF (YR+1.EQ.MAXYR.AND.A5.GT.0) EAC5 = A5                  ;
MODL              IF (YR+1.EQ.MAXYR.AND.A6.GT.0) EAC6 = A6                  ;
MODL              IF (YR+1.EQ.MAXYR.AND.A7.GT.0) EAC7 = A7                  ;
CMNT
MODL  L(89)       END ;
*RTY*
```

```
                                   RUN DESCRIPTION
                                   ***************

     DEMONSTRATION RUN: TWO PLATFORM CASE
  .0012001                      LISTING OF INPUT DECK
                                ---------------------

 END
 DATA     30
 TITL DEMONSTRATION RUN: TWO PLATFORM CASE
 LEAS            DEMO
 PROB  C         BASEYR          1
 PROB  C         PRODYR          5
 PROB  C         OUNITS          1
 TABL      1     GROIL           0          0          0          0      19200
 TABL      2     GROIL       67200     124600     153600     153600     153600
 TABL      3     GROIL      153600     153600     153600     153600     153600
 TABL      4     GROIL      153600     153600          0          0          0
 TABL      5     GROIL           0          0          0          0          0
 TABL      6     GROIL           0          0          0          0          0
 PROB  C         DCLINE          1
 PROB  C         DCLSW        0.45
 PROB  C         DCLPCT      0.171
 PROB  C         OILRSV     500000
 PROB  C         QTO         12176
 PROB  C         OILP           18
 TABL      1     INVTAN      37450     114650     201200     167200      76900
 TABL      2     INVTAN      65700      33300          0          0          0
 TABL      3     INVTAN          0          0          0          0          0
 TABL      4     INVTAN          0          0          0          0          0
 TABL      5     INVTAN          0          0          0          0          0
 TABL      6     INVTAN          0          0          0          0          0
 TABL      1     INVINT      37450     114650     201200     167200      76900
 TABL      2     INVINT      65700      33300          0          0          0
 TABL      3     INVINT          0          0          0          0          0
 TABL      4     INVINT          0          0          0          0          0
 TABL      5     INVINT          0          0          0          0          0
 TABL      6     INVINT          0          0          0          0          0
 PROB  C         GANDA       10000
 PROB  C         OPCOST      70000
 PROB  C         ROYRAT     0.1667
 PROB  C         NI1             1
 PROB  C         FITRAT       0.46
 PROB  C         CREDIT          1
 PROB  C         ITXCR         0.1
 PROB  C         MIDYR           1
 COMP      M
 END
 .0014101
```

DEMONSTRATION RUN: TWO PLATFORM CASE

YEAR	GROSS OIL MBBL	NET INTRST OIL MBBL	EFFECT OIL PRICE $/BBL	NET REVENU OIL M$	TOTAL NET REVENUE M$
1.00	0.000	0.000	18.00	0.000	0.000
2.00	0.000	0.000	18.00	0.000	0.000
3.00	0.000	0.000	18.00	0.000	0.000
4.00	0.000	0.000	18.00	0.000	0.000
5.00	7008.000	7008.000	18.00	126144.000	105115.795
6.00	24528.000	24528.000	18.00	441504.000	367905.283
7.00	45552.000	45552.000	18.00	819936.000	683252.669
8.00	56064.000	56064.000	18.00	1009152.000	840926.362
9.00	56064.000	56064.000	18.00	1009152.000	840926.362
10.00	54005.314	54005.314	18.00	972095.649	810047.304
11.00	45353.763	45353.763	18.00	816367.734	680279.233
12.00	37598.270	37598.270	18.00	676768.852	563951.484
13.00	31168.965	31168.965	18.00	561041.378	467515.780
14.00	25839.072	25839.072	18.00	465103.303	387570.582
15.00	21420.591	21420.591	18.00	385570.638	321296.012
16.00	17757.670	17757.670	18.00	319638.059	266354.394
17.00	14721.108	14721.108	18.00	264979.951	220807.793
18.00	12203.799	12203.799	18.00	219668.379	183049.660
19.00	10116.949	10116.949	18.00	182105.086	151748.168
20.00	8386.951	8386.951	18.00	150965.117	125799.232
21.00	6952.782	6952.782	18.00	125150.082	104287.563
22.00	5763.857	5763.857	18.00	103749.418	86454.390
23.00	4778.237	4778.237	18.00	86008.267	71670.689
24.00	0.000	0.000	18.00	0.000	0.000
25.00	0.000	0.000	18.00	0.000	0.000
26.00	0.000	0.000	18.00	0.000	0.000
27.00	0.000	0.000	18.00	0.000	0.000
28.00	0.000	0.000	18.00	0.000	0.000
29.00	0.000	0.000	18.00	0.000	0.000
30.00	0.000	0.000	18.00	0.000	0.000
	485283.328	485283.328		8735099.911	7278958.756

.0014102

DEMONSTRATION RUN: TWO PLATFORM CASE

YEAR	INTANGIBLE DRILL COST M$	OPERATING COST M$	GENERL AND ADMNSTRATV M$	DEPRECIATN M$	TOTAL DEDUCTIONS M$	TAXABLE INCOME M$
1.00	37450.000	0.000	10000.000	0.000	47450.000	-47450.000
2.00	114650.000	0.000	10000.000	0.000	124650.000	-124650.000
3.00	201200.000	0.000	10000.000	0.000	211200.000	-211200.000
4.00	167200.000	0.000	10000.000	0.000	177200.000	-177200.000
5.00	76900.000	70000.000	10000.000	8627.082	165527.082	-60411.287
6.00	65700.000	70000.000	10000.000	33564.164	179264.164	168641.119
7.00	33300.000	70000.000	10000.000	65676.458	178976.458	504276.211
8.00	0.000	70000.000	10000.000	80832.563	160832.563	680093.799
9.00	0.000	70000.000	10000.000	80832.563	160832.563	680093.799
10.00	0.000	70000.000	10000.000	77864.368	157864.368	652182.936
11.00	0.000	70000.000	10000.000	65390.641	145390.641	534888.592
12.00	0.000	70000.000	10000.000	54208.842	134208.842	429742.643
13.00	0.000	70000.000	10000.000	44939.130	124939.130	342576.651
14.00	0.000	70000.000	10000.000	37254.539	117254.539	270316.043
15.00	0.000	70000.000	10000.000	30884.012	110884.012	210412.000
16.00	0.000	70000.000	10000.000	25602.846	105602.846	160751.548
17.00	0.000	70000.000	10000.000	21224.760	101224.760	119583.033
18.00	0.000	70000.000	10000.000	17595.326	97595.326	85454.335
19.00	0.000	70000.000	10000.000	14586.525	94586.525	57161.643
20.00	0.000	70000.000	10000.000	12092.229	92092.229	33707.002
21.00	0.000	70000.000	10000.000	10024.458	90024.458	14263.105
22.00	0.000	70000.000	10000.000	8310.276	88310.276	-1855.886
23.00	0.000	70000.000	10000.000	6889.219	86889.219	-15218.529
24.00	0.000	0.000	0.000	0.000	0.000	0.000
25.00	0.000	0.000	0.000	0.000	0.000	0.000
26.00	0.000	0.000	0.000	0.000	0.000	0.000
27.00	0.000	0.000	0.000	0.000	0.000	0.000
28.00	0.000	0.000	0.000	0.000	0.000	0.000
29.00	0.000	0.000	0.000	0.000	0.000	0.000
30.00	0.000	0.000	0.000	0.000	0.000	0.000
	696400.000	1330000.000	230000.000	696400.000	2952800.000	

.0014103

DEMONSTRATION RUN: TWO PLATFORM CASE

YEAR	NET REVENUE M$	OPERATING COSTS M$	GENERL AND ADMNSTRATV M$	CAPITAL INVESTMENT M$	PRE-TAX CASH FLOW M$	FEDERAL INCOME TAX M$	AFTER-TAX CASH FLOW M$	PRSNT WRTH AFT TAX CF DISC1 M$
1.00	0.000	0.000	10000.000	74900.000	-84900.000	-21827.000	-63073.000	-63073.000
2.00	0.000	0.000	10000.000	229300.000	-239300.000	-57339.000	-181961.000	-173493.006
3.00	0.000	0.000	10000.000	402400.000	-412400.000	-97152.000	-315248.000	-273251.977
4.00	0.000	0.000	10000.000	334400.000	-344400.000	-81512.000	-262888.000	-207151.961
5.00	105115.795	70000.000	10000.000	153800.000	-128684.205	-27789.192	-100895.013	-72276.198
6.00	367905.283	70000.000	10000.000	131400.000	156505.283	43374.957	113130.326	73673.611
7.00	683252.669	70000.000	10000.000	66600.000	536652.669	205727.015	330925.654	195916.344
8.00	840926.362	70000.000	10000.000	0.000	760926.362	312843.147	448083.214	241160.525
9.00	840926.362	70000.000	10000.000	0.000	760926.362	312843.147	448083.214	219236.841
10.00	810047.304	70000.000	10000.000	0.000	730047.304	300004.150	430043.153	191282.048
11.00	680279.233	70000.000	10000.000	0.000	600279.233	246048.752	354230.481	143237.067
12.00	563951.484	70000.000	10000.000	0.000	483951.484	197681.616	286269.869	105233.119
13.00	467515.780	70000.000	10000.000	0.000	387515.780	157585.259	229930.521	76838.830
14.00	387570.582	70000.000	10000.000	0.000	307570.582	124345.380	183225.202	55664.286
15.00	321296.012	70000.000	10000.000	0.000	241296.012	96789.520	144506.492	39910.403
16.00	266354.394	70000.000	10000.000	0.000	186354.394	73945.712	112408.682	28223.178
17.00	220807.793	70000.000	10000.000	0.000	140807.793	55008.195	85799.598	19583.875
18.00	183049.660	70000.000	10000.000	0.000	103049.660	39308.994	63740.666	13226.267
19.00	151748.168	70000.000	10000.000	0.000	71748.168	26294.356	45453.812	8574.293
20.00	125799.232	70000.000	10000.000	0.000	45799.232	15505.221	30294.011	5195.078
21.00	104287.563	70000.000	10000.000	0.000	24287.563	6561.028	17726.535	2763.545
22.00	86454.390	70000.000	10000.000	0.000	6454.390	-853.708	7308.097	1035.748
23.00	71670.689	70000.000	10000.000	0.000	-8329.311	-7000.524	-1328.787	-171.204
24.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
25.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
26.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
27.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
28.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
29.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
.0014201				1392800.000	4326158.756	1920393.028	2405765.728	631337.715

DEMONSTRATION RUN: TWO PLATFORM CASE

SINGLE-VALUED RESULTS TABLE

EQUIV AMORTIZ COST ($/BBL)	=	16.275
PRESENT BARREL EQUIV (MBBL)	=	113255.347
DISC AFTER TAX CAP COST ($/BBL	=	3.990
CUM DISC OPERATING COST ($/BBL	=	2.190
CUM DISC ROYALTY COST ($/BBL)	=	3.001
CUM DISC FEDERAL TAX ($/BBL)	=	2.991
CUM DISC G AND A ($/BBL)	=	.565
CUM DISC CAPITAL INVEST ($/BBL	=	7.528
CUM AFTER TAX INVESTMENT (M$)	=	1040421.600
NPV OF PRE TAX C.F.AT DISC1 M$	=	1327645.865
PRSNT WRT AFT TAX CF (DISC1 M$	=	631337.715
PRSNT WRT AFT TAX CF (DISC2 M$	=	245491.052
PRSNT WRT AFT TAX CF (DISC3 M$	=	8700.007
PRSNT WRT AFT TAX CF (DISC4 M$	=	-139534.720
BEFORE-TAX DCF RATE OF RETURN	=	24.56
AFTER-TAX DCF RATE OF RETURN	=	20.07
DISC PROFIT/INVST AT DISC1	=	.55
AFT TAX PROFIT/INVST (DECML)	=	1.73
AFT TAX RETRN ON INVST(DECML)	=	2.73
MAX. NEGATIVE CASH FLOW	=	-315248.000
PAYOUT (YEARS)	=	8.07
FIRST REVERSION POINT	=	0.0000
STOCHASTIC PROFIT (M$)	=	0.000

3.0 Norton Sound Equivalent Amortized Costs (EAC) Of Field Development Cases

3.1 Oil

Table A-13 shows the equivalent amortized costs of producing oil in the Norton Basin for the fields that comprise the High Find, Medium Find, and Low Find scenarios. These costs are pegged to the fields on Tables 6-1, 7-1 and 8-1. Since some of the fields specified in one scenario have the same characteristics (location, water depth, platform type, pipeline size and distance, etc.) as those in another, those fields are not reiterated in the tables. Consequently, there are fewer fields specified in these tables than the total of the low, medium and high find scenarios. However, the EAC of each unique field is given in the tables.

Development costs are calculated to range from $16.15 to $19.84 per barrel. The after tax range of uncertainty around these costs is between minus 10 percent and plus 15 percent. Development costs include the costs to produce and deliver by pipeline to a shore terminal at Cape Nome. Transportation costs from Cape Nome to Los Angeles were estimated in Section 3.5.4.3 to range between $2.00-2.50 per barrel in 1979 dollars. This assumed transport by ice-reinforced shuttle tankers from Cape Nome to a terminal in the Aleutians such as Dutch Harbor for transfer to large conventional tankers.

Adding $2.25 per barrel as the transport charge to the EAC costs implies that oil can be laid-into Los Angeles between $18.40 and about 22.00 per barrel.

The largest component of cost is the capital charge which is computed assuming a 15 percent value of money. The $19.84 development cost shown for the 180 million barrel field on Table A-13 exceeds the assumed wellhead price of crude oil used in the anlysis. Hence, a field of this size is not economic assuming 15 percent value of money. With 10 percent value of money, this field is marginally economic.

3.2 Gas

Table A-14 shows the EAC calculation for non-associated gas fields that comprise the High Find, Medium Find, and Low Find scenarios. These fields are described on Tables 4-7, 4-8, and 4-9 of Chapter 4. Since some of the fields specified in one scenario have the same characteristics (location, water depth, platform type, pipeline size and distance, etc.) as those in another, those fields are not reiterated in the tables. Consequently, there are fewer fields specified in these tables than the total of the low, medium and high find scenarios. However, the EAC of each unique field is given in the tables.

Development costs are calculated to range between \$2.15 and \$2.43 per MCF. By coincidence, these 1979 costs closely bracket the \$2.36 per MCF price allowed in 1980 by section 102 of the NGPA for new natural gas.

The problem with developing Norton Basin gas is that it must be converted to LNG. Appendix F which addresses the marketability of LNG estimated that natural gas could be converted to LNG at Cape Nome and transported to Pt. Conception, California, for approximately <u>\$3.92 per MCF</u> in 1980 dollars. Converting these to 1979 dollars with an inflation rate of 15 percent implies <u>\$3.40 per MCF</u> as the cost of marketing Norton Basin LNG consistent with the development costs shown on Table A-14.

Adding \$3.40 per MCF to the range of calculated development costs implies that Norton Basin natural gas can be laid-in to California for \$5.55 to \$5.83 per MCF in 1979 dollars. In view of the range of uncertainty shown on Table A-14 for development costs and the uncertainty within the LNG cost estimation, these costs must be judged very speculative. They do indicate with certainty, however, that developing and marketing Norton Basin LNG will be a costly adventure.

TABLE A-13

EQUIVALENT AMORTIZED COST OF OIL PRODUCTION IN NORTON SOUND
($/BBl - 1979)

Field Size (MMB)	750	500	250	250	250	500	200
Location	Outer Sound	Central Sound	Outer Sound	Outer Sound	Central Sound	Inner Sound	Inner Sound
Description	3 Platforms, Shared 129 km Pipeline	2 Platforms, Shared 34 km Pipeline	Shared 140 km Pipeline	Shared 95 km Pipeline	Shared 58 km Pipeline	Shared 34 km Pipeline, 2 Gravel Islands	Shared 133,146 or 150 km Pipeline, Gravel Island
Total Capital Charge	6.97	7.78	9.67	9.04	8.50	7.32	8.75[1]
Of which, capital cost @ 15%	3.70	4.12	5.12	4.80	4.52	3.87	4.65
General and Administrative Expenses Costs	0.52	0.61	0.95	0.95	0.95	0.61	1.00
Operating Costs	2.07	2.13	1.29	1.29	1.29	2.13	1.90
Royalty @ 16.67%	3.01	3.01	3.01	3.01	3.01	3.01	3.01
Federal Taxes Net of Tax Credits	3.58	3.05	2.59	2.73	2.86	3.35	3.18
SUBTOTAL DEVELOPMENT COSTS:	16.15	16.58	17.51	17.02	16.61	16.42	17.84
Transport to Los Angeles	2.25	2.25	2.25	2.25	2.25	2.25	2.25
TOTAL LAID IN COST:	18.40	18.54	19.76	19.27	18.86	18.25	20.09
Allocation of Capital Charge:							
Offshore Production	4.87	5.90	6.25	6.16	6.07	5.25	5.22
Pipeline To Shore	.70	.18	1.57	1.03	0.63	0.20	1.62
Terminal	1.40	1.70	1.85	1.85	1.85	1.87	1.91
TOTAL	6.97	7.78	9.67	9.04	8.50	7.32	8.75
Present Barrel Equivalent (PBE)-MMB	161.80	115.83	62.33	62.33	62.33	115.83	53.94

Source: Dames and Moore

NOTE: [1]Based on 140 km pipeline , 32 km offshore, 108 km onshore.

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

TABLE A-14

EQUIVALENT AMORTIZED COST OF GAS PRODUCTION IN NORTON SOUND
($/MCF - 1979)

Field Size (BCF)	2000	1300	1200	1000	1200	
Location	Central Sound	Central Sound	Central Sound	Central Sound	Central Sound	
Description	Shared 51 km Pipeline, 2 Platforms	Shared 64 km Pipeline	Unshared 51 km Pipeline	Shared 43 km Pipeline	Unshared 34 km Pipeline	Range of Uncertainty[1]
Total Capital Charge	0.72	0.75	0.96	0.85	0.91	-25% to +40%
Of which, capital cost @ 15%	0.38	0.40	0.52	0.45	0.50	-25% to +40%
General and Administrative Expenses	0.14	0.16	0.17	0.18	0.17	-25% to +50%
Operating Costs	0.32	0.35	0.35	0.38	0.35	-25% to +50%
Royalty @ 16.67%	0.43	0.43	0.43	0.43	0.43	Fixed
Federal Taxes Net of Tax Credits	0.54	0.53	0.52	0.54	0.53	Will offset aprox half of cost change
SUBTOTAL: DEVELOPEMENT COSTS -	2.15	2.22	2.43	2.38	2.39	
LNG Convert & Transport	3.40	3.40	3.40	3.40	3.40	-10% to +15%
TOTAL Regasified Cost @ PT. Conception	5.55	5.62	5.83	5.78	5.79	-10% to +15%
Allocation of Capital Charge:						
Offshore Production	0.61	0.60	0.67	0.70	0.66	
Pipeline	0.11	0.15	0.29	0.15	0.25	
TOTAL	0.72	0.75	0.96	0.85	0.91	
Present Barrel Equivalent (PBE)-BCF	421.70	238.5	237.8	226.7	237.8	

Source: Dames and Moore

*A field with these characteristics is not specified in the scenarios. It is shown here to demonstrate the equivalent amortized costs of a large 2-platform gas field.

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

200 Central Sound Shared 34 or 50 km Pipeline	180 Central Sound Shared 58 km Pipeline	Range of Uncertainty[2]
9.15	10.17	-25% to +40%
4.85	5.40	-25% to +40%
1.00	1.11	-25% to +50%
1.90	2.11	-25% to +50%
3.01	3.01	Fixed
3.07	3.44	will offset aprox half of cost change
18.13	19.84	-10% to +15%
2.25	2.25	-11% to +11%
20.38	22.09	-10% to +15%
6.74	7.26	
0.41	0.76	
2.00	2.15	
9.15	10.17	
53.94	48.55	